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Docket No. 150196-EI
Comprehensive Exhibit List for Entry into Hearing Record
December 1-2, 2015

EXH #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
STAFF					
1		Exhibit List	Comprehensive Exhibit List		
FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)					
2	Steven R. Sim	SRS-1	FPL's 2015 Capacity Request for Proposals (RFP)	1, 2, 3, 4, 5, 6	
3	Steven R. Sim	SRS-2	Projection of FPL's Resource Needs: 2015 through 2020	1, 2, 3, 4, 5, 6	
4	Steven R. Sim	SRS-3	Evaluation of FPL Self-Build Options: A Representative List of CC and CT Generating Options at Two Sites Evaluated in the First Stage of the Analyses	1, 2, 3, 4, 5, 6	
5	Steven R. Sim	SRS-4	Evaluation of FPL Self-Build Options: Results of Analyses of CC and CT Generating Options at Two Sites Evaluated in the First Stage of the Analyses	1, 2, 3, 4, 5, 6	
6	Steven R. Sim	SRS-5	Evaluation of FPL Self-Build Options: List of Generating Option Technologies Evaluated in the Second Stage of the Analyses and the Results of These Analyses	1, 2, 3, 4, 5, 6	

7	Richard Feldman	RF-1	Florida Population	1, 3	
8	Richard Feldman	RF-2	Total Average Customers	1, 3	
9	Richard Feldman	RF-3	Real Disposable Income per Household	1, 3	
10	Richard Feldman	RF-4	Real Price of Gasoline Lagged	1, 3	
11	Richard Feldman	RF-5	Summer Peak Load (MW)	1, 3	
12	Richard Feldman	RF-6	Risk-Adjusted Summer Peak Forecast (MW)	1, 3	
13	Richard Feldman	RF-7	Winter Peak Load (MW)	1, 3	
14	Richard Feldman	RF-8	Calendar Net Energy for Load (GWh)	1, 3	
15	Jacquelyn K. Kingston	JKK-1	Typical 3x1 Combined Cycle Unit Schematic	1, 2, 3	
16	Jacquelyn K. Kingston	JKK-2	FPL Combined Cycle Power Plants	1, 2, 3	
17	Jacquelyn K. Kingston	JKK-3	History of FPL Combined Cycle Capital Construction Costs	1, 2, 3	
18	Jacquelyn K. Kingston	JKK-4	OCEC Unit 1 Site Regional Map	1, 2, 3	
19	Jacquelyn K. Kingston	JKK-5	OCEC Unit 1 Site Property Delineation	1, 2, 3	
20	Jacquelyn K. Kingston	JKK-6	Aerial Photo of Okeechobee FPL Property (January 2015)	1, 2, 3	

21	Jacquelyn K. Kingston	JKK-7	OCEC Unit 1 Proposed Site Plan Rendering	1, 2, 3	
22	Jacquelyn K. Kingston	JKK-8	OCEC Unit 1 Plant Specifications	1, 2, 3	
23	Jacquelyn K. Kingston	JKK-9	OCEC Unit 1 Water Balance	1, 2, 3	
24	Jacquelyn K. Kingston	JKK-10	Florida Reliability Coordinating Council Letter	1, 2, 3	
25	Jacquelyn K. Kingston	JKK-11	OCEC Unit 1 Expected Construction Schedule	1, 2, 3	
26	Jacquelyn K. Kingston	JKK-12	OCEC Unit 1 Plant Construction Cost Components	1, 2, 3	
27	Heather C. Stubblefield	HSC-1	FPL's November 3, 2014 and October 7, 2013 Fuel Price Forecasts	3, 4	
SOUTHERN ALLIANCE FOR CLEAN ENERGY (SACE) – (DIRECT) ***Pursuant to Order No. PSC-15-0546-PCO-EI, Exhibit NAM-2 has been stricken.***					
28	John D. Wilson	JDW-1	Resume of John D. Wilson	1, 2, 3, 5, 6	
29	John D. Wilson	JDW-2	Generation Reserve Margin Study, Duke Energy Carolinas, Astrape Consulting, 2012	1, 2, 3, 5, 6	
30	John D. Wilson	JDW-3	Bob Barrett, "The Need for a 3rd Reliability Criterion for FPL: a Generation-Only Reserve Margin (GRM) Criterion," February 28, 2014. Sim Deposition, Ex. 3	1, 2, 3, 5, 6	
31	John D. Wilson	JDW-4	FPL, "Calculation of 'Generation – Only Reserve Margins," undated. Sim Deposition, Exhibit 2, (p.49)	1, 2, 3, 5, 6	
32	Natalie Mims	NAM-1	Resume of Natalie Mims	2, 4, 5, 6	

*33	Natalie Mims	NAM-2	Letter re: Measures Not Included in FPL's EE Potential Study	2, 4, 5, 6	**Stricken**
ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)					
34	Karl Rábago	KRR-1	Resume of Karl Rábago	1-7, Proposed Issues 8-12	
35	Karl Rábago	KRR-2	Table of Previous Testimony by Karl Rábago	1-7, Proposed Issues 8-12	
36	Karl Rábago	KRR-3-A	FPL 2001-2010 Ten Year Site Plan	1-7, Proposed Issues 8-12	
37	Karl Rábago	KRR-3-B	FPL 2002-2011 Ten Year Site Plan	1-7, Proposed Issues 8-12	
38	Karl Rábago	KRR-3-C	FPL 2003-2012 Ten Year Site Plan	1-7, Proposed Issues 8-12	
39	Karl Rábago	KRR-3-D	FPL 2004-2013 Ten Year Site Plan	1-7, Proposed Issues 8-12	
40	Karl Rábago	KRR-3-E	FPL 2005-2014 Ten Year Site Plan	1-7, Proposed Issues 8-12	
41	Karl Rábago	KRR-3-F	FPL 2006-2015 Ten Year Site Plan	1-7, Proposed Issues 8-12	
42	Karl Rábago	KRR-3-G	FPL 2007-2016 Ten Year Site Plan	1-7, Proposed Issues 8-12	
43	Karl Rábago	KRR-3-H	FPL 2008-2017 Ten Year Site Plan	1-7, Proposed Issues 8-12	
44	Karl Rábago	KRR-3-I	FPL 2009-2018 Ten Year Site Plan	1-7, Proposed Issues 8-12	
45	Karl Rábago	KRR-3-J	FPL 2010-2019 Ten Year Site Plan	1-7, Proposed Issues 8-12	

46	Karl Rábago	KRR-3-K	FPL 2011-2020 Ten Year Site Plan	1-7, Proposed Issues 8-12	
47	Karl Rábago	KRR-3-L	FPL 2012-2021 Ten Year Site Plan	1-7, Proposed Issues 8-12	
48	Karl Rábago	KRR-3-M	FPL 2013-2022 Ten Year Site Plan	1-7, Proposed Issues 8-12	
49	Karl Rábago	KRR-3-N	FPL 2014-2023 Ten Year Site Plan	1-7, Proposed Issues 8-12	
50	Karl Rábago	KRR-3-O	FPL 2015-2024 Ten Year Site Plan	1-7, Proposed Issues 8-12	
51	Karl Rábago	KRR-4	Order No. PSC-13-0505-PAA-EI, In re: Petition for Prudence Determination Regarding New Pipeline System by Florida Power & Light Company.	1-7, Proposed Issues 8-12	
52	Karl Rábago	KRR-5-A	FPL LOLP Table with and without 10% Generation Only Reserve Margin from Docket No. 130199-EI	1-7, Proposed Issues 8-12	
53	Karl Rábago	KRR-5-B	Affidavit of Steven R. Sim	1-7, Proposed Issues 8-12	
54	Karl Rábago	KRR-5-C	Interrogatory Answer from Docket No. 130199-EI	1-7, Proposed Issues 8-12	
55	Karl Rábago	KRR-6	Chance of Meteor Strike	1-7, Proposed Issues 8-12	
56	Karl Rábago	KRR-7	The Economic Ramifications of Resource Adequacy, January 2013, Eastern Interconnection States' Planning Council	1-7, Proposed Issues 8-12	
57	Karl Rábago	KRR-8	Order No. PSC-99-2507-S-EU, In re: Generic Investigation into the Aggregate Electric Utility Reserve Margins Planned for Peninsular Florida	1-7, Proposed Issues 8-12	

58	Karl Rábago	KRR-9	Rating the States on Nat Gas Overreliance	1-7, Proposed Issues 8-12	
STAFF					
59		Staff's Exhibit #59	FPL's Response to Staff's Interrogatories, Nos. 1-10, 32-34, 44 (including supplemental), 45, 58-63, 65, 76, 84, 85. **See also excel files contained on Staff Exhibit CD for Nos. 5, 33-34, 44-45, 60, 62, 84.** FPL's Response to Staff's Request for Production of Documents, Nos. 1, 2, 3 (excel file), 4, 5. **See also excel files contained on Staff Exhibit CD for Nos. 1, 2, 3, 4, 5.** *[Bates Nos. 00001-00053]*	1, 6 *This Exhibit may also be relevant to additional issues*	**Stipulated**
60		Staff's Exhibit #60	FPL's Response to Staff's Interrogatories, Nos. 19, 25, 26, 66, 71, 74, 75. *[Bates Nos. 00054-00066]*	2, 6 *This Exhibit may also be relevant to additional issues*	**Stipulated**

61		Staff's Exhibit #61	FPL's Response to Staff's Interrogatories, Nos. 11, 12 (without Confidential Attachment No. 1), 13, 14 (**including Confidential response in Document No. 06341-15, part 3 of 4**), 15, 16, 39, 49, 52, 53, 57 (non-confidential response), 64, 68, 77, 78, 80, 82. **See also excel files contained on Staff Exhibit CD for Nos. 39, 80.** FPL's Response to Staff's Request for Production of Documents, Nos. 6a and 6b (**the latter includes Confidential Document No. 07172-15, part 4**). *[Bates Nos. 00067-00099]*	3, 6 *This Exhibit may also be relevant to additional issues*	**Stipulated**
62		Staff's Exhibit #62	FPL's Response to Staff's Interrogatories, Nos. 20, 21, 51, 55, 56, 70, 72. **See also excel files contained on Staff Exhibit CD for Nos. 56, 70, 72.** *[Bates Nos. 00100-00114]*	4, 6 *This Exhibit may also be relevant to additional issues*	**Stipulated**

63		Staff's Exhibit #63	FPL's Response to Staff's Interrogatories, Nos. 17, 18, 22, 23, 24, 27, 28, 29, 30, 31, 36 (including supplemental), 37, 38, 40, 42 (corrected), 43 (corrected & supplemental), 46, 47, 62, 79, 81, 83 (corrected). **See also excel files contained on Staff Exhibit CD for Nos. 18, 24, 28, 30-31, 36, 42-43, 46-47, 62, 79, 81, 83.** FPL Response to Staff's Request for Production of Documents, No. 7. **See also pdf file contained on Staff Exhibit CD for No. 7** *[Bates Nos. 00115-00153]*	5, 6 *This Exhibit may also be relevant to additional issues*	**Stipulated**
64		Staff's Exhibit #64	FPL's Response to ECOSWF's Interrogatories, Nos. 1, 3, 4, 15. **See also excel files contained on Staff Exhibit CD for Nos. 1, 3, 4.** *[Bates Nos. 00154-00159]*	1, 6 *This Exhibit may also be relevant to additional issues*	**Stipulated**
FLORIDA POWER & LIGHT COMPANY (FPL) – (REBUTTAL) ***Pursuant to Order No. PSC-15-0546-PCO-EI, Exhibit SRS-6 – Pages 10-14 and Exhibit SRS-12 has been withdrawn.***					
*65	Steven R. Sim	SRS-6	Incorrect and/or Misleading Statements Made in the Testimonies of Witnesses Rábago, Wilson, and Mims	1, 2, 3, 4, 5, 6	**Pages 10-14 withdrawn**
66	Steven R. Sim	SRS-7	Commission Proceedings Approving or Applying 20% Reserve Margin	1, 2, 3, 4, 5, 6	
67	Steven R. Sim	SRS-8	Duke Energy Progress, North Carolina Integrated Resource Plan (Annual Report), September 1, 2015	1, 2, 3, 4, 5, 6	
68	Steven R. Sim	SRS-9	Relevant Testimony from FPL Witness Rene Silva in the Petition to Determine Need for Riviera Plant and Cape Canaveral Plant (Docket Nos. 080245-EI and 080246-EI)	1, 2, 3, 4, 5, 6	

69	Steven R. Sim	SRS-10	A Look at January 11, 2010 if FPL Had Planned to a 15% Total Reserve Margin Criterion	1, 2, 3, 4, 5, 6	
70	Steven R. Sim	SRS-11	The Need for a 3rd Reliability Criterion for FPL: A Generation-Only Reserve Margin (GRM) Criterion	1, 2, 3, 4, 5, 6	
71	Steven R. Sim	SRS-12	Comparison of the Major Drivers of Benefits in DSM Cost-Effectiveness: 2014 DSM Goals Docket Inputs and Forecasts versus 2015 Inputs and Forecasts	1, 2, 3, 4, 5, 6	**Withdrawn**
72	Richard Feldman	RF-9	Winter Peak Weather Impact	1, 3	

HEARING EXHIBITS

Exhibit Number	Witness	Party	Description	Moved In/Due Date of Late Filed
73	Sim	ECOSWF	Excerpt of FPL 2015 Storm Hardening Preparedness and Distribution Reliability	
74	Sim	ECOSWF	Excerpt of FPL's 2015 Petition for Approval of Demand Side Management Plan	
75	Sim	ECOSWF	FPL Residential Load Control Program Rate Sheets 8.217, 8.218 and 8.219	
76	Sim	ECOSWF	FPL's 2014 Demand-Side Management Annual Report	
77	Sim	SACE	Exhibit 1to Sim 10.8.15 Deposition	
78	Wilson	FPL	Wilson Blog	
79	Sim	SACE	Rebuttal Testimony and Exhibits of Roberto R. Denis 9. 27. 1999	

Florida Power & Light Company's

2015 Request for Proposals

To Meet Generation Capacity Needs Beginning in 2019

March 16, 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 2
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Steven R. Sim SRS-1

2015 Request for Proposals - Generation Capacity

Section I - 2015 RFP Overview

A. Introduction

Florida Power & Light Company (FPL) set forth a comprehensive resource plan in its 2014 Ten Year Power Plant Site Plan (Site Plan). This plan included a mix of cost-effective demand side management (DSM) and generation resources to meet FPL's projected resource needs. The 2014 Site Plan document projected that, after all cost-effective DSM had been accounted for, FPL would have a need for additional generation beginning in the year 2019. Although a number of key forecasts have changed since those used in the resource planning work reflected in the 2014 Site Plan, FPL continues to project a significant need for new generation beginning in the year 2019. FPL currently projects a need for new generation of approximately 1,052 MW beginning in the Summer of 2019.

Therefore, FPL is initiating a Request for Proposals (RFP) process in 2015 to identify viable firm capacity and energy generation resources that will be compared to FPL's best self-build generation option; i.e., FPL's Next Planned Generating Unit (NPGU), to meet FPL's projected capacity needs beginning in 2019.

The aim of this RFP process is to obtain a variety of eligible supply-side resource proposals that can provide firm capacity, then evaluate those proposals, and/or combinations of proposals, in comparison to FPL's NPGU. This will enable FPL to select the best, most cost-effective generation resource or combination of generation resources that meets FPL's system reliability and performance standards in an environmentally responsible manner, all for the benefit of FPL's customers.

B. General Notices

1. Definition of RFP

It is important that all participants in this RFP process clearly understand that, in order to protect the interests of FPL's customers, FPL retains the right during the RFP process to: select only FPL's NPGU, or selecting FPL's NPGU in conjunction with one or more proposals, or select a proposal or combination of proposals that is, or is not, the lowest-priced generating unit, proposal, or combination, waive a non-compliance aspect in any proposal, reject any and all proposals, modify or cancel the RFP process, modify the cost and/or performance assumptions of FPL's NPGU, and modify FPL's projected need for new generation resources. In the event that FPL modifies the cost and/or performance assumptions of FPL's NPGU, those Proposers that have eligible and competitive proposals under evaluation at that time will be given an opportunity to amend their proposals with respect to only those aspects that are affected by FPL's modifications to the NPGU.

This RFP is not an offer to enter into a contract. It is a solicitation of exclusive firm offers of fixed duration from Proposers. Nothing in this RFP or any communication associated with this RFP shall be taken as constituting an offer or representation between FPL and any other party. Neither issuance of this RFP, nor the entry of FPL into negotiations with any Proposer, will be deemed to create any commitment or obligation on the part of FPL to enter into a binding agreement with any Proposer. Those entities that elect to submit proposals do so without recourse against FPL or any of its affiliates for either FPL's rejection of their proposal(s) or for failure, for any reason, of the Proposer and FPL to execute a definitive purchase agreement or tolling agreement (jointly "Purchase Agreement") related to FPL's RFP.

2. Regulatory Background

The Florida Administrative Code Rule 25-22.082 requires public utilities to issue an RFP prior to filing a petition for Determination of Need in accordance with Section 403.519, Florida Statutes. FPL's projections indicate that FPL will have a need for additional generation capacity from a reliability perspective starting in 2019, and this projected capacity need increases every year thereafter. FPL has determined that adding the most cost-effective FPL self-build option that can provide additional capacity starting in 2019 would require a Determination of Need**.** FPL recognizes that proposals that may be submitted as alternatives to FPL's NPGU may or may not require a Determination of Need.

3. Overall RFP Description

This RFP addresses FPL's projected capacity needs starting in the Summer of 2019. The RFP presents a NPGU with a June 1, 2019 in-service date. The RFP seeks alternatives with an in-service date of June 1, 2019 that can be compared to FPL's self-build option. (Proposals with earlier and later in-service dates are unacceptable.) This process will enable FPL to select the most cost-effective generation capacity resource(s) that will meet FPL's reliability and performance requirements and that can be placed in service to meet FPL's 2019 capacity need.

4. Proposal Price

All proposals must ensure their price reflects all capital costs to construct, and all O&M costs to operate and maintain, any pipeline laterals(s), railway equipment, fuel handling equipment, facility infrastructure, land costs, and any other facilities necessary to deliver the full fuel or energy requirements (including backup fuel requirements) to the proposed generating unit.

5. Types of Proposals

The solicitation is designed to accommodate a wide range of proposals for supply-side generation alternatives from various fuels, technologies, locations, and under differing commercial frameworks. For example, FPL may receive proposals for power sales under a Purchase Power Agreement from existing facilities (currently in operation) and newly constructed facilities (greenfield or brownfield offerings). These proposals may have fuel supply and firm transportation arrangements or request a natural gas tolling arrangement where FPL would provide the natural gas supply and firm transportation. A reasonable attempt will be made to accommodate creative variations that may be proposed. Nonetheless, it is conceivable that a Proposer may offer a unique attribute that has not been explicitly considered in this RFP and the associated forms. In that instance, FPL will contact the Proposer to understand, and if possible, evaluate the unique features of a particular offering.

FPL will not consider or evaluate proposals to sell an existing, or new (turnkey project) generating unit to FPL. FPL will not consider or evaluate proposals from specific units that use coal or petroleum coke as fuel. However, FPL will consider and evaluate proposals of system sales that include units that use coal or petroleum coke as a fuel, subject to the conditions specified below in section III, 7 below.

6. Firm Capacity and Dispatchability

FPL seeks proposals that would allow FPL to meet its firm capacity requirement in future years. Therefore, all proposals will be required to offer the commitment of firm capacity and energy to FPL. FPL defines Firm Capacity and Energy as follows:

> *"All electric energy and capacity owned or acquired by the Proposer to be made available exclusively to FPL pursuant to the RFP as if FPL owned the generating capacity on its own system. Firm Capacity and Energy shall not include any electric generating capacity that another Party, including the Proposer, can utilize or purchase."*

The firm capacity and energy proposed in any proposal must be fully dispatchable under the operational control of FPL and must include all of the facility's output, inclusive of ancillary service products and environmental attributes. Requiring that all proposals satisfy the firm and dispatchability conditions ensures that proposals can be evaluated on an equal basis regarding their total costs and reliability benefits to FPL's customers.

C. Description of Appendices

There are five appendices to this 2014 RFP that are summarized below.

Appendix A provides a copy of FPL's 2014 Ten Year Power Plant Site Plan.

Appendix B lists key conditions that will be incorporated into any Power Purchase Agreement (PPA) that may be entered into as a result this RFP.

Appendix C provides the specific forms that Proposers will need to submit as part of their proposals, and a description of the information that must be provided in those forms.

Appendix D provides detailed information regarding FPL's evaluation methodology, including examples of how specific evaluation calculations will be applied.

Appendix E discusses changes in key forecasts from those utilized in the development of FPL's 2014 Ten Year Site Plan (provided in Appendix A). The current forecasts will be used in the evaluation of the NPGU and proposals submitted in response to this RFP and have been used in the evaluation of FPL's NPGU. This appendix also discusses key changes to FPL's resource plan, compared to the resource plan discussed in FPL's 2014 Ten Year Site Plan, up to the year 2019.

D. Projected RFP Schedule

FPL envisions that the milestone schedule for the RFP process will be as described below in Table I.D below. FPL reserves the right to change the schedule at its sole discretion.

Table I.D Schedule of Milestones

Milestone	Date
• RFP Pre-Issuance Discussion Meeting	March 9, 2015
• Release RFP Document	March 16, 2015
• Pre-Bid Workshop	March 24, 2015
• Cutoff Date for RFP Questions	April 17, 2015
• Proposals Due	May 15, 2015
• Short List Announcement – if relevant	TBD
• Permitting Activity Commences	TBD
• Best and Final Offers Due – if relevant	TBD
• Initial Negotiations – if relevant	June 15 to July 30, 2015
• Selection Announced (on or before)	July 31, 2015

Note: The above dates are projections. All dates are subject to change at FPL's sole discretion to accommodate unforeseen delays or required procedural actions. Certain dates are listed as TBD because these dates are heavily dependent upon the number, type, and/or complexity of eligible proposals that will be received and evaluated.

E. Pre-Bid Meeting, RFP Notices, and Addenda

1. Pre-Bid Meeting

FPL will hold a Pre-Bid Meeting in the Miami, Florida area. The meeting will be on Tuesday, March 24, 2015 beginning at 9:30 a.m. at the InterContinental At Doral, 2505 NW 87th Avenue, Doral, Florida 33172-1610. The hotel's phone number is 305-468-1400. Interested parties may attend in person or remotely via a conference call connection. Regardless of whether an interested party plans to attend in person or remotely, the party must first register for the meeting on FPL's RFP website at FPL.com/2015rfp. This meeting is scheduled to conclude by 12 p.m. The purpose of the Pre-Bid Workshop is to assist Proposers in understanding the submittal requirements, provide background on FPL's most recent resource planning results, and begin to respond to questions from potential proposers.

2. RFP Notices and Addenda

RFP-related notices and addenda will, as needed, be posted on the RFP website. In addition, all RFP-related questions posed to FPL, along with FPL's responses to those questions, will also be posted on the RFP website.

Section II - General Information

A. Issues Influencing Evaluation Regarding System Costs, Environmental Impacts, and Reliability

1. Geographic Location

System cost-effectiveness and reliability measures are improved when new generation units are located near the system load center. The ability of a generator to deliver power in or near the area of greatest need lowers the cost of delivering that power to customers and provides greater operational flexibility for the system. FPL's RFP evaluation methodology recognizes the value of geographic location and this is discussed in more detail in Appendix D.

2. Greenhouse Gas (GHG) Emissions

FPL's evaluation process will examine the projected impacts of proposals (and FPL's NPGU) on FPL's system emissions including GHG emissions (as represented by carbon dioxide, CO2). GHG emission-related costs to the FPL system will be addressed as discussed in Appendix D.

3. Fuel Diversity

FPL's has always sought to maintain a generation system that utilizes a diverse range of fuel sources in order to ensure reliable service to its customers. For example, FPL's NPGU would receive natural gas through the new Sabal Trail and Florida Southeast Connection pipelines, which would enable FPL to obtain natural gas from diverse geographic locations.

In addition to FPL's economic analyses of proposals and FPL's NPGU, FPL's RFP evaluation process will also generally recognize the value offered by fuel diverse generation options in the context of the non-economic evaluation of environmental and technical or operational factors. The non-economic aspects of a proposal, including fuel diversity, will be appropriately balanced with the economic aspects of the proposal, during the overall evaluation process.

B. Proposer Responsibilities

1. Regulatory Compliance

The Proposer is solely responsible for acquiring and maintaining compliance with all licenses, permits, and other regulatory approvals (including environmental) that will be required by current or future federal, state, or other local government laws, regulations, or ordinances to successfully implement the proposal. For a selected proposal that requires new power plant construction falling under the Florida Electrical Power Plant Siting Act, Section 403.501 – 403.518, Florida Statutes (Siting Act), FPL would be a co-applicant in a Determination of Need filing with the Florida Public Service Commission under Section 403.519, Florida Statutes. FPL will cooperate with any selected Proposer(s) to provide information or such other assistance as may reasonably be necessary for the Proposer(s) to satisfy licensing and regulatory requirements. Likewise, the selected Proposer(s) shall fully support all of FPL's regulatory requirements associated with this potential capacity and energy arrangement.

For any proposal that requires new power plant construction falling under the Siting Act, the Proposer must demonstrate as part of the proposal a permitting and construction schedule that allows the new plant to be in commercial operation on or before the Capacity Delivery Date. Appendix C includes a discussion of Form # 7 that requires, in part, key milestone dates regarding permitting and construction schedules.

2. Development Activities

The Proposer is solely and completely responsible for the location, acquisition, and development of the plant site and other land or infrastructure that is needed for any proposed new generating units.

The Proposer is also completely responsible for securing, locating, or guaranteeing any emissions allowances, credits, or offsets which may be required by the Title IV Clean Air Act Amendments, Clean Air Interstate Rule, Clean Air Mercury Rule or other federal, state, or local requirements, or otherwise complying with environmental regulations to allow the construction and/or operation of the proposed facility. Proposers whose proposals offer the sale of capacity and energy from an existing power plant(s) must secure the emission allowances, credits, or approvals necessary, or in otherwise complying with environmental regulations to operate the facility during the term of the contract.[1]

3. Project Funding and Costs

All Proposers are completely responsible for all financing activities related to the project and for engineering, design, procurement, and construction of all aspects of the facility. These include, but are not limited to: the cost of the land, the power block, environmental control systems, fuel delivery systems (from the fuel delivery point, if a tolling arrangement is proposed), and transmission system interconnections. The Proposer is also completely responsible for sourcing and contracting for a reliable fuel supply and firm fuel transportation (unless the proposal is a gas tolling proposal) and any other activity required for the reliable delivery of firm capacity and energy to FPL at the identified delivery or interconnection point. All costs associated with the design, construction, operation, and maintenance of the transmission interconnection facilities (including but not limited to generator step-up transformers and high-voltage breakers) and natural gas pipeline laterals associated with the delivery of firm capacity and energy to FPL will be the responsibility of the Proposer.

4. Interconnection and Transmission Service

The Proposer must secure with the appropriate transmission provider(s) all needed transmission facilities and arrangements required to deliver the firm capacity and energy to the FPL transmission system on a firm long-term basis for the entire term of the proposal. Per FPL's OATT, the Proposer will also be responsible for funding (on a reimbursable basis) any network upgrades to FPL's transmission system that are necessitated by the purchase of capacity and energy form the Proposer's resource.

5. Cooperation

Any selected Proposer(s) agrees by the act of submitting a proposal in response to this RFP to file, as needed, an application under the Siting Act and to fully

[1] Due to uncertainty regarding GHG regulations and costs, a projection of GHG $/ton costs (represented by projected CO_2 costs) will be used in the evaluation of proposals and the NPGU regarding their projected impacts on system GHG emissions and costs. The treatment of GHG regulation-based operational costs in a potential power purchase agreement will be addressed in negotiations for such an agreement. However, FPL and its customers will not agree to pay the Proposer for any GHG emission costs due to GHG emission rates higher than the guaranteed rates submitted by the Proposer and must take into consideration any free GHG emission allowances or credits that are ultimately allocated to the Seller/resource under environmental law. In the event of a future change in law or regulation that would have the effect of shifting to or imposing upon FPL GHG emission costs greater than those agreed to in the PPA, FPL would have the right to terminate the PPA if such additional costs were not found to be prudent and approved for FPL cost recovery by the Florida PSC.

support, as requested by FPL, any FPL regulatory proceeding(s) related to firm capacity purchases emanating from this solicitation. Proposers shall be responsible for all of Proposer's costs to participate in the necessary regulatory proceedings.

C. Contact Person and Confidentiality

1. FPL Contact Person

Name: Steven Sim
Florida Power & Light Company
Department: Resource Assessment & Planning/RAP
Street Address: 9250 W. Flagler Street
City/State/Zip Code: Miami, Florida 33174
Email: steve.r.sim@fpl.com
Office Phone: 305-552-2246
Fax: 305-552-2716

FPL's evaluation of all proposals and FPL's NPGU will be reviewed, and a parallel evaluation will be conducted, by Sedway Consulting, Inc. Therefore, please copy Alan.Taylor@sedwayconsulting.com on all RFP-related questions and emails to FPL. All answers to questions will be provided solely on FPL's RFP website.

2. Proposal Confidentiality

FPL will take reasonable precautions and use reasonable efforts to protect proprietary and confidential information contained in a proposal, provided that such information is clearly identified by the Proposer as Proprietary and Confidential on each page(s) on which the information appears.

To clearly identify confidential information, the Proposer must (1) stamp each such page with the label "**Confidential Information**" and (2) highlight/shade the specific confidential information contained on the pages stamped "**Confidential Information**". (A blanket statement that an entire page or proposal is proprietary and confidential will not be considered clear identification.)

Notwithstanding the foregoing, FPL shall disclose Confidential Information in the event that it determines, in its sole discretion, that disclosure is necessary in order to comply with any applicable law, order, regulation, ruling, subpoena, or order of the Florida Public Service Commission or other governmental authority or tribunal with competent jurisdiction. Such disclosure may include, but is not limited to, production of Confidential Information to the Florida Public Service Commission and to parties in legal and regulatory proceedings conducted to consider and to approve the project(s) which is the subject of this Request for Proposals.

In the event that FPL is requested or required to disclose any Confidential Information, FPL will provide prior notice to the entity whose Confidential Information has been requested so that such entity may, if it chooses, seek an appropriate protective order subject to protections available under the Florida Statutes, Florida Administrative Code, and Florida Rules of Civil Procedure.

With respect to any disclosure made by FPL pursuant to the foregoing paragraphs, FPL will furnish only that portion of the Confidential Information that FPL determines in its sole discretion to be consistent with the scope of the subpoena, demand, or request and will seek reasonable assurances that confidential treatment will be accorded such Confidential Information.

Section III. Minimum Requirements for Proposals

Proposers must agree, both in their proposals and as part of any Power Purchase Agreement arising from this RFP, to comply with (as applicable) each of the provisions of the Minimum Requirements for Proposals listed in this Section III, and of the Minimum Requirements Pursuant to Purchase Agreement listed in Section IV. Failure of a Proposer to agree to and/or comply with (as applicable), or failure of a proposal to agree with or comply with one or more Minimum Requirements for Proposals or Minimum Requirements Pursuant to Purchase Agreement, will be grounds for determining a proposal ineligible. FPL reserves the right to waive inconsequential non-compliance with these Minimum Requirements. Proposals determined to be ineligible will be returned to the Proposer along with a refund of 50% of the RFP Evaluation Fee.

1. Financial Viability Requirements of Proposers

For each proposal submitted pursuant to FPL's RFP, the Proposer or Qualified Guarantor of the Proposer must have a senior unsecured debt rating of no less than "BBB-" from Standard & Poor's, or"Baa3" from Moody's Investors Service with a "stable" outlook, and be able to satisfy the Completion and Performance Security requirements set forth in section 8 below.

Each proposer must certify (as part of its proposal) that there are no pending legal or civil or regulatory actions that could affect the ability of the Proposer to maintain an acceptable debt rating consistent with the above criteria.

2. Experience of Proposer

Proposers whose proposal reflects (i) the construction of a new generating unit, or (ii) an upgrade to an existing generating unit (each a "New Unit") must demonstrate that it has successfully executed the development, permitting, design, procurement, construction and commissioning of a project similar to that reflected in the proposal.

The entity that will operate and maintain the proposed generating unit(s) submitted pursuant to FPL's RFP must demonstrate that it has a minimum of 5 years of experience in the successful, reliable operation and maintenance of generating units utilizing similar technology. The success and reliability of operations may be demonstrated through operational records and/or NERC GADS reporting data as requested in Appendix C, Form # 4.

3. Proposal Submission Requirements

All proposals and variations to proposals must be received by the FPL RFP Contact Person by 4:00 p.m., Eastern Daylight Savings Time, on May 15, 2015 (Proposal Due Date and Time). Proposers must submit five (5) bound hard copies, plus an electronic copy of the completed forms on a CD, by the Proposal Due Date and Time. The RFP Evaluation Fee and/or Variation Fee, must accompany each proposal and, separately, each proposal variation.

All forms specified in the RFP must be submitted by the Proposer, and the information requested therein must be complete and accurate. FPL may choose to contact a Proposer to request that omitted or incomplete information be provided, but is under no obligation to do so. Any attempt by a Proposer to disclaim generally the terms and conditions of this RFP without stating specific exceptions and alternative language will be grounds for determining a proposal to be incomplete, and therefore, ineligible.

Proposer must comply with the Publication Notice requirement of Rule 25-22.082(7), Florida Administrative Code, which requires a notice to be published in a newspaper of general circulation in each county in which the Proposer intends to build a new electric generating unit or upgrade an existing electrical generating unit. The Publication Notice shall be at least one-quarter of a page and shall be published not later than 10 days after the Proposal Due Date. The Publication Notice shall state that the Proposer has submitted a proposal to build a new electric generating unit or upgrade an existing electrical generating unit, and shall include the name and address of the Proposer submitting the proposal, the name and address of the public utility that solicited the proposals, and a general description of the proposed new or upgraded generating and its location. A copy of the notice, including an affidavit confirming publication, must be submitted to the FPL Contact Person within 10 days of publication of such notice, or within 20 days of the Proposal Due Date.

4. RFP Evaluation Fee

Each proposal must be accompanied by a non-refundable check of $25,000 ("RFP Evaluation Fee") made out to "Florida Power & Light Company" and delivered to the FPL RFP Contact Person on or before the Proposal Due Date (no later than 4:00 p.m. EDST). If more than one proposal is submitted by a specific Proposer, then a separate, non-refundable $25,000 fee must accompany each proposal. Proposals deemed ineligible or otherwise non-responsive after an initial review will not be evaluated further and 50% of the Evaluation Fee will be refunded.

One proposal consists of a specific combination of a site, technology, fuel source, total capacity level, term (*e.g.*, 10 years), and pricing submittal. If a Proposer submits variations of term and/or price related to a specific proposal (a single variation is defined as a change in one or both term and/or price), the Proposer must accompany such variations with an additional check for $5,000 per variation (the Variation Fee). There are no limitations to the number of price/term variations submitted, as long as each variation is accompanied by a separate $5,000 Variation Fee.

Changes in site, technology, fuel source, or capacity level, or in any parameter other than term or price will constitute a separate proposal and will require a separate full $25,000 RFP Evaluation Fee. Any proposals and the related variations that are deemed by FPL to be ineligible or non-responsive (as determined by FPL at its sole discretion) will not be evaluated further and 50% of the applicable fee(s) received will be refunded.

5. Term of the Proposal

Proposals must offer to deliver firm capacity and energy beginning on June 1, 2019, and throughout the term specified in the proposal (the "Proposal Term"). The acceptable proposal terms for proposals are as follows:

i. The minimum proposal term for proposals offering system sales or sales from new or existing units that do not require a need determination is five (5) years.
ii. The minimum proposal term for proposals offering PPA or Tolling sales from a new unit that requires a need determination is ten (10) years.
iii. The minimum term length for proposals requiring a Natural Gas Tolling Agreement is fifteen (15) years.

iv. The maximum proposal term of any proposal is thirty (30) years.

6. Range of Acceptable Proposals

FPL will consider a power purchase agreement pursuant to which FPL would purchase firm capacity and energy from:

i. An existing generating unit that is currently in operation and that satisfies (in whole or in part) FPL's projected 2019 generation needs ("Existing Unit"); and
ii. A New Unit that satisfies (in whole or in part) FPL's projected 2019 generation needs.

FPL will also consider a gas Tolling Agreement pursuant to which FPL would deliver natural gas and purchase firm capacity and energy from:

a. An Existing Unit that satisfies (in whole or in part) FPL's projected 2019 generation needs, and
b. A New Unit that satisfies (in whole or in part) FPL's projected 2019 generation needs.

FPL will also consider a purchase from a system sale subject to the conditions specified below in section 7 below.

FPL will not consider or evaluate proposals to sell an existing, or new (turnkey project) generating unit to FPL. FPL will not consider or evaluate proposals from specific units that use coal or petroleum coke as fuel. However, FPL will consider and evaluate proposals of system sales that include units that use coal or petroleum coke as a fuel, subject to the conditions specified below in section 7 below.

7. System Sales

Proposals that consist of system sales will be considered only if such system sales are: (i) from electric systems that are subject to the jurisdiction of the Florida Public Service Commission ("FPSC") (or similar public regulatory authority), (ii) have direct control of generation and transmission facilities, and (iii) are members in good standing of a NERC reliability coordinating council.

Proposers that offer firm capacity and energy sales from system sales must provide a clear explanation of how the firm capacity and energy will be produced, scheduled, and delivered to FPL.

Proposers that offer firm capacity and energy system sales must also describe how the Proposer's commitment of such firm capacity to FPL would affect the

Proposer's own reserve margin, and explain how the Proposer's reserve margin will remain above the minimum reserve margin criteria approved for the Proposer by the FPSC or similar public regulatory authority.

8. Firm Capacity Nature of Proposal

i. Proposals must offer firm capacity solely to FPL year-round.
ii. Proposed firm capacity and energy must be fully dispatchable under the operational control of FPL for all proposals except those that are system sales.
    a. With respect to proposals for sales from a generating unit with capacity greater than 100 MW, such unit must be equipped with automatic generation control ("AGC") that can be directed remotely by FPL.
iii. Proposals offering firm capacity and energy from an identifiable unit (*i.e.*, not a system sale) must dedicate to FPL all of the unit's output, including any ancillary service products and environmental attributes.
    a. No portion of the output of the proposed generating unit shall be available to any third party, nor to the Proposer.
iv. The firm capacity and energy delivery must commence within the required time frame of the solicitation and remain as firm capacity and energy throughout the term of the proposal.
v. Capacity and energy from a system sale must be delivered to FPL when called upon by FPL based on FPL's own economic dispatch.

9. Permit and Authorization Feasibility

The Proposer must demonstrate that there are no significant barriers to obtaining the necessary regulatory and governmental permits and authorizations to execute or implement the proposed project on a schedule that meets the Capacity Delivery Date. All proposed projects will be subject to the approval of the appropriate Regulatory Authorities.

The Proposer is responsible for acquiring and maintaining compliance with all licenses, permits, and other regulatory approvals (including environmental) that will be required by current or future federal, state, or other local government laws, regulations, or ordinances to successfully implement the proposal during the Proposal Term.

10. Binding Nature of Proposal

Each proposal must be firm and binding, and must be certified (as part of the proposal) as a "binding, definitive proposal" by an Officer of the proposing entity. "Indicative" proposals are not eligible for consideration and will be rejected.

The terms of each proposal must remain valid and binding for 180 days from the Proposal Due Date, unless the proposal is withdrawn in full. Proposals cannot be modified, except where modified specifically in response to a modification of FPL's description of its NPGU, or in response to FPL's explicit invitation for a Proposer to submit a Best and Final Offer ("BAFO"). Clarifications requested by FPL are not considered modifications.

If FPL selects a proposal for a "Short List" and invites the selected Proposer to submit a BAFO, such BAFO (or the original proposal if the Proposer elects to remain with the original proposal) must then remain valid and binding for 180 days from the date the Proposer submits a BAFO.

11. Identifiable Capacity Source

The proposal's firm capacity and energy must be from one or more specific generating unit(s) that is/are clearly identified and described in detail in the proposal.

Exceptions to this requirement will be made for system sales from electric systems that are subject to the jurisdiction of the FPSC or similar public authority, have direct control of generation and transmission assets, and are members in good standing of a NERC reliability coordinating council. Firm capacity and energy sales from systems must include a clear explanation of how the capacity is to be obtained and delivered. The proposal must also explain how commitment of such system capacity to FPL will affect the Proposer's ability to meet the FPSC reserve margin requirements (or the requirements of other state agencies as appropriate).

12. Site Description

With respect to a proposed new generating unit, the Proposer shall provide a detailed description of the site on which the unit is proposed to be built including, but not limited to, the exact location of the site, the required transmission interconnection, fuel delivery system(s), and water resources to be used by the Proposer in operating the resources, and any other site or project characteristics that affect the capacity and energy values associated with the proposal.

FPL will not consider any proposals that would use property owned or controlled by FPL.

13. OATT Requirement

All generating units reflected in proposals must be located within FPL's transmission system and be interconnected to FPL's transmission system or, if located outside FPL's system, must have accounted for all interconnection and system upgrades necessary to allow the generating unit to qualify as a designated network resource (pursuant to FPL's OATT).

In order to be considered, each Proposer submitting a proposed, new generating unit to be located within FPL's system must also submit, as applicable, at least 15 days prior to the Proposal Due Date, a completed "Large Generator Interconnect Request" application and a security deposit (as applicable) in accordance with the provisions of FPL's OATT. To evidence that the application and security deposit have been submitted, the Proposer must include a copy of the OASIS request confirmation statement with the proposal.

14. OEM Parts for Critical Components

Proposers whose proposals are based on natural gas-fired combustion turbines and/or combined cycle units will be required to represent that, if selected, the proposed generating unit will install and continue to use original equipment manufacturer (OEM) parts for gas turbine hot path components listed below:

- Rotor Discs, Spacers, and Stud Assembly Hardware (e.g., Turbine Thru Bolts, Nuts, and Washers)
- Turbine Stationary Airfoils (e.g., Vanes/Nozzles/Diaphragm)
- Turbine Rotating Airfoils (e.g., Blades/Buckets)
- Turbine Vane Support Rings or Vane Carriers

Any power purchase arrangement entered into pursuant to the RFP will reflect this OEM commitment, and the OEM parts will be installed prior to the start of the purchase arrangement. On an annual basis, the Proposer will be required to obtain a certification from the equipment manufacturer(s) to the effect that OEM parts have been installed and maintained in accordance with the requirements of the purchase arrangement entered into pursuant to this RFP.

Failure to install and properly maintain such OEM parts, or to obtain and deliver to FPL OEM's annual certification, will place the selected Proposer in default, with 120 days to cure. If not cured, FPL may terminate the Purchase Agreement and or collect damages as specified in the Purchase Agreement.

15. Resource Block Size (MW) Range

The minimum power block size associated with a generating unit ("Power Block") that FPL will consider in a proposal is 50 MW. The maximum Power Block size that will be considered for a proposal is 1,650 MW (Summer).

16. Security Requirements

i. By submitting a proposal, a Proposer agrees to provide Completion Security and Performance Security as specifically defined in section IV, 8 of this document.
ii. For proposals supported by existing facilities, Proposer must agree to provide the Performance Security as specifically defined in section IV, 8.
iii. Proposer must certify that there are no pending legal or civil actions that would affect the ability of the Proposer and/or its guarantor to maintain the criteria identified in section IV, 8.

17. Proposal Pricing and Fuel Supply, Transportation, and Delivery Choices

Except as set forth in subsection i. below in regard to GHG costs, a proposal's price must reflect an "all in" contract price (including any related fees and expenses) that FPL would pay to the selected Proposer for all aspects related to, and products (including ancillary services and environmental attributes) associated with the generation and delivery to FPL of firm capacity and energy, including without limitation:

i. Payments related to all costs, fees, and expenses incurred by Proposer to maintain compliance with all laws and regulations applicable to Proposer's generating unit(s) during the Proposal Term. This includes, but is not limited to, the costs of all equipment, development, design, construction, commissioning, and all costs of meeting and maintaining compliance with environmental regulations that are in effect as of the Capacity Delivery Date or are known as of the Capacity Delivery Date to be in effect during the pendency of a PPA that would result from selection of the proposal. Due to the uncertainty currently existing in regard to GHG costs, the treatment of GHG regulation-based operational costs in any power purchase agreement would be addressed in negotiations for such an agreement.

ii. Payments related to all capital and O&M costs incurred by Proposer. This includes, but is not limited to, costs to transport natural gas from the Proposer-designated interstate pipeline to the proposed generating unit. This requirement applies to all PPAs, including natural gas tolling or non-tolling agreements.

iii. Payments related to all costs, fees, and expenses the Proposer would incur related to the purchase of fuel, delivery of fuel to Proposer's generating unit, and inventory of fuel to support operation of Proposer's generating unit.

iv. Payments related to all costs for transmission facilities (and any necessary transmission upgrades) the Proposer would incur to enable its proposed generating unit to interconnect to the FPL system and deliver firm capacity and energy to a receipt point on FPL's system acceptable to FPL.

v. FPL will not make any payments not reflected in the proposal pricing other than those for GHG emission costs agreed to in negotiations.

vi. Proposers of Natural Gas Tolling arrangements must acknowledge and agree that Proposer will post additional security to cover costs that may arise from any firm gas transportation agreement entered into by FPL to support the project in the event of a Proposer, then Seller's, default.

If a Proposer offers to provide its own fuel supply, the proposal price must also include all costs for the required amount of firm fuel transportation and delivery. The Proposer must also provide evidence of feasibility documenting arrangements that support the above fuel transportation and delivery costs. The proposal must also guarantee these fuel transportation and delivery costs and demonstrate credit support for the guarantee that is satisfactory to FPL.

If a Proposer wishes FPL to use Proposer's fuel commodity costs – instead of FPL's projected fuel commodity costs – in the evaluation of its proposal, the Proposer must also provide evidence of feasibility documenting the basis for Proposer's fuel commodity costs, and must also guarantee these fuel commodity costs for the proposed contract term and demonstrate credit support satisfactory to FPL for such guarantee.

vii. The proposed prices must be presented in the format specified in Appendix C, Form # 5.

18. Proposal Transmission Requirements

i. For proposals with generation located outside of the FPL system, FPL will not accept any proposal that requires FPL to secure firm transmission service and any associated rights, as this shall be a responsibility of the Proposer. Proposed prices must include all costs of delivering capacity and energy to the Proposer-designated FPL System Receipt Point. Form # 5 in Appendix C requires the Proposer’s projection of transmission losses (MW) associated with the third party transmission service that was used by the Proposer in developing the proposed prices.

ii. Transmission interconnection costs to connect the proposed units to the FPL system, or to a third party system, must be included in the proposal price and separately identified in Appendix C, Form # 5.

iii. Transmission integration costs on the FPL system and the costs of energy and capacity losses within the FPL system will be developed by FPL during the economic analysis of eligible proposals and resource plans and should not be included in the proposal price.

iv. To the extent a RTO or ISO or similar arrangement is implemented in Florida, proposers should note that the FPL System Receipt Point shall be defined as the location where the facility (or a third party transmission system if the facility is not in FPL territory) connects with the FPL system.

19. Dual Fuel Capability for Natural Gas-Fired Proposals

Based on the impact of hurricanes and other unforeseeable events on the production and transport of natural gas, FPL considers that, for newly built natural gas-fired generation proposals, the fuel continuity and operability characteristics of on-site distillate fuel oil capability as a backup fuel source is the most effective approach to meet system reliability and service continuity needs. Just as FPL's NPGU has on-site distillate fuel oil capability, all proposals based on New Unit additions designed to operate on natural gas as primary fuel must include the capability to operate on distillate fuel oil as a backup fuel, while complying with all applicable regulations, to satisfy system reliability and service continuity needs.

Proposals supported by such new unit gas-fired generation, and the specified prices for such proposals, shall reflect the necessary equipment to meet the following backup fuel continuity and operability characteristics. The distillate fuel oil inventory must be: immediately accessible to the new unit, sized to provide seventy-two (72) hours of continuous operation at full capacity (as rated on distillate oil) at a minimum, and must be independent of the primary fuel supply. The new unit must be able to start up on distillate fuel oil and operate at full capacity for a minimum of 72 continuous hours while complying with all applicable regulations. Additionally, the new unit must be able to make the transition from natural gas fuel supply to distillate fuel oil supply without disconnecting electrically from the transmission grid. Test demonstrations of these capabilities will be required as a condition in any PPA that might be signed between FPL and the Proposer. These are the same continuity and operability requirements that FPL requires of its own NPGU.

Due to the sequence of the permitting process, FPL recognizes that Proposers will be unable to ascertain, by the Proposal Due Date, the success of permitting the facility for full use of distillate fuel oil capability. However, a selected Proposer will be required to obtain permits and authorizations necessary to support a minimum of 500 hours of operation per year on distillate fuel oil as a contract obligation.

20. Project Milestone Schedule

All Proposers must agree to meet all applicable Critical Milestone dates presented below. FPL retains the right to terminate negotiations if a Finalist with whom FPL is negotiating a contract fails to meet the filing dates scheduled for the Site Certification filing, Air Permit filing, or Interconnection Application filing. The remaining milestones would be a part of any contract entered into by FPL as a result of this RFP and are referenced below as months prior to (-) the Capacity Delivery Date (CDD):

Site Certification Application Filed	CDD - 39 months
Air Permit Application Filed	CDD - 39 months
Interconnection Application Filed	CDD - 39 months
Irrevocable Orders Placed for Major Equipment	CDD - 28 months
Fuel Transportation Agreement(s) Executed	CDD - 24 months
Contractor Mobilized, Financing Closed	CDD - 20 months

Section IV. Minimum Requirements of Selected Proposer Pursuant to Purchase Agreement

1. General Minimum Purchase Agreement Requirements

Site Acquisition and Development

A selected Proposer shall be responsible for the location, acquisition, development, and permitting of the Proposer's own site where the proposed generating unit is to be constructed (if applicable). The selected Proposer shall also establish "site control" and demonstrate to FPL's satisfaction that Proposer has "site control" for the Proposal Term by the Proposal Due Date. The selected

Proposer shall procure adequate water resources to operate the generating unit during the Proposal Term and demonstrate to FPL's satisfaction that Proposer has adequate water resources to operate the generating unit for the Proposal Term.

Licenses and Permits

A selected Proposer will be solely responsible for obtaining and maintaining all licenses, permits, and approvals required now, or in the future, by current or future federal, state or local government laws, regulations or ordinances, to construct, upgrade, operate and maintain the Proposer's proposed generating units (including a Site Certification under the Florida Power Plant Siting Act (the "Siting Act"), if applicable), as well as maintaining compliance with all laws and regulations applicable to Proposer's generating units during the Proposal Term.

Emission Allowances, Credits and Offsets

A selected Proposer will be solely responsible for securing, locating, or guaranteeing any emission allowances, credits, or offsets which may be required by any law, regulation, or government agency. Proposer shall be solely responsible for paying any costs related to emissions from Proposer's unit(s) other than those GHG emission costs agreed to in the PPA.

Project Funding and Costs

A selected Proposer will be solely responsible for any necessary financing with respect to all aspects of the proposed generating unit(s). All costs associated with the design, construction, upgrade, operation, and maintenance of the generating units including, but not limited to, (i) the power block, (ii) environmental control systems, (iii) fuel delivery systems (including natural gas pipeline laterals), (iv) transmission facilities and upgrades (including, step-up transformers and high voltage breakers) necessary to interconnect to FPL's system will be the sole responsibility of a selected Proposer. A selected Proposer will be permitted to assign the Purchase Agreement as collateral for any financing or refinancing of the generating units with the prior written consent of FPL and pursuant to a form of consent acceptable to FPL in its sole discretion.

Fuel Supply

Except with respect to a proposed gas Tolling Agreement, a selected Proposer will be solely responsible for maintaining reliable fuel supply (primary and backup fuel) that is delivered to the Proposer's proposed generating unit(s) to ensure reliable delivery of firm capacity and energy to FPL at the specified delivery point on FPL's system.

Interconnection and Transmission

A selected Proposer is solely responsible for securing all necessary transmission facilities and rights necessary for delivering firm capacity and energy to FPL at the specified delivery point on FPL's system. The Proposer would acknowledge that the Purchase Agreement will be between (i) Proposer and (ii) FPL, acting solely in its power procurement function, and that Proposer would have no rights against FPL under the Purchase Agreement with respect to any relationship between the parties in which FPL is acting in its capacity as transmission owner, including orders or instructions relating to Electric System Upgrades and/or curtailments.

Dispatch, Control, Operation and Maintenance of the Generating Unit

i. Proposer shall at all times operate the generating unit consistent with FPL's dispatch and control instructions. Control shall be either by Proposer's manual control pursuant to FPL's oral or written directions, or by Automated Generation Control by FPL's system control center for units with capacity greater than 100 MW, unless otherwise explicitly agreed to by FPL.

ii. During the term, Proposer shall employ qualified and trained personnel for managing, operating, and maintaining the generating unit and shall ensure that such personnel are on-duty 24 hours per day, each day, throughout the term of the agreement.

iii. Proposer shall be responsible for compliance with all applicable NERC regulations and requirements.

iv. Proposer shall operate and maintain the generating unit in accordance with good engineering and operating practices, including all applicable environmental requirements. Proposer shall operate the generating unit with all automatic controls (except Automatic Generation Control) and have appropriate protection equipment in service whenever the generating unit is connected to, or operating in parallel with, the FPL system. Automatic Generation Control shall be operated pursuant to FPL's direction.

v. On an annual basis, Proposer shall submit to FPL preliminary, desired outage schedules for the following five years, and a detailed plan for the next year. FPL shall notify Proposer if the outage schedule is accepted, or will cooperate reasonably with Proposer to agree upon a revised schedule. Under no circumstances will outages be scheduled during peak months.

Exclusivity

During the Proposal Term, Proposer shall have no right to sell energy, capacity, ancillary services or environmental attributes generated by the generating unit to any third party.

Testing and Capacity Rating

i. A capacity test will be required to demonstrate commercial operation and such test results must be satisfactory to FPL in all respects.

ii. FPL, in its sole discretion, may require Proposer to perform an annual summer period capacity test and an annual winter period capacity test. In addition, a capacity test will be required in the event Proposer is (A) unable to comply with any material obligation under the Purchase Agreement for a period of 30 days or more as a consequence of an event of Force Majeure, or (B) at any time should Proposer fail, on two consecutive times, to satisfy the operating levels set by FPL dispatch instructions. Upon completion of a capacity test, the available capacity will be the lower of the demonstrated capacity or committed capacity, but in no case shall it be less than the minimum contract capacity.

Role in Regulatory Proceedings

A selected Proposer that proposes a new unit that is subject to the Siting Act shall apply to obtain a Determination of Need from the FPSC and, at Proposer's sole cost and expense, shall satisfy all requirements imposed by the FPSC, as well as fully support FPL in its role as co-applicant in the Determination of Need proceeding.

2. Generating Unit Operating Characteristics

i. **Operating Characteristics** Generating units must achieve and maintain operation at the proposed level of availability, reliability, heat rate and capacity, as well as satisfy the proposed cold start time and ramp rate, all of which shall be guaranteed by the Proposer or, if applicable, the Qualified Guarantor. If the unit in a selected proposal fails to achieve the availability, reliability, capacity, and/or heat rate levels reflected in the proposal and guaranteed in the PPA, the Proposer would be subject to liquidated damages. The selected Proposer will have 120 days to cure the problem. If not cured, FPL may terminate the PPA

   a. A proposal will be rejected if:

      1. The demonstrated average, actual availability of an Existing Unit over the past five years is less than 85%;

2. With respect to a new unit, the demonstrated average, actual availability of Proposer's similar existing units over the past five years is less than 85%; or
3. With respect to an existing unit or a new unit, the guaranteed availability submitted with the proposal is less than 85%.

b. A proposal with a CC unit will be rejected if any of the EFOR levels below is above 4.2%:
   1. The demonstrated average, actual EFOR of an existing unit over the past five years is above 4.2%;
   2. With respect to a new unit, the demonstrated average, actual EFOR of Proposer's similar existing units over the past five years is above 4.2%; or
   3. With respect to an existing unit or a new unit, the guaranteed EFOR submitted as part of the proposal is above 4.2%.
c. A proposal with a CT unit will be rejected if any of the FOF levels below is above 2.6%:
   1. The demonstrated average, actual FOF of an existing unit over the past five years is above 2.6%;
   2. With respect to a new unit, the demonstrated average, actual FOF of Proposer's similar existing units over the past five years is above 2.6%; or
   3. With respect to an existing unit or a new unit, the guaranteed FOF submitted as part of the proposal is above 2.6%.
d. The Availability, EFOR, and FOF to be reflected in the economic analysis of a proposal that has not been rejected for the reasons set forth above shall be the "worse of" the actual average Availability, EFOR, and FOF levels, or the levels guaranteed in the proposal.

ii. Heat Rate Levels

Proposer must guarantee that the generating unit will consistently achieve the heat rate levels reflected in the proposal and must provide to FPL the results of annual heat rate tests. FPL shall have the right to require a heat rate test at any time, at its sole discretion. If the generating unit fails to achieve the heat rate levels reflected in the proposal, liquidated damages in the form of a heat rate adjustment payment will be due from the Proposer. In addition, in the event of a chronic heat rate failure, the Proposer will be in default, subject to a 120 day cure period. If not cured, FPL may terminate the Purchase Agreement and collect damages, all as prescribed in the Purchase Agreement.

iii. Capacity Payment

Proposer must guarantee that the peak capacity levels reflected in the proposal will be achieved and, on an annual basis, will provide to FPL the results of peak capacity tests. Failure to achieve such peak capacity levels will result in economic penalties as described below. In addition, if the Capacity Billing Factor is below 64%, the Proposer will be in default and will have 120 days to cure. If not cured, FPL may terminate the Purchase Agreement and collect damages.

a. Capacity payments shall be made on a sliding scale, based upon Capacity Billing Factor ("CBF") over a rolling 12-month period:
   1. if the CBF is less than 64%, there is no capacity payment;
   2. if the CBF is greater than 94%, then the full capacity payment will be received;
b. between 64% and 94%, the Proposer will forfeit 2% of capacity payment for each 1% that CBF is below 94%;
c. Proposer will be entitled to a capacity bonus of 0.5% of capacity payment for each 1% that CBF is above 96% in any month;
d. Failure to maintain a CBF of 64% or greater is an event of default, and FPL can terminate the purchase agreement and collect damages.

iv. Pipeline Quality Gas

Proposed generating units that utilize natural gas must (i) be designed to handle the expected range of fuels from its source(s). However, all specified unit performance values provided by the Proposer shall be based on the "Average Fuel Analysis" specifications as presented in RFP Form # 4 in Appendix C, (ii) satisfy the operating characteristics specified in the proposal, and (iii) maintain compliance with the conditions of all permits and authorizations.

v. Compliance with Changes in Laws

Notwithstanding any change in law, during the Proposal Term the Proposer will be solely responsible for taking all actions necessary to continue to deliver reliably to FPL the firm capacity and energy offered in the proposal, in a manner that is in compliance with all applicable laws, regulations, ordinances, licenses, permits, and other regulatory approvals (including compliance with all applicable environmental law).

4. Project Execution

The Proposer will be solely and completely responsible for ensuring that the implementation of any and all parts of the proposal is carried out in full compliance with any changes, modifications, or additions to laws, regulations, ordinances, licenses, permits, and other regulatory approvals (including environmental) that affect the proposal. FPL shall not bear any price or cost risk associated with any such changes, modifications, or additions, required by regulation or legislation in existence or enacted prior to the date of the proposal.

5. Effect of FPSC Denial of Authorization for FPL Cost Recovery

i. FPL would only agree to enter into a Purchase Agreement on the basis of Rule 25.22-082(15), Florida Administrative Code, which States:

   "*If the Commission approves a purchase power agreement as a result of the RFP, the public utility shall be authorized to recover the prudently incurred costs of the agreement through the public utility's capacity, fuel and purchased power cost recovery clauses absent evidence of fraud, mistake, or similar grounds sufficient to disturb the finality of the approval under governing law.*"

ii. The selected Proposer must agree that if, at any time during the Proposal Term, FPL fails to obtain, or is denied, the authorization of the FPSC (or that of any other applicable legislative, administrative, judicial or regulatory body which now has, or in the future may have, jurisdiction over FPL's rates and charges) to recover from its customers all of the payments required to be made to the selected Proposer by FPL under such Purchase Agreement (or any subsequent amendment thereto), FPL may, in FPL's sole discretion, adjust the payments made under such Purchase Agreement to the amount(s) which FPL is authorized to recover from its customers.

iii. In the event that FPL so adjusts the payments to which the selected Proposer is otherwise entitled to under the Purchase Agreement, then the selected Proposer may, at its sole option, terminate such Purchase Agreement upon 180 days' notice to FPL. If such a determination of disallowance is ultimately reversed and such payments previously disallowed are found to be recoverable, FPL shall pay all withheld payments.

iv. The selected Proposer also acknowledges that any amounts initially received by FPL from its customers, but for which recovery is subsequently disallowed and which amounts are charged back to FPL, may be offset or credited against subsequent payments to be made by FPL to the selected Proposer under the Purchase Agreement.

v. If at any time FPL receives notice that the FPSC or any other legislative, administrative, judicial, or regulatory entity seeks or will seek to prevent full recovery by FPL from its customers of all payments required to be paid by FPL under the terms of the Purchase Agreement, then FPL shall, within 30 days of its receipt of such notice, give notice thereof to the selected Proposer. FPL shall use reasonable efforts to defend and uphold the validity of the Purchase Agreement and its right to recover from its customers all payments required to be made by FPL under the terms of such Purchase Agreement, and will cooperate in any effort by the selected Proposer to intervene in any proceeding that challenges the validity of the Purchase Agreement or the right of FPL to recover from its customers all payments required under the Purchase Agreement, and to defend such validity and such right to recover costs.

6. Conditions Precedent

The selected Proposer must agree that, pursuant to an executed Purchase Agreement, the obligations of the Proposer to generate, deliver, and sell to FPL firm capacity and energy, and the obligations of FPL to accept delivery of, purchase and pay for such firm capacity and energy, shall be subject to the satisfaction of the following conditions precedent:

i. The FPSC shall have issued a final Determination of Need (if applicable) with respect to the Purchase Agreement and a final order approving such agreement, which order includes a finding that FPL is authorized to recover from its customers all payments for firm capacity and energy purchased under the agreement, and which order is no longer subject to appeal.

ii. The Federal Energy Regulatory Commission ("FERC") and any other governmental authority having jurisdiction over such Purchase Agreement, or over either FPL or the selected Proposer, shall have issued final orders approving such agreement authorizing the selected Proposer to make the sale and authorizing FPL, with conditions acceptable to FPL at its sole discretion, to make the purchase of such firm capacity and energy, and which orders are no longer subject to appeal.

iii. Execution by the Proposer of an (i) engineering, procurement, and construction agreement, and (ii) operation and maintenance agreement by specified dates (as applicable to the nature of the proposal).
iv. Receipt by Proposer of all necessary permits.
v. Successful execution by Proposer of long-term financing (for a New Unit only).
vi. Execution by Proposer of transmission interconnection agreements.
vii. Implementation by Proposer of adequate insurance coverage.
viii. Execution by Proposer of adequate fuel supply and delivery contracts.

7. FIN 46R Compliance

Certain accounting rules now in effect, or as they might be amended or interpreted in the future, may require that the selected Proposer under the PPA or tolling contract be consolidated into the financial statements of FPL. Within ten business days after being selected to supply firm capacity and energy to FPL, the selected Proposer must deliver to FPL an analysis, with supporting information, evaluating whether or not FPL would be required to consolidate the selected Proposer under the provisions of Financial Accounting Standards Board Interpretation No. 46 (Revised December 2003) (FIN 46R).

The selected Proposer who enters into a contract with FPL under this RFP must also agree to comply with terms to be included in the Purchase Agreement that specify requirements for FPL's ongoing compliance with FIN 46R. Failure of Proposer to provide the required certification, or if at any time Proposer becomes a VIE and FPL becomes the Primary Beneficiary, shall constitute an event of default under the Purchase Agreement.

8. Completion and Performance Security; Step in Rights; Security Interest

i. For all proposals with respect to a new unit or existing unit, a Proposer selected to enter into a Purchase Agreement shall provide Completion Security and Performance Security (in the amounts set forth in Table 1 – New Unit; and Table 2 – Existing Unit, below).

Table 1
Security Milestone Schedule - New Unit

Event	Security Amount	Security Type
Execution of Purchase Agreement	$20,000/MW	Completion Security
FPSC and FERC Authorization Received	$185,000/MW	Completion Security
Commercial Operation	$200,000/MW	Performance Security

Table 2
Security Milestone Schedule - Existing Unit

Event	Security Amount	Security Type
Execution of Purchase Agreement	$20,000/MW	Completion Security
FPSC and FERC Authorization Received	$200,000/MW	Performance Security

ii. Completion Security secures (i) the Proposer's obligation to negotiate a Purchase Agreement in good faith (ii) with respect to a new unit, a Proposer's obligations to satisfy certain project milestones and deliver firm capacity and energy by a June 1, 2019 in-service date, and (ii) for damages incurred by FPL related to an early termination event.

iii. Performance Security secures (i) the Proposer's performance obligations from June 1, 2019 (the "In-Service Date") through the Proposal Term, and (ii) damages incurred by FPL related to an early termination event.

iv. With respect to a new unit during the construction phase, the Proposer must provide evidence, satisfactory to FPL in all respects, that the project milestones reflected in the Purchase Agreement are being achieved (*i.e.*, execution of definitive EPC and O&M Agreements, Start of Construction and Commercial Operations). If the Proposer fails to satisfy such project milestones, FPL may, in its sole discretion, be paid delay liquidated damages and/or terminate the Purchase Agreement.

v. Form of Security:

a. Completion Security may be provided via a combination of cash or letter of credit issued in a form and by an Eligible LC Bank ("LOC"), in each case acceptable to FPL in its sole discretion. "Eligible LC Bank" means either a U.S. commercial bank, or a foreign bank issuing a LOC through its U.S. branch, and such bank must have a Credit Rating of at least: (a) "A-, with a stable designation" from S&P and "A3, with a stable designation" from Moody's, if such bank is rated by both S&P and Moody's; or (b) "A-, with a stable designation" from S&P or "A3, with a stable designation" from Moody's, if such bank is rated by either S&P or Moody's, but not both, even if such bank was rated by both S&P and Moody's as of the date of issuance of the LOC but ceases to be rated by either, but not both of those ratings agencies.

b. FPL may consider on a case-by-case basis accepting a guaranty in a form to be provided by FPL from a "Qualified Guarantor" acceptable to FPL and based on such Qualified Guarantor's credit quality and tangible net worth in accordance with Table 3 below.

Table 3

Qualified Guarantor

A credit limit may be calculated for each Proposer or Qualified Guarantor based on the entity's unsecured debt rating and tangible net worth (the "Credit Limit") as follows:

Unsecured Debt Rating	% of Tangible Net Worth
AAA+/Aaal to AA-/Aa3	20%
A+/A1 to A-/A3	15%
BBB+/Baal to BBB-/Baa3	10%
BB+/Bal and below or unrated	0%

Performance Security in excess of the Credit Limit shall be in the form of cash in U.S. Dollars or an LOC. The Credit Limit shall be recalculated and the form of Performance Security may be adjusted quarterly, in FPL's sole discretion, based on the Proposer's or Qualified Guarantor's most recent financial statements.

Definitions
"Credit Limit" means the maximum credit exposure FPL will accept from a Qualified Guarantor in the form of a guarantee.

"Qualified Guarantor" means an entity which at the time it is to provide a guaranty has (i) (A) a credit rating equal to or greater than the Ratings Limit, and (B) a consolidated net worth of at least $1,000,000,000; or (ii) is acceptable to FPL in its sole discretion as having a verifiable creditworthiness and net worth sufficient to secure a Qualified Guarantor's obligations pursuant to a guaranty.

"Ratings Limit" means with respect to Proposer or any Qualified Guarantor, a long-term credit rating (corporate or long-term senior unsecured debt) (a) "Baa3" or higher by Moody's, or (b) "BBB-" or higher by S&P, or (iii) if rated by Moody's and S&P, both (i) and (ii).

"Tangible Net Worth" means the net worth per most recent quarterly financial statements of a Qualified Guarantor providing credit support less goodwill and intangible assets.

vi. Upon the failure of a Proposer to satisfy any project milestone, or upon an event of default by Proposer and failure by Proposer to cure such default within the cure period provided, FPL (or its designee) shall have the right, but not the obligation, to enter upon and complete the licensing, permitting, construction, start-up, testing and commissioning, or operate and maintain the generating unit, as applicable, as agent for the Proposer. FPL's step-in right shall continue until the earlier of: (i) Proposer demonstrates to FPL's satisfaction that cause of the failure or default has been remedied, (ii) FPL elects, in its sole discretions, to discontinue exercising its step-in rights, or (iii) expiration or termination of the Purchase Agreement.

vii. As additional security for Proposer's performance obligations, Proposer shall execute, deliver to FPL, and record a Mortgage and Security Agreement to granting to FPL a fully perfected, subordinated security interest and mortgage lien in any and all real and personal property, contractual rights or other rights the Proposer holds with respect to the development, procurement, construction, operation, and maintenance of the generating unit.

9. Assignment; Right of First Refusal

i. The Proposer must agree that the Purchase Agreement may not be assigned in whole or in part without the express written consent of FPL at FPL's sole discretion. Any direct or indirect change of control of Proposer (whether voluntary or by operation of Law) shall be deemed an assignment and shall require the prior express written consent of FPL at FPL's sole discretion.

ii. During the Proposal Term, FPL shall have a right of first refusal with respect to any sale of the generating unit or facility that produces the capacity and energy that is the subject of the PPA.

Section V. Overview of the Evaluation Process

1. General Evaluation Concepts

i. Proposer Exceptions.

FPL will consider proposals that contain exceptions to the general terms and conditions of the RFP. However, **FPL will not accept any exceptions to the Minimum Requirements for Proposals or the Minimum Requirements Pursuant to Purchase Agreement.**

If a Proposer identifies exceptions, the exceptions must be explained in writing as part of the proposal using Form # 9 presented in Appendix C. For each exception, the Proposer must fully explain in writing the condition, requirement, or facet of the RFP to which the Proposer takes exception and provide the replacement language proposed.

Inclusion of exception information with a proposal will be used to compare proposals to one another and will facilitate potential negotiations by allowing FPL to evaluate the specific core issues of the exceptions, rather than addressing generic or conceptual comments. A more detailed discussion of the non-price evaluation is provided in Appendix D. FPL reserves the right to request from a Proposer whether, or to what extent, FPL's contemplated rejection of a particular exception would affect the pricing of the proposal.

If a Proposer fails to state exceptions and pose alternative language to the material terms set forth in the RFP, FPL shall assume that a Proposer has no objection to such terms and conditions.

ii. **Proposer Questions and Communications**

Proposers are to follow all instructions contained in this RFP and provide all information requested in the RFP and on the forms presented and discussed in Appendix C of this document. Proposers also are expected to provide supporting documentation, and answer any follow-up questions from FPL, as requested.

Proposers are encouraged, up to the Cutoff Date for RFP Questions, to contact the FPL Contact Person with questions to ensure complete and accurate proposals. Following the RFP issuance date, all questions will be recorded. FPL will post questions and answers on FPL's RFP website. All questions and answers from the Pre-Bid Workshop, and any subsequent questions posed to FPL and answers to these questions, will be posted on this website for the benefit of all Proposers.

iii. **Fuel Plan for Evaluation**

FPL will evaluate the generator-specific fuel costs of each natural gas-based proposal based on the designated FPL Fossil Fuel Price Forecast (unless a Proposer directs FPL to use Proposer's own firm, guaranteed fuel price forecast, which shall be included in the proposal). FPL system fuel cost impacts for all proposals will also be based on the above-mentioned FPL forecast. FPL's forecast will be posted on the RFP website once the RFP document has been issued.

A specific fuel plan, including Proposer's fuel transportation cost (for Non-Tolling proposals) or FPL's projection of the gas transportation cost (for natural gas Tolling proposals), will be developed by FPL for each candidate portfolio based on the size, location, and fuel requirements of the individual units included in the candidate portfolio. This will allow FPL to capture the unique fuel cost attributes offered by certain asset combinations. The portfolio-specific fuel plan will be used to conduct the detailed economic evaluation.

1. Non-Tolling Proposals

   Non-tolling proposals must be accompanied by a complete Fuel Plan. The Fuel Plan must designate the fuel type, the intended fuel source, and transportation method to be used. For proposals relying on natural gas, the Fuel Plan must provide the level of firm gas transportation that is appropriate for the technology proposed. The Fuel Plan must be accompanied by evidence of feasibility (letter of intent or other indicative planning documents) that identify the required volume, pressure, and pipeline infrastructure upgrades that will be accomplished to operate the proposed unit(s) at capacity. The proposed pricing for non-Tolling proposals must reflect firm fuel transportation costs for the entire Proposal Term. FPL will evaluate non-Tolling proposals using FPL's fuel price forecast unless the Proposer specifies and guarantees a different set of future fuel prices to be applied to such proposal.

2. Natural Gas Tolling Proposals (For specific units only - not for system sales)

   Natural Gas Tolling proposals will be evaluated using the data outlined in the designated FPL Fossil Fuel Price Forecast, as modified for the specific fuel plan of the candidate portfolio(s). FPL will not consider tolling agreements for fuels other than natural gas.

   As a part of a natural gas tolling arrangement, FPL will be required to negotiate and commit to a Firm Transportation Agreement to support the needs of the project. Selected Proposers entering into a Natural Gas Tolling agreement will be required to provide an appropriate level of additional security to cover the costs that may arise from a Proposer-default to protect FPL's customers. This will be a part of the definitive agreements that comprise the Tolling Agreement.

FPL will evaluate all natural gas tolling proposals and the NPGU utilizing FPL's forecast(s) of future fuel commodity prices.

2. The Evaluation Process

The objective of the RFP is to solicit proposals that allow FPL to assess the best eligible generating alternatives that meet the RFP's capacity requirement in the most economic, cost-effective, and reliable manner for FPL's customers. It is anticipated that FPL will receive a variety of proposals that may vary in length of term, siting, capacity, price, fuel, and other pertinent characteristics. In addition to the variations that may be presented within individual proposals, there may be a need to combine multiple proposals to develop portfolios that meet the RFP capacity need requirements.

FPL will employ an evaluation methodology that will anticipate responses that offer a wide range of individual characteristics and can evaluate the costs and benefits offered by combining various proposals into unique portfolios of generating alternatives that address FPL's resource needs beginning in the year 2019. Therefore, eligible proposals that pass initial screening and individual economic ranking (if applicable), but do not individually meet the full resource need requirement for 2019, will be evaluated in portfolios that combine them with other proposals to meet these capacity needs. FPL will then develop multi-year resource plans that incorporate proposals that individually meet the 2019 resource need, portfolios of smaller proposals, and/or the NPGU.

FPL's evaluation will examine these portfolios and resource plans from both economic and non-economic perspectives. In regard to the economic analyses, FPL typically conducts economic analyses of resource plans using a levelized system average electric rate minimization (*i.e.*, a Rate Impact Measure) approach. However, because FPL is soliciting only generation resources in this capacity RFP, the amount of projected DSM will be the same for each of these resource plans. Therefore, FPL will be comparing portfolios and resource plans based on a Cumulative Present Value of Revenue Requirements (CPVRR) approach. This is because in analyses in which DSM values will not change: (i) a levelized system average electric rate approach and a CPVRR approach will yield identical rankings for the resource plans being evaluated, and (ii) the CPVRR approach is simpler to calculate. In regard to non-economic analyses, several different perspectives will be taken.

Ultimately, FPL's objective is, after considering both economic and non-economic perspectives, to identify the best option(s) for FPL's customers with which to meet FPL's capacity needs beginning in 2019. FPL's evaluation methodology, including a description of the criteria to be used to evaluate price and non-price attributes, is discussed in detail in Appendix D.

Section VI - Detailed Information Regarding FPL's Capacity Needs and NPGU

A. FPL's Capacity Need

The projected generation capacity resource need values described below represent an update from the information presented in FPL's 2014 Ten-Year Power Plant Site Plan (Site Plan), a copy of which is attached to this RFP as Appendix A. This new capacity need projection is based on a number of factors including updated forecasts from those used in FPL's previous resource planning work that led to FPL's 2014 Site Plan. Key changes to these forecasts are discussed in Appendix E. FPL's projected capacity needs are potentially subject to further change as FPL's 2015 resource planning work continues.

FPL's projected capacity need in 2019, based on exactly meeting both the 10% generation-only reserve margin (GRM) planning criterion and the 20% total reserve margin planning criterion is 1,052 MW by June 1, 2019.

B. FPL's NPGU

Rule 25-22.082, Florida Administrative Code, requires that specific information about FPL's "next planned generating unit" (NPGU) be included in an RFP seeking firm capacity.

FPL's NPGU is a CC unit based on 3 combustion turbines in combined cycle form with 3 heat recovery system generators and a single steam turbine generator (a 3x1 G configuration). The NPGU CC would add approximately 1,622 MW (Summer).

FPL has now identified a CC unit at FPL's Okeechobee Clean Energy Center site ("OCEC Unit 1") to be installed by June 1, 2019 as the NPGU in accordance with the requirements of Rule 25-22.082(5)(a), Florida Administrative Code. The eligible proposals submitted in response to this RFP will be evaluated against this NPGU and against all other proposals received in response to this RFP.

1. **Required Information**

   FPL is providing a technical description of its NPGU with the information that follows. This technical description for the unit complies with the requirements of Rule 25-22.082 (5)(a).

2. **Tables**

   The technical information required by Rule 25-22.082 (5) (a) is presented in Tables VI.B - 1, VI.B - 2, and VI.B - 3 for FPL's NPGU.

Table VI.B – 1

Next Planned Generating Unit Data – Okeechobee Clean Energy Center (Combined Cycle)

The following data represent FPL's current estimates for this 2019 capacity addition. These planning estimates are subject to further refinement in regard to site-specific costs, detailed engineering, or vendor quotes. FPL reserves the right to modify the construction costs and/or performance parameters for this unit. If FPL exercises this option, it will do so concurrent with publication of a Short List. In that case, FPL would then inform the Short List Proposers (if any) of its intent and permit such Short List Proposers to revise their proposals.

1. A three-on-one combined cycle generating unit to be located at the Okeechobee Clean Energy Center (OCEC) in Okeechobee County, Florida.
2. Planned size is 1,622 MW (Summer rating).
3. Commercial operation for the facility is June 1, 2019.
4. The primary fuel is natural gas. Ultra low sulfur light (distillate) oil will be the backup fuel type.
5. The estimated total direct cost (without AFUDC) is $ 1,083.4 million (in 2019$). This value includes the cost of generation, transmission interconnection, and transmission integration.
6. The estimated annual levelized capital (generation, plus transmission interconnection, and transmission integration) revenue requirement with AFUDC is $136.9 million over 30 years.
7. The estimated annual value of deferral with AFUDC of this unit is $5.75/kW-year in 2019$ (excludes variable O&M, fixed O&M, and capital replacement).
8. The estimated fixed O&M, capital replacement, and variable O&M annual costs are presented in Table III.B - 2.
9. The estimated fuel cost in 2019 for the NPGU is currently forecast to be $4.69/MMBTU. Firm gas transportation for the unit will be provided from the Sabal Trail/Florida Southeast Connection (FSC) pipeline. These costs are considered sunk and will not be included in the economic analysis. A gas pipeline lateral is needed between FSC and the Okeechobee site and will be built by FSC. The costs for this lateral will be recovered through an adjustment to the rate over 25 years. This adjustment to the annual transportation rate, in $/MMBTU, is shown in Table III.B-3 and will be included in the economic evaluation of the Okeechobee Clean Energy Center. See Note 1.
10. The following are the estimates for:

Planned Outage Factor	See Table III.B - 4 and Note 2
Forced Outage Rate	See Table III.B - 4 and Note 2
Heat Rate at maximum capacity at 100% (Base Operational Mode)	6,293 Btu/kWh @75F (HHV)
Minimum load	400 MW
Ramp Rate	120 MW/min

11. The estimated transmission interconnection and integration costs associated with this unit are $52.0 million (without AFUDC in 2019 $) and are included in the cost estimate in item 5 above.
12. Air, water discharge, and other permits will be required for this unit. It is FPL's plan to comply with all air and water quality standards of the Local, State, and Federal governments.
13. The major financial assumptions in the development of these numbers were:

Capital replacement escalation for the OCEC unit, based on contract (approx.)	2.0%
General capital escalation for other than OCEC	3.0%
Escalation for O&M	2.5%
Fuel escalation	Varies by year. See Note 1
Capital Structure	40.38 % debt @ 5.05 % 59.62 % equity @ 10.5 %

Table VI.B-2

Next Planned Generating Unit Data - OCEC

Year	Estimated Fixed O&M Costs ($Millions)	Estimated Variable O&M Costs * ($Millions)	Estimated Capital Replacement Costs ($Millions)
2019	3.3	3.2	0.0
2020	4.7	3.2	19.5
2021	3.6	3.3	0.1
2022	6.9	3.3	40.0
2023	4.0	3.4	23.9
2024	5.5	3.4	0.1
2025	7.7	3.5	15.9
2026	4.8	3.6	25.0
2027	4.7	3.6	2.4
2028	9.1	3.7	79.7
2029	5.2	3.7	39.2
2030	6.3	3.8	0.2
2031	5.6	3.8	0.1
2032	25.7	3.9	0.1
2033	6.1	4.0	66.0
2034	6.4	4.0	35.9
2035	10.4	4.1	0.1
2036	6.9	4.1	0.1
2037	12.4	4.2	0.3
2038	7.9	4.3	20.1
2039	13.7	4.3	44.1
2040	8.1	4.4	0.2
2041	8.8	4.5	0.3
2042	15.2	4.5	0.4
2043	18.3	4.6	55.4
2044	10.8	4.7	33.5
2045	12.9	4.7	0.2
2046	10.3	4.8	0.2
2047	10.9	4.8	0.0
2048	11.2	4.9	0.0
2049	11.5	4.9	0.0

* Based on an average capacity factor for the life of the unit of approxi

Table VI.B-3

Lateral Cost Adder to FSC Firm Transporation Rate

Period	Dates	Okeechobee Lateral Transport Rate $/Dth
1	Sep 1, 2018 - April 30, 2019	0.0279
2	May 1, 2019 - April 30, 2020	0.0273
3	May 1, 2020 - April 30, 2021	0.0175
4	May 1, 2021 - April 30, 2022	0.0167
5	May 1, 2022 - April 30, 2023	0.0161
6	May 1, 2023 - April 30, 2024	0.0154
7	May 1, 2024 - April 30, 2025	0.0148
8	May 1, 2025 - April 30, 2026	0.0142
9	May 1, 2026 - April 30, 2027	0.0136
10	May 1, 2027 - April 30, 2028	0.0130
11	May 1, 2028 - April 30, 2029	0.0124
12	May 1, 2029 - April 30, 2030	0.0118
13	May 1, 2030 - April 30, 2031	0.0112
14	May 1, 2031 - April 30, 2032	0.0106
15	May 1, 2032 - April 30, 2033	0.0100
16	May 1, 2033 - April 30, 2034	0.0094
17	May 1, 2034 - April 30, 2035	0.0090
18	May 1, 2035 - April 30, 2036	0.0087
19	May 1, 2036 - April 30, 2037	0.0083
20	May 1, 2037 - April 30, 2038	0.0080
21	May 1, 2038 - April 30, 2039	0.0077
22	May 1, 2039 - April 30, 2040	0.0074
23	May 1, 2040 - April 30, 2041	0.0071
24	May 1, 2041 - April 30, 2042	0.0068
25	May 1, 2042 - April 30, 2043	0.0065

Table VI.B-4

Next Planned Generating Unit Data - OCEC
Base & Peak Firing Operational Modes

Year	Projected Annual Planned Outage Hours	Projected Annual Forced Outage Hours
2019	193	96
2020	193	96
2021	193	96
2022	193	96
2023	193	96
2024	193	96
2025	193	96
2026	193	96
2027	193	96
2028	193	96
2029	193	96
2030	193	96
2031	193	96
2032	193	96
2033	193	96
2034	193	96
2035	193	96
2036	193	96
2037	193	96
2038	193	96
2039	193	96
2040	193	96
2041	193	96
2042	193	96
2043	193	96
2044	193	96
2045	193	96
2046	193	96
2047	193	96
2048	193	96
2049	193	96

Notes for:
Next Planned Generating Unit Data – Okeechobee Clean Energy Center

1. For the economic evaluation of capacity options in this RFP, both for proposals received in response to this RFP and FPL's NPGU, FPL will use the designated FPL fuel cost forecast which will be provided on the RFP website.
2. The projected outage hour estimates for FPL's self-build options represent arithmetic averages of expected outage hours over the 30-year life of the unit period and do not represent "new & clean" unit values. An average capacity factor of 80% for the unit as a whole was used in making these projections. Maintenance outage hours were not included in these projections.

   Using these outage hour values, FPL projects the following values for both the Base and Peak Firing operational modes:

POF	2.2%
FOR	1.1%
Availability	96.7%

APPENDIX A

2014 Ten Year Site Plan

Ten Year Power Plant Site Plan 2014 – 2023

FPL

Ten Year Power Plant Site Plan

2014-2023

Submitted To:

***Florida Public
Service Commission***

***Miami, Florida
April 2014***

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List of Schedules

Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan (Site Plan). This Site Plan should include an estimate of the utility's future electric power generating needs, a projection of how these estimated generating needs could be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The information contained in this Site Plan is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains uncertain forecasts and tentative planning information. Forecasts evolve, and all planning information is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This Site Plan document is based on Florida Power & Light Company's (FPL) integrated resource planning (IRP) analyses that were carried out in 2013 and that were on-going in the first Quarter of 2014. The forecasted information presented in this plan addresses the years 2014 through 2023.
This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, based on FPL's IRP work in 2013 and early 2014. This chapter also discusses a number of issues that may change the resource plan presented in this Site Plan. Furthermore, this chapter briefly discusses the status of FPL's DSM planning efforts, as well as FPL's, renewable energy efforts, transmission planning additions, and fuel cost forecasts.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as Preferred and Potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional information that is included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	***Abbreviation***	***Definition***
Unit Type	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	ST	Stean Unit (Fossil or Nuclear)
	PV	Photovoltaic
Fuel Type	NUC	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	Solar	Solar Energy
	SUB	Sub Bituminous Coal
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	L	Regulatory approval pending. Not under construction
	P	Planned Unit
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	ESP	Electrostatic Precipitators

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Executive Summary

Florida Power & Light Company's (FPL) 2014 Ten Year Power Plant Site Plan (Site Plan) presents FPL's current plans to augment and enhance its electric generation capability (owned or purchased) as part of its efforts to meet its projected incremental resource needs for the 2014 - 2023 time period. By design, the primary focus of this document is on supply side additions; i.e., electric generation capability and the sites for these additions. The supply side additions discussed in this document are resources projected to be needed, based on FPL's load forecast, after accounting for FPL's demand side management (DSM) resource additions. In 2014, new DSM Goals for FPL for the time period 2015 through 2024 will be set by the Florida Public Service Commission (FPSC). At almost the same time FPL is filing this 2014 Site Plan, FPL will also be filing its proposed DSM Goals with the FPSC. Consequently, the level of DSM additions reflected in the 2014 Site Plan is consistent with FPL's proposed DSM Goals. The proposed level of DSM is discussed further below and in Chapter III.

FPL's load forecast accounts for a significant amount of efficiency that results from federal and state energy efficiency codes and standards. The projected impacts of these codes and standards are directly accounted for in FPL's load forecast as discussed below and in Chapter II.

The resource plan that is presented in FPL's 2014 Site Plan contains four key similarities to the resource plan presented in FPL's 2013 Site Plan. However, there are several factors that have contributed to differences between the resource plan presented in the 2014 Site Plan and the resource plan that was previously presented in FPL's 2013 Site Plan. Additional factors will continue to influence FPL's on-going resource planning work and could result in changes in the resource plan presented in this document. A brief discussion of these similarities and factors is provided below. Additional information regarding these topics is presented in Chapter III.

I. Similarities Between the Current Resource Plan and the Resource Plan Previously Presented in FPL's 2013 Site Plan:

There are four key similarities between the current resource plan presented in this document and the resource plan presented in the 2013 Site Plan.

Similarity # 1: Modernizations of Existing Power Plant Sites.

The modernization of FPL's Cape Canaveral plant site was completed on time in 2013 and the modernization of FPL's existing Riviera Beach plant site is scheduled to be completed on/near the April 1, 2014 date this 2014 Site Plan is to be filed. In addition, the modernization of FPL's existing Port Everglades plant site is underway and is projected to be completed in 2016.

Similarity # 2: FPL continues to pursue additional nuclear energy generation to significantly (i) reduce its use of fossil fuels, (ii) lower system fuel costs, (iii) lower system air emissions, and (iv) provide a valuable hedge against future increases in fuel costs and environmental compliance costs.

In 2013 FPL successfully completed its capacity uprate projects at its four existing nuclear units ; Turkey Point Units 3 & 4 and St. Lucie Units 1 & 2. The nuclear uprate project added about 520 MW of additional nuclear capacity to FPL's system which was about 30% more additional nuclear capacity than was originally projected when the project began. FPL's customers are already benefiting from lower fuel costs and reduced system air emissions provided by this additional nuclear capacity.

FPL is also continuing its work to obtain all of the licenses, permits, and approvals that will be necessary to construct and operate two new nuclear units at its Turkey Point site in the future. The earliest deployment dates for these two new units remain 2022 and 2023, respectively, and this Site Plan projects the two new nuclear units going in-service in those years.

Similarity #3: FPL is projected to serve Vero Beach's electrical load.

An agreement to this effect was reached between Vero Beach and FPL on February 19, 2013, and a referendum was held on March 12, 2013 that resulted in a majority of Vero Beach voters approving the agreement. FPL's current load forecast projects that FPL will begin serving Vero Beach's load in January 2015.

Similarity #4: Specific generating units are projected to be retired and/or converted to synchronous condenser operation.

In the last two years, FPL has retired a number of older, less efficient generating units including: Sanford Unit 3, Cutler Units 5 & 6, Cape Canaveral Units 1 & 2, Riviera Beach Units 3 & 4, and Port Everglades Units 1 – 4. In addition, Turkey Point Unit 2 has been converted to operate in synchronous condenser mode to provide voltage support for the transmission system in Southeastern Florida.

This trend is projected to continue. Putnam Units 1 & 2 are now projected to be retired by the end of 2014. And, similar to the earlier conversion of Turkey Point Unit 2, FPL projects that Turkey Point Unit 1 will be converted to run in synchronous condenser mode starting in 2016. In addition, for planning purposes, FPL is projecting that all of its existing gas turbines (GTs) at its two Broward County sites will be retired by the end of 2018 and that 5 new combustion turbines (CTs) will be installed at FPL's Lauderdale plant site also by the end of 2018. This projection is further discussed later in this executive summary and in Chapter III.

II. Factors Influencing FPL's Resource Planning Work Which Have Impacted, or Which Could Impact, FPL's Resource Plan:

There are a number of factors that influence FPL's resource planning work. Eight (8) of these are briefly discussed below and are discussed again in Chapters II and/or III.

Two of these factors are on-going system concerns that FPL has considered in its resource planning work for a number of years. These two on-going system concerns are: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward Counties.

The third and fourth factors that will be discussed are factors that directly impacted the resource plan presented in this document because they affect FPL's forecast of its future load and its future firm load. The third factor is the impact of federal and state energy efficiency codes and standards on FPL's future loads. The impact of these codes and standards has been incorporated into FPL's current load forecast. The magnitude of efficiency that is being delivered to FPL's customers through these codes and standards is significant. For example, by the year 2023 (the last year addressed in this Site Plan), FPL's Summer peak is projected to be lower by approximately 3,477 MW compared to what the projected load would have been without the codes and standards based on cumulative savings beginning in 2005. This represents a decrease of approximately 12% in what the forecasted Summer peak load for 2023 would have been without the codes and standards. Likewise, FPL's forecasted net energy for load (NEL) in the year 2023 is projected to be approximately 9,991 GWh lower compared to what the projected NEL would have been without the efficiency codes and standards based on cumulative savings beginning in 2005. This represents a decrease of approximately 7% from what the forecasted NEL for 2023 would have been without the codes and standards.

There are two significant impacts from these codes and standards. The first impact is to substantially lower FPL's forecasted peak load and NEL. The second impact is that the codes and standards lower the potential for future MW and GWh reductions from FPL's DSM programs that address the specific appliances and equipment impacted by the codes and standards. Thus, significant energy efficiency regarding this equipment will be delivered to FPL's customers through codes and standards, thus precluding the potential for FPL to pursue these same efficiency gains through utility DSM programs.

The fourth factor is a projected decline in the cost-effectiveness of a number of utility DSM measures due to reasons that are beneficial overall for FPL's customers. Compared to 2009 (when DSM Goals were last set): (i) forecasted fuel costs have dropped by 50%, thus lowering the potential benefits from DSM kwh reductions; (ii) projected compliance costs for carbon dioxide (CO_2), have not only been significantly lowered, but their forecasted start date has been delayed by almost a decade, thus again lowering the potential benefits from DSM kwh reductions; and, (iii) FPL's generating system, due to the retirement of older, less efficient generators and replacement with highly efficient generators, plus additional nuclear capacity, has gotten more fuel-efficient, thus lowering fuel-related costs that would otherwise represent potential benefits for DSM kwh reductions. These factors are benefitting FPL's customers through lower electric rates, but they also lower the potential economic benefits that otherwise could be offered by DSM. When combined with the previously discussed fact that codes and standards have reduced the potential for efficiency gains in regard to appliance and equipment addressed by these codes and standards, the result is that FPL is logically projecting a lower contribution from utility DSM in the near-term. That lower contribution is accounted for in the 2014 Site Plan. These factors are discussed in detail in the filing FPL is making in its DSM Goals proceeding.

The fifth factor is the need to take measures to limit FPL's projected increasing dependence upon DSM resources to maintain system reliability. This factor has been previously discussed in FPL's 2011, 2012, and 2013 Site Plans. In these previous Site Plans, FPL has discussed this projection of increasing dependence upon DSM resources using a new type of reserve margin projection as an indicator: a "generation-only reserve margin" or "GRM".

The GRM projections from the 2011, 2012, and 2013 Site Plans consistently showed that these values were projected to significantly decrease over the 10-year reporting period of the Site Plans, declining to single-digit values in the latter years of the reporting periods. These projections indicated a steadily growing dependence on DSM resources to maintain system reliability. FPL's analyses show that system reliability risk increases, particularly from a system operations perspective, as dependence on DSM resources increases to a point where DSM resources account for more than half of FPL's 20% total reserve margin criterion value. Therefore, FPL is implementing a new reliability criterion of a 10% GRM in its resource planning work to complement its other two reliability criteria: a 20% total reserve margin criterion for Summer and Winter, and an annual 0.1 day/year loss-of-load-probability (LOLP) criterion. FPL is implementing the GRM criterion so that FPL's resource plans will begin to meet this criterion in the year 2019. A further discussion of the GRM criterion is presented in Chapter III.

There are additional factors that did not impact FPL's resource plan presented in this document, but which could result in future changes to this resource plan. For example, a sixth factor is the project schedule for the Turkey Point Units 6 & 7 nuclear units. At the time the 2014 Site Plan is being finalized, the Nuclear Regulatory Commission (NRC) has not provided a schedule for its review of FPL's Combined Operating License Application (COLA). Once the NRC's COLA review schedule is available, FPL will review the overall schedule for the Turkey Point Units 6 & 7 project. FPL's review will also consider the impacts of the recently amended nuclear cost recovery clause (NCRC) statute and the ongoing feasibility analyses that are part of Florida Nuclear Cost Recovery process.

The seventh factor is environmental regulation. As developments occur in regard to either new environmental regulations, and/or in how environmental regulations are interpreted and applied, the potential exists for such developments to affect FPL's resource plan that is presented in this document. For example, FPL is aware of potential impacts to generating units of recent EPA changes to the National Ambient Air Quality Standards that include shorter duration 1-hour standards for nitrogen dioxide (NO_2) and sulfur dioxide (SO_2). As a consequence, FPL filed in mid-2013 for FPSC approval to recover costs through the environmental cost recovery clause for removing all of its existing gas turbines (GTs) and partially replacing that peaking unit capacity with new combustion turbines (CTs). Although FPL withdrew its filing in December 2013 pending further analyses including on-site monitoring, FPL believes that the results of the monitoring and analyses will require that the Broward GTs be replaced. Therefore, FPL is currently projecting the retirement of all GTs in Broward County; i.e., at its existing Lauderdale and Port Everglades plant sites (a decrease in generating capacity of 1,260 MW Summer), and the installation of 5 new 201 MW CTs at its existing Lauderdale plant site (an increase of 1,005 MW Summer).

The eighth factor that will be discussed is the possibility of the establishment of a Florida standard for renewable energy or clean energy. Although no such legislation has been enacted to-date, Renewable Portfolio Standards, or Clean Energy Portfolio Standards legislation, or other legislative initiatives regarding renewable or clean energy contributions, may occur in the future at either the state or national level. If such legislation is enacted, FPL would then determine what steps need to be taken to address the legislation.

Each of these factors will continue to be examined in FPL's on-going resource planning work during the rest of 2014 and in future years.

Table ES-1 presents a current projection of major changes to specific generating units and firm capacity purchases for 2014 – 2023. (Although this table does not specifically identify the impacts of projected DSM additions on FPL's resource needs and resource plan, FPL's projected DSM additions have been fully accounted for in the resource plan presented in this Site Plan.)

Table ES-1: Projected Capacity & Firm Purchase Power Changes

Year *	Projected Capacity & Firm Purchase Power Changes	Summer MW	Date	Summer Reserve Margin **
2014	Martin Unit 1 ESP - Return from ESP outage	823	March-14	
	Martin Unit 2 ESP - Temporary Outage to install ESPs	(826)	March-14	
	Turkey Point Unit 5 CT Upgrade	30	March-14	
	Sanford 5 CT Upgrade	9	September-13	
	Riviera Beach Next Generation Clean Energy Center	1,212	April-14	
	Total of MW changes to Summer firm capacity:	**1,247**		**28.0%**
2015	Manatee Unit 3 CT Upgrade	32	October-14	
	Martin Unit 2 ESP - Returned from ESP Outage	823	December-14	
	Putnam 1&2 Retirement	(498)	December-14	
	OUC - Stanton PPAs	37	January-15	
	Vero Beach Combined Cycle [1/]	46	January-15	
	Palm Beach SWA - additional capacity	70	January-15	
	Fort Myers Unit 2 CT Upgrades	18	June-15	
	Fort Myers Unit 2 CT Upgrades	18	March-15	
	Fort Myers Unit 2 CT Upgrades	18	May-15	
	Total of MW changes to Summer firm capacity:	**563**		**27.5%**
2016	UPS Replacement	(928)	December-15	
	Port Everglades Next Generation Clean Energy Center	1,237	June-16	
	Total of MW changes to Summer firm capacity:	**309**		**26.6%**
2017	Turkey Point Unit 1 synchronous condenser	(396)	October-16	
	Total of MW changes to Summer firm capacity:	**(396)**		**22.6%**
2018	OUC - Stanton PPAs	(37)	December-17	
	Vero Beach Combined Cycle [1/]	(46)	January-18	
	Total of MW changes to Summer firm capacity:	**(83)**		**20.5%**
2019	Port Everglades GT retirement	(420)	December-18	
	Lauderdale GT retirement	(840)	December-18	
	Lauderdale CT	1,005	January-19	
	SJRPP suspension of energy	(381)	April-19	
	Unsited CC	1,269	June-19	
	Total of MW changes to Summer firm capacity:	**633**		**21.6%**
2020	Unspecified Purchase	129	June-20	
	Total of MW changes to Summer firm capacity:	**129**		**20.5%**
2021	Eco-Gen PPA	180	January-21	
	Unspecified Purchase	168	June-21	
	Total of MW changes to Summer firm capacity:	**348**		**20.6%**
2022	Cape Next Generation Clean Energy Center	87	June-22	
	Turkey Point Nuclear Unit 6	1,100	June-22	
	Total of MW changes to Summer firm capacity:	**1,187**		**22.6%**
2023	Riviera Beach Next Generation Clean Energy Center	55	June-23	
	Turkey Point Nuclear Unit 7	1,100	June-23	
	Total of MW changes to Summer firm capacity:	**1,155**		**24.4%**

* Year shown reflects when the MW change begins to be accounted for in Summer reserve margin calculations. (Note that addition of MW values for each year will not yield a current cumulative value.)

** Winter Reserve Margins are typically high than Summer Reserve Margin. Winter Reserve Margin are shown on Schedule 7.2 in Chapter III.

1/ This unit will be added as part of the agreement that FPL will serve Vero Beach's electric load starting January, 2015. This unit is expected to be retired within 3 years.

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 9.0 million people. FPL served an average of 4,626,934 customer accounts in thirty-five counties during 2013. These customers were served by a variety of resources including: FPL-owned fossil-fueled, renewable, and nuclear generating units, non-utility owned generation, demand side management (DSM), and interchange/purchased power.

I.A. FPL-Owned Resources

The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory, plus one site in Georgia (partial FPL ownership of one unit) and one site in Jacksonville, Florida (partial FPL ownership of two units). The current electrical generating facilities consist of four nuclear units, three coal units, sixteen combined cycle (CC) units, five fossil steam units, forty-eight combustion gas turbines, two simple cycle combustion turbines, and two photovoltaic facilities[1]. The locations of these eighty generating units are shown on Figure I.A.1 and in Table I.A.1.

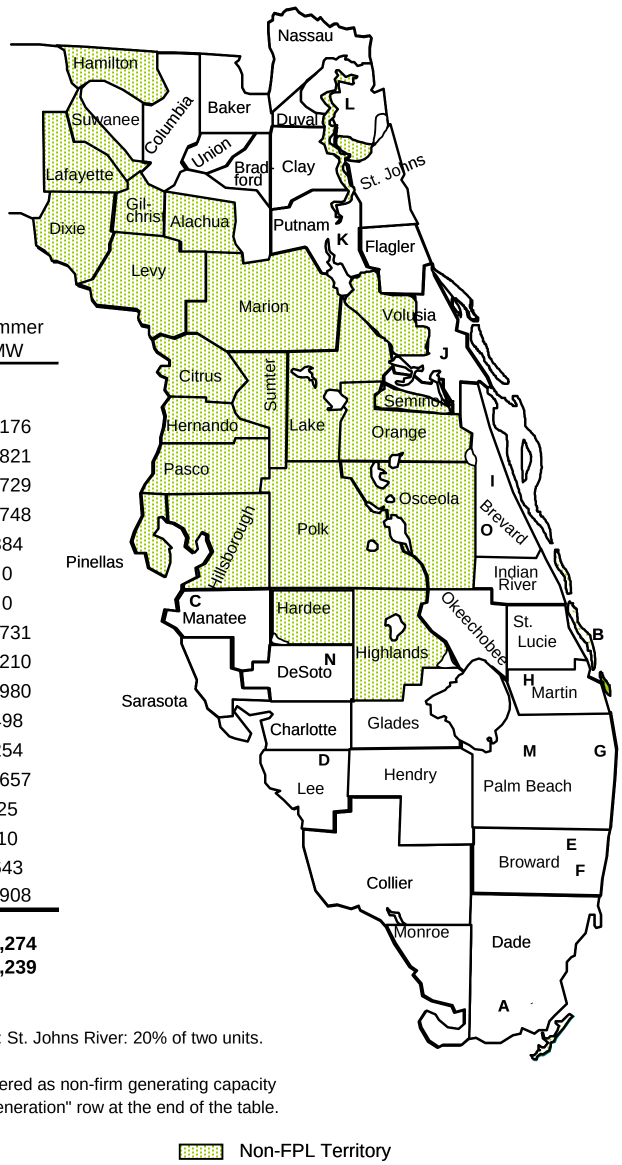
FPL's bulk transmission system is comprised of 6,734 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 589 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2.

1 FPL also has one 75 MW solar thermal facility at its Martin plant site. This facility does not generate electricity as the other units mentioned above do. Instead, it produces steam that reduces the use of fossil fuel to produce steam for electricity generation.

FPL Generating Resources by Location

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	4	3,176
B	St. Lucie [1/]	2	1,821
C	Manatee	3	2,729
D	Fort Myers	3	1,748
E	Lauderdale	2	884
F	Everglades [2/]	0	0
G	Riviera [2/]	0	0
H	Martin	5	3,731
I	Cape Canaveral	1	1,210
J	Sanford	2	1,980
K	Putnam	2	498
L	St. John's River Power Park [1/]	2	254
M	West County	3	3,657
N	DeSoto [3/]	1	25
O	Space Coast [3/]	1	10
	Scherer [4/]	1	643
	Gas Turbines	48	1,908
	Total System Generation =	**80**	**24,274**
	System Firm Generation =	**78**	**24,239**



1/ Represents FPL's ownership share: St Lucie nuclear: 100% Unit 1, 85% Unit 2: St. Johns River: 20% of two units.
2/ Will be site of new Modernization Plants.
3/ The 25 MW of PV at DeSoto and the 10 MW of PV at Space Coast are considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generation" row at the end of the table.
4/ The Scherer unit is located in Georgia and is not shown on this map.

Figure I.A.1: Capacity Resources by Location (as of December 31, 2013)

Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2013)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Nuclear				
St. Lucie [1/]	Hutchinson Island, FL	2	Nuclear	1,821
Turkey Point	Florida City, FL	2	Nuclear	1,632
Total Nuclear:		**4**		**3,453**
Coal Steam				
Scherer	Monroe County, Ga	1	Coal	643
St. John's River Power Park [2/]	Jacksonville, FL	2	Coal	254
Total Coal Steam:		**3**		**897**
Combined-Cycle				
Fort Myers	Fort Myers, FL	1	Gas	1,432
Manatee	Parrish, FL	1	Gas	1,111
Martin	Indiantown, FL	3	Gas	2,079
Sanford	Lake Monroe, FL	2	Gas	1,980
Cape Canaveral	Cocoa, FL	1	Gas/Oil	1,210
Lauderdale	Dania, FL	2	Gas/Oil	884
Putnam	Palatka, FL	2	Gas/Oil	498
Turkey Point	Florida City, FL	1	Gas/Oil	1,148
West County	Palm Beach County, FL	3	Gas/Oil	3,657
Total Combined Cycle:		**16**		**13,999**
Oil/Gas Steam				
Manatee	Parrish, FL	2	Oil/Gas	1,618
Martin	Indiantown,FL	2	Oil/Gas	1,652
Turkey Point	Florida City, FL	1	Oil/Gas	396
Total Oil/Gas Steam:		**5**		**3,666**
Gas Turbines(GT)				
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Total Gas Turbines/Diesels:		**48**		**1,908**
Combustion Turbines				
Fort Myers	Fort Myers, FL	2	Gas/Oil	316
Total Combustion Turbines:		**2**		**316**
PV				
DeSoto [3/]	DeSoto, FL	1	Solar Energy	25
Space Coast [3/]	Brevard County, FL	1	Solar Energy	10
Total PV:		**2**		**35**
Total System Generation as of December 31, 2013 =		**80**		**24,274**
System Firm Generation as of December 31, 2013 =		**78**		**24,239**

1/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/860. FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively.
2/ Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit. Represents FPL's ownership share: SJRPP coal: 20% of two units).
3/ The 25 MW of PV at DeSoto and the 10 MW of PV at Space Coast are considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generation" row at the end of the table.

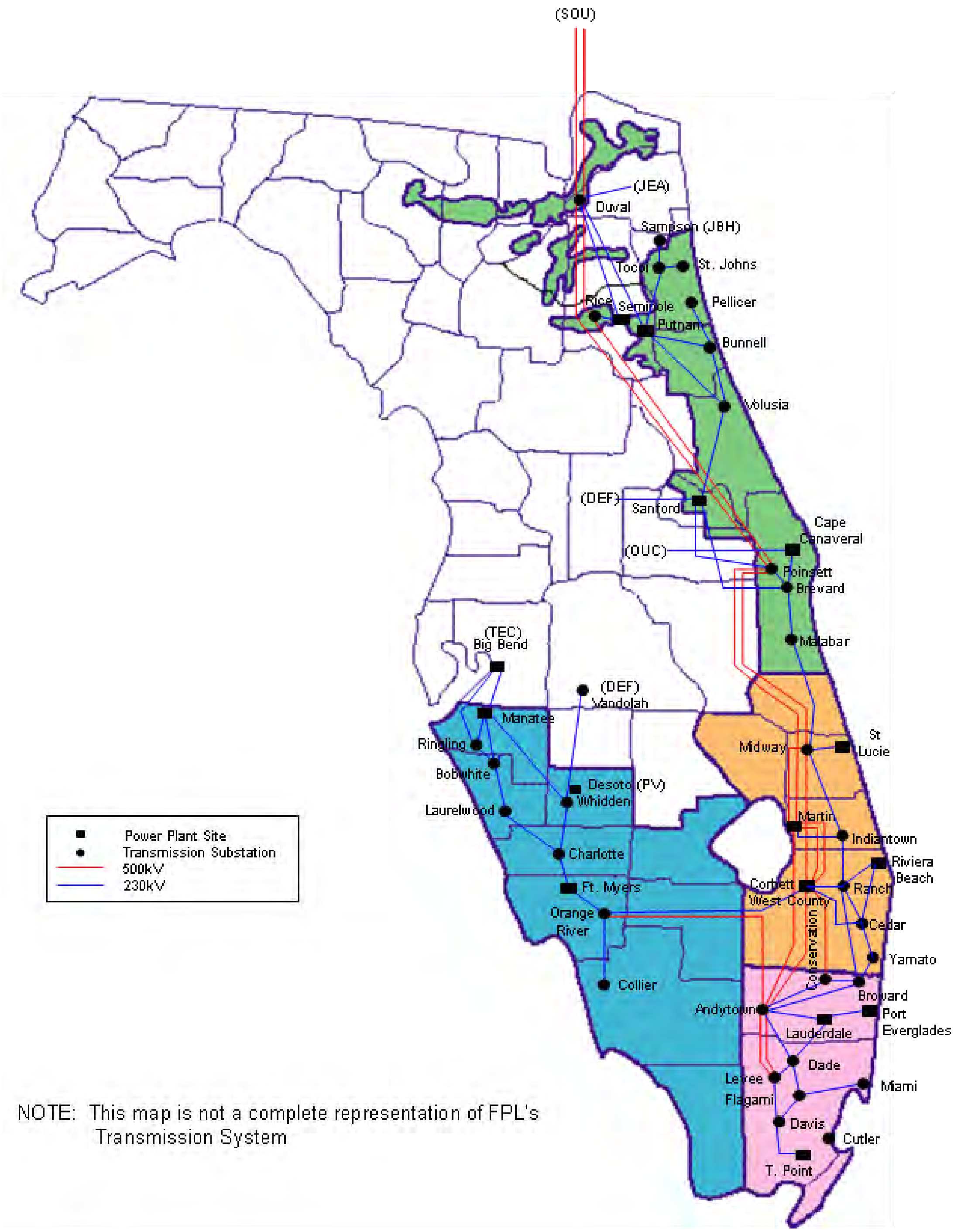


Figure I.A.2: FPL Substation and Transmission System Configuration

Description of Existing Resources

I.B Capacity and Energy Power Purchases

Firm Capacity Purchases from Qualifying Facilities (QF)

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has contracts with eight qualifying facilities; i.e., cogeneration/small power production facilities, to purchase firm capacity and energy during the 10-year reporting period of this Site Plan as shown in Table I.A.3, Table I.B.1, and Table I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source solar, wind, waste, geothermal, or other renewable resources.

Firm Capacity Purchases from Utilities

FPL has a Unit Power Sales (UPS) contract to purchase 928 MW from the Southern Company (Southern) through the end of December 2015. This capacity is being supplied by Southern from a mix of gas-fired and coal-fired units.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 375 MW (Summer) and 383 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. However, due to Internal Revenue Service (IRS) regulations, the total amount of energy that FPL may receive from this purchase is limited. FPL currently assumes, for planning purposes, that this limit will be reached in April 2019. Once this limit is reached, FPL will be unable to receive firm capacity and energy from these purchases. (However, FPL will continue to receive firm capacity and energy from its ownership portion of the SJRPP units.)

As part of the agreement that FPL will begin serving Vero Beach's electrical needs beginning in January 2015, FPL has acquired two existing power purchase agreements totaling approximately 37 MW of coal-fired capacity. These agreements will run through the end of 2017.

These purchases are shown in Table I.A.3, Table I.B.1, and Table I.B.2. FPL also has ownership interest in the SJRPP units. The ownership amount is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.

Firm Capacity Other Purchases

FPL has two other firm capacity purchase contracts with non-QF, non-utility suppliers. These contracts with the Palm Beach Solid Waste Authority were previously listed as QFs. However, the addition of a second unit will cause both units to no longer meet the statutory definition of a QF. These contracts are therefore listed as "Other Purchases" after the current estimated in-service date of the new unit. Table I.B.1 and I.B.2 present the Summer and Winter MW, respectively, resulting from these contracts under the category heading of Other Purchases.

Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. Table I.A.3 shows the amount of energy purchased in 2013 from these facilities.

Table 1.A.3: Purchase Power Resources by Contract (as of December 31, 2013)

Firm Capacity Purchases (MW)	Location (City or County)	Fuel	Summer MW
I. Purchases from QF's: Cogeneration/Small Power Production Facilities			
Cedar Bay Generating Co.	Duval	Coal (Cogen)	250
Indiantown Cogen., LP	Martin	Coal (Cogen)	330
Broward South	Broward	Solid Waste	4
Broward North	Broward	Solid Waste	11
Palm Beach SWA - extension			40
		Total:	**635**
II. Purchases from Utilities:			
UPS from Southern Company	Various in Georgia	Coal	928
SJRPP	Jacksonville, FL	Coal	381
		Total:	**1,309**
		Total Net Firm Generating Capability:	**1,944**

Non-Firm Energy Purchases (MWH)

Project	County	Fuel	In-Service Date	Energy (MWH) Delivered to FPL in 2013
Okeelanta (known as Florida Crystals and New Hope Power Partners) *	Palm Beach	Bagasse/Wood	11/95	87,723
Broward South *	Broward	Solid Waste	9/09	90,116
Broward North *	Broward	Solid Waste	1/12	81,316
Waste Management - Renewable Energy *	Broward	Landfill Gas	1/10	47,249
Waste Management - Collier County Landfill *	Broward	Landfill Gas	5/11	25,578
Tropicana	Manatee	Natural Gas	2/90	8,900
Georgia Pacific	Putnam	Paper by-product	2/94	5,294
Rothenbach Park (known as MMA Bee Ridge)	Sarasota	PV	10/07	289
First Solar	Miami	PV	4/11	210
Customer - Owned PV & Wind	Various	PV/Wind	9/12	1,018
INEOS Bio *	Indian River	Wood	Various	922
Miami Dade Resource Recovery*	Dade	Solid Waste	12/13	28,759

* These Non-Firm Energy Purchases are Renewable and are reflected on Schedule 11.1 row 9 column 6.

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA -extension 1/	01/01/12	04/01/32	40	0	0	0	0	0	0	0	0	0
U.S. EcoGen - Clay 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
U.S. EcoGen -Okeechobee 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
U.S. EcoGen - Martin 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
QF Purchases Sub Total:			**635**	**595**	**595**	**595**	**595**	**595**	**595**	**775**	**775**	**775**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
UPS Replacement	06/01/10	12/31/15	928	928	0	0	0	0	0	0	0	0
SJRPP 3/	04/02/82	04/01/19	375	375	375	375	375	0	0	0	0	0
OUC - Stanton 1 4/	01/01/15	12/31/17	0	21	21	21	0	0	0	0	0	0
OUC - Stanton 2 4/	01/01/15	12/31/17	0	16	16	16	0	0	0	0	0	0
Utility Purchases Sub Total:			**1,303**	**1,340**	**412**	**412**	**375**	**0**	**0**	**0**	**0**	**0**
Total of QF and Utility Purchases =			**1,938**	**1,934**	**1,006**	**1,006**	**970**	**595**	**595**	**775**	**775**	**775**

III. Other Purchases:

	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Palm Beach SWA -extension 1/	01/01/12	04/01/32	0	40	40	40	40	40	40	40	40	40
Palm Beach SWA - additional	01/01/15	04/01/32	0	70	70	70	70	70	70	70	70	70
Unspecified Purchases 5/	01/01/20	12/31/20	0	0	0	0	0	0	129	0	0	0
Unspecified Purchases 5/	01/01/21	12/31/21	0	0	0	0	0	0	0	168	0	0
Other Purchases Sub Total:			**0**	**110**	**110**	**110**	**110**	**110**	**239**	**278**	**110**	**110**
Total "Non-QF" Purchase =			**1,303**	**1,450**	**522**	**522**	**485**	**110**	**239**	**278**	**110**	**110**

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Summer Firm Capacity Purchases Total MW:	**1,938**	**2,044**	**1,116**	**1,116**	**1,080**	**705**	**834**	**1,053**	**885**	**885**

1/ When the second unit comes into service at the Palm Beach SWA, neither unit will meet the standards to be a small power producers, and both units then will be accounted for under "Other Purchases".

2/ The EcoGen units will enter service in 2019, and initially provide non-firm energy. Firm capacity delivery will commence in 2021.

3/ Contract End Date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.

4/ These units are part of the purchase of the Vero Beach Electric System.

5/ These unspecified purchases are short-term purchases that are included for resource planning purposes. No decision regarding such purchases is needed at this time.

Table I.B.2: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA -extension 1/	01/01/12	04/01/32	40	0	0	0	0	0	0	0	0	0
U.S. EcoGen - Clay 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
U.S. EcoGen -Okeechobee 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
U.S. EcoGen - Martin 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
		QF Purchases Sub Total:	**635**	**595**	**595**	**595**	**595**	**595**	**595**	**775**	**775**	**775**

II. Purchases from Utilities:	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
UPS Replacement	06/01/10	12/31/15	928	928	0	0	0	0	0	0	0	0
SJRPP 3/	04/02/82	04/01/19	383	383	383	383	383	383	0	0	0	0
OUC - Stanton 1 4/	01/01/15	12/31/17	0	21	21	21	0	0	0	0	0	0
OUC - Stanton 2 4/	01/01/15	12/31/17	0	16	16	16	0	0	0	0	0	0
		Utility Purchases Sub Total:	**1,311**	**1,348**	**420**	**420**	**383**	**383**	**0**	**0**	**0**	**0**
		Total of QF and Utility Purchases =	**1,946**	**1,942**	**1,014**	**1,014**	**978**	**978**	**595**	**775**	**775**	**775**

III. Other Purchases:	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Palm Beach SWA -extension 1/	01/01/12	04/01/32	0	40	40	40	40	40	40	40	40	40
Palm Beach SWA - additional	01/01/15	04/01/32	0	70	70	70	70	70	70	70	70	70
Unspecified Purchases 5/	01/01/20	12/31/20	0	0	0	0	0	0	129	0	0	0
Unspecified Purchases 5/	01/01/21	12/31/21	0	0	0	0	0	0	0	168	0	0
		Other Purchases Sub Total:	**0**	**110**	**110**	**110**	**110**	**110**	**239**	**278**	**110**	**110**
		"Non-QF" Purchase =	**1,311**	**1,458**	**530**	**530**	**493**	**493**	**239**	**278**	**110**	**110**

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Winter Firm Capacity Purchases Total MW:	**1,946**	**2,052**	**1,124**	**1,124**	**1,088**	**1,088**	**834**	**1,053**	**885**	**885**

1/ When the second unit comes into service at the Palm Beach SWA, neither unit will meet the standards to be a small power producers, and both units then will be accounted for under "Other Purchases".
2/ The EcoGen units will enter service in 2019, and initially provide non-firm energy. Firm capacity delivery will commence in 2021.
3/ Contract End Date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.
4/ These units are part of the purchase of the Vero Beach Electric System.
5/ These unspecified purchases are short-term purchases that are included for resource planning purposes. No decision regarding such purchases is needed at this time.

I.C Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include a number of conservation/energy efficiency and load management initiatives. FPL's DSM efforts through 2013 have resulted in a cumulative Summer peak reduction of approximately 4,753 MW at the generator and an estimated cumulative energy saving of approximately 66,782 Gigawatt-hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2013 have eliminated the need to construct the equivalent of approximately 14 new 400 MW generating units. New DSM Goals for FPL for the 2015 through 2024 time period will be set by the FPSC in the second half of 2014. DSM is discussed further in Chapter III.

Schedule 1

Existing Generating Facilities
As of December 31, 2013

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability [1/] Winter MW	(14) Net Capability [1/] Summer MW
Cape Modernization		Brevard County											
		19/24S/36F									1,295,400	1,355	1,210
	1		CC	NG	FO2	PL	TK	Unknown	Apr-13	Unknown	1,295,400	1,355	1,210
DeSoto [2/]		DeSoto County											
		27/36S/25E									27,000	25	25
	1		PV	Solar	Solar	N/A	N/A	Unknown	Oct-09	Unknown	27,000	25	25
Fort Myers		Lee County											
		35/43S/25E									2,841,990	2,552	2,396
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,721,490	1,490	1,432
	3A		CT	NG	FO2	PL	TK	Unknown	Jun-03	Unknown	188,190	176	158
	3B		CT	NG	FO2	PL	TK	Unknown	Jun-03	Unknown	188,190	176	158
	1-12		GT	FO2	No	TK	No	Unknown	May-74	Unknown	744,120	710	648
Lauderdale		Broward County											
		30/50S/42E									1,873,968	1,884	1,724
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	483	442
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	483	442
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
Manatee		Manatee County											
		18/33S/20E									2,951,110	2,806	2,729
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	819	809
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	819	809
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,168	1,111
Martin		Martin County											
		29/29S/38E									4,317,510	3,870	3,731
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	832	826
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	832	826
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	489	469
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	489	469
	8 [3/]		CC	NG	FO2	PL	TK	Unknown	Jun-05	Unknown	1,224,510	1,228	1,141
Port Everglades		City of Hollywood											
		23/50S/42E									410,734	459	420
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	459	420
Putnam		Putnam County											
		16/10S/27E									580,008	530	498
	1		CC	NG	FO2	PL	TK	Unknown	Apr-78	Unknown	290,004	265	249
	2		CC	NG	FO2	PL	TK	Unknown	Aug-77	Unknown	290,004	265	249

1/ These ratings are peak capability.

2/ The capacity shown for the PV facility at DeSoto is considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generating Capacity as of December 31, 2013" row at the end of the table.

3/ Martin Unit 8 is also partially fueled by a 75 MW solar thermal facility that supplies steam when adequate sunlight is available, thus reducing fossil fuel use.

Schedule 1

Existing Generating Facilities
As of December 31, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt.		Actual/			
						Fuel		Fuel	Commercial	Expected	Gen.Max.	Net Capability [1/]	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Sanford		Volusia County											
		16/19S/30E									2,377,720	2,158	1,980
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,860	1,078	989
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	1,080	991
Scherer [2/]		Monroe, GA									680,368	651	643
	4		ST	SUB	No	RR	No	Unknown	Jul-89	Unknown	680,368	651	643
Space Coast [3/]		Brevard County											
		13/23S/36E									10,000	10	10
	1		PV	Solar	Solar	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10
St. Johns River		Duval County											
Power Park [4/]		12/15/28E											
		(RPC4)									271,836	260	254
	1		ST	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	130	127
	2		ST	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	130	127
St. Lucie [5/]		St. Lucie County											
		16/36S/41E									1,743,775	1,863	1,821
	1		ST	Nuc	No	TK	No	Unknown	May-76	Unknown	1,020,000	1,003	981
	2		ST	Nuc	No	TK	No	Unknown	Jun-83	Unknown	723,775	860	840
Turkey Point		Miami Dade County											
		27/57S/40E									3,380,960	3,263	3,176
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	398	396
	3		ST	Nuc	No	TK	No	Unknown	Nov-72	Unknown	877,200	839	811
	4		ST	Nuc	No	TK	No	Unknown	Jun-73	Unknown	877,200	848	821
	5		CC	NG	FO2	PL	TK	Unknown	May-07	Unknown	1,224,510	1,178	1,148
West County		Palm Beach County											
		29&32/43S/40E									2,733,600	4,005	3,657
	1		CC	NG	FO2	PL	TK	Unknown	Aug-09	Unknown	1,366,800	1,335	1,219
	2		CC	NG	FO2	PL	TK	Unknown	Nov-09	Unknown	1,366,800	1,335	1,219
	3		CC	NG	FO2	PL	TK	Unknown	May-11	Unknown	1,366,800	1,335	1,219
Total System Generating Capacity as of December 31, 2013 [6/] =												**25,691**	**24,274**
System Firm Generating Capacity as of December 31, 2013 [7/] =												**25,656**	**24,239**

1/ These ratings are peak capability.
2/ These ratings represent Florida Power & Light Company's share of Scherer Unit 4, adjusted for transmission losses.
3/ The capacity shown for the PV facility at Space Coast is considered as non-firm generating capacity due to the intermittent nature of the solar resource.
4/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Units 1 and 2, excluding the Jacksonville Electric Authority (JEA) share of 80%.
5/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/860.FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively, as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.
6/ The Total System Generating Capacity value shown includes FPL-owned firm and non-firm generating capacity.
7/ The System Firm Generating Capacity value shown includes only firm generating capacity.

CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

II. A. Overview of the Load Forecasting Process

Long-term forecasts of sales, net energy for load (NEL), and peak loads are typically developed on an annual basis for resource planning work at FPL. New long-term forecasts were developed by FPL in late 2013 that replaced the previous long-term load forecasts that were used by FPL during 2013 in much of its resource planning work and which were presented in FPL's 2013 Site Plan. These new load forecasts are utilized throughout FPL's 2014 Site Plan. These forecasts are a key input to the models used to develop FPL's integrated resource plan.

The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads. Consistent with past forecasts, the primary drivers to develop these forecasts include economic conditions and weather.

The projections for the national and Florida economies are obtained from the consulting firm IHS Global Insight. Population projections are obtained from the Florida Legislature's Office of Economic and Demographic Research (EDR). These projections are developed in conjunction with the Bureau of Economic and Business Research (BEBR) of the University of Florida. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects FPL's energy sales and peak demand. Three sets of weather variables are developed and used in FPL's forecasting models:

1. Cooling degree-hours based on 72^{o} F, winter heating degree-days based on 66^{o} F, and heating degree-days based on 45^{o} F are used to forecast energy sales.
2. The maximum temperature on the peak day, along with the build-up of cooling degree-hours prior to the peak, is used to forecast Summer peaks.
3. The minimum and average temperatures on the peak day, along with the build-up of heating degree-hours based on 66^{o} F, one and two days prior to the peak, are used to forecast Winter peaks.

The cooling degree-hours and winter heating degree-days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. Heating degree-days based on 45^{o} F are used to capture heating load resulting from sustained periods of unusually cold weather not fully captured by heating degree-days based on 66^{o} F. A composite hourly temperature profile is derived using hourly temperatures across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained. In developing the composite hourly profile, these regional temperatures are weighted by regional energy sales. The resulting composite temperature is used to derive projected cooling and heating degree-hours and heating degree-days. Similarly, composite temperature and hourly profiles of temperatures are used to calculate the weather variables used in the Summer and Winter peak models.

II. B. Comparison of FPL's Current and Previous Load Forecasts

While reflecting some fluctuations by year, FPL's current load forecast is generally in line with the load forecast presented in its 2013 Site Plan. There are four primary factors that are driving the current load forecast: projected population growth, the continued recovery of the Florida economy, energy efficiency codes and standards, and the additional load expected as a result of the acquisition of the City of Vero Beach electric utility.

In early 2013, FPL came to an agreement with the City of Vero Beach to purchase the City's electric system. This agreement was approved by the City voters on March 12, 2013. Beginning in January 2015, NEL, customers, and peaks for Vero Beach are included in FPL's forecasts and are reflected in FPL's 2014 Site Plan.

The customer forecast is based on recent population projections as well as the actual levels of customer growth experienced historically and the additional customers expected as a result of the acquisition of Vero Beach. Population projections are derived from the EDR's July 2013 Demographic Estimating Conference. This forecast is generally consistent with previous forecasts indicating a gradual rebound in Florida's population growth. Net migration into Florida fell to a record low in 2009 during the height of the recession. Florida has since experienced an improvement in net migration which now accounts for a majority of the population growth. However, population growth rates have remained modest by historical standards. Moderately higher rates of population growth are projected from 2014 until 2018 when the projected rate of population growth gradually begins to decelerate. Consistent with past population projections, the rates of population growth in the later years of the forecast are below the rates historically experienced in Florida.

Effective January 2015, FPL is expected to begin providing electric service to more than 34,000 customers formerly served by the City of Vero Beach. Reflecting this increase, the current forecast shows an increase in customer growth in 2015. Thereafter, customer growth is expected to mirror the overall level of population growth in the state. By 2019, the total number of customers served by FPL is expected to exceed five million. Between 2013 and 2023 the total number of customers is projected to increase at an annual rate of 1.4%, the same increase projected in the 2013 Site Plan.

The economic projections incorporated into FPL's load forecast are provided by IHS Global Insight, a leading economic forecasting firm. IHS Global Insight projects a continued recovery in the Florida economy with relatively healthy increases in employment and income levels between 2014 and 2020. Particularly robust growth is projected for the tourism and healthcare industries. Consistent with past projections, economic growth in the later years of the forecast is expected to moderate slightly.

Estimates of savings from energy efficiency codes and standards are developed by ITRON, a leading expert in this area. Included in these estimates are savings from federal and state energy efficiency codes and standards, including the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the savings occurring from the use of compact fluorescent bulbs[2]. The impact of these savings began in 2005 and their cumulative impact on the Summer peak is expected to reach 3,477 MW by 2023, the equivalent of approximately a 12% reduction in what the forecasted Summer peak load for 2023 would have been without these codes and standards. The cumulative impact from these savings on NEL is expected to reach 9,991 GWH over the same period while the cumulative impact on the Winter peak is expected to be 1,689 MW by 2023. This represents a decrease of approximately 7% in the forecasted NEL for 2023 and a 4% reduction in forecasted Winter peak load for 2023.

Consistent with the forecast presented in FPL's 2013 Site Plan, the total growth projected for the ten-year reporting period of this document is significant. The Summer peak is projected to increase to 26,528 MW by 2023, an increase of 4,952 MW over the 2013 actual Summer peak. Likewise, NEL is projected to reach 132,357 GWH in 2023, an increase of 20,702 GWH from the actual 2013 value.

II.C. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for the major revenue classes and are adjusted to match the NEL forecast. The results of these sales forecasts for the years 2014 - 2023 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and NEL forecast are outlined below.

[2] Note that in addition to the fact that these energy efficiency codes and standards lower the forecasted load (as described later in this chapter), these standards also lower the potential for efficiency gains that would otherwise be available through utility DSM programs.

1. Residential Sales

Residential electric usage per customer is estimated by using an econometric model. Residential sales are a function of the following variables: cooling degree-hours, winter heating degree-days, lagged cooling degree-hours, lagged winter heating degree-days, retail gasoline prices, and Florida real per capita income weighted by the percent of the population employed. The impact of weather is captured by the cooling degree-hours, heating degree-days, and the one month lag of these variables. The impact energy prices have on electricity consumption is captured through retail gasoline prices. As energy prices rise, less disposable income is available for all goods and services, electricity included. To capture economic conditions, the model includes a composite variable based on Florida real per capita income and the percent of the state's population that is employed. Residential energy sales are forecasted by multiplying the forecasted residential use per customer by the number of residential customers forecasted.

2. Commercial Sales

The commercial sales forecast is also developed using an econometric model. Commercial sales are a function of the following variables: Florida real per capita income weighted by the percent of the population employed, cooling degree-hours, heating degree-hours, lagged cooling degree-hours, a variable designed to reflect the impact of empty homes, dummy variables for the month of December and for the specific months of January 2007, November 2005, and March 2013, and an autoregressive term. Cooling degree-hours, heating degree-hours, and the one month lag of cooling degree-hours are used to capture weather-sensitive load in the commercial sector.

3. Industrial Sales

The industrial class is comprised of three distinct groups: very small accounts (those with less than 20 kW of demand), medium accounts (those with 21 kW to 499 kW of demand), and large accounts (those with demands of 500 kW or higher). As such, the forecast is developed using a separate econometric model for each group of industrial customers. The small industrial sales model utilizes the following variables: cooling degree-hours, heating degree-hours, dummy variables for the specific months of November 2005 and August 2004, and two autoregressive terms. The medium industrial sales model utilizes the following variables: cooling degree-hours, Florida real per capita income weighted by the percent of the population employed, dummy variables for the specific months of February 2005 and 2006 and November 2005, and three autoregressive terms,. The large industrial sales model utilizes the following variables: cooling degree-hours, Florida real per capita income weighted by the percent of the population employed, the Consumer Price Index, and dummy variables for the specific months of October 2004 and 2005, November 2004, and September 2005.

4. Railroad and Railways Sales and Street and Highway Sales

This class consists solely of Miami-Dade County's Metrorail system. The projections for railroad and railways sales are based on a historical moving average.

The forecast for street and highway sales is developed by first developing a trended use per customer value, then multiplying this value by the number of forecasted customers.

5. Other Public Authority Sales

This class consists of a sports field rate schedule, which is closed to new customers, and one government account. The forecast for this class is based on its historical usage characteristics.

6. Total Sales to Ultimate Customer

Sales forecasts by revenue class are summed to produce a total sales forecast.

7. Sales for Resale

Sales for resale (wholesale) customers are composed of municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers. Currently there are five customers in this class: the Florida Keys Electric Cooperative; Lee County Electric Cooperative; Wauchula; Winter Park; and Blountstown. In addition, FPL will begin making sales to Seminole Electric Cooperative in June 2014 under a long term agreement[3].

Beginning in May 2011, FPL began providing service to the Florida Keys Electric Cooperative under a long-term full requirements contract. Previously FPL was serving the Florida Keys under a partial requirements contract. The sales to Florida Keys Electric Cooperative are based on customer-supplied information and historical coincidence factors.

Lee County has contracted with FPL for FPL to supply a portion of their load through 2013, then to begin serving their entire load beginning in 2014. This contract began in January 2010. Lee County provides a forecast of their sales by delivery point which is used to derive their sales forecast.

FPL's sales to Wauchula began in October 2011 and will continue through December 2016.

[3] FPL continues to evaluate the possibility of serving the electrical loads of other entities at the time the 2014 Site Plan is being prepared. Because these possibilities are still being evaluated, the load forecast presented in this Site Plan does not include these potential loads.

Sales to Winter Park began in January 2014 and will continue through December 2016.

Blountstown became an FPL wholesale customer in May 2012. FPL's contract with Blountstown expires in April 2017.

A new contract with Seminole Electric Cooperative is included in the forecast which includes delivery of 200 MW beginning in June 2014 and continuing through May 2021.

II.D. Net Energy for Load (NEL)

An econometric model is developed to produce a NEL per customer forecast. The inputs to the model include Florida real per capita income weighted by the percent of the population employed, and a proxy for energy prices. The model also includes several weather variables including cooling degree-hours and heating degree-days by calendar month, and heating degree-days based on 45^{o} F. In addition, the model also includes variables for energy efficiency codes and standards and a variable designed to capture the impact of empty homes. Dummy variables are included for the specific months of May 2004, and November 2005. There is also an autoregressive term in the model.

The energy efficiency variable is included to capture the impacts from major codes and standards, including those associated with the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the savings occurring from the use of compact fluorescent bulbs. The estimated impact from these codes and standards is inclusive of engineering estimates and any resulting behavioral changes. The impact of these savings began in 2005 and their cumulative impact on NEL is expected to reach 9,991 GWH by 2023. This represents a 7.0% reduction in what the forecasted NEL for 2023 would have been absence these codes and standards. On an incremental basis, net of the reduction already experienced through 2013, the reduction in 2023 is expected to reach 6,075 GWH.

The decline in the number of empty homes resulting from the current housing recovery has affected use per customer and is captured in a separate variable. The forecast was also adjusted for additional load estimated from hybrid vehicles, beginning in 2013, which resulted in an increase of approximately 1,587 GWH by the end of the ten-year reporting period. The forecast was also adjusted for the incremental load resulting from FPL's economic development riders which began in 2013, and this incremental load is projected to grow to 537 GWH before leveling off in 2018. An additional adjustment to the NEL forecast was made to reflect the acquisition of the Vero Beach electric system. The Vero Beach acquisition is projected to add 793 GWH by 2023.

The NEL forecast is developed by first multiplying the NEL per customer forecast by the total number of customers forecasted (excluding the customers formerly served by Vero Beach) and then adjusting the forecasted results for the expected incremental load resulting from hybrid vehicles, new wholesale contracts, the Vero Beach acquisition, and FPL's economic development riders. Once the NEL forecast is obtained, total billed sales are computed using a historical ratio of sales to NEL. The sales by class forecasts previously discussed are then adjusted to match the total billed sales. The forecasted NEL values for 2014 - 2023 are presented in Schedule 3.3 that appears at the end of this chapter.

II.E. System Peak Forecasts

The rate of absolute growth in FPL system peak load has been a function of the size of the customer base, varying weather conditions, projected economic conditions, changing patterns of customer behavior, and more efficient appliances and lighting. FPL developed the peak forecast models to capture these behavioral relationships. In addition, FPL's peak forecast also reflects changes in load expected as a result of the acquisition of Vero Beach, changes in wholesale contracts, and the expected number of hybrid vehicles.

The savings from energy efficiency codes and standards incorporated into the peak forecast include the impacts from the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the use of compact fluorescent light bulbs. The impact from these energy efficiency standards began in 2005 and their cumulative impact on the Summer peak is expected to reach 3,477 MW by 2023. This reduction is inclusive of engineering estimates and any resulting behavioral changes. The cumulative 2023 impact from these energy efficiency codes and standards effectively reduces FPL's Summer peak for that year by 11.6%. On an incremental basis, net of the reduction already experienced through 2013, the impact on the Summer peak from these energy efficiency codes and standards is expected to reach 1,997 MW in 2023. By 2023, the Winter peak is expected to be reduced by 1,689 MW as result of the cumulative impact from these energy efficiency standards since 2005. On an incremental basis, net of the reduction already experienced through 2013, the impact on the Winter peak from these energy efficiency standards is expected to reach 1,065 MW in 2023.

The forecast was also adjusted for additional load estimated from hybrid vehicles which results in an expected increase of approximately 443 MW in the Summer and 221 MW in the Winter by the end of the ten-year reporting period and for the acquisition of the Vero Beach electric system. The Vero Beach acquisition will add 169 MW to the Summer peak, and 179 MW to the Winter peak, forecast by the end of the ten-year reporting period.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2014 – 2023 are presented at the end of this chapter in Schedules 3.1 and 3.2, and in Chapter III in Schedules 7.1 and 7.2.

1. System Summer Peak

The Summer peak forecast is developed using an econometric model. The variables included in the model are the price of gasoline, lagged one month, Florida real household disposable income, cooling degree-hours two days prior to the peak day, the maximum temperature on the day of the peak, a variable for energy efficiency standards, and a moving average term. The model is based on the Summer peak contribution per customer which is multiplied by total customers (excluding the customers that have been served by Vero Beach), and adjusted to account for incremental loads resulting from hybrid vehicles, new wholesale contracts, the Vero Beach acquisition, and FPL's economic development riders to derive FPL's system Summer peak.

2. System Winter Peak

Like the system Summer peak model, this model is also an econometric model. The model consists of three weather-related variables: the average temperature on the peak day, heating degree-hours for the prior day squared, and heating degree-hours two days prior to the peak day. The model also includes two dummy variables; one for Winter peaks occurring on weekends and one for winter peaks with minimum temperature below 40.5 degrees. Also included in the model are a variable for housing starts per capita, and an autoregressive term. The forecasted results are adjusted for the impact of energy efficiency standards. The model is based on the Winter peak contribution per customer which is multiplied by total customers (excluding the customers that have been served by Vero Beach), and then adjusted for the expected incremental loads resulting from hybrid vehicles, new wholesale contracts, the Vero Beach acquisition, and FPL's economic development riders.

3. Monthly Peak Forecasts

The forecasting process for monthly peaks consists of the following steps:

a. The forecasted annual summer peak is assumed to occur in the month of August. The month of August has historically accounted for more annual summer peaks than any other month.

b. The forecasted annual winter peak is assumed to occur in the month of January. The month of January has historically accounted for more annual winter peaks than any other month.

c. The remaining monthly peaks are forecasted based on the historical relationship between the monthly peaks and the annual summer peak.

II.F. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2014 - 2023 are produced using a System Load Forecasting "shaper" program. This model uses years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model generates a projection of hourly load values based on these load shapes and the forecast of monthly peaks and energy.

II.G. Uncertainty

In order to address uncertainty in the forecasts of aggregate peak demand and NEL, FPL first evaluates the assumptions underlying the forecasts. FPL takes a series of steps in evaluating the input variables, including comparing projections from different sources, identifying outliers in the series, and assessing the series' consistency with past forecasts. As needed, FPL reviews additional factors which may affect the input variables.

Uncertainty is also addressed in the modeling process. Generally, econometric models are used to forecast the aggregate peak demand and NEL. During the modeling process, the relevant statistics (goodness of fit, F-statistic, P-values, mean absolute deviation (MAD), mean absolute percentage error (MAPE), etc.) are scrutinized to ensure that the models adequately explain historical variation. Once a forecast is developed, it is compared with past forecasts. Deviations from past forecasts are examined in light of changes in input assumptions to ensure that the drivers underlying the forecast are well understood. Finally, forecasts of aggregate peak demand and NEL are compared with the actual values as these become available. An ongoing process of variance analyses is performed. To the extent that the variance analysis identifies large unexplained deviations between the forecast and actual values, revisions to the econometric model may be considered.

The inherent uncertainty in load forecasting is addressed in different ways in regard to FPL's overall resource planning and operational planning work. In regard to FPL's resource planning work, FPL's utilization of a 20% total reserve margin criterion, and a 10% generation-only reserve margin criterion, are designed to maintain reliable electric service to FPL's customers in light of forecasting (and other) uncertainty. In addition, banded forecasts of the projected Summer peak and net energy for load are produced based on an analysis of past forecasting variances. In regard to operational planning, a banded forecast for the projected Summer and Winter peak days is developed based on the historical weather variations. These bands are then used to develop similar bands for the monthly peaks.

II.H. DSM

The effects of FPL's DSM energy efficiency programs implementation through August 2013 are assumed to be imbedded in the actual usage data for forecasting purposes. The impacts of incremental energy efficiency that FPL plans to implement in the future, plus the cumulative and projected incremental impacts of FPL's load management programs, are accounted for as "line item reductions" to the forecasts as part of the IRP process as shown in Chapter III in Schedules 7.1 and 7.2. After making these adjustments to the load forecasts, the resulting "firm" load forecast is then used in FPL's IRP work.

Schedule 2.1
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,620,855	2.21	54,570	3,906,267	13,970	44,487	478,867	92,901
2007	8,729,806	2.19	55,138	3,981,451	13,849	45,921	493,130	93,121
2008	8,771,694	2.20	53,229	3,992,257	13,333	45,561	500,748	90,987
2009	8,732,591	2.19	53,950	3,984,490	13,540	45,025	501,055	89,860
2010	8,762,399	2.19	56,343	4,004,366	14,070	44,544	503,529	88,464
2011	8,860,158	2.20	54,642	4,026,760	13,570	45,052	508,005	88,685
2012	8,948,850	2.21	53,434	4,052,174	13,187	45,220	511,887	88,340
2013	9,025,275	2.20	53,930	4,097,172	13,163	45,341	516,500	87,786

Historical Values (2004 - 2013):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent actual energy sales including the impacts of existing conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.1
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2014	9,111,384	2.20	55,739	4,141,538	13,458	47,155	524,494	89,905
2015	9,302,665	2.20	57,047	4,228,484	13,491	48,634	538,771	90,267
2016	9,437,042	2.20	58,097	4,289,564	13,544	49,793	547,360	90,969
2017	9,571,922	2.20	58,693	4,350,874	13,490	50,418	555,714	90,726
2018	9,705,104	2.20	59,404	4,411,411	13,466	51,110	563,753	90,661
2019	9,835,541	2.20	60,036	4,470,700	13,429	51,667	571,672	90,379
2020	9,961,263	2.20	60,791	4,527,847	13,426	52,337	579,453	90,322
2021	10,079,425	2.20	61,219	4,581,557	13,362	52,675	587,147	89,713
2022	10,198,087	2.20	61,929	4,635,494	13,360	53,264	594,908	89,534
2023	10,318,293	2.20	62,870	4,690,133	13,405	54,043	602,612	89,681

Projected Values (2014 - 2023):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent forecasted energy sales that do not include the impact of incremental conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.2
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads	Street &	Sales to	Sales to
		Average No. of	Average kWh Consumption	& Railways	Highway Lighting	Public Authorities	Ultimate Consumers
Year	GWh	Customers	Per Customer	GWh	GWh	GWh	GWh
2004	3,964	18,512	214,139	93	413	58	99,095
2005	3,913	20,392	191,873	95	424	49	102,296
2006	4,036	21,211	190,277	94	422	49	103,659
2007	3,774	18,732	201,499	91	437	53	105,415
2008	3,587	13,377	268,168	81	423	37	102,919
2009	3,245	10,084	321,796	80	422	34	102,755
2010	3,130	8,910	351,318	81	431	28	104,557
2011	3,086	8,691	355,104	82	437	27	103,327
2012	3,024	8,743	345,871	81	441	25	102,226
2013	2,956	9,541	309,772	88	442	28	102,784

Historical Values (2004 - 2013):

Col. (10) and Col.(15) represent actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.2
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads	Street &	Sales to	Sales to
		Average No. of	Average kWh Consumption	& Railways	Highway Lighting	Public Authorities	Ultimate Consumers
Year	GWh	Customers	Per Customer	GWh	GWh	GWh	GWh
2014	2,990	10,242	291,973	82	442	24	106,432
2015	3,009	10,890	276,263	83	453	23	109,248
2016	3,008	11,520	261,101	82	460	23	111,463
2017	3,001	11,893	252,369	83	466	23	112,684
2018	2,970	12,003	247,426	83	473	23	114,063
2019	2,931	12,030	243,618	83	478	23	115,218
2020	2,875	12,017	239,256	83	484	23	116,593
2021	2,814	11,991	234,676	83	489	23	117,303
2022	2,754	11,971	230,057	83	494	23	118,548
2023	2,692	11,907	226,087	83	499	23	120,210

Projected Values (2014 - 2023):

Col. (10) and Col.(15) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2004	1,531	7,467	108,093	3,029	4,224,509
2005	1,506	7,498	111,301	3,156	4,321,895
2006	1,569	7,909	113,137	3,218	4,409,563
2007	1,499	7,401	114,315	3,276	4,496,589
2008	993	7,092	111,004	3,348	4,509,730
2009	1,155	7,394	111,303	3,439	4,499,067
2010	2,049	7,870	114,475	3,523	4,520,328
2011	2,176	6,950	112,454	3,596	4,547,051
2012	2,237	6,403	110,866	3,645	4,576,449
2013	2,158	6,713	111,655	3,722	4,626,934

Historical Values (2004 - 2013):

Col. (19) represents actual energy sales including the impacts of existing conservation.

Col. (19) = Col. (16) + Col. (17) + Col. (18). Historical NEL includes the impacts of existing conservation and agrees to Col. (5) on schedule 3.3. Historical GWH, prior to 2011, are based on a fiscal year beginning 12/29 and ending 12/28. The 2011 value is based on 12/29/10 to 12/31/11. The 2012-2013 values are based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 2.3
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2014	4,907	6,662	118,001	3,780	4,680,054
2015	5,654	6,703	121,606	4,323	4,782,469
2016	5,706	6,775	123,943	4,383	4,852,827
2017	5,419	6,811	124,914	4,437	4,922,918
2018	5,440	6,896	126,399	4,491	4,991,659
2019	5,496	6,959	127,673	4,543	5,058,945
2020	5,559	7,035	129,187	4,592	5,123,909
2021	5,133	7,018	129,454	4,638	5,185,333
2022	4,846	7,124	130,517	4,681	5,247,054
2023	4,908	7,239	132,357	4,724	5,309,376

Projected Values (2014 - 2023):

Col. (19) represents forecasted energy sales that do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

Col. (19) = Col. (16) + Col. (17) + Col. (18). These values are based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 3.1
History of Summer Peak Demand (MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2004	20,545	258	20,287	0	894	846	588	577	19,063
2005	22,361	264	22,097	0	902	895	600	611	20,858
2006	21,819	256	21,563	0	928	948	635	640	20,256
2007	21,962	261	21,701	0	952	982	716	683	20,295
2008	21,060	181	20,879	0	966	1,042	760	706	19,334
2009	22,351	249	22,102	0	981	1,097	811	732	20,558
2010	22,256	419	21,837	0	990	1,181	815	758	20,451
2011	21,619	427	21,192	0	1,000	1,281	821	781	19,798
2012	21,440	431	21,009	0	1,013	1,351	833	810	19,594
2013	21,576	396	21,180	0	1,025	1,394	833	827	19,718

Historical Values (2004 - 2013):

Col. (2) - Col. (4) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) represent actual DSM capabilities starting from January 1988 and are annual (12-month) values except for 2013 values which are through August.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.1
Forecast of Summer Peak Demand (MW)

(1) August of Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management*	(7) Residential Conservation	(8) C/I Load Management*	(9) C/I Conservation	(10) Net Firm Demand
2014	22,768	1,173	21,595	0	1,077	65	816	33	20,777
2015	23,356	1,206	22,149	0	1,093	88	830	46	21,298
2016	23,778	1,212	22,565	0	1,103	89	841	49	21,695
2017	24,190	1,159	23,031	0	1,113	91	853	52	22,081
2018	24,544	1,166	23,378	0	1,124	92	865	56	22,407
2019	24,896	1,172	23,723	0	1,134	94	877	62	22,729
2020	25,239	1,179	24,061	0	1,144	97	889	67	23,042
2021	25,439	985	24,454	0	1,154	100	901	73	23,211
2022	25,908	992	24,916	0	1,165	104	912	79	23,648
2023	26,528	998	25,530	0	1,175	109	924	85	24,235

Projected Values (2014 - 2023):

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected August values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC.

Schedule 3.2
History of Winter Peak Demand:Base Case

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2004	14,752	211	14,541	0	813	567	534	227	13,405
2005	18,108	225	17,883	0	816	583	542	233	16,751
2006	19,683	225	19,458	0	823	600	550	240	18,311
2007	16,815	223	16,592	0	846	620	577	249	15,392
2008	18,055	163	17,892	0	868	644	636	279	16,551
2009	20,081	207	19,874	0	881	666	676	285	18,524
2010	24,346	500	23,846	0	895	687	721	291	22,730
2011	21,126	383	20,743	0	903	717	723	303	19,501
2012	17,934	382	17,552	0	856	755	722	314	16,356
2013	15,931	348	15,583	0	843	781	567	326	14,521

Historical Values (2004 - 2013):

Col. (2) - Col. (4) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand. For year 2011, the actual peaked occurred in December of 2010.

Col. (5) - Col. (9) for 2003 through 2012 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.2
Forecast of Winter Peak Demand:Base Case

(1) January of Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management*	(7) Residential Conservation	(8) C/I Load Management*	(9) C/I Conservation	(10) Net Firm Demand
2014	19,875	992	18,883	0	883	13	601	5	18,373
2015	20,971	1,235	19,736	0	905	52	557	16	19,442
2016	21,490	1,238	20,252	0	913	52	562	17	19,947
2017	21,731	1,164	20,567	0	921	53	568	17	20,173
2018	21,968	1,159	20,809	0	929	53	573	18	20,396
2019	22,180	1,162	21,018	0	937	53	579	19	20,592
2020	22,383	1,165	21,218	0	945	54	584	20	20,780
2021	22,584	1,168	21,416	0	953	54	590	22	20,965
2022	22,601	971	21,630	0	961	55	595	23	20,966
2023	22,891	974	21,918	0	970	56	601	24	21,240

Projected Values (2014 - 2023):

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected January values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC.

Schedule 3.3
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1) Year	(2) Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) **Actual** Net Energy For Load GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Total Billed Retail Energy Sales (GWh)	(9) Load Factor(%)
2004	111,659	1,872	1,693	108,093	1,531	7,467	99,095	59.9%
2005	115,065	1,970	1,793	111,301	1,506	7,498	102,296	56.8%
2006	117,116	2,078	1,901	113,137	1,569	7,909	103,659	59.2%
2007	118,518	2,138	2,066	114,315	1,499	7,401	105,415	59.4%
2008	115,379	2,249	2,126	111,004	993	7,092	102,919	60.0%
2009	115,844	2,345	2,196	111,303	1,155	7,394	102,755	56.8%
2010	119,220	2,487	2,259	114,475	2,049	7,870	104,557	58.7%
2011	117,460	2,683	2,324	112,454	2,176	6,950	103,327	59.4%
2012	116,083	2,823	2,394	110,866	2,237	6,403	102,226	58.9%
2013	117,087	2,962	2,469	111,655	2,158	6,713	102,784	59.1%

Historical Values (2004 - 2013):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5).

Col. (3) & Col. (4) are DSM values starting in January 1988 and are annual (12-month) values. Col. (3) and Col. (4) for 2013 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWh reductions experienced each year .

Col. (5) is the actual Net Energy for Load (NEL) for years 2003 - 2013.

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 3.3
Forecast of Annual Net Energy for Load (GWh)
(All values are "at the generator"values except for Col (8))

(1) Year	(2) Forecasted Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Net Energy For Load Adjusted for DSM GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Forecasted Total Billed Retail Energy Sales w/o DSM GWh	(9) Load Factor(%)
2014	118,001	91	53	117,858	4,907	6,662	106,432	59.2%
2015	121,606	142	80	121,383	5,654	6,703	109,248	59.4%
2016	123,943	144	81	123,718	5,706	6,775	111,463	59.3%
2017	124,914	147	81	124,686	5,419	6,811	112,684	58.9%
2018	126,399	150	81	126,168	5,440	6,896	114,063	58.8%
2019	127,673	155	80	127,438	5,496	6,959	115,218	58.5%
2020	129,187	159	81	128,948	5,559	7,035	116,593	58.3%
2021	129,454	164	82	129,208	5,133	7,018	117,303	58.1%
2022	130,517	170	82	130,264	4,846	7,124	118,548	57.5%
2023	132,357	179	83	132,095	4,908	7,239	120,210	57.0%

Projected Values (2014 - 2023):

Col. (2) represents Forecasted Net Energy for Load and does not include incremental DSM from 2013 - on. The Col. (2) values are extracted from Schedule 2.3, Col(19). The effects of conservation implemented prior to September 2012 are incorporated into the load forecast values in Col. (2).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation from Jan 2014 - on and are mid-year (6-month) values reflecting DSM signups occurring evenly thoughout each year.

Col. (5) is the forecasted Net Energy for Load (NEL) after adjusting for impacts of incremental DSM for years 2014 - 2023 using the formula:
Col. (5) = Col. (2) - Col. (3) - Col. (4)

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7).
These values are at the meter.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of
Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2013 Actual		2014 FORECAST		2015 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	15,135	8,089	19,875	8,719	20,971	9,093
FEB	15,627	7,468	17,441	7,781	18,050	8,126
MAR	15,931	7,936	17,273	8,753	17,875	9,103
APR	18,419	8,967	18,149	9,047	18,782	9,386
MAY	19,579	9,494	20,331	10,369	21,040	10,701
JUN	21,147	10,460	21,852	10,865	22,416	11,127
JUL	20,261	10,649	22,413	11,625	22,991	11,884
AUG	21,576	11,392	22,768	11,840	23,356	12,096
SEP	20,297	10,229	21,959	10,997	22,525	11,256
OCT	19,313	9,969	20,458	10,354	20,986	10,617
NOV	18,028	8,506	17,994	8,686	18,458	8,960
DEC	16,161	8,497	17,563	8,965	18,016	9,257
Annual Values:		**111,655**		**118,001**		**121,606**

Col. (3) annual value shown is consistent with value shown in Col.(5) of Schedule 3.3.

Cols. (4) - (7) do not include the impacts of cumulative load management, incremental conservation, and incremental load management.

Cols. (5) and Col. (7) annual values shown are consistent with values shown in Col.(2) of Schedule 3.3.

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CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL utilizes its well established integrated resource planning (IRP) process in whole or in part as analysis needs are warranted, to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of new power plants, the primary subjects of this document, are determined as part of the IRP process work.

This section describes FPL's basic IRP process. Some of the key assumptions, in addition to a new load forecast, that were used in developing the resource plan presented in this Site Plan are also discussed.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental steps to FPL's resource planning. These steps can be generally described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Evaluate the competing options and resource plans in regard to system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process

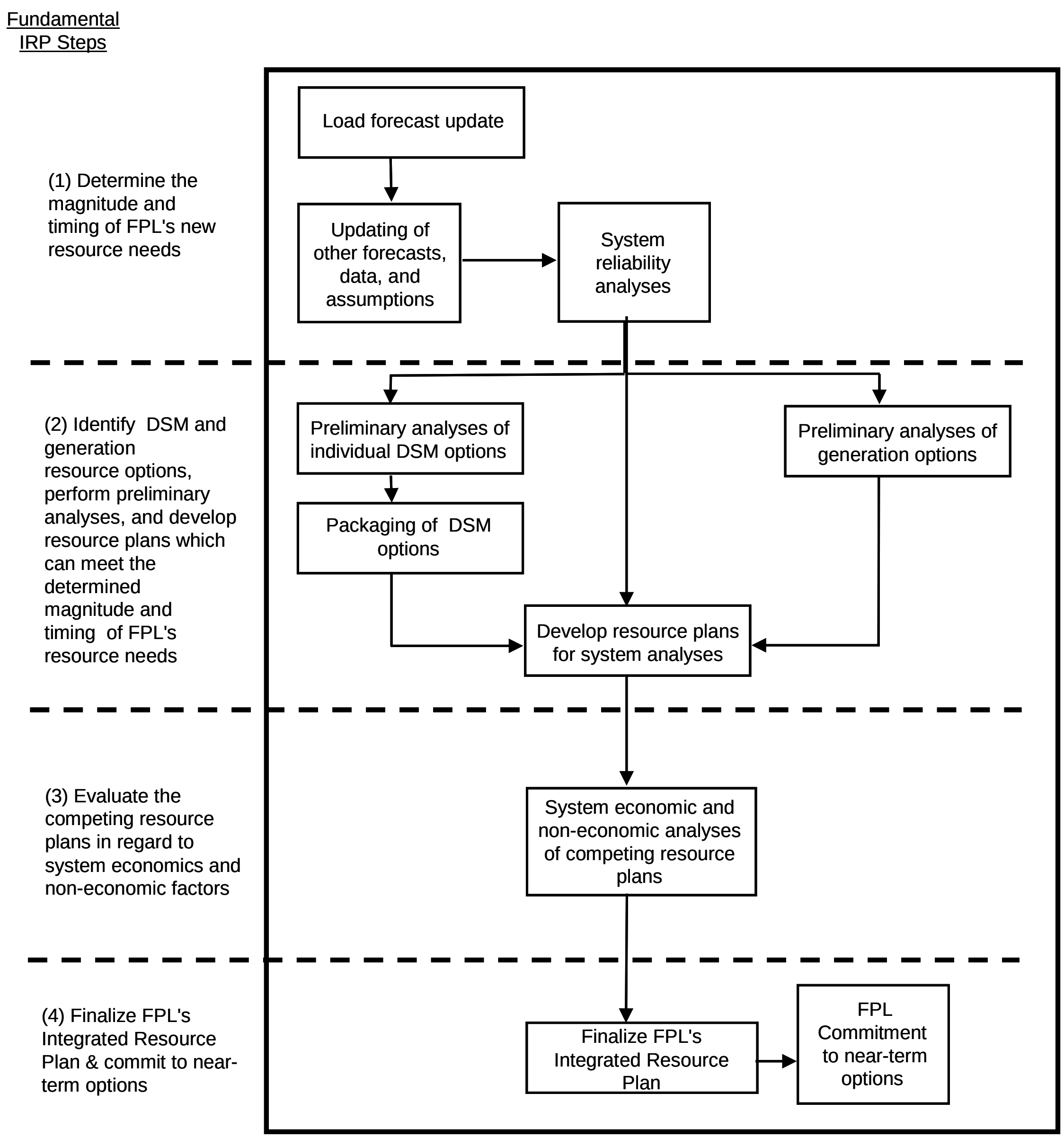

Figure III.A.1: Overview of FPL's IRP Process

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of the four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed to maintain system reliability. Also determined in this step is when the MW additions are needed to meet FPL's reliability criteria. This step is often referred to as a reliability assessment, or resource adequacy, analysis for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include, but are not limited to: delivered fuel price projections, current financial and economic assumptions, and power plant capability and operating assumptions. FPL also includes key sets of assumptions regarding three specific types of resources: (1) FPL unit capacity changes, (2) firm capacity power purchases, and (3) demand side management (DSM) implementation.

Key Assumptions Regarding the Three Types of Resources:

The first set of assumptions, FPL unit capacity changes, is based on the current projection of new generating capacity additions and planned retirements of existing generating units. In FPL's 2014 Site Plan, there are five such projected capacity changes. These are listed below in chronological order:

1) Planned retirement of existing Putnam Units 1 & 2:

   Analyses conducted during 2013 and early 2014 showed that it would be cost-effective to retire the two existing units, Putnam Units 1 & 2, and replace the capacity with new combined cycle (CC) capacity at a later date and at a site to be determined. The new CC capacity would have a significantly better heat rate, thus reducing FPL's system fuel usage and system emissions. Consequently, FPL currently projects that the two existing units will be retired by the end of 2014.

2) CT upgrades at existing CC plant sites:

   In the fourth quarter of 2011, FPL started upgrading the 7FA combustion turbines (CT) that are components at a number of its existing CC units. These upgrades will economically benefit FPL's customers by increasing the MW output of these CC units by approximately 209 MW (Summer peak value) in total. As reflected in Schedule 1 in Chapter I, 133 MW of the increased capacity from these CT upgrades is already in service. The work for the remaining upgrades is continuing and the project is projected to be completed in 2015.

3) Modernization of the Port Everglades plant site:

The work to modernize the existing Port Everglades site by adding new combined cycle (CC) capacity continues. The new generating unit, called the Port Everglades Next Generation Clean Energy Center (PEEC), is projected to be in-service in mid-2016 and is projected to have a peak Summer output of 1,237 MW. The FPSC issued the final need order for this modernization project in April 2012 in Order No. PSC-12-0187-FOF-EI. The site certification order for the project, DOAH Case No. 12-0422EPP, was received for the Port Everglades project in October 2012. (Note that a similar modernization of the FPL's existing Riviera Beach plant site is scheduled to be completed on/near the April 1, 2014 filing date of this 2014 Site Plan.)

4) Retirement of existing gas turbines (GTs) in Broward County and partial capacity replacement with new combustion turbines (CTs) at FPL's Lauderdale plant site:

Due to new nitrogen dioxide (NO_2) environmental regulations, FPL filed in June 2013 for FPSC approval to recover costs for removing all of its existing GTs and replacing a portion of the GT capacity with new CTs. In December 2013, FPL withdrew this request pending additional environmental monitoring and analyses. Computer modeling of the emissions from the GTs projected that the GTs would exceed the new NO_2 limit. FPL believes this monitoring and analyses will confirm that the operation of its existing GTs in Broward County will not comply with the new NO_2 regulations. Therefore, for planning purposes, FPL has assumed that all of its existing Broward County GTs will be removed (a loss of 1,260 MW Summer) and that this capacity will be partially replaced by 5 new CTs that would be sited in Broward County (an increase of 1,005 MW Summer). This GT removal and CT partial replacement is assumed to occur by the end of 2018.

5) Turkey Point Nuclear Units 6 & 7:

FPL is continuing its work to obtain all of the licenses, permits, and approvals that will be necessary to construct and operate two new nuclear units at its Turkey Point site. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. FPL received need determination approval from the FPSC for the two nuclear units in April 2008 in Order No. PSC-08-0237-FOF-EI. The earliest deployment dates for these two new units, Turkey Point Units 6 & 7, remain 2022 and 2023, respectively. Each new nuclear unit is projected to have a peak Summer output of 1,100 MW.

Also in regard to FPL unit capacity changes, as part of FPL's planned acquisition of Vero Beach's electric utility system, FPL is projected to take ownership of Vero Beach's five existing generating units starting January 2015. The current plan, based on the units' poor economics, is to immediately retire three of these older generating units and operate the remaining two, which supply approximately 46 MW (Summer) of combined cycle capacity, for a maximum of three years.

The second set of assumptions involves firm capacity power purchases. FPL's current projection of firm capacity purchases has changed from the projection in the 2013 Site Plan in regard to only two purchases. As part of the projected agreement that FPL will begin serving Vero Beach's electrical needs beginning in January 2015, FPL has acquired two existing power purchase agreements totaling approximately 37 MW of coal-fired capacity. These agreements are now projected to run through the end of 2017 instead of 2016 as projected in FPL's 2013 Site Plan. In addition, FPL now projects that Internal Revenue Service (IRS) regulations regarding the amount of energy that FPL can receive under its purchase agreement with Jacksonville Electric Authority (JEA) for St. Johns Regional Power Park (SJRPP)-based capacity and energy will not result in the suspension of the delivery of capacity and energy receipts to FPL until April 2019. [4]

None of the other purchase projections has changed from those in the 2013 Site Plan. FPL's current projection includes an additional 70 MW from the Palm Beach Solid Waste Authority (SWA) starting in year 2015. In addition, FPL projects that it will begin receiving a total of 180 MW of firm capacity in 2021 from biomass-based power purchase agreements with EcoGen.

In total, the projected firm capacity purchases are from a combination of utility and independent power producers. Details, including the annual total capacity values for these purchases, are presented in Chapter I in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's resource planning work.

The third set of assumptions involves a projection of the amount of additional DSM that is anticipated to be implemented annually over the ten-year period. A key aspect of FPL's IRP process is the evaluation of DSM resources. Since 1994, FPL's resource planning work has assumed that, at a minimum, the DSM MW called for in FPL's FPSC-approved DSM Plan will be achieved. In 2014, FPL is required to propose new DSM Goals for the 2015 through 2024 time period. Those proposed goals will be filed with the FPSC on April 2, 2014; i.e., one day after this 2014 Site Plan is filed with the FPSC. FPL's filing to support its proposed DSM goals provides extensive detail regarding how DSM resources were evaluated in FPL's most current IRP planning

[4] FPL's projected suspension date for the SJRPP purchase is based on a system reliability perspective and represents the earliest projected date at which the suspension of capacity and energy could occur.

analyses. The DSM assumptions presented in this 2014 Site Plan, and which are assumed in the analyses whose results are reflected in the Site Plan, are consistent with FPL's proposed goals. The FPSC is expected to make a decision regarding FPL's 2015 – 2024 DSM Goals later in 2014.

The Three Reliability Criteria Used to Determine FPL's Projected Resource Needs:

These key assumptions, plus the other updated information described above, are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's future resource needs. This determination is accomplished by system reliability analyses which for FPL have traditionally been based on dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry. Beginning this year, FPL is also using a third reliability criterion: a 10% generation-only reserve margin (GRM) criterion.

Historically, two types of methodologies, deterministic and probabilistic, have been utilized in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Among the most widely used is loss-of-load probability (LOLP) which FPL utilizes. Simply stated, LOLP is an index of how well a generating system may be able to meet its firm demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in terms of the projected probability that a utility will be unable to meet its entire firm load at some point during a year. The probability of not being able to meet the entire firm load is calculated for each day of the year using the daily peak hourly load. These daily probabilities are then summed to develop an annual probability value. This annual probability value is commonly expressed as "the number of days per year" that the entire system firm load could not be met. FPL's standard for LOLP, commonly accepted throughout the industry, is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

FPL's recent integrated resource planning work has resulted in FPL's resource plans showing a significant shift in the mix of generation and DSM resources over the next 10 years in regard to the relative contribution of these resources to system reliability. In order to gauge the extent of this shift and its potential implications for FPL's system reliability, FPL developed a new metric: a generation-only reserve margin (GRM). This GRM metric reflects reserves that would be provided only by actual generating resources. The GRM value is calculated by setting to zero all incremental energy efficiency (EE) and load management (LM), plus all existing LM, in a reserve margin calculation. The resulting GRM value provides an indication of how large a role generation is projected to play in each year as FPL maintains its 20% Summer and Winter "total" reserve margins (which account for both generation and DSM resources).

FPL has been reporting the GRM metric in its Site Plans since 2011 when it presented projections of its Summer GRM for the years 2011-2020. The 2011 projection showed a steady decrease in GRM values from a "balanced" 11.5% in 2011 to much reduced 7.2% by 2020. In its 2012 Site Plan, FPL's projected GRM values steadily decreased over the 10-year period from 16.2% in 2012 to 5.5% in 2021. The projected pattern in the 2013 Site Plan was similar: a steady decrease from 16.3% in 2013 to 6.9% in 2021. (The projected GRM value for 2022 presented in the 2013 Site Plan increased to 8.9% due to the planned addition of the new Turkey Point 6 nuclear unit in 2022.) Thus FPL's resource planning projections over the last 3 years have each shown a general downwards trend in projected GRM in the latter portion of this decade. This indicates increasing reliance on DSM resources, particularly EE resource additions, and decreasing reliance on generation resources, to maintain system reliability. As a result, FPL has analyzed what impact(s) this trend could have on system reliability. Two types of evaluations were conducted. One of these evaluations is from the perspective of FPL's system operators who are responsible for operating the bulk electric system. The other evaluation is from a resource planning perspective.

The first evaluation examined what impact an increasing reliance on EE resource additions was projected to have on the amount and type of reserves that operators would have at their disposal to meet load on a system peak hour. FPL first used a "looking back" perspective at a recent actual peak load day of January 11, 2010 to see how the system actually operated. Then, assuming a "what if" situation in which the system was assumed to have been designed to have an identical total reserve margin, but higher and lower GRM respectively, FPL analyzed what the impact would have been on FPL's ability to serve its customers on that peak day with these alternative assumed systems.

FPL also performed analyses taking a "looking forward" perspective at the projected year of 2021. Three scenarios were analyzed: (i) the system with its projected GRM and total reserve margin values consistent with the 2013 Site Plan; (ii) a system with an identical total reserve margin, but a higher GRM; and (iii) a system with an identical total reserve margin, but a lower GRM. Recognizing that the impacts from EE resource additions will already have been accounted for in the peak load that system operators must react to on an actual peak day, the analyses assumed an adverse peak day situation which consisted of significantly higher load and significantly less available generation than projected. The results from both the "looking back" and "looking forward" analyses were similar. For resource plans with identical total reserve margins, but different GRM levels, system operators were projected to have significantly higher levels (MW) of reserves, either generation and/or load management reserves, available on the peak days with a resource plan that had a higher GRM level than with a resource plan that had a lower GRM level. Thus a resource plan with a higher GRM, compared with a lower GRM, results in better system reliability for customers due to a greater likelihood of meeting customers' firm demand on peak load days, despite unexpected conditions or events. Better system reliability to customers translates to a reduced risk of shedding firm load.

The second evaluation was from the resource planning perspective of loss-of-load-probability (LOLP). For this evaluation, FPL also analyzed resource plans with identical total reserve margins, but higher and lower GRM levels. The results of these analyses for the FPL system showed that a resource plan with a higher GRM resulted in a projection of lower LOLP values than a resource plan with a lower GRM.

Based on these operational and resource planning evaluations, FPL has concluded that resource plans for its system with identical total reserve margins, but different GRM values, are not equal in regard to system reliability. A resource plan with a higher GRM value is projected to result in more MW being available to system operators on adverse peak load days, and in lower LOLP values, than a resource plan with a lower GRM value, even though both resource plans have an identical total reserve margin. Therefore, FPL has applied a minimum GRM criterion as a third reliability criterion in its resource planning process.

Based on the expertise and experience of FPL's system operators regarding the amount of generation MW needed for reliable operations, the GRM criterion is set at a minimum of 10% for Summer and Winter. From an operational perspective, FPL believes it is necessary to have approximately 2,650 MW of generation reserves. These reserves will allow FPL to address a variety of operational considerations including: (i) unplanned generation unavailability; (ii) the deployment of real-time operating reserves to meet its 15-minute obligations as part of the Florida Reserve Sharing Group; (iii) the requirement pursuant to NERC Reliability Standards to replace with other resources within 30 minutes following the unplanned loss of a large generation unit; and (iv) higher-than-forecasted loads. The sum of the operational reserves to cover for these requirements and considerations is approximately 2,650 MW. This MW value is consistent with a 10% GRM for the foreseeable future. FPL is planning its system so that the minimum 10% GRM criterion is met beginning in the Summer of 2019.

The 10% minimum Summer and Winter GRM criterion augments the two existing reliability criteria used by FPL: a 20% total reserve margin criterion for Summer and Winter, and a 0.1 day/year LOLP criterion. The total reserve margin and LOLP criteria continue to identify the timing and magnitude of FPL's future resource needs. The GRM criterion provides direction regarding the mix of generation and DSM resources that should be added to maintain and enhance FPL's system reliability.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, preliminary economic screening analyses of new capacity options that are identical, or virtually identical, in regard to certain key characteristics may be conducted to determine which new capacity options appear to be the most competitive on FPL's system. This preliminary analysis work can also help identify capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. Similarly, preliminary economic screening analyses of new DSM options and/or evaluation of existing DSM options are often conducted in this second fundamental IRP step.

FPL typically utilizes the P-MArea production cost model and a Fixed Cost Spreadsheet, and/or an optimization models and spreadsheet analyses, to perform the preliminary economic screening of generation resource options. For the preliminary economic screening analyses of DSM resource options, FPL typically uses its DSM CPF model which is an FPL spreadsheet model utilizing the FPSC's approved methodology for performing preliminary economic screening of individual DSM measures and programs. In addition, a years-to-payback screening test based on a two-year criterion is also used in the preliminary economic screening of individual DSM measures and programs. Then, as the focus of DSM analyses progresses from analysis of individual DSM measures to the development of DSM portfolios, FPL uses two additional models. One of these models is FPL's non-linear programming model that is used for analyzing the potential for lowering system peak loads through additional load management/demand response capability. The other model that FPL typically utilizes is its linear programming model with which FPL develops DSM portfolios.

The individual new resource options, both Supply options and DSM portfolios, emerging from these preliminary economic screening analyses are then typically "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's projected new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet and/or dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans in Regard to System Economics and Non-Economic Factors:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for evaluating these resource options and resource plans in system economic analyses that aim to account for all of the impacts to the FPL system from the competing resource options/resource plans. In FPL's 2013 and early 2014 resource planning work, once the resource plans were developed, FPL utilized the P-MArea production cost model and a Fixed Cost Spreadsheet, and/or the Strategist model, to perform the system economic analyses. Other spreadsheet models may also be used to further analyze the resource plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM methodology). In analyses in which the DSM contribution has already been determined through the same IRP process and FPSC approval, and therefore the only competing options were new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and resource plans in such cases can be evaluated on a system cumulative present value revenue requirement (CPVRR) basis.

Other factors are also included in FPL's evaluation of resource options and resource plans. While these factors may have an economic component or impact, they are often discussed in quantitative, but non-economic, terms such as percentages, tons, etc. rather than in terms of dollars. These factors are often referred to by FPL as "system concerns" that include (but are not limited to) maintaining/enhancing fuel diversity in the FPL system, system emission levels, and maintaining a regional balance between load and generating capacity, particularly in the Southeastern Florida counties of Miami-Dade and Broward. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL's system, the non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan. These, and other, factors are discussed later in this chapter in section III.C.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps are typically used to develop FPL's current resource plan. The current resource plan is presented in the following section.

III.B Projected Incremental Resource Additions/Changes in the Resource Plan

FPL's projected incremental generation capacity additions/changes for 2014 through 2023 are depicted in Table III.B.1. These capacity additions/changes include the 5 generation additions/changes previously discussed. The table shows three more generation changes: a CC unit being added in 2019, a short-term PPA of 129 MW being added in 2020, and a short-term PPA of 168 MW being added in 2021. The CC unit is added in 2019 to meet the Summer total reserve margin criterion and the two PPAs are added in 2020 and 2021 to meet the GRM criterion.

Although FPL's projected DSM additions that are developed in the IRP process are not explicitly presented in this table, these DSM additions have been fully accounted for in all of FPL's resource planning work reflected in this document. The projected MW reductions from these DSM additions are also reflected in the projected total reserve margin values shown in the table below and in Schedules 7.1 and 7.2 presented later in this chapter. DSM is further addressed later in this chapter in section III.D.

III.C Discussion of the Projected Resource Plan and Issues Impacting FPL's Resource Planning Work

As indicated in the Executive Summary, FPL's resource planning efforts in 2013 and early 2014 were influenced by a number of factors. These factors are expected to continue to influence FPL's resource planning work for the foreseeable future. In addition, other factors may also influence FPL's on-going resource planning work in the future and may result in changes to the resource plan discussed in this document. Eight (8) of these factors are discussed below (in no particular order of importance).

1) Maintaining/enhancing fuel diversity in the FPL system;
2) Maintaining a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward Counties;
3) Updated projections of Federal and state energy efficiency codes and standards;
4) Decline in the projected cost-effectiveness of utility DSM measures and programs;
5) FPL's growing dependence upon DSM resources to maintain system reliability;
6) The schedule for the new Turkey Point Nuclear Units 6 & 7;
7) Environmental regulation and/or legislation; and,
8) Possible establishment of a Florida standard for renewable energy or clean energy.

These 8 factors, and their various impacts on FPL's resource planning efforts including the current resource plan that is presented in this Site Plan, are briefly discussed below.

1. Maintaining/Enhancing System Fuel Diversity:

FPL currently uses natural gas to generate approximately 2/3 of the total electricity it delivers to its customers. In the future, the percentage of FPL's electricity that is generated by natural gas is projected to remain at a high level. For this reason, and due to evolving environmental regulations, FPL is continually seeking opportunities to economically maintain and enhance the fuel diversity of its system.

In 2007, following express direction by the FPSC to do so, FPL sought approval from the FPSC to add two new advanced technology coal units to its system. These two new units would have been placed in-service in 2013 and 2014. However, in part due to concerns over potential greenhouse gas emission legislation/regulation, FPL was unable to obtain approval for these units. Several other factors are currently unfavorable to new coal units compared to new CC units. The first of these factors is a significant reduction in the fuel cost difference between coal and natural gas compared to the fuel cost difference projected in 2007 that favored coal; i.e., the projected fuel cost advantage of coal versus natural gas has been significantly reduced. Second is the continuation of significantly higher capital costs for coal units compared to capital costs for CC units. Third is the increased fuel efficiency of new CC units compared to projected CC unit efficiencies in 2007. Fourth are existing and proposed environmental regulations, including those that address greenhouse gas emissions, that are unfavorable to new coal units when compared to new CC units. Consequently, FPL does not believe that new advanced technology coal units are currently economically, politically, or environmentally viable fuel diversity enhancement options in Florida.

Therefore, FPL has turned its attention to nuclear energy and renewable energy to enhance its fuel diversity, to diversifying the sources of natural gas, to diversifying the gas transportation paths used to deliver natural gas to FPL's generating units, and to using natural gas more efficiently. In regard to nuclear energy, in 2008 the FPSC approved the need to increase capacity at FPL's four existing nuclear units and authorized FPL to recover project-related expenditures that are approved as a result of annual nuclear cost recovery filings. FPL has now successfully completed the nuclear capacity uprate project. Approximately 520 MW of additional nuclear capacity were delivered by the project which represents an increase of approximately 30% more capacity than was originally forecasted when the project began. FPL's customers are already benefitting from lower fuel costs and reduced system emissions provided by this additional nuclear capacity.

FPL is continuing its work to obtain all of the licenses, permits, and approvals that would be necessary to construct and operate two new nuclear units at its Turkey Point site in the future. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. The earliest deployment dates for the two new nuclear units, Turkey Point Units 6 & 7, remain 2022 and 2023, respectively.

FPL also has been involved in activities to investigate adding or maintaining renewable resources as a part of its generation supply. One of these activities is a variety of discussions with the owners of existing facilities aimed at maintaining or extending current agreements. In addition, FPL considers new cost-effective renewable energy projects such as the power purchase agreements with EcoGen that will result in FPL receiving 180 MW of firm capacity from biomass facilities beginning in 2021.

FPL also sought and received approval from the FPSC in 2008 to add 110 MW through three new FPL-owned solar facilities: one solar thermal facility and two photovoltaic (PV) facilities.

One 25 MW PV facility began commercial operation in 2009. The remaining two solar facilities, a 10 MW PV facility and a 75 MW solar thermal steam generating facility, began commercial operation in 2010. The addition of these renewable energy facilities was made possible due to enabling legislation from the Florida Legislature in 2008. FPL remains strongly supportive of federal and/or state legislation that enables electric utilities to add renewable energy resources and authorize the utilities to recover appropriate costs for these resources. FPL is planning to introduce two new PV-based solar programs in 2014. These are discussed further in section III.F.4 of this chapter.

In regard to using natural gas more efficiently, FPL received approvals in 2008 from the FPSC to modernize the existing Cape Canaveral and Riviera Beach plant sites with new, highly efficient CC units that replace the former steam generating units on each of those sites. The Cape Canaveral modernization was commissioned on April 24, 2013 and the Riviera Beach modernization is projected to go in-service on/near the April 1, 2014 date this 2014 Site Plan is filed with the FPSC. On April 9th, 2012, FPL received FPSC approval to proceed with a similar modernization project at the Port Everglades site which is scheduled for completion in mid-2016. The modernization of the Port Everglades site will retain the capability of receiving water-borne delivery of oil as a backup fuel.

In regard to diversity in natural gas sourcing and delivery, in 2013 FPL was granted approval from the FPSC to build a new 3rd natural gas pipeline into Florida and FPL's service territory. The process to obtain approval for the new pipeline from the Federal Energy Regulatory Commission (FERC) is underway. The new pipeline will utilize a new route that will result in a more reliable, more economic, and more diverse natural gas supply for FPL's customers and the state of Florida.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity. In this regard, FPL is maintaining the ability to utilize fuel oil at existing units that have that capability. For this purpose, FPL has installed electrostatic precipitators (ESPs) at its two 800 MW steam generating units at the Manatee site and at one of its two 800 MW steam generating units at the Martin site. FPL is in the process of installing ESPs on its remaining 800 MW steam generating unit at the Martin site. These installations will enable FPL to retain the ability to burn oil, as needed, at these sites while retaining the flexibility to use natural gas when economically attractive.

2. Maintaining a Balance Between Load and Generation in Southeastern Florida:

An imbalance has existed between regionally installed generation and regional peak load in Southeastern Florida. As a result of that imbalance, a significant amount of energy required in the Southeastern Florida region during peak periods is provided by operating less efficient generating units located in Southeastern Florida out of economic dispatch, by importing the energy through the transmission system from plants located outside the region, or by a combination of the two. FPL's prior planning work concluded that, as load inside the region grows, either additional installed generating capacity in this region, or additional installed transmission capacity capable of delivering more electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location, four recent capacity addition decisions (Turkey Point Unit 5 and WCEC Units 1, 2, & 3) were determined to be the most cost-effective options to meet FPL's capacity needs in the near-term. In addition, FPL has added increased capacity at FPL's existing two nuclear units at Turkey Point as part of the previously mentioned nuclear capacity uprates project. The Port Everglades modernization project scheduled for completion in 2016 will also assist in addressing this imbalance. Adding the additional generation capacity through the projects mentioned above contributes to addressing the imbalance between generation, transmission capacity, and load in Southeastern Florida for approximately the remainder of this decade.

The planned addition of two new nuclear units at FPL's Turkey Point site, Turkey Point Unit 6 in 2022 and Turkey Point Unit 7 in 2023, will also address the imbalance issue for an additional period of time beginning in the next decade. Due to forecasted steadily increasing load in the Southeastern region, the Southeastern Florida imbalance issue will remain an important consideration in FPL's on-going resource planning work in future years.

3. Projections of Federal and State Energy Efficiency Codes and Standards:

As discussed in Chapter II, FPL's load forecast includes projected impacts from federal and state energy efficiency codes and standards. The magnitude of energy efficiency that is now projected to be delivered to FPL's customers through these codes and standards is significant.

In FPL's 2013 Site Plan, the projected cumulative Summer peak impact for the year 2022 from the codes and standards since 2005 was 2,898 MW compared to what the projected load would have been without the codes and standards. The current projection of cumulative Summer peak impact for the year 2023 from the codes and standards since 2005 is 3,477 MW.

In addition to lowering FPL's load forecast from what it otherwise would have been, and thus serving to lower FPL's projected resource needs, this projection of efficiency from the codes and standards also affects FPL's resource planning in another way. The projected impacts from the efficiency codes and standards lower the potential for utility DSM programs to deliver energy efficiency for the appliances and equipment that are directly addressed by the codes and standards. This effect is taken into account in FPL's proposed DSM Goals for the 2015 – 2024 time period and it is one reason why FPL's resource plan shows a diminished role for utility DSM for the years addressed by this 2014 Site Plan.

4. **Decline in the Projected Cost-Effectiveness of Utility DSM Measures and Programs:** There is another important reason why FPL's resource plan currently shows a diminished role for utility DSM: a decline in the projected cost-effectiveness of utility DSM measures and programs. The supporting testimony that FPL is filing in the DSM Goals proceeding discusses in detail the reasons for the declining cost-effectiveness of DSM. One portion of that discussion is summarized here for illustrative purposes.

The cost-effectiveness of DSM is driven in large part by the potential benefits that the kw (demand) reduction and kwh (energy) reduction characteristics of DSM programs are projected to provide. This discussion focuses solely on the current projection of potential benefits that DSM's kwh reductions can provide. At least three factors are each resulting in projections of lower kwh reduction-based benefits and thus projections of lower DSM cost-effectiveness.

The first factor is lower fuel costs. For example, comparing current fuel cost forecasts with those forecasted in 2009 – the year when FPL's DSM Goals were last set by the FPSC – shows that current forecasted fuel costs are now much lower than those forecasted in 2009, particularly in the near-term. This can be seen by comparing the 2009 and current forecasted costs ($/mmBTU) for natural gas for two specific years addressed in this Site Plan and which were addressed in the 2009 DSM goals-setting: 2015 and 2019:

Year	2009 Forecast	Current Forecast
2015	$9.64	$4.26
2019	$12.63	$6.15

As shown from these values, natural gas prices are currently forecast to be less than 50% of what they were forecast to be in 2009 when DSM goals were last set. Although lower forecasted natural gas costs are a very good thing for FPL's customers, lower fuel costs also result in lower potential fuel savings benefits from the kWh reductions of DSM measures. These lowered benefit values result in DSM being less cost-effective.

A second factor contributing to the decline in the cost-effectiveness of utility DSM is the steadily increasing efficiency with which FPL generates electricity. FPL's generating system has steadily gotten more efficient in regard to its ability to generate electricity using less fossil fuel. For example, FPL used 20% less fossil fuel to generate the same number of kwh in 2012 than it did in 2001. This is a very good thing for FPL's customers because it helps to significantly lower fuel costs.

The improvements in generating system efficiency affect DSM cost-effectiveness in much the same way that lower forecasted fuel costs do: both lower the fuel costs of energy delivered to FPL's customers. Therefore, the improvements in generating system efficiency further reduce the potential fuel savings benefits from the kWh reduction impacts of DSM, thus lowering potential DSM benefits and DSM cost-effectiveness.

A third factor for declining cost-effectiveness of utility DSM is due to significant changes in projected carbon dioxide (CO_2) compliance costs. For example, comparing CO_2 compliance forecasts with those forecasted in 2009 – the year when FPL's DSM Goals were last set by the FPSC – shows that current forecasted compliance costs are much lower than those forecasted in 2009, particularly in the near-term. This can be seen by comparing the 2009 and current forecasted costs ($/ton) for two specific years addressed in this Site Plan and which were addressed in the 2009 DSM goals-setting: 2015 and 2019:

Year	2009 Forecast	Current Forecast
2015	$17.00	$0.00
2019	$25.00	$0.00

(FPL's current forecast does not project non-zero CO_2 compliance costs until the year 2023.) While lower forecasted CO_2 compliance costs are again a good thing for FPL's customers, lower compliance costs also result in lower compliance cost savings benefits from the kWh reductions of DSM measures. These lower potential DSM benefits again result in lowering DSM cost-effectiveness.

Each of these three factors discussed above – lower forecasted fuel costs, greater efficiency in FPL's electricity generation, and lower forecasted CO_2 compliance costs – are good for FPL's customers because they will result in lower electric rates. Although good for FPL's customers, these factors also contribute to lowering the cost-effectiveness of utility DSM programs. Therefore, these factors (and other factors not discussed above), plus the growing impacts of energy efficiency codes and standards, lead to FPL's resource plan showing a diminished role for utility DSM.

5. **FPL's Increasing Dependence On DSM Resources to Maintain System Reliability:**

As discussed earlier in section III.A of this chapter, FPL's 2011, 2012, and 2013 Site Plans each projected that FPL's system was becoming increasingly dependent upon DSM resources to maintain system reliability. FPL's analyses of this projected trend showed that, from an operational perspective, there can be significant differences between resources plans on the peak day even though the resource plans have identical total reserve margins. For this reason, FPL has begun using a 10% minimum generation-only reserve margin (GRM) in its resource planning work to complement its existing 20% total reserve margin and 0.1 day/year LOLP reliability criteria. FPL will begin applying the GRM criterion in the year 2019.

6. **The Schedule for the New Turkey Point Nuclear Units 6 & 7:**

At the time the 2014 Site Plan is being finalized, the schedule for the project is under review. Several items will be considered that potentially influence the project schedule, including the Nuclear Regulatory Commission's (NRC's) schedule for reviewing the Combined Operating License Application (COLA), the impacts of the recently amended nuclear cost recovery clause (NCRC) statute, and the ongoing feasibility analyses that are part of the NCRC process.

7. **Environmental Regulation and/or Legislation:**

The seventh factor is environmental regulation. As developments occur in regard to either new environmental regulations, and/or in how environmental regulations are interpreted and applied, the potential exists for such developments to affect FPL's resource plan that is presented in this document. For example, FPL is aware of potential impacts to generating units of recent EPA changes to the National Ambient Air Quality Standards that include shorter duration 1-hour standards for nitrogen dioxide (NO_2) and sulfur dioxide (SO_2). As a consequence, FPL filed in mid-2013 for FPSC approval to recover costs through the environmental cost recovery clause for removing all of its existing gas turbines (GTs) and partially replacing that peaking unit capacity with new combustion turbines (CTs). Although FPL withdrew its filing in December 2014 pending further analyses including on-site monitoring, FPL believes that the results of the monitoring and analyses will require that the Broward GTs be replaced. Therefore, FPL is currently projecting the retirement of all GTs in Broward County; i.e., at its existing Lauderdale and Port Everglades plant sites (a decrease in generating capacity of 1,260 MW Summer), and the installation of 5 new 201 MW CTs at its existing Lauderdale plant site (an increase of 1,005 MW Summer), both by the end of 2018.

8. **Possible establishment of a Florida standard for renewable energy or clean energy:** Although no such legislation has been enacted to-date, Renewable Portfolio Standards (RPS) or Clean Energy Portfolio Standard (CPS) legislation, or other legislative initiatives regarding renewable or clean energy contributions, may occur in the future at either the state or national level. If such legislation is enacted, FPL would then determine what steps need to be taken to address the legislation.

Each of these 8 factors will continue to be examined in FPL's on-going resource planning work during the rest of 2014 and in future years.

III.D Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978 and DSM has been a key focus of FPL's IRP process for decades. During that time FPL's DSM programs have included numerous energy efficiency and load management initiatives. FPL's DSM efforts through 2013 have resulted in a cumulative Summer peak reduction of approximately 4,753 MW (Summer) at the generator and an estimated cumulative energy saving of approximately 66,782 Gigawatt Hour (GWh) at the generator. After accounting for the 20% total reserve margin requirement, FPL's DSM efforts through 2013 have eliminated the need to construct the equivalent of approximately 14 new 400 MW power plants.

FPL has consistently been among the leading utilities nationally in DSM achievement. For example, according to the U.S. Department of Energy's 2012 data (the last year for which the DOE data was available at the time this Site Plan is being developed), FPL ranked # 2 nationally in cumulative DSM demand reduction. And, importantly, FPL has achieved these significant DSM accomplishments while minimizing the DSM-based impact on electric rates for all of its customers.

In 2014, new DSM Goals for the years 2015 through 2024 will be set for FPL by the FPSC. As part of this goals-setting process, FPL must propose new DSM Goals for this time period based on its most recent resource planning analyses. The results of those analyses are reflected in this 2014 Site Plan and FPL is filing its proposed new DSM Goals on April 2, 2014 (i.e., one day after the 2014 Site Plan is filed). As discussed in the previous section of this chapter, two factors have influenced the analyses that led to the amount of DSM that FPL is proposing as its new DSM Goals: (i) increased energy efficiency that will be delivered to FPL's customers through Federal and state energy efficiency codes and standards; and (ii) a decline in the projected cost-effectiveness of DSM measures.

Based on these factors and FPL's most recent resource planning analyses, FPL is proposing that its DSM Goals be set at 337 MW of Summer MW reduction. After accounting for the 20% total reserve margin requirements, this represents the elimination of the need to construct the equivalent of another 400 MW power plant. The resource plan presented in this 2014 Site Plan accounts for the proposed amount of annual DSM implementation through the year 2023 and the DSM contribution is shown in Schedules 7.1 and 7.2 that appear later in this chapter. The FPSC is expected to make its decision regarding what FPL's DSM Goals will be for 2015 through 2024 later this year.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy to FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV bulk transmission lines that must be certified under the Transmission Line Siting Act.

Table III.E.1: List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	St. Johns 1/	Pringle	25	Dec – 18	230	759
FPL	Manatee 2/	Bob White	30	Dec – 14	230	1195

1/ Final order certifying the corridor was issued on April 21, 2006. This project is to be completed in two phases. Phase I consisted of 4 miles of new 230 kV line (Pringle to Pellicer) and was completed in May-2009. Phase II consists of 21 miles of new 230 kV line (St. Johns to Pellicer) and is scheduled to be completed by Dec-2018.
2/ Final order certifying the corridor was issued on November 6, 2008. This project consists of 30 miles of new 230 kV line (Manatee to Bob White) and is scheduled to be completed by Dec-2014

In addition, there will be transmission facilities needed to connect several of FPL's projected generating capacity additions to the system transmission grid. These transmission facilities (described on the following pages) are for the Port Everglades modernization, the planned Lauderdale gas turbine replacements, and the planned new nuclear capacity addition at the Turkey Point site from Turkey Point Units 6 & 7.[5] Please see discussion in the Turkey Point Preferred Site section, subsection r, of the possibility of a transmission corridor/land swap between FPL and the National Park Service. At the time the 2014 Site Plan is being prepared, no

[5] Please see discussion in the Turkey Point Preferred Site section, subsection r of the possibility of a transmission corridor/land sway between FPL and National Park Service.

site has been selected for the planned addition of a CC unit in 2019. Therefore, no transmission information for this new unit is presented.

II.E.1 Transmission Facilities for Port Everglades Next Generation Clean Energy Center (Modernization)

The work required to connect the Port Everglades Next Generation Clean Energy Center in 2016 to the FPL grid is projected to be:

I. Substation:

1. Construct two string busses to connect two combustion turbines (CT) to the Port Everglades 138 kV Substation.
2. Construct two string busses to connect one CT, and one steam turbine (ST) to the Port Everglades 230 kV Substation.
3. Add four main step-up transformers (3-450 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. Replace ten (10) 138 kV breakers.
5. Replace eight (8) 230 kV breakers.
6. At Port Everglades Switchyard replace twenty-two 138 kV disconnect switches. Also upgrade associated jumpers, bus work, and equipment connections.
7. Expand switchyard relay vault and add relays and other protective equipment.

II. Transmission:

1. Upgrade of existing transmission facilities:
   - An ampacity upgrade up to 1905 amps on the Port Everglades-Port Everglades Tap 138kV line section.
   - An ampacity upgrade up to 1905 amps on the Port Everglades Tap-Port Everglades Tap 2 138 kV line section.
   - An ampacity upgrade up to 1695 amps on the Port Everglades Tap 1-Dania 138 kV line section.
   - An ampacity upgrade up to 1695 amps on the Dania-Hollywood 138 kV line section.

III.E.2 Transmission Facilities for the Lauderdale GT Replacement Project

The work required to connect the five Lauderdale combustion turbines (CT) in 2018 to the FPL grid is projected to be:

I. Substation:

1. Construct a collector switchyard for the five (5) CTs at Lauderdale Plant.
2. Install five (5) main step-up transformers (5 - 320 MVA), one for each CT.
3. Construct one 230 kV collector buss to connect two (2) CT step-up transformers to collector switchyard.
4. Construct one 138 kV collector buss to connect two (2) CT step-up transformers to collector switchyard.
5. Construct Cable Termination Structures (CTS) in the collector switchyard and the Lauderdale 138 kV Substation to connect the 138 kV collector buss for the two CTs to the Lauderdale 138 kV Substation Outside Bus.
6. Construct CTS in the collector switchyard and the Lauderdale 138 kV Substation to connect the fifth CT to the Lauderdale 138 kV Substation Inside Bus.
7. Add relays and other protective equipment.

II. Transmission:

1. Construct overhead 230 kV string bus to connect the 230 kV collector buss to the Lauderdale 230 kV Substation Inside Bus.
2. Construct two (2) underground 138 kV cables connecting the collector switchyard to the Lauderdale Substation Inside and Outside Busses.

III.E.3 Transmission Facilities for Turkey Point Nuclear Unit 6

The work required to connect the Turkey Point Nuclear Unit 6 by Summer 2022 to the FPL grid is projected to be:

I. Substation:

1. Build new Clear Sky 500/230kV Switchyard with six (6) bays on the 230 kV section for generator main step-up transformer connection, reserve auxiliary transformer connections, four (4) 230 kV line terminals, two (2) autotransformers and two (2) 500 kV line terminals.
2. At Turkey Point Switchyard add a new bay to accommodate the Turkey Point-Clear Sky 230 kV line terminal.
3. At Pennsuco Substation install a fourth line terminal to accommodate the Pennsuco-Clear Sky 230 kV line by converting the ring bus to a breaker and a half scheme and adding four (4) 230 kV breakers.
4. At Davis Substation construct two (2) new 230kV line terminals for the Clear Sky-Davis 230 kV line and the Davis-Miami 230 kV line.
5. At Levee Substation expand 500 kV section to accommodate the two (2) Levee-Clear Sky 500 kV lines.
6. At Andytown Substation install two (2) 5-Ohm inductors combined with external shunt capacitors on the 230kV side of the 500/230 autotransformers (one per auto).
7. At Miami Substation expand the 230kV section to a double bus configuration and add a new 230kV line terminal for Davis line and replace one (1) autotransformer.
8. Breaker replacements:
   Flagami Substation – Replace five (5) 230 kV breakers and three (3) 138 kV breakers
   Miami Substation – Replace one (1) 230 kV breaker and four (4) 138 kV breakers
   Davis Substation - Replace two (2) 230 kV breakers

II. Transmission:

1. FPL will design and construct two (2) 500kV transmission lines from the new Clear Sky Substation to the existing FPL Levee 500kV Substation switchyard. The lines will be approximately 43 miles long.
2. Construct a new Clear Sky-Davis 230kV line (approximately 19 miles) with a rating of 2990 Amperes.
3. Construct a new Clear Sky-Pennsuco 230kV line (approximately 52 miles) with a rating of 2990 Amperes.
4. Construct a new Davis-Miami 230kV line (approximately 18 miles) with a rating of 2297 Amperes.
5. Construct a new Clear Sky-Turkey Point 230kV line (approximately 0.5 miles) with a rating of 2990 Amperes.

III.E.4 Transmission Facilities for Turkey Point Nuclear Unit 7

The work required to connect the Turkey Point Nuclear Unit 7 by Summer 2023 to the FPL grid is projected to be:

I. Substation:

1. At Gratigny Substation install a second 230/138 kV autotransformer with one (1) 230 kV breaker and one (1) 138 kV breaker.
2. At Davis Substation construct a switch-able inductor to be installed on the Davis-Miami 230 kV line.
3. At Flagami Substation install a small inductor on one end of the Flagami-Miami 230kV #2 circuit.
4. Breaker replacements:
   Dade Substation - Replace seven (7) 230 kV breakers
   Court Substation – Replace one (1) 138 kV breaker.

II. Transmission:

1. The transmission line facilities required for Turkey Point Unit 7 will be constructed with the transmission line facilities needed for Turkey Point Unit 6, as described above in section III. E.3.

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to effectively utilize renewable energy technologies to serve its customers. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. For purposes of discussing FPL's renewable energy efforts in this document, those efforts will be placed into five categories.

Two of these categories are Supply-Side Efforts – Power Purchases, and Supply-Side Efforts – FPL Facilities. Since 2011, the energy (MWh) total output from these renewable energy sources has been greater than the energy produced from oil-fired generation. The renewable energy information is presented in Schedule 11.1, and the oil-based energy information is presented in Schedule 6.1 and in Schedule 11.1. Both of these schedules are presented at the end of this chapter.

1) <u>Early Research & Development Efforts:</u>

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970s in demonstrating the first residential photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-kilowatt (kW) system was placed into operation in 1984. (The system was removed in 1990 at the conclusion of the PV testing to make room for substation expansion.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. This FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site became the home for PV capacity which was installed as a result of other FPL renewable energy initiatives.

2) <u>Demand Side & Customer Efforts:</u>

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers who chose solar water heaters. Before the program ended (due to the fact that it was no longer projected to be cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for six passive home designs with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code was one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the FPSC to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test were deemed to be solvable, particularly when new pools are constructed. However, challenges included the significant percentage of sites with unacceptable shading and various customer satisfaction issues.

FPL has since continued to analyze and promote the utilization of PV. These efforts have included PV research, development, and education, as well as development and implementation of the FPL Next Generation Solar Station Program. This initiative also delivers teacher training and curriculum that is tied to the Sunshine Teacher Standards in Florida. The program provides teacher grants to promote and fund projects in the classrooms.

In addition, FPL assists customers who are interested in installing PV equipment at their facilities. Consistent with Florida Administrative Code Rule 25-6.065, Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned PV systems. Through December 2013, approximately 2,565 customer systems (predominantly residential) have been interconnected.

As part of its 2009 DSM Goals decision, the FPSC imposed a requirement for Florida's investor-owned utilities to spend up to a set, not-to-exceed amount of money annually to facilitate demand side solar water heater and PV applications. FPL's not-to-exceed amount of money for these applications is approximately $15.5 million per year through 2014. In regard to this direction, FPL received approval from the FPSC in 2011 to initiate a solar pilot portfolio that consists of three PV-based programs and three solar water heating-based programs, plus Conservation Research and Development. These programs are currently projected to be offered through 2014. FPL's analyses of the results to-date from these programs shows that none of these programs are projected to be cost-effective using any of the three cost-effectiveness screening tests used by the State of Florida. The fate of these solar programs, including their potential replacement with new solar initiatives, will be determined later in 2014 as part of the FPSC's 2014 DSM Goals docket.

FPL has also been investigating fuel cell technologies through monitoring of industry trends, discussions with manufacturers, and direct field trials. From 2002 through the end of 2005, FPL conducted field trials and demonstration projects of Proton Exchange Membrane (PEM) fuel cells with the objectives of serving customer end-uses while evaluating the technical performance, reliability, economics, and relative readiness of the PEM technology. The demonstration projects were conducted in partnership with customers and included five locations. The research projects were useful to FPL in identifying specific issues that can occur in field applications and the current commercial viability of this technology. FPL will continue to monitor the progress of these technologies and conduct additional field evaluations as significant developments in fuel cell technologies occur.

3) Supply Side Efforts – Power Purchases:

FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy, and as-available energy, have been purchased by FPL from these types of facilities. (Please refer to Tables I.B.1, I.B.2, and I.C.1 in Chapter I).

FPL issued Renewable Requests for Proposals (RFPs) in 2007 and 2008 soliciting proposals to provide firm capacity and energy, and energy only, at or below avoided costs, from renewable generators. FPL also promptly responds to inquiries for information from prospective renewable energy suppliers either by e-mail or phone.

On April 22, 2013 in Order No. PSC-13-1064-PAA-EQ, the FPSC approved three 60 MW power purchase agreements with affiliates of U.S. EcoGen for biomass-fired renewable energy facilities. These facilities are expected to begin service in 2019, and to begin providing firm renewable energy and capacity to FPL's customers in 2021.

With regard to existing contracts that have recently ended, FPL and the Solid Waste Authority of Palm Beach (SWA) agreed to extend their contract that expired March 31, 2010 for a 20-

year term beginning in April 1, 2012 through April 1, 2032. However, the SWA refurbished their generating unit ahead of schedule and, as of January 2012, this unit began delivering firm capacity to FPL. In 2011, the FPSC approved a contract for an additional 70 MW between FPL and SWA for a new unit to be constructed and to begin delivering firm capacity and energy beginning on January 1, 2015. At the end of December 2011, the contract between FPL and Okeelanta (New Hope) expired. However, Okeelanta continues to deliver energy to FPL as an as-available, non-firm supplier of renewable energy.

4) Supply Side Efforts – FPL Facilities:

With regard to solar generating facilities, FPL has three such facilities: (i) a 75 MW steam generation solar thermal facility in Martin County (the Martin Next Generation Solar Energy Center); (ii) a 25 MW PV electric generation facility in DeSoto County (the DeSoto Next Generation Solar Energy Center); and (iii) a 10 MW PV electric generation facility in Brevard County at NASA's Kennedy Space Center (the Space Coast Next Generation Solar Energy Center). The DeSoto County project was completed in 2009 and the other two projects were completed in 2010. These three solar facilities were constructed in response to the Florida Legislature's House Bill 7135 which was signed into law by the Governor in June 2008.

House Bill 7135 was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in the State of Florida. Specifically, the bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land, zoning, and transmission rights in place. FPL's three solar projects met the specified criteria, and were granted approval for cost recovery in 2008. Each of the three solar facilities is discussed below.

a. The Martin Next Generation Solar Energy Center:

This facility began commercial operation in 2010 and provides 75 MW of solar thermal capacity in an innovative way that directly displaces fossil fuel usage on the FPL system. This facility consists of solar thermal technology which generates steam that is integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired CC plant. This project is the first "hybrid" solar plant in the world, and, at the time the facility came in-service, was the second largest solar facility in the world and the largest solar plant of any kind in the U.S. outside of California.

b. The DeSoto Next Generation Solar Energy Center:

This PV facility began commercial operation in 2009 and provides 25 MW of non-firm capacity and energy, making it one of the largest PV facilities in the U.S. The facility utilizes a tracking PV array that is designed to follow the sun as it traverses across the sky.

c. <u>The Space Coast Next Generation Solar Energy Center:</u>

Located at the Kennedy Space Center, this facility is part of an innovative public/private partnership with NASA. This non-tracking PV facility began commercial operation in 2010 and provides 10 MW of non-firm capacity and energy.

At the time the 2014 Site Plan is being prepared, FPL considers the output from these renewable facilities to be "as available," non-firm energy only. This is due to several factors. First, the Martin solar thermal facility is a "fuel-substitute" facility, not a facility that provides additional capacity and energy. The solar thermal facility displaces the use of fossil fuel to produce steam on the FPL system when the solar thermal facility is operating. Second, in regard to the two PV facilities, the intermittent nature of the solar resource has made it difficult to-date to accurately determine what contribution the PV facilities at these specific locations can consistently make at FPL's late Summer afternoon and early Winter morning peak load hours. This is, in part, due to the fact that at least several years worth of Summer and Winter peak load periods are needed to accurately gauge the actual output of these PV facilities during system peak hours. FPL is now evaluating what portion, if any, of the PV facilities' output can be projected as firm capacity at the projected peak hours in FPL's resource planning work.

In addition to these three solar facilities, FPL is currently in the process of identifying other potential sites in the state for central station PV facilities. FPL is evaluating existing FPL generation sites along with potential Greenfield sites within FPL's service territory. These sites are discussed further in Chapter IV.

In regard to PV distributed generation (DG), FPL is planning to implement two PV DG solar programs in 2014. The first program is a voluntary customer participation program that will be pursued on a pilot basis. FPL will file for FPSC approval of this program near the April filing date of the 2014 Site Plan. The second program is designed to research the effects of increasing PV DG on the FPL system. This program will be introduced later in 2014. A brief description of the two programs follows.

d. <u>Voluntary, Community-based Solar Partnership Pilot Program</u>

FPL will be filing for FPSC approval of a tariff that provides customers an opportunity to make voluntary contributions toward the construction of PV facilities on a local level throughout FPL's service territory. The pilot program will provide all customers the opportunity to support the use of solar energy at a community scale, and is designed to be especially attractive for customers who do not wish, or are not able, to place solar equipment on their roof.

d. **C&I Solar Partnership Program:**

This is also a PV-focused research program that will be conducted in partnership with interested commercial and industrial (C&I) customers. Limited investments will be made in rooftop PV facilities in selected geographic areas in order to examine the effect of PV DG on FPL's distribution system. FPL will attempt to site these PV facilities in areas where PV DG already exists to better study feeder loading impacts. The PV facilities will be located on C&I customer property near the targeted feeders. The objective of the program is to gather data that will result in a better understanding of the effects of high PV DG penetrations on FPL's system.

5) **Ongoing Research & Development Efforts:**

FPL has developed alliances with several Florida universities to promote development of emerging technologies. For example, FPL has an alliance has been established with the newly formed Southeast National Marine Renewable Energy Center (SNMREC) at Florida Atlantic University (FAU), which will focus on the commercialization of ocean current, ocean thermal (i.e., energy conversion as well as cold water air conditioning), and hydrogen technologies. FPL has been supporting FAU with the discussions being held with the U.S. Department of the Interior's Minerals Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE). BOEMRE is working to establish the permitting process for ocean energy development on the outer continental shelf.

FPL has also developed a "Living Lab" to demonstrate FPL's solar energy commitment to employees and visitors at its Juno Beach office facility. To-date, FPL has installed five different PV arrays (different technologies) of rooftop PV totaling 24 kW at the Living Lab. In addition, two PV-covered parking structures with a total of approximately 90 kW of PV are in use at the FPL Juno office parking lot. Through these Living Lab projects, FPL is able to evaluate multiple solar technologies and applications for the purpose of developing a renewable business model resulting in the most cost-effective and reliable uses of solar energy for FPL's customers. FPL plans to continue to expand the Living Lab as new solar products come to market.

FPL has also been in discussions with several private companies on multiple emerging technology initiatives including ocean current, ocean thermal, hydrogen, fuel cell technology, biomass, biofuels, and energy storage

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fired generation. In the early 1980s, FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership (20%) and additional purchases (30%) from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit 4 which began serving FPL's customers in 1991.

The trend since the early 1990s has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective CC generating units and the ready availability of natural gas. Most recently, FPL placed into commercial operation two new gas-fired CC units at the West County Energy Center (WCEC) site in 2009. A third new CC unit was added to the WCEC site in 2011. In addition, FPL finished modernization of its Cape Canaveral and Riviera Beach plant sites and is currently modernizing its existing Port Everglades plant site by removing the steam generating units previously on the site and replacing them with one highly efficient new CC unit. The new CC units at each of these three sites will provide highly efficient generation that will dramatically improve the efficiency of FPL's generation system in general and, more specifically, the efficiency at which natural gas is utilized.

In addition, FPL increased its utilization of nuclear energy through capacity uprates of its four existing nuclear units. With these uprates, more than 520 MW of additional nuclear capacity have been added to the FPL system. FPL is also pursuing plans to obtain licenses, permits, and approvals to construct and operate two new nuclear units at its existing Turkey Point site that, in total, would add approximately 2,200 MW of new nuclear generating capacity. The earliest dates by which these two new nuclear units could practically be deployed remain 2022 and 2023, respectively.

In regard to utilizing renewable energy, FPL has a 110 MW of solar generating capacity through a 75 MW solar thermal steam generating facility at FPL's existing Martin site, a 25 MW PV facility in DeSoto County, and a 10 MW PV facility in Brevard County. The DeSoto facility was placed into commercial operation in 2009. The other two solar facilities were placed into commercial operation in 2010.

FPL's future resource planning work will continue to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance FPL's long-term fuel diversity. These fuel diverse alternatives may include: the purchase of power from renewable energy facilities, additional FPL-owned renewable energy facilities, obtaining additional access to diversified sources of natural gas such as liquefied natural gas (LNG) and natural gas from the Mid-Continent unconventional reserves, preserving FPL's ability to utilize fuel oil at its existing units, and increased utilization of nuclear energy. (As previously discussed, new advanced technology coal generating units are not currently considered as viable options in Florida in the ten-year reporting period of this document due, in part, to current projections of relatively small differences in fuel costs between coal and natural gas, significantly higher capital costs for coal units compared to CC units, greater efficiencies of CC units, and concerns over environmental regulations that would impact coal units more negatively than CC units.) The evaluation of the feasibility and cost-effectiveness of these, and other possible fuel diversity alternatives, will be part of FPL's on-going resource planning efforts.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2023 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

FPL's Fossil Fuel Cost Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future resource needs. FPL's forecasts are generally consistent with other published contemporary forecasts. An October 2013 fuel cost forecast was used in the analyses whose results led to the resource plan presented in this 2014 Site Plan.

Future oil and natural gas prices, and to a lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, coal, and petroleum coke. These drivers include U.S. and worldwide demand, production capacity, economic growth, environmental legislation, and politics.

The inherent uncertainty and unpredictability in these factors today and tomorrow clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal and petroleum coke) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed and utilized Low, Medium, and High price forecasts for fossil fuels in some of its 2013 and early 2014 resource planning work, particularly in regard to analyses conducted as part of the nuclear cost recovery filing work.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

a. For 2014 through 2015, the methodology used the October 7, 2013 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil, ultra low sulfur diesel fuel oil, and Henry Hub natural gas commodity prices;

b. For the next two years (2016 and 2017), FPL used a 50/50 blend of the October 7, 2013 forward curve and the most current projections at the time from The PIRA Energy Group;

c. For the 2018 through 2030 period, FPL used the annual projections from The PIRA Energy Group; and,

d. For the period beyond 2030, FPL used the real rate of escalation from the Energy Information Administration (EIA). In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach:

a. Delivered price forecasts for Central Appalachian (CAPP), Illinois Basin (IB), Powder River Basin (PRB), and South American coal and petroleum coke were provided by JD Energy; and,

b. The coal price forecast for SJRPP and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for oil, natural gas, coal, and petroleum coke prices were based on the historical volatility of the 12-month forward price, one year ahead. FPL developed these forecasts to account for the uncertainty which exists within each commodity as well as across commodities. These forecasts reflect a range of reasonable forecast outcomes.

3. Natural Gas Storage

FPL was under contract through March 2013 for 2 billion cubic feet (Bcf) of firm natural gas storage capacity in the Bay Gas storage facility located in Alabama. The Bay Gas storage facility is interconnected with the Florida Gas Transmission (FGT) pipeline. Starting on April 1, 2013, FPL entered into a new deal with Bay Gas Storage for one year for 2.5 billion cubic feet (Bcf) of firm natural gas storage capacity. In December 2013, FPL elected to extend this transaction for an additional three years which resulted in a lower annual cost for Bay Gas. FPL has predominately utilized natural gas storage to help mitigate gas supply problems caused by severe weather and/or infrastructure problems. Over the past several years, FPL has acquired upstream transportation capacity on several pipelines to help mitigate the risk of off-shore supply problems caused by severe weather in the Gulf of Mexico. While this transportation capacity has reduced FPL's off-shore exposure, a portion of FPL's supply portfolio remains tied to off-shore natural gas sources. Therefore, natural gas storage remains an important tool to help mitigate the risk of supply disruptions. For these reasons, FPL has typically maintained nearly full natural gas inventory during normal operations from June through November (hurricane season). From December through March, FPL typically maintains lower levels of natural gas inventory compared to Summer peak months.

As FPL's reliance on natural gas has increased, its ability to manage the daily "swings" that can occur on its system due to weather and unit availability changes has become more challenging, particularly from oversupply situations. Natural gas storage is a valuable tool to help manage the daily balancing of supply and demand. From a balancing perspective, injection and withdrawal rights associated with gas storage have become an increasingly important part of the evaluation of overall gas storage requirements.

As FPL's system grows to meet customer needs, it must maintain adequate gas storage capacity to continue to help mitigate supply and/or infrastructure problems and to provide FPL the ability to manage its supply and demand on a daily basis. FPL continues to evaluate its gas storage portfolio and is likely to subscribe for additional gas storage capacity to help increase reliability, provide the necessary flexibility to respond to demand changes, and diversify the overall portfolio.

4. Securing Additional Natural Gas:

The recent trend of increasing reliance upon natural gas to produce electricity for FPL's customers is projected to continue due to FPL's growing load. The addition of highly fuel-efficient CC units at Cape Canaveral and Riviera Beach due to completed modernization projects, and the on-going Port Everglades modernization project, will serve to reduce the growth in natural gas use from what it otherwise might have been due to the high fuel-efficiency levels of these new CC units. However, these efficiency gains do not fully offset the effects of FPL's growing load. Therefore, FPL will need to secure more natural gas supply and more firm gas transportation capacity in the future as fuel requirements dictate. The issue is how to secure these additional natural gas resources in a manner that is economical for FPL's customers and which maintains and/or enhances the reliability of natural gas supply and deliverability to FPL's generating units.

FPL has historically purchased the gas transportation capacity required for new natural gas supply from two existing natural gas pipeline companies. As more natural gas is delivered through these two pipelines, the impact of a supply disruption on either pipeline becomes more problematic. Therefore, FPL issued a Request for Proposals (RFP) in December 2012 for gas transportation capacity to meet FPL's system natural gas requirements beginning in 2017. The RFP encouraged bidders to propose new gas transportation infrastructure to meet Florida's growing need for natural gas. A third pipeline would have benefits for FPL and its customers by increasing the diversity of FPL's fuel supply sources, increasing the physical reliability of the pipeline delivery system, and enhancing competition among pipelines. The RFP process was completed in June 2013 and the winning bidders, Sabal Trail Transmission, LLC (Sabal Trail) and Florida Southeast Connection, LLC (FSC), have begun the Federal Energy Regulatory Commission approval process with a planned in-service date of May 2017. The contracts with Sabal Trail and FSC were reviewed by the FPSC and were approved for cost recovery in late 2013. The order approving this cost recovery became final in January 2014.

5. Nuclear Fuel Cost Forecast

This section reviews the various steps needed to fabricate nuclear fuel for delivery to the nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

a) Steps Required for Nuclear Fuel to be delivered to FPL's Plants

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

(1) Mining: Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U_3O_8 (sometimes referred to as yellowcake).

(2) Conversion: During the second step, the U_3O_8 is chemically converted into UF_6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

(3) Enrichment: The third step is called enrichment. Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to almost five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 2.2% to as high as 4.95%). The output of this enrichment process is enriched uranium in the form of UF6.

(4) Fabrication: During the last step, fuel fabrication, the enriched UF6 is changed to a UO2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) Mining: The impact of the earthquake and tsunami that struck the Fukushima nuclear complex in Japan in March 2011 is still being felt in the uranium market. Current demand has declined and several of the production facilities have announced delays. Factors of importance are:

- Hedge funds are still very active in the market. This causes more speculative demand that is not tied to market fundamentals and causes the market price to move up or down just based on news that might affect future demand.
- Some of the uranium inventory from the U.S. Department of Energy (DOE) is finding its way into the market periodically to fund cleanup of certain Department of Energy facilities.
- Although a limited number of new nuclear units are scheduled to start production in the U.S. during the next 5 to 10 years, other countries, more specifically China, have announced an increase in construction of new units which may cause uranium prices to trend up in the near future.

Over a 10-year horizon, FPL expects the market to be more consistent with market fundamentals. The supply picture is more stable, with laws enacted to resolve the import of Russian-enriched uranium, by allowing some imports of Russian-enriched uranium to meet about 20-25% of needs for currently operating units, but with no restriction on the first core for new units and no restrictions after 2020. New and current uranium production facilities continue to add capacity to meet demands. Actual demand tends to grow over time because of the long lead time to build nuclear units. However, FPL cannot discount the possibility of future periodic sharp increase in prices, but believes such occurrences will likely be temporary in nature.

(2) Conversion: The conversion market is also in a state of flux due to the Fukushima events. Planned production after 2016 is currently forecasted to be insufficient to meet the higher demand scenario, but it is projected to be sufficient to meet most reference case scenarios. As with additional raw uranium production, supply will expand beyond current level once more firm commitments are made including commitments to build new nuclear units. FPL expects long term price stability for conversion services to support world demand.

(3) Enrichment: As a result of the Fukushima events in March 2011, the near-term price of enrichment services has been declining for the last three years. However, plans for construction of several new facilities that were expected to come on-line in the next few years have been delayed. Also, some of the existing high operating cost diffusion plants have shut down. As with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand. Meanwhile, world supply and demand will continue to be balanced such that FPL expects adequate supply of enrichment services. The current supply/demand profile will most likely result in the price of enrichment services remaining stable or declining for the next few years before starting to increase.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the Nuclear Regulatory Commission (NRC), not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand is expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies. The calculations for the nuclear fuel cost forecasts used in FPL's 2013 and early 2014 resource planning work were performed consistent with the method then used for FPL's Fuel Clause filings, including the assumption of refueling outages every 18 months and plant operation at power uprate levels. The costs for each step to fabricate the nuclear fuels were added to come up with the total costs of the fresh fuel to be loaded at each refueling (acquisition costs). The acquisition cost for each group of fresh fuel assemblies were then amortized over the energy produced by each group of fuel assemblies. FPL also added 1 mill per kilowatt hour net to reflect payment to DOE for spent fuel disposal.

Schedule 5
Fuel Requirements
(for FPL only)

	Fuel Requirements	Units	Actual 1/ 2012	2013	Forecasted 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	Nuclear	Trillion BTU	188	273	298	300	306	303	300	306	302	300	357	455
(2)	Coal	1,000 TON	2,692	3,540	3,414	3,778	2,124	3,076	3,574	3,791	3,835	3,803	3,756	3,756
(3)	Residual (FO6) - Total	1,000 BBL	459	150	715	1,130	1,139	561	546	164	176	188	111	52
(4)	Steam	1,000 BBL	459	150	715	1,130	1,139	561	546	164	176	188	111	52
(5)	Distillate (FO2) - Total	1,000 BBL	23	152	37	35	226	61	293	247	284	282	184	126
(6)	Steam	1,000 BBL	4	0	0	0	0	0	0	0	0	0	0	0
(7)	CC	1,000 BBL	15	140	7	30	88	6	186	144	160	153	100	76
(8)	CT	1,000 BBL	4	12	30	6	139	56	107	104	124	129	84	51
(9)	Natural Gas - Total	1,000 MCF	595,396	550,350	550,782	544,663	584,056	578,902	581,638	580,361	596,131	600,152	570,533	518,693
(10)	Steam	1,000 MCF	46,112	30,348	4,413	8,395	10,562	9,343	8,967	2,912	3,104	3,280	2,021	1,001
(11)	CC	1,000 MCF	546,386	514,793	544,967	534,847	571,277	567,674	568,822	575,025	590,083	593,852	566,719	516,379
(12)	CT	1,000 MCF	2,899	5,208	1,403	1,421	2,216	1,884	3,849	2,424	2,944	3,020	1,793	1,313

1/ Source: A Schedules.
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual [1/] 2012	2013	Forecasted 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	Annual Energy Interchange 2/	GWH	5,186	4,445	3,539	3,876	2,165	2,316	2,640	962	0	0	0	0
(2)	Nuclear	GWH	16,916	25,243	27,792	27,981	28,593	28,279	27,959	28,550	28,177	27,971	33,464	42,915
(3)	Coal	GWH	4,745	5,981	6,020	6,662	3,827	5,486	6,488	6,850	6,923	6,867	6,778	6,779
(4)	Residual(FO6) -Total	GWH	378	75	437	722	684	333	327	104	111	118	69	32
(5)	Steam	GWH	378	75	437	722	684	333	327	104	111	118	69	32
(6)	Distillate(FO2) -Total	GWH	54	120	13	26	104	17	208	177	203	200	131	91
(7)	Steam	GWH	2	2	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	49	114	6	25	72	5	148	115	128	122	80	60
(9)	CT	GWH	4	5	7	1	32	12	60	63	75	78	51	31
(10)	Natural Gas -Total	GWH	80,505	75,208	78,228	77,979	84,154	83,812	84,144	84,899	87,546	88,092	83,914	76,379
(11)	Steam	GWH	5,543	2,472	381	724	932	817	789	249	267	283	172	84
(12)	CC	GWH	74,668	72,308	77,722	77,131	83,029	82,833	82,978	84,412	86,994	87,519	83,567	76,167
(13)	CT	GWH	295	428	125	124	194	163	377	238	285	291	176	129
(14)	Solar [3/]	GWH	159	155	191	176	195	194	194	194	194	188	192	192
(15)	PV	GWH	71	68	72	71	71	70	70	69	69	68	68	67
(16)	Solar Thermal	GWH	89	87	119	104	125	124	124	124	125	119	124	124
(17)	Other [4/]	GWH	2,922	428	1,782	4,185	4,220	4,475	4,435	5,936	6,032	6,015	5,967	5,968
	Net Energy For Load [5/]	GWH	110,866	111,656	118,002	121,606	123,942	124,914	126,395	127,670	129,184	129,451	130,515	132,356

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report
2/ The projected figures are based on estimated energy purchases from SJRPP, the Southern Companies (UPS contract), and other utilities.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
5/ Net Energy For Load values for the years 2014- 2023 are also shown in Col. (19) on Schedule 2.3.

Schedule 6.2
Energy Sources % by Fuel Type

			Actual [1/]		Forecasted									
	Energy Source	**Units**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
(1)	Annual Energy Interchange [2/]	%	4.7	4.0	3.0	3.2	1.7	1.9	2.1	0.8	0.0	0.0	0.0	0.0
(2)	Nuclear	%	15.3	22.6	23.6	23.0	23.1	22.6	22.1	22.4	21.8	21.6	25.6	32.4
(3)	Coal	%	4.3	5.4	5.1	5.5	3.1	4.4	5.1	5.4	5.4	5.3	5.2	5.1
(4)	Residual (FO6) -Total	%	0.3	0.1	0.4	0.6	0.6	0.3	0.3	0.1	0.1	0.1	0.1	0.0
(5)	Steam	%	0.3	0.1	0.4	0.6	0.6	0.3	0.3	0.1	0.1	0.1	0.1	0.0
(6)	Distillate (FO2) -Total	%	0.0	0.1	0.0	0.0	0.1	0.0	0.2	0.1	0.2	0.2	0.1	0.1
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CC	%	0.0	0.1	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.0
(9)	CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0
(10)	Natural Gas -Total	%	72.6	67.4	66.3	64.1	67.9	67.1	66.6	66.5	67.8	68.1	64.3	57.7
(11)	Steam	%	5.0	2.2	0.3	0.6	0.8	0.7	0.6	0.2	0.2	0.2	0.1	0.1
(12)	CC	%	67.3	64.8	65.9	63.4	67.0	66.3	65.7	66.1	67.3	67.6	64.0	57.5
(13)	CT	%	0.3	0.4	0.1	0.1	0.2	0.1	0.3	0.2	0.2	0.2	0.1	0.1
(14)	Solar [3/]	%	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1
(15)	PV	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(16)	Solar Thermal	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(17)	Other [4/]	%	2.6	0.4	1.5	3.4	3.4	3.6	3.5	4.6	4.7	4.6	4.6	4.5
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report
2/ The projected figures are based on estimated energy purchases from SJRPP, the Southern Companies (UPS contract), and other utilities.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled
Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Reserve Margin MW	Generation Reserve Margin % of Peak
2014	25,488	1,303	0	635	27,426	22,768	1,992	20,777	6,649	32.0	826	5,823	28.0	3,831	16.8
2015	25,121	1,450	0	595	27,165	23,356	2,057	21,298	5,867	27.5	0	5,867	27.5	3,810	16.3
2016	26,358	522	0	595	27,474	23,778	2,082	21,696	5,779	26.6	0	5,779	26.6	3,697	15.5
2017	25,962	522	0	595	27,078	24,190	2,108	22,082	4,996	22.6	0	4,996	22.6	2,888	11.9
2018	25,916	485	0	595	26,996	24,544	2,136	22,408	4,587	20.5	0	4,587	20.5	2,452	10.0
2019	26,930	110	0	595	27,635	24,896	2,165	22,731	4,904	21.6	0	4,904	21.6	2,739	11.0
2020	26,930	239	0	595	27,764	25,239	2,195	23,044	4,720	20.5	0	4,720	20.5	2,524	10.0
2021	26,930	278	0	775	27,983	25,439	2,227	23,212	4,770	20.6	0	4,770	20.6	2,544	10.0
2022	28,117	110	0	775	29,002	25,908	2,259	23,649	5,353	22.6	0	5,353	22.6	3,094	11.9
2023	29,272	110	0	775	30,157	26,528	2,292	24,236	5,921	24.4	0	5,921	24.4	3,628	13.7

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2013 load forecast without incremental DSM or cumulative load management.
Col. (8) represents cumulative load management capability, plus incremental conservation,and load management, from 9/2013-on intended for use with the 2013 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period; i.e., Martin Unit 2's planned outage in Summer 2014 for the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)
Col. (15) =Col. (6) - Col. (7)
Col. (16) = Col.(15) / Col.(7)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
January of Year	Firm Installed Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Reserve Margin MW	Generation Reserve Margin % of Peak
2014	25,671	1,311	0	635	27,617	19,875	1,502	18,373	9,243	50.3	832	8,411	45.8	6,910	34.8
2015	26,597	1,458	0	595	28,649	20,971	1,530	19,442	9,208	47.4	0	9,208	47.4	7,678	36.6
2016	26,653	530	0	595	27,777	21,490	1,543	19,947	7,831	39.3	0	7,831	39.3	6,287	29.3
2017	27,601	530	0	595	28,725	21,731	1,558	20,173	8,552	42.4	0	8,552	42.4	6,994	32.2
2018	27,557	493	0	595	28,645	21,968	1,573	20,396	8,249	40.4	0	8,249	40.4	6,676	30.4
2019	27,295	493	0	595	28,383	22,180	1,588	20,592	7,790	37.8	0	7,790	37.8	6,203	28.0
2020	28,724	239	0	595	29,558	22,383	1,603	20,780	8,777	42.2	0	8,777	42.2	7,174	32.1
2021	28,724	278	0	775	29,777	22,584	1,619	20,966	8,811	42.0	0	8,811	42.0	7,192	31.8
2022	28,724	110	0	775	29,609	22,601	1,634	20,967	8,642	41.2	0	8,642	41.2	7,007	31.0
2023	29,910	110	0	775	30,795	22,891	1,651	21,241	9,554	45.0	0	9,554	45.0	7,903	34.5

Col. (2) represents capacity additions and changes projected to be in-service by January 1st. These MW are generally considered to be available to meet winter peak loads which are forecasted to occur during January of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2013 load forecast without incremental DSM or cumulative load management. 2013 load is an actual load value.
Col. (8) represents cumulative load management capability, plus incremental conservation and load management,, from 9/2013-on intended for use with the 2013 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Winter peak period; i.e., Martin Unit 1's planned outage during the Winter of 2014 for the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)
Col. (15) =Col. (6) - Col. (7)
Col. (16) = Col.(15) / Col.(7)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (1)

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability (2)		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2014														
Sanford CT Upgrade	5B	Volusia County	CC	NG	No	PL	No	Aug-13	Sep-13	Unknown	188,190	10	9	OT
Turkey Point CT Upgrade	5A	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	---	7	OT
Turkey Point CT Upgrade	5B	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	---	7	OT
Turkey Point CT Upgrade	5C	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	---	7	OT
Turkey Point CT Upgrade	5D	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	---	7	OT
Martin (3)	1	Martin County	ST	FO6	NG	PL	PL	Jun-13	Mar-14	Unknown	934,500	(832)	823	ESP
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	TK	WA	Jun-12	Apr-14	Unknown	1,295,400	---	1,212	U
Martin (3)	2	Martin County	ST	FO6	NG	PL	PL	Mar-14	Dec-14	Unknown	934,500	---	(826)	OT
											2014 Changes/Additions Total:	**(822)**	**1,247**	
2015														
Turkey Point CT Upgrade	5A	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	8	---	OT
Turkey Point CT Upgrade	5B	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	8	---	OT
Turkey Point CT Upgrade	5C	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	8	---	OT
Turkey Point CT Upgrade	5D	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	8	---	OT
Martin (3)	1	Martin County	ST	FO6	NG	PL	PL	Jun-13	Mar-14	Unknown	934,500	832	---	ESP
Manatee CT Upgrade	3A	Manatee County	CC	NG	No	PL	No	Aug-14	Oct-14	Unknown	188,190	9	8	OT
Manatee CT Upgrade	3B	Manatee County	CC	NG	No	PL	No	Aug-14	Oct-14	Unknown	188,190	9	8	OT
Manatee CT Upgrade	3C	Manatee County	CC	NG	No	PL	No	Apr-14	Oct-14	Unknown	188,190	9	8	OT
Manatee CT Upgrade	3D	Manatee County	CC	NG	No	PL	No	Apr-14	Oct-14	Unknown	188,190	9	8	OT
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	TK	WA	Jun-12	Jun-14	Unknown	188,190	1,344	---	U
Vero Beach Combined Cycle	1	Indian River	CC	NG	DFO	PL	TK	---	Jan-15	Unknown	---	44	46	OT
Martin (3)	2	Martin County	ST	FO6	NG	PL	PL	Mar-14	Dec-14	Unknown	934,500	---	823	ESP
Putnam	1	Putnam County	CC	NG	FO2	PL	TK	---	---	Jun-15	290,004	(265)	(249)	
Putnam	2	Putnam County	CC	NG	FO2	PL	TK	---	---	Jun-15	290,004	(265)	(249)	
Ft. Myers CT Upgrade	2A	Lee County	CC	NG	No	PL	No	---	Jun-15	Unknown	188,190	---	9	OT
Ft. Myers CT Upgrade	2B	Lee County	CC	NG	No	PL	No	---	Mar-15	Unknown	188,190	---	9	OT
Ft. Myers CT Upgrade	2C	Lee County	CC	NG	No	PL	No	---	Jun-15	Unknown	188,190	---	9	OT
Ft. Myers CT Upgrade	2D	Lee County	CC	NG	No	PL	No	---	May-15	Unknown	188,190	---	9	OT
Ft. Myers CT Upgrade	2E	Lee County	CC	NG	No	PL	No	---	May-15	Unknown	188,190	---	9	OT
Ft. Myers CT Upgrade	2F	Lee County	CC	NG	No	PL	No	---	Mar-15	Unknown	188,190	---	9	OT
											2015 Changes/Additions Total:	**1,758**	**456**	
2016														
Ft. Myers CT Upgrade	2B	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	188,190	9	---	OT
Ft. Myers CT Upgrade	2F	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	188,190	9	---	OT
Ft. Myers CT Upgrade	2D	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	188,190	9	---	OT
Ft. Myers CT Upgrade	2E	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	188,190	9	---	OT
Ft. Myers CT Upgrade	2A	Lee County	CC	NG	No	PL	No	Jun-15	Jul-15	Unknown	188,190	9	---	OT
Ft. Myers CT Upgrade	2C	Lee County	CC	NG	No	PL	No	Jul-15	Aug-15	Unknown	188,190	9	---	OT
Port Everglades Next Generation Clean Energy Center	1	City of Hollywood	CC	NG	FO2	TK	WA	Jun-14	Jun-16	Unknown	Unknown	---	1,237	U
											2016 Changes/Additions Total:	**55**	**1,237**	

(1) Schedule 8 shows only planned and prospective changes to generating facilities and does not reflect changes to existing purchases. Those changes are reflected on Tables ES-1, I.B.1 and I.B.2.
The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring after August each year will be picked up for reserve margin calculation purposes in the following year.
(2) This generating unit is currently serving as a synchronous condenser and is not included in reserve margin calculation.
(3) Outages for ESP work.

Schedule 8
Planned And Prospective Generating Facility Additions And Changes [1]

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability [2]		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2017														
Port Everglades Next Generation Clean Energy Center	1	City of Hollywood	CC	NG	FO2	TK	WA	Jun-14	Jun-16	Unknown	Unknown	1,346	---	U
Turkey Point Synchronous Condenser	1	Miami Dade County	ST	FO6	NG	WA	PL	---	---	Jun-17	402,050	(398)	(396)	OT
									2017 Changes/Additions Total:			**948**	**(396)**	
2018														
Vero Beach Combined Cycle	1	Indian River	CC	NG	DFO	PL	TK	---	---	Jan-18	---	(44)	(46)	OT
									2018 Changes/Additions Total:			**(44)**	**(46)**	
2019														
Lauderdale GT	1-12	Broward County	GT	NG	FO2	PL	PL	---	---	Dec-18	410,734	(459)	(420)	P
Lauderdale GT	12-24	Broward County	GT	NG	FO2	PL	PL	---	---	Dec-18	410,734	(459)	(420)	P
Port Everglades GT	1-12	Broward County	GT	NG	FO2	PL	PL	---	---	Dec-18	410,734	(459)	(420)	P
Lauderdale CT	1-5	Broward County	CT	NG	FO3	PL	PL	---	Jan-19	Unknown	Unknown	1,115	1,005	P
Unsited 3x1 CC unit	1	---	CC	NG	FO2	TK	WA	Jun-17	Jun-19	Unknown	Unknown	---	1,269	P
									2019 Changes/Additions Total:			**(262)**	**1,014**	
2020														
Unsited 3x1 CC unit			CC	NG	FO2	TK	WA	Jun-17	Jun-19	Unknown	Unknown	1,429	---	P
									2020 Changes/Additions Total:			**1,429**	**0**	
2021														
												---	---	
									2021 Changes/Additions Total:			**0**	**0**	
2022														
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	TK	---	Jun-22	Unknown	1,295,400	---	87	P
Turkey Point	6	Miami Dade County	ST	NP	No	TK	No	2014	Jun-22	Unknown	Unknown	---	1,100	T
									2022 Changes/Additions Total:			**0**	**1,187**	
2023														
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	TK	---	Jun-22	Unknown	1,295,400	87	---	P
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	TK	WA	Jun-12	Apr-14	Unknown	1,295,400	---	55	P
Turkey Point	6	Miami Dade County	ST	NP	No	TK	No	2014	Jun-22	Unknown	Unknown	1,100	---	L
Turkey Point	7	Miami Dade County	ST	NP	No	TK	No	2015	Jun-23	Unknown	Unknown	---	1,100	L
									2022 Changes/Additions Total:			**1,187**	**1,155**	

(1) Schedule 8 shows only planned and prospective changes to generating facilities and does not reflect changes to existing purchases. Those changes are reflected on Tables ES-1, I.B.1 and I.B.2.
(2) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring after August each year will be picked up for reserve margin calculation purposes in the following year.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Vero Beach Combined Cycle Capacity

(2) **Capacity**
a. Summer 46 MW
b. Winter 44 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: Not Applicable - See Note 1 below.
b. Commercial In-service date: 2015

(5) **Fuel**
a. Primary Fuel Gas
b. Alternate Fuel Oil

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 16 Acres

(9) **Construction Status:** See note 1 below

(10) **Certification Status:** See note 1 below

(11) **Status with Federal Agencies:** See note 1 below

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	20.5%	
Forced Outage Factor (FOF):	0.0%	
Equivalent Availability Factor (EAF):	72.5%	
Resulting Capacity Factor (%):	3.88%	
Average Net Operating Heat Rate (ANOHR):	9,397	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data**

Book Life (Years):	TBD	years
Total Installed Cost ($/kW):	Not Applicable	
Direct Construction Cost ($/kW):	Not Applicable	
AFUDC Amount ($/kW):	Not Applicable	
Escalation ($/kW):	Not Applicable	
Fixed O&M ($/kW-Yr): ($)	Not Applicable	
Variable O&M ($/MWH): ($)	Not Applicable	
K Factor:	Not Applicable	

NOTE 1: The combined cycle capacity consists of two existing units. This existing unit is being acquired by FPL as part of the arrangement for FPL to serve Vero Beach's load beginning in January 2015. FPL is also taking ownership of three steam units.The three steam units will be retired as soon as they aquired. FPL plans to retire the CC unit at the end of 2017.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Port Everglades Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,237 MW
b. Winter 1,429 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2014
b. Commercial In-service date: 2016

(5) **Fuel**
a. Primary Fuel — Natural Gas
b. Alternate Fuel — Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** Existing Site Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.5%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	95.4%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,330	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2016 $/kW):	928	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	87	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2016 $)	30.00	
Variable O&M ($/MWH): (2016 $)	0.10	
K Factor:	1.51	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing plant are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Lauderdale CT's (5 CTs will be added)

(2) **Capacity (for each CT)**

a. Summer	201	MW
b. Winter	223	MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2017
b. Commercial In-service date: 2018

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Water to Air Heat Exchangers

(8) **Total Site Area:** Existing Site Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	1.6%	
Forced Outage Factor (FOF):	1.0%	
Equivalent Availability Factor (EAF):	97.4%	
Resulting Capacity Factor (%):	3%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	10,057	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2018 $/kW):	547	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	56	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2018 $)	17.63	
Variable O&M ($/MWH): (2018 $)	0.07	
K Factor:	1.59	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing GTs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited 3x1 CC

(2) **Capacity**

a. Summer 1,269 MW

b. Winter 1,429 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2017
b. Commercial In-service date: 2019

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.5%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	95.4%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,334	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2019 $/kW):	968	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	95	
Escalation ($/kW):	872.79	
Fixed O&M ($/kW-Yr): (2019 $)	22.25	
Variable O&M ($/MWH): (2019 $)	0.72	
K Factor:	1.51	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas lateral, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point Nuclear Unit 6

(2) **Capacity**

a. Summer	1,100	MW
b. Winter	1,100	MW

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2015
b. Commercial In-service date:	2022

(5) **Fuel**

a. Primary Fuel	Uranium Dioxide
b. Alternate Fuel	N/A

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** Mechanical Draft Cooling Towers

(8) **Total Site Area:** 211 Acres

(9) **Construction Status:** L (Regulatory approval pending.Not under construction)

(10) **Certification Status:** L (Regulatory approval pending.Not under construction)

(11) **Status with Federal Agencies:** L (Regulatory approval pending.Not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	TBD	
Forced Outage Factor (FOF):	TBD	
Equivalent Availability Factor (EAF):	TBD	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	TBD	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	TBD	years
Total Installed Cost ($/kW):	TBD	
Direct Construction Cost ($/kW):	TBD	
AFUDC Amount ($/kW):	TBD	
Escalation ($/kW):	TBD	
Fixed O&M ($/kW-Yr): ($)	TBD	
Variable O&M ($/MWH): ($)	TBD	
K Factor:	TBD	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point Nuclear Unit 7

(2) **Capacity**
a. Summer 1,100 MW
b. Winter 1,100 MW

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2015
b. Commercial In-service date: 2023

(5) **Fuel**
a. Primary Fuel Uranium Dioxide
b. Alternate Fuel N/A

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** Mechanical Draft Cooling Towers

(8) **Total Site Area:** 211 Acres

(9) **Construction Status:** L (Regulatory approval pending.Not under construction)

(10) **Certification Status:** L (Regulatory approval pending.Not under construction)

(11) **Status with Federal Agencies:** L (Regulatory approval pending.Not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	TBD	
Forced Outage Factor (FOF):	TBD	
Equivalent Availability Factor (EAF):	TBD	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	TBD	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	TBD	years
Total Installed Cost ($/kW):	TBD	
Direct Construction Cost ($/kW):	TBD	
AFUDC Amount ($/kW):	TBD	
Escalation ($/kW):	TBD	
Fixed O&M ($/kW-Yr): ($)	TBD	
Variable O&M ($/MWH): ($)	TBD	
K Factor:	TBD	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Vero Beach Existing Combined Cycle Capacity

The Vero Beach existing combined cycle capacity that FPL is projected to take ownership of starting January 1, 2015 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Port Everglades Next Generation Clean Energy Center

The Port Everglades Next Generation Clean Energy Center which will result from the modernization of the Port Everglades power plant site does not require any “new” transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Lauderdale Combustion Turbine Project

The Lauderdale Combustion Turbine (CT) project, which will result in the retirement of 36 aero-derivative combustion gas turbines at the Lauderdale and Port Everglades plant sites, and their replacement with 5 simple-cycle combustion turbines at the Lauderdale site, does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Unsited Combined Cycle in 2019

No projection of a new transmission line(s) can be made until a site is selected for this unit.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 6

The Turkey Point New Nuclear Project starting with the addition of Turkey Point Unit 6 will require a new substation and five new transmission lines terminating at existing substations.

(1)	Point of Origin and Termination:	New Clear Sky Substation – Levee Substation
(2)	Number of Lines:	2
(3)	Right-of-way	FPL Owned
(4)	Line Length:	43 miles
(5)	Voltage:	500 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Levee Substation
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	New Clear Sky Substation – Pennsuco Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	52 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Pennsuco Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 6 (continued)

(1)	Point of Origin and Termination:	New Clear Sky Substation – Davis Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	19 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Davis Substation
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	Davis Substation – Miami Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	18 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	Davis Substation and Miami Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 6 (continued)

(1)	Point of Origin and Termination:	New Clear Sky Substation – Turkey Point Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	0.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Turkey Point Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 7

The transmission lines required for Turkey Point Unit 7 will be constructed with Turkey Point Unit 6 and are listed in the Schedule 10 for Turkey Point Nuclear Unit 6.

Schedule 11.1

Existing FIRM and NON-FIRM Capacity and Energy by Primary Fuel Type
Actuals for the Year 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				**NEL**	**Fuel Mix**
	Generation by Primary Fuel	**Summer (MW)**	**Summer (%)**	**Winter (MW)**	**Winter (%)**	**GWh (2)**	**%**
(1)	Coal	897	3.4%	911	3.3%	5,981	5.4%
(2)	Nuclear	3,453	13.2%	3,550	12.8%	25,243	22.6%
(3)	Residual	3,666	14.0%	3,700	13.4%	75	0.1%
(4)	Distillate	648	2.5%	710	2.6%	120	0.1%
(5)	Natural Gas	15,575	59.4%	16,785	60.6%	75,208	67.4%
(6)	Solar (Non-Firm)	35	0.1%	35	0.1%	155	0.1%
(7)	***FPL Existing Units Total (1) :***	***24,274***	***92.6%***	***25,691***	***92.8%***	***106,782***	***95.6%***
(8)	Renewables (Purchases)- Firm	61.0	0.2%	112.0	0.4%	43	0.0%
(9)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	362	0.3%
(10)	***Renewable Total:***	61.0	0.2%	112.0	0.4%	405	0.36%
(11)	***Purchases Other :***	1,883.0	7.2%	1,891.0	6.8%	4,468	4.0%
(12)	***Total :***	*26,218.0*	*100.0%*	*27,694.0*	*100.0%*	*111,655*	*100.0%*

Note:
(1) FPL Existing Units Total values on row (7), columns (2) and (4), match the System Firm Generating Capacity values found on Schedule 1 for Summer and Winter.
(2) Net Energy for Load GWh values on row (12), column (6), matches Schedule 6.1 value for 2013.

Schedule 11.2

Existing NON-FIRM Self-Service Renewable Generation Facilities
Actuals for the Year 2013

(1)	(2)	(3)	(4)	(5)	(6) = (3)+(4)-(5)
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh)	Annual Energy Purchased from FPL (MWh)	Annual Energy Sold to FPL (MWh)	Projected Annual Energy Used by Customers
Customer-Owned Renewable Generation (0 kW to 10 kW)	12.86	16,142	111,831	465	127,508
Customer-Owned Renewable Generation (> 10 kW to 100 kW)	6.69	8,758	197,171	376	205,553
Customer-Owned Renewable Generation (> 100 kW - 2 MW)	7.94	10,475	62,050	177	72,348
	27.49	35,375	371,052	1,018	405,409

Notes:

(1) There were 2,565 customers with renewable generation facilities interconnected with FPL on December 31, 2013.
(2) The Installed Capacity value is the sum of the nameplate ratings (DC MW) for all of the customer-owned renewable generation facilities connected as of Dec. 31,2013. One system does not have a DC rating. The AC valued of 0.75 MW was included in the (> 100 - 2 MW) row.
(3) The Projected Annual Output value is based on NREL's PV Watts 1 program and the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.
(4) The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2013.
(5) The Annual Energy Sold to FPL is an actual value from FPL's metered data for 2013.
(6) The Projected Annual Energy Used by Customers is a projected value that equals:
(Renewable Projected Annual output + Annual Energy Purchased) minus the Annual Energy Sold to FPL.

CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

Florida is a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered or threatened plant and animal species. Florida's residents, wildlife, and ecosystems require the same air, land, and water resources that are necessary to meet the demand for the generation, transmission, and distribution of electricity. The general public has an expectation that a large corporation, such as FPL, will conduct their business in an environmentally responsible manner that minimizes impacts to the natural environment.

FPL has been recognized for many years as one of the leaders among electric utilities for its commitment to the environment. Being responsible stewards of the environment is ingrained in FPL's corporate culture. FPL has one of the lowest emissions profiles among U.S. utilities and in 2013 its carbon dioxide (CO_2) emission rate was 35% lower (better) than the industry average.

FPL's environmental leadership and that of its parent company, NextEra Energy, Inc., has been heralded by many outside organizations as demonstrated by a few recent examples.

FPL's responsible tree care practices across its 35-county service area have been recognized for almost a decade. FPL has been the recipient of the Tree Line USA award annually from 2003 - 2013. This award is sponsored by the Arbor Day Foundation in cooperation with the National Association of State Foresters. The recognition is given to utilities that demonstrate quality tree care practices, annual worker training, and public education programs.

In 2013, FPL continued to support the Loggerhead Marinelife Center with a $21,500 donation toward the acquisition of a larger tank to assist in sea turtle rehabilitation. Two FPL employees serve as members of the Loggerhead Marinelife Center and are committed to its success. In addition, through a "Power to Care" charity event an additional $500 was collected by FPL staff and given to the Center. In past years, FPL has won the Loggerhead Marinelife Center's "Blue Business of the Year" award, which is given to those who are leading the way in raising awareness about, and have made significant contributions to improve and protect, South Florida's oceans, beaches, and wildlife. The award recognized FPL's protection and conservation of the endangered Florida manatee and the fostering of public and employee education and support.

FPL employees serve as board members for many organizations that focus on environmental restoration, preservation, and stewardship. A partial list of these organizations includes: Audubon Florida, the Everglades Foundation, the Arthur R. Marshall Foundation, The Nature Conservancy, and the Palm Beach Zoo.

IV.B FPL's Environmental Statement

At FPL and its parent company, NextEra Energy, Inc., we are committed to being an industry leader in environmental protection and stewardship, not only because it makes business sense, but because it is the right thing to do. Our commitment to compliance, conservation, communication, and continuous improvement fosters a culture of environmental excellence and drives the sustainable management of our business planning, operations, and daily work.

In accordance with our commitments to environmental protection and stewardship, FPL and NextEra Energy, Inc. endeavor to:

Comply

- Comply with all applicable environmental laws, regulations, and permits
- Proactively identify environmental risks and take action to mitigate those risks
- Pursue opportunities to exceed environmental standards
- Participate in the legislative and regulatory process to develop environmental laws, regulations, and policies that are technically sound and economically feasible
- Design, construct, operate, and maintain our facilities in an environmentally sound and responsible manner

Conserve

- Prevent pollution, minimize waste, and conserve natural resources
- Avoid, minimize, and/or mitigate impacts to habitat and wildlife
- Promote the efficient use of energy, both within our company and in our communities

Communicate

- Communicate this policy to all employees and publish it on the corporate website
- Invest in environmental training and awareness to achieve a corporate culture of environmental excellence
- Maintain an open dialogue with stakeholders on environmental matters and performance

Continuously Improve

- Establish, monitor, and report progress toward environmental targets
- Review and update this policy on a regular basis
- Drive continuous improvement through ongoing evaluations of our environmental management system to incorporate lessons learned and best practices.

This statement was updated in 2013 by FPL's parent company, NextEra Energy, Inc. to reflect changing expectations and ensure that employees are doing the utmost to protect the environment. FPL complies with all environmental laws, regulations, and permit requirements. FPL designs, constructs, and operates its facilities in an environmentally sound and responsible manner. It also responds immediately and effectively to any known environmental hazards or non-compliance situations. FPL's commitment to the environment does not end there. It proactively pursue opportunities to exceed current environmental standards, including reducing waste and emission of pollutants, recycling materials, and conserving natural resources throughout its operations and day-to-day work activities. FPL also encourages the efficient use of energy, both within the Company and in communities served by FPL. These actions are just a few examples of how FPL is committed to the environment.

To ensure that FPL is adhering to its environmental commitment, it has developed rigorous environmental governance procedures and programs. These include its Environmental Assurance Program and Corporate Environmental Governance Council. Through these programs, FPL conducts periodic environmental self-evaluations to verify that its operations are in compliance with environmental laws, regulations, and permit requirements. Regular evaluations also help identify best practices and opportunities for improvement.

IV.C Environmental Management

In order to successfully implement the Environmental Statement, FPL has developed a robust Environmental Management System program to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program. Other components of the system include: executive management support and commitment, a dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

As part of its commitment to excellence and continuous improvement, FPL began implementing an enhanced environmental data management information system (EDMIS) in 2013. Environmental data management software systems are increasingly viewed as an industry best-management practice to ensure environmental compliance. FPL's top goals for this project are to: 1) improve the flow of environmental data between site operations and corporate services to ensure compliance, and 2) improve operating efficiencies. In addition, the EDMIS will help standardize environmental data collection, thus improving external reporting to the public.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities that are designed to evaluate environmental performance, verify compliance with corporate policy as well as legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and FPL policies. In addition to FPL facility audits, the Environmental Assurance Program performs audits of third-party vendors used for recycling and/or disposal of waste generated by FPL operations. Vendor audits provide information used for selecting candidates or incumbent vendors for disposal and recycling needs.

FPL has also implemented a Corporate Environmental Governance System, in which quarterly reviews are performed by each business unit deemed to have significant environmental exposures. Quarterly reviews evaluate operations for potential environmental risks and consistency with the company's Environmental Policy. Items tracked during the quarterly reviews include processes for the identification and management of environmental risks, metrics, and indicators and progress / changes since the most recent review.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2013 environmental outreach activities are summarized in Table IV.E.1.

Table IV.E.1: 2013 FPL Environmental Outreach Activities

Activity	Count (#)
Visitors to FPL's Energy Encounter at St. Lucie	2,900
Visitors to Manatee Park, Ft. Myers	>210,000
Number of website visits to FPL's Environmental & Corporate Responsibility Websites	245,630
Visitors to Barley Barber Swamp (Treasured Lands Partnership)	1,492
Martin Energy Center Solar Tours	~850
Solar Schools Program (# of schools actively generating)	24 schools 5 demo sites An additional 67 schools will come online by the end of 2014

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified six (6) Preferred Sites and four (4) Potential Sites for future generation additions. Preferred Sites are those locations where FPL has conducted significant reviews and has either taken action, is currently committed to take action, or is likely to take action, to site new generating capacity. Potential Sites are those sites that have attributes that support the siting of generation and are under consideration as a location for future generation. Some of these sites are currently in use as existing generation sites and some are not. The identification of a Potential Site does not indicate that FPL has made a definitive decision to pursue generation (or generation expansion or modernization in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of a generator has been determined. Analyses of any modernization candidates would include evaluation of numerous factors including: fuel delivery, transmission, permitting, etc. The Preferred Sites and Potential Sites are discussed in separate sections below.

IV.F.1 Preferred Sites

The modernization of FPL's Riviera Beach site was scheduled to be completed on/near April 1, 2014 (the filing date for this 2014 Site Plan). Therefore, the Riviera Beach modernization is not discussed further in this chapter. FPL currently has identified six (6) Preferred Sites. Four of these are existing plant sites: Port Everglades, Lauderdale, Putnam and Turkey Point; two of these would be new plant sites: Hendry County and Northeast (NE) Okeechobee County.

The Port Everglades site is a location where modernization work, to replace the former steam generating units with new combined cycle (CC) technology, is in progress. The modernization work is scheduled to be completed in mid-2016. The existing gas turbines (GTs) at the Port Everglades and the Lauderdale sites are projected to be removed by the end of 2018. Five new combustion turbines (CTs) are projected to be added at the Lauderdale site by the end of 2018 to partially replace the capacity from existing GTs at Port Everglades and at the Lauderdale sites. These actions will aid in addressing compliance with new air emissions standards. The Hendry County, NE Okeechobee County, and Putnam sites are the likely next locations for new CC units after the Port Everglades and Lauderdale projects mentioned above have been completed. In addition, the Hendry County and Okeechobee County sites are also likely sites for new photovoltaic (PV) facilities.

In regard to the Turkey Point site, the nuclear capacity uprate project was successfully completed in 2013. The new Turkey Point nuclear Units 6 & 7 are currently projected to come in-service in 2022 and 2023, respectively.

The first two Preferred Sites discussed below are in general chronological order with respect to when the capacity additions are projected to occur. The remaining four Preferred Sites are discussed in alphabetical order.

Preferred Site # 1: Port Everglades Plant, Broward County

This site is located on the existing FPL Port Everglades Plant property within the City of Hollywood, Broward County. The site is surrounded by the Port of Port Everglades. The site has barge access via the Port of Port Everglades. A rail line is located near the plant.

The previous site generating capacity was made up of two 200 MW (approximate) steam generating units (Units 1 & 2) and two 400 MW (approximate) steam generating units (Units 3 & 4). The four units have been taken out of service and dismantled as part of the modernization of the plant site.

The Port Everglades Plant site has been listed as a Preferred or Potential Site in previous FPL Site Plans for both CC and CT generation options. On April 9, 2012, the FPSC issued the final need order for the modernization of the existing Port Everglades Plant. As a result of the modernization of the site, the new generating unit - to be renamed the Port Everglades Next Generation Clean Energy Center (PEEC) – will replace the existing steam generating units with modern, highly efficient, lower-emission next-generation advanced CC technology. The existing four steam units have been removed from the site and will be replaced by a single new CC unit.

a. U.S. Geological Survey (USGS) Map

A USGS map of the PEEC site is found at the end of this chapter.

b. Proposed Facilities Layout

A general layout of the PEEC generating facilities is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing Port Everglades Plant formerly consisted of two 200 MW (approximate) and two 400 MW (approximate) generating units with conventional dual-fuel fired steam boilers and steam turbine units. These generating units have now been removed as part of the modernization project. The plant site includes minimal vegetation. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of facilities related to electric power generation for the former Port Everglades Plant generating units. The site is located adjacent to the Intracoastal Waterway. The site provides warm water as required for manatees pursuant to the facility's Manatee Protection Plan.

2. Listed Species

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species. The warm water discharges from the plant attract manatees, an endangered species. FPL continues to work closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process and upon operation of the new plant. FPL plans to install a temporary heating system to provide warm water for manatees as required pursuant to the facility's Manatee Protection Plan. FPL also anticipates complying with other manatee-related conditions of certification to ensure the protection of the manatees during the modernization work and during future operations of PEEC.

3. Natural Resources of Regional Significance Status

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option is to replace the former units (Units 1 through 4) with one new approximately 1,237 MW (Summer) unit consisting of three new CTs, three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit is projected to be in service in mid-2016. Natural gas delivered via an existing pipeline is the primary fuel type for the unit with ultra-low sulfur light fuel oil serving as a backup fuel.

In addition, all of the existing GTs at the Port Everglades site are projected to be removed by the end of 2018.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is a combination of "Electrical Generating Facility" and "Utilities Use". A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Port Everglades site has been selected for modernization due to consideration of various factors including system load, ability to provide generation in the Miami-Dade/Broward region to help balance load and generation in the region, and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of replacing the former steam units with a new CC unit including a significant reduction in system air emissions, improved aesthetics at the site, and continued warm water discharge for the manatees as required pursuant to the facility's Manatee Protection Plan. Further, modernizing this existing facility reduces the impact on natural resources by not requiring new land or new water resources.

i. Water Resources

Water from the Intracoastal Waterway via the Port of Port Everglades Slip No. 3 is currently used for once-through cooling water supply. The new plant will utilize portions of the existing once-through cooling water intake and discharge structures. Process and potable water for the modernized plant will come from the existing City of Ft. Lauderdale potable water supply.

j. Geological Features of Site and Adjacent Areas

FPL's Port Everglades Plant site is underlain by the surficial aquifer system. The surficial aquifer system in eastern Broward County is primarily composed of sand, sandstone, shell, silt, calcareous clay (marl), and limestone deposited during the Pleistocene and Pliocene ages. The sediments forming the aquifer system are the Pamlico Sand, Miami Oolite, Anastasia Formation, Key Largo Formation, and Fort Thompson Formation (Pleistocene) and the Tamiami Formation (Pliocene). The sediments in the eastern portion of the county are appreciably more permeable than in the west.

The surficial aquifer is underlain by at least 600 feet of the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Approximately 600 mgd of cooling water would be cycled through the once-through cooling water system which is a reduction of more than 51% from the previous fossil steam unit's capability. Potable water demand is expected to average .001 mgd.

l. Water Supply Sources by Type

The modernized plant will continue to use the Intracoastal Waterway as the source of once-through cooling water. Process and potable water for the new plant will come from the existing City of Ft. Lauderdale potable water supply.

m. Water Conservation Strategies Under Consideration

No additional water resources will be required as a result of the modernization project. CC technology uses less water by design than traditional steam generation units.

n. Water Discharges and Pollution Control

The modernized plant will utilize portions of the existing once-through cooling water system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system prior to discharge. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit would be transported to the site via an existing natural gas pipeline to the site. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit will be installed either at the existing site or off-site. Ultra-low sulfur light fuel oil would be received by truck, pipeline, or barge and stored in a new above-ground storage tank.

p. Air Emissions and Control Systems

The regulated air emission rates at the new plant would be approximately 90 percent lower than the previous Port Everglades Plant's emission rates, resulting in significant annual emissions reductions and air quality benefits per unit of energy produced. The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. CC facility emissions of greenhouse gas emissions (GHGs) from combustion of natural gas achieve an emission rate substantially lower than the EPA proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of PEEC would incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. Status of Applications

FPL filed a need determination with the FPSC on November 21, 2011. The FPSC's final need order was issued on April 9, 2012. The Site Certification Application (SCA) was submitted January 24, 2012 resulting in the issuance of Final Order PA 12-57 on October 9, 2012. Concurrent with the SCA filing, FPL submitted applications for a Greenhouse Gas (GHG) permit, a Prevention of Significant Deterioration (PSD) permit, and an Industrial Wastewater Facility permit revision. The revised Industrial Wastewater Facility permit was issued

December 16, 2012. The GHG permit was issued December 26, 2013 and the PSD permit was issued May 1, 2012.

Preferred Site # 2: Lauderdale Plant, Broward County

This site is located at and situated within the existing FPL Lauderdale Plant property, approximately 392 acres, within the Cities of Dania Beach and Hollywood in Broward County, Florida. The jurisdiction for the City of Hollywood is a small area south of SW 42nd Street in the eastern portion of the property. The remainder of the Plant property is located in the City of Dania Beach. The Plant property is located east of U.S. Highway 441, north of Griffin Road, west of SW 30th Avenue, and south of Interstate 595. The existing accesses to the Plant are from SW 24th Avenue and SW 42nd Street. The adjacent properties include residential properties to the south, the South Broward County Resource Recovery Facility to the west, Pond Apple Slough to the north and commercial properties to the east.

The Lauderdale Plant includes two banks of 12 simple cycle gas turbines (GTs) that began operation in the early 1970s. These GTs are first generation GTs that are used to serve peak and emergency demands in a quick-start manner. Each bank of GTs has a net capacity of 420 (Summer) megawatts (MWs), and are authorized to operate on natural gas and distillate oil. Due to new nitrogen dioxide (NO_2) environmental regulations, FPL filed in June 2013 for FPSC approval to recover costs for removing all of its existing GTs and replacing a portion of the GT capacity with new CTs. In December 2013, FPL withdrew this request pending additional environmental monitoring and analyses. Computer modeling of the emissions from the GTs projected that the GTs would exceed the new NO_2 limit. FPL believes this monitoring and analyses will confirm that the operation of its existing GTs in Broward County will not comply with the new NO_2 regulations. Therefore, for planning purposes, FPL has assumed that all of its existing Broward County GTs will be removed (a loss of 1,260 MW Summer) and that this capacity will be partially replaced by 5 new CTs that would be sited in Broward County (an increase of 1,005 MW Summer). This GT removal and CT partial replacement is assumed to occur by the end of 2018.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Lauderdale site is found at the end of this chapter.

b. Proposed Facilities Layout

A general layout of the Lauderdale generating facilities is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing Lauderdale Plant includes two combined cycle units (Units 4 and 5) and two banks of 12 simple cycle gas turbines (GT1 through GT12 and GT13 through GT24). Units 4 and 5 have net capacity of 442 (Summer) MW each. Each bank of GTs has a net capacity of 420 (Summer) MW. The northern portion of the property is comprised of a forested wetland area adjacent to the Pond Apple Slough.

The adjacent properties to the Lauderdale Site include residential properties to the south, the South Broward County Resource Recovery Facility to the west, Pond Apple Slough to the north and commercial properties to the east. The Dania Cut-off Canal is located along the southern boundary and the South New River Canal is located along the western and northern boundaries.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

FPL Lauderdale Plant property consists of approximately 392 acres, within the Cities of Dania Beach and Hollywood in Broward County, Florida. The Project area comprises approximately 20 acres in the northern portion of the existing Plant site, and includes the approximately 6-acre north gas turbine site containing 12 gas turbines as well as approximately 14 acres of surrounding forested wetlands and upland spoil piles.

2. Listed Species

No negative impacts to threatened or endangered species are anticipated as a result of the CT Project.

Based upon the field assessment conducted in 2013, review of United States Fish and Wildlife (USFWS) and Florida Fish and Wildlife Conservation Commission (FWC) literature and databases, the Florida Natural Areas Inventory (FNAI) database of documented listed species occurrences, and the lack of suitable habitat, federally listed species are not anticipated to utilize the CT Project area. The potential occurrence of listed flora and fauna within the CT Project area is limited due to the surrounding land uses (industrial, commercial, and residential areas, as well as Ft. Lauderdale-Hollywood International Airport), and lack of suitable habitat within and surrounding the CT Project area to support partial or full life-cycle requirements of federally listed species known to occur within Broward County.

3. Natural Resources of Regional Significance Status

The construction and operation of the CT Project at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands. No named wetlands, named surface waters, Outstanding Florida Waters, or Aquatic Preserves would be impacted by the proposed Project.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

In the event monitoring confirms that emissions from operation of the existing GTs would not comply with the NO_2 regulations, the design option is to remove 24 gas turbines (GTs) at the existing Lauderdale Plant, and an additional 12 simple cycle GTs at their nearby Port Everglades Plant, and replace them with five new highly efficient simple cycle combustion turbines (CTs). The CTs operate in simple cycle mode with associated stacks and produce electrical energy by direct connection to an electric generator. The CTs will operate using natural gas and ultra-low sulfur distillate (ULSD) oil as fuel.

g. Local Government Future Land Use Designations

The site is zoned General Industrial by the City of Dania Beach, a designation intended to provide for light and medium intensity industrial, research, and assembly fabrication uses. Electrical power plants are permitted within a General Industrial zoning designation as a special exception use only.

A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Lauderdale Plant site has been selected as a "Preferred" for the location of peaking unit facilities due to consideration of various factors including maximizing opportunities to utilize existing utility infrastructure, system load, transmission interconnection, and economics.

i. Water Resources

The Project will require a marginal increase in demineralized water that will be obtained from the existing Lauderdale Plant's water treatment system.

j. Geological Features of Site and Adjacent Areas

According to the Natural Resource Conservation Service (NRCS) Soil Survey of Broward County, the Project area is dominated by Okeelanta muck, with Udorthents, shaped as a minor association.

The Okeelanta series consists of very deep, very poorly drained, rapidly permeable soils in large fresh water marshes and small depressional areas. They formed in decomposed hydrophytic non-woody organic material overlying sand. Slopes range from zero to two percent. In un-drained areas the water table is at depths of less than ten inches below the surface or the soil is covered by water 6 to 12 months during most years. Areas of Okeelanta muck within the Project area support a mixed native and exotic hardwood wetland community.

k. Projected Water Quantities for Various Uses

The CT Project consists of CTs that are operated in simple cycle mode and do not require a heat dissipation system. As a result, there are no associated cooling water uses, cooling water discharges, or other heat dissipation impacts.

l. Water Supply Sources by Type

The CT Project would continue to acquire water from existing water contracts with Broward County. Therefore, the Project will have no adverse impact to groundwater. The CT Project would not use onsite groundwater or a new groundwater source for any purpose. The CT Project would have no adverse impact to surface water.

The CT Project would continue to use municipal potable water from the City of Hollywood to provide drinking water for employees. There is no projected increase in employment at the Lauderdale Plant as a result of the CT Project and no associated potable water use increase for that purpose. Therefore, there would be no impact to drinking water sources from the CT Project.

m. Water Conservation Strategies Under Consideration

No additional water resources would be required as a result of the CTs project.

n. Water Discharges and Pollution Control

There would be no surface water discharges required for the operation of the CT Project, other than storm water discharges from non-contact areas. Operation of the CT Project would not generate leachate and the stormwater management system has been designed to prevent direct discharge to surface waters. Therefore, there would be no adverse impact to water supplies due to runoff or leachate from the CT Project.

The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The fuel to be used in the CTs is natural gas and ULSD oil. Natural gas will be transported to the facility via existing pipeline. No onsite storage is provided for natural gas. ULSD oil would be trucked or piped to the facility and stored in double walled ULSD oil tanks.

p. Air Emissions and Control Systems

Air emission rates for NOx with the CT Project would be approximately 90 percent lower than the existing GT emission rates, resulting in significantly lower air quality impacts. In addition to lower air emissions, the maximum total air quality impacts for the CT Project are predicted to be well below and in compliance with the National Ambient Air Quality Standards (NAAQS). For pollutants such as NO_2, the CT Project's total air quality impacts are predicted to be significantly reduced by 40 percent or more compared to the existing GTs.

The use of clean fuels (natural gas and ULSD oil) and combustion controls would minimize air emissions of SO_2, sulfuric acid mist (SAM), particulates (PM/PM10/PM2.5), and other fuel-bound contaminants and ensure compliance with applicable emission-limiting standards. Combustion controls will minimize the formation of NOx and the formation of CO and VOCs by combustor design. Further NOx reduction will be achieved by water injection during oil firing.

q. Noise Emissions and Control Systems

It is not expected that noise from the CT Project would exceed the maximum permissible sound levels in Section 17-86 of the City of Dania Beach noise ordinance. The operation of the CTs is not expected to exceed the City of Dania Beach maximum permissible sound levels in residential areas.

The design of the CT Project includes components that mitigate noise from being emitted to the surrounding environment. The majority of the noise sources, such as the CTs, are located within enclosures that mitigate sounds emitted by equipment.

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. Status of Applications

No licenses or permits have been issued for the CT Project. FPL has submitted applications to: the Florida Department of Environmental Protection (FDEP) for the Prevention of Significant Deterioration (PSD) air permit; U.S. Environmental Protection Agency (EPA) for the Greenhouse Gas air permit; and to the U. S. Army Corps of Engineers (USACE) for the 404 dredge and fill permit. These applications are currently in review with the respective agencies.

Preferred Site # 3: Hendry County, Hendry County

FPL has acquired an approximately 3,120-acre site in southeast Hendry County, off CR 833. The Hendry County site has been listed as a Preferred or Potential Site in previous FPL Site Plans as a possibility for a future PV facility and/or natural gas-fired CC generation. FPL currently views the Hendry site as one of the most likely sites to be used for future large-scale generation.

a. Geological Survey (USGS) Map

A USGS map of the site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the property owned by FPL is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing and future land uses on the site are zoned Planned Unit Development (PUD). The PUD is currently being challenged. The existing land uses that are adjacent to the site are predominately agricultural. The property to the south is the Seminole Big Cypress Reservation.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The natural environment adjacent to the north, east, and west of the site are used predominately for agricultural activities such as improved, unimproved, and woodland pasture. The majority of the pasture lands includes upland scrub, pine, and hardwoods. The Seminole Big Cypress Reservation lies to the south.

2. Listed Species

FPL strives to have no adverse impacts on federal- or state-listed terrestrial plants and animals. Much of southwest Florida is considered habitat for the endangered Florida

Panther. Although few or no impacts are expected in association with future construction at the site, FPL anticipates minimizing or mitigating for unavoidable wildlife or wetland impacts.

3. Natural Resources of Regional Significance Status

Future construction and operation of a solar and/or a natural gas-fired CC generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

Options include construction of CC and/or solar power generation technologies. Mitigation for unavoidable impacts may occur through a combination of on- and off-site mitigation.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is Utility. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Hendry County site has been selected as "Preferred" due to consideration of various factors including system load, transmission interconnection, and economics.

i. Water Resources

Groundwater is anticipated to supply water to the Hendry County site.

j. Geological Features of Site and Adjacent Areas

The site is at an approximate elevation of 10 to 12 feet above mean sea level (msl) and is located on the Immokalee Rise and the Big Cypress Spur considered terraces created by high sea level events. The terraces are composed of fine quartz sands that lie discontinuously upon the surficial aquifer system whose sediments are the Fort Thompson (Pleistocene), Caloosahatchee Marl (Pleistocene and Pliocene), and Tamiami Formations (Pliocene). Other soil types in the area include limestone rock, calcareous muds, sands, organic materials, and mixed solids.

The surficial aquifer is underlain by the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing at a CC unit is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Potable water demand is expected to average .001 mgd. Minimal amounts of water would be required for a PV facility. Approximately 7.5 mgd of cooling water would be used in cooling towers for one CC unit.

l. Water Supply Sources by Type

Potential water supply source is groundwater. Additional evaluations are necessary to determine the exact source. Process and potable water for the new plant will come from the existing potable water supply.

m. Water Conservation Strategies Under Consideration

CC and cooling tower technologies utilize less water by design than traditional steam generation units. PV facilities have minimal water demands. Specific water conservation strategies will be evaluated and selected during the detailed design phase of any development project.

n. Water Discharges and Pollution Control

A CC unit at the site would utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's cooling water flow prior to discharge. Wastewater disposal is anticipated via discharge to an Underground Injection Control well system. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral to the site. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary Ultra-low sulfur light fuel oil will be received by truck or pipeline and stored in an above-ground storage tank.

p. Air Emissions and Control Systems

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize regulated air emissions from a CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of SO_2, PM, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of NO_x and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra low sulfur fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA's proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida. PV generation does not produce air emissions.

q. Noise Emissions and Control Systems

Noise anticipated to be caused by unit construction at the site is expected to be minimal.

r. Status of Applications

FPL has not submitted any application associated with the Hendry County site.

Preferred Site # 4: NE Okeechobee County, Okeechobee County

FPL has purchased a site of approximately 2,800 acres in Northeast Okeechobee County. The site is in an unincorporated, rural area and is predominantly used for agricultural production. FPL's transmission lines intersect the property. The Northeast Okeechobee County site has been listed as a Preferred or Potential Site in previous FPL Site Plans as a possibility for a natural gas-fired CC generation and/or future PV facility. Natural gas-fired CC generation will be made possible by the May,2017 projected commercial operating date of the Florida Southeast Connection (FSC) natural gas pipeline. FSC is within 3 miles of the NE Okeechobee County site. FPL currently views the Okeechobee site as one of the most likely sites to be used for future large-scale generation.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Northeast Okeechobee site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the property owned by FPL is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The Northeast Okeechobee County site is predominantly used for agricultural production (cattle and citrus). Adjacent land uses include primarily agriculture and conservation.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of lands dedicated to agricultural production.

2. Listed Species

Minimal impacts to federal- or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species.

3. Natural Resources of Regional Significance Status

The construction and operation of a power generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

Options include construction of PV or CC technologies. Mitigation for unavoidable impacts may occur through a combination of on- and off-site mitigation.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is predominantly unimproved pasture. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Northeast Okeechobee County site has been selected as a Preferred Site due to consideration of various factors including system load, transmission interconnection, the proximity of the proposed FSC natural gas pipeline, and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity.

i. Water Resources

Groundwater is anticipated to supply water to the Northeast Okeechobee County site.

j. Geological Features of Site and Adjacent Areas

The hydrostratigraphy of the Northeast Okeechobee County site is similar to that of most of South Florida. In general, the groundwater system underlying Okeechobee County consists of the Surficial Aquifer System (SAS), the Intermediate Confining Unit (ICU), and the Floridan Aquifer System (FAS). The SAS consists of approximately 100 to 250 feet of undifferentiated deposits of sand, shell, clay and silt. The ICU consists of approximately 200 feet of carbonate rocks interbedded with sandy and silty clay. The multiple layers of the FAS extend thousands of feet below the ICU.

k. Projected Water Quantities for Various Uses

Potable water demand is expected to average .001 mgd. The estimated quantity of water required for processing at a CC unit is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Approximately 7.5 mgd of cooling water would be used in cooling towers for a CC unit. Minimal amounts of water would be required for a PV facility.

l. Water Supply Sources by Type

Potential water supply source is groundwater. Additional evaluations are necessary to determine the exact source. Process and potable water for the new plant will come from the existing a potable water supply.

m. Water Conservation Strategies Under Consideration

CC technology utilizes less water by design than traditional steam generation units. PV facilities have minimal water demands. Specific water conservation strategies will be evaluated and selected during the detailed design phase of any development project.

n. Water Discharges and Pollution Control

A CC plant is anticipated to utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's cooling water flow prior to discharge. Wastewater disposal is anticipated via discharge to an Underground Injection Control well system. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ Best

Management Practices (BMP) and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary. Back-up fuel supplies of ultra-low sulfur light fuel oil will be received by truck or pipeline and stored in an above-ground storage tank to ensure reliability of operations.

p. Air Emissions and Control Systems

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize regulated air emissions from a CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of SO_2, PM, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of NO_x and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA's proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida. PV generation does not produce air emissions.

q. Noise Emissions and Control Systems

Noise anticipated to be caused by unit construction at the site is expected to be minimal.

r. Status of Applications

FPL has not filed any applications associated with the Northeast Okeechobee County site.

Preferred Site # 5: Putnam Site, Putnam County

FPL is currently evaluating the existing Putnam Plant site for future natural gas-fired generation as part of a potential modernization project. This 66 acre site is located on the east side of Highway 100 opposite the former FPL Palatka Plant in East Palatka. The Putnam site has been listed as a Potential Site in previous FPL Site Plans as a possibility for future natural gas-fired CC generation.

FPL currently views the Putnam site as one of the most likely sites to be used for future large-scale generation.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Putnam site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the property owned by FPL is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The Putnam site is designated as Industrial land use. Adjacent land uses include power generation and associated facilities (the former Palatka Plant) as well as Mixed Wetland Hardwoods, Residential, and Hardwood-Coniferous Mixed.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is developed and has facilities necessary for power plant operations. No significant environmental features have been identified at this time.

2. Listed Species

Minimal impacts to federal- or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species.

3. Natural Resources of Regional Significance Status

The construction and operation of a power generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

Options include construction of CC technology. Mitigation for unavoidable impacts may occur through a combination of on- and off-site mitigation.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is Industrial. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Putnam site has been selected as a Preferred Site due to consideration of various factors including system load, transmission interconnection, and economics.

i. Water Resources

The St John's River and/or regional water supply initiatives are potential water sources.

j. Geological Features of Site and Adjacent Areas

The hydrostratigraphy of the Putnam site is similar to that of most of North Florida. In general, the groundwater system underlying Putnam consists of the Surficial Aquifer System (SAS), and the Floridan Aquifer System (FAS).

k. Projected Water Quantities for Various Uses

Potable water demand is expected to average .001 million gallons per day (mgd). The estimated quantity of water required at a CC unit is approximately 0.24 mgd for uses such as process water and service water. Approximately 7.5 mgd of cooling water would be used in cooling towers for a CC unit.

l. Water Supply Sources by Type

Potential water supply source is the St. John's River. Additional evaluations are necessary to determine the exact source. Process and potable water for the new plant will come from the existing a potable water supply.

m. Water Conservation Strategies Under Consideration

CC and cooling tower technologies utilize less water by design than traditional steam generation units. Specific water conservation strategies will be evaluated and selected during the detailed design phase of the project development.

n. Water Discharges and Pollution Control

A CC plant is anticipated to utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's cooling water flow prior to discharge. Wastewater disposal is anticipated via discharge to surface and/or ground water as is the case with the existing Putnam Plant. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ Best Management Practices (BMP) and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o. <u>Fuel Delivery, Storage, Waste Disposal, and Pollution Control</u>

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary. Back-up fuel supplies of ultra-low sulfur light fuel oil will be received by water-borne delivery, truck, or pipeline and stored in an above-ground storage tank to ensure reliability of operations.

p. <u>Air Emissions and Control Systems</u>

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize regulated air emissions from a CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of SO_2, PM, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of NO_x and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra- low sulfur light fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA's proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida.

q. <u>Noise Emissions and Control Systems</u>

Noise anticipated to be caused by unit construction at the site is expected to be minimal.

r. <u>Status of Applications</u>

FPL has not submitted any applications associated with the Putnam site.

<u>Preferred Site # 6: Turkey Point Plant, Miami-Dade County</u>

The Turkey Point Plant (Turkey Point) is located on the west side of Biscayne Bay, 25 miles south of Miami. Turkey Point is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. The land surrounding Turkey Point is owned by FPL and acts as a buffer zone. Turkey Point is comprised of two natural gas/oil conventional steam units (Units 1 & 2), two nuclear units (Units 3 & 4), one combined cycle natural gas unit (Unit 5), nine small diesel generators, and the cooling canals. A capacity uprate project for the two nuclear units was successfully completed in 2013. The Everglades Mitigation Bank (EMB), an approximately 13,000 acre, FPL-maintained natural wildlife and wetlands area that has been set aside, is located to the south and west of the site.

In regard to Turkey Point Units 6 & 7, FPL is pursuing licensing for two new nuclear units at Turkey Point. Each of these two units would provide 1,100 MW of capacity. The current projections for the earliest in-service dates for the two new units remain 2022 (for Turkey Point Unit 6) and 2023 (for Turkey Point Unit 7). In addition to the two generating units, supporting buildings, facilities, and equipment will be located on the Turkey Point Units 6 & 7 site, along with a construction laydown area. Proposed associated facilities include: a nuclear administration building, a training building, a parking area, an FPL reclaimed water treatment facility and reclaimed water pipelines, radial collector wells and delivery pipelines, an equipment barge unloading area, transmission lines (and transmission system improvements elsewhere within Miami-Dade County), access roads and bridges, and potable water pipelines.

a. U.S. Geological Survey (USGS) Map

USGS maps of the Turkey Point area, with the proposed location of Turkey Point Units 6 & 7 identified, are found at the end of this chapter.

b. Proposed Facilities Layout

Maps of the general layout of Turkey Point Units 6 &7 are found at the end of this chapter.

c. Map of Site and Adjacent Areas

Land Use / Land Cover overview maps of the Turkey Point Units 6 & 7 site and adjacent areas are also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

Turkey Point Plant is currently home to five generating units and support facilities that occupy approximately 150 acres of the approximately 9,400-acre Turkey Point property. Prominent features beyond the power block area include the intake system, cooling canal system, switchyard, spent fuel storage facilities, and technical and administrative support facilities The cooling canal system occupies approximately 5,900 acres.

The two 400-megawatt (MW) (nominal) fossil fuel-fired steam electric generation units at Turkey Point have been in service since 1967 (Unit 1) and 1968 (Unit 2). These units have historically burned residual fuel oil and/or natural gas with a maximum equivalent sulfur content of one percent. Unit 2 is currently serving, not as a power generating unit, but as a synchronous condenser to provide voltage support to the southeastern end of FPL's transmission system. The two original 700-MW (nominal) nuclear units have been in service since 1972 (Unit 3) and 1973 (Unit 4) and were uprated to a total of approximately 1,632 (Summer) MW's in 2013. Turkey Point Units 3 and 4 are pressurized water reactor (PWR) units. Turkey Point Unit 5 is a net 1,148 (Summer) MW natural gas-fired combined cycle unit that began operation in 2007. The site for the new Units 6 & 7 is south of existing Units 3 and 4 and occupies approximately 300 acres within the existing cooling canal system.

Properties adjacent to Turkey Point property are almost exclusively undeveloped land. The FPL-owned EMB is adjacent to most of the western and southern boundaries of Turkey Point property. The South Florida Water Management District (SFWMD) Canal L-31E is also situated to the west of Turkey Point property. The eastern portions of Turkey Point property are adjacent to Biscayne Bay, the Biscayne National Park (BNP), and Biscayne Bay Aquatic Preserve. The southeastern portion of Turkey Point property is bounded by state-owned land located on Card Sound. The Homestead Bayfront Park, owned and operated by Miami-Dade County, is situated to the north of the Turkey Point property.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

Turkey Point is located directly on the northwest, west, and southwest shoreline of Biscayne Bay and the Biscayne National Park, 25 miles south of Miami. Biscayne National Park was first established in 1968 as a National Monument and was expanded in 1980 to approximately 173,000 acres of water, coastal lands, and 42 keys. A portion of Biscayne Bay Aquatic Preserve, a state-owned preserve, is adjacent to the eastern boundary of the Turkey Point plant property. The Biscayne Bay Aquatic Preserve is a shallow, subtropical lagoon consisting of approximately 69,000 acres of submerged State land that has been designated as an Outstanding Florida Water.

The approximately 300-acre Turkey Point Units 6 & 7 site consists of the plant area and adjacent areas designated for laydown and ancillary facilities. The site includes hypersaline mud flats, man-made active cooling canals, man-made remnant canals, previously filled areas/roadways, mangrove heads associated with historical tidal channels, dwarf mangroves, open water /discharge canal associated with the cooling canals on the western portion of the site, wet spoil berms associated with remnant canals, and upland spoil areas.

2. <u>Listed Species</u>

Threatened, endangered, and/or animal species of special concern known to occur at the site, transmission line corridors, or in the nearby Biscayne National Park, include the peregrine falcon *(Falco peregrinus)*, wood stork *(Mycteria americana)*, American crocodile *(Crocodylus acutus)*, roseate spoonbill (*Ajaja ajaja)*, little blue heron *(Egretta caerulea),* snowy egret *(Egretta thula),* American oystercatcher *(Haematopus palliates),* least tern *(Sterna antillarum)*, the white ibis *(Eudocimus albus)*, Florida manatee (Trichechus manatus latirostris), eastern indigo snake (Drymarchon couperi), snail kite (Rostrhamus sociabilis plumbeus), white-crowned pigeon (Patagioenas leucocephala), and bald eagle *(Haliaeetus leucocephalus)*. No bald eagle nests are known to exist in the vicinity of the site. The federally listed, threatened American crocodile thrives at Turkey Point, primarily in and around the southern end of the cooling canals which lie south of the Turkey Point Unit 6 & 7 area. The majority of Turkey Point is considered American crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American Crocodile and the program is credited with survival improvement and contributing to the downlisting of the American Crocodile from endangered to threatened.

Some listed flora species likely to occur at the site or vicinity include pinepink (Bletia purpurea), Florida brickell-bush (Brickellia mosieri), Florida lantana (Lantana depressa var. depressa), mullien nightshade (Solanum donianum), and lamarck's trema (Trema lamarckianum).

The construction, and operation after construction, of Turkey Point Unit 6 & 7 project is not expected to adversely affect any rare, endangered, or threatened species.

3. <u>Natural Resources of Regional Significance Status</u>

Significant features within the vicinity of the site include Biscayne National Park, the Biscayne Bay Aquatic Preserve, Miami-Dade County Homestead Bayfront Park, and Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park. Biscayne National Park contains 180,000 acres, approximately 95 percent of which is open water interspersed with more than 40 keys. The Biscayne National Park headquarters is located approximately two miles north of Turkey Point and is adjacent to the Miami-Dade County Homestead Bayfront Park, which contains a marina and day-use recreational facilities.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

For Turkey Point Units 6 & 7, the technology proposed is the Westinghouse AP1000 pressurized water reactor (PWR). This design is certified by the Nuclear Regulatory Commission (NRC) under 10 CFR 52 and incorporates the latest technology and more advanced safety features than today's nuclear plants that have already achieved record safety levels. The Westinghouse AP1000 unit consists of the reactor, steam generators, pressurizer, and steam turbine/electric generator. Condenser cooling for the Units 6 & 7 steam turbines will be accomplished using six circulating water cooling towers. The makeup water reservoir is the reinforced concrete structure beneath the circulating water system cooling towers that will contain reserve reclaimed water capacity to be used for the circulating water system. The structures for the Westinghouse AP1000 are the nuclear island (containment building, shield building, and auxiliary building), turbine building, annex building, diesel generator building, and radwaste building. The plant area will also contain the Clear Sky substation (switchyard) that will connect Units 6 & 7 to FPL's transmission system.

g. Local Government future Land Use Designations

The Turkey Point Plant site is designated by the Miami-Dade County Comprehensive Development Management Plan as an IU-3 (Industrial, Utilities, and Communications) Unlimited Manufacturing District that carries a dual designation of MPA (Mangrove Protection Area) in portions of the property. There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. Site Selection Criteria Process

For Turkey Point Units 6 & 7, FPL conducted an extensive site selection analysis leading to the selection of the Turkey Point site as the site that, on balance, provided the most favorable location for developing new nuclear generation to serve FPL's customers. The Site Selection Study employed the principles of the Electric Power Research Institute (EPRI) siting guidelines and is modeled upon applicable NRC site suitability and National Environmental Policy Act (NEPA) criteria regarding the consideration of alternative sites. The study convened a group of industry and FPL subject matter experts to develop and assign weighting factors to a broad range of site selection criteria. Twenty-three candidate sites were then ranked using the siting criteria. This review allowed the list of candidates to be reduced until the best site emerged. Key factors contributing to the selection of the Turkey Point site include the existing transmission and transportation infrastructure to support new generation, the large size and seclusion of the site while being relatively close to the load center, and the long-standing record of safe and secure operation of nuclear generation at the site since the early 1970s.

i. Water Resources

In regard to Turkey Point Units 6 & 7, the primary source of cooling water makeup will be reclaimed water from the Miami-Dade County Water and Sewer Department (MDWASD), with potable water also from MDWASD. When reclaimed water is not available in sufficient quantity and quality of water needed for cooling, makeup water will be saltwater supplied by radial collector wells that are recharged from the marine environment of Biscayne Bay. Horizontal collector wells (radial collector wells) have become widely used for the purpose of inducing infiltration from surface water bodies into hydraulically-connected aquifer systems in order to develop moderate to high capacity water supplies. Turkey Point Units 6 & 7 wastewater will be discharged via on-site deep injection wells.

j. Geological Features of Site and Adjacent Areas

Turkey Point lies upon the Floridian Plateau, a partly-submerged peninsula of the continental shelf. The peninsula is underlain by approximately 4,000 to 15,000 feet of sedimentary rocks consisting of limestone and associated formations that range in age from Paleozoic to Recent. Little is known about the basement complex of Paleozoic igneous and metamorphic rocks due to their great depth.

Generally in Miami-Dade County, the surficial aquifer (Biscayne Aquifer) consists of a wedge-shaped system of porous clastic and carbonate sedimentary materials, primarily limestone and sand deposits of the Miocene to late Quaternary age. The Biscayne Aquifer is thickest along the eastern coast and varies in thickness from 80 to 200 feet thick. The surficial aquifer is typically composed of Pamlico Sand, Miami Limestone (Oolite), the Fort Thompson and Anastasia Formations (lateral equivalents), Caloosahatchee Marl, and the Tamiami formation. The lower confining layers below the surficial aquifer range in thickness from 350 to 600 feet and are composed of the Hawthorn Group. Beneath the Hawthorn Group, the Floridan Aquifer System ranges from 2,800 to 3,400 feet thick and consists of Suwannee Limestone, Avon Park Limestone, and the Oldsmar Formations.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for the new Turkey Point Units 6 & 7 for industrial processing is approximately 936 gallons per minute (gpm) for uses such as process water and service water. Approximately 55.3 million gallons per day (mgd) of cooling water would be cycled through the cooling towers. Water quantities needed for other uses such as potable water are estimated to be approximately 50,400 gallons per day (gpd) for Units 6 & 7.

l. Water Supply Sources and Type

The water for the various water needs of Turkey Point 6 & 7 will be obtained from a reclaimed water supply, a saltwater supply, and a potable water supply. Reclaimed water will be used as makeup water to the cooling water system with saltwater from radial collector wells as a back-up water source to be used when reclaimed water is not available in sufficient quantity or quality.

Potable water will be used as makeup water for the service water system. The potable water supply will also provide water to the fire protection system, demineralized water treatment system, and other miscellaneous uses.

m. Water Conservation Strategies

Use of reclaimed water from MDWASD Turkey Point Units 6 & 7 is a beneficial and cost-effective means of increasing the use of reclaimed water. This use of reclaimed water helps Miami-Dade County meet approximately half of its wastewater reuse goals and will provide environmental benefits by reducing the volume of wastewater discharged by the County. In the absence of reuse opportunities, this treated domestic wastewater would likely continue to be discharged to the ocean or into deep injection wells.

Miami-Dade County is required to eliminate ocean outfalls and increase the amount of water that is reclaimed for environmental benefit and other beneficial uses. Turkey Point Units 6 & 7 will use reclaimed water 24 hours per day, 365 days per year when operating and when the reclaimed water is available in sufficient quantity and quality.

n. Water Discharges and Pollution Control

Turkey Point Units 6 & 7 will dissipate heat from the power generation process using cooling towers. Blowdown water or discharge from the cooling towers, along with other wastestreams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Storm water runoff will be released to the closed-loop cooling canal system.

Turkey Point Units 6 & 7 will employ Best Management Practices (BMP) plans and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The Turkey Point Units 6 & 7, reactors will contain enriched uranium fuel assemblies. A fuel assembly consists of 264 fuel rods, 24 guide thimbles, and 1 instrumentation tube in a 17-by-

17 square array. The fuel rods consist of enriched uranium, in the form of cylindrical pellets of sintered uranium dioxide contained in ZIRLO™ tubing.

New fuel assemblies will be transported to Turkey Point for use in Units 6 & 7 by truck from a fuel fabrication facility in accordance with U.S. Department of Transportation (DOT) and NRC regulations. Spent fuel assemblies being discharged will remain in the spent fuel pool while short half-life isotopes decay.

After a sufficient decay period, the fuel would be transferred to an on-site independent spent fuel storage installation facility or an off-site disposal facility. Packaging of the fuel for off-site shipment will comply with the applicable DOT and NRC regulations for transportation of radioactive material.

The U.S. Department of Energy (DOE) is responsible for spent fuel transportation from reactor sites to a repository under the Nuclear Waste Policy Act of 1982, as amended. FPL has executed a standard spent nuclear fuel disposal contract with DOE for fuel used in Units 6 & 7.

p. <u>Air Emissions and Control Systems</u>

Turkey Point Units 1, 2, and 5, and the emergency diesel generators associated with Units 3 and 4, are classified as a major source of air pollution. FDEP has issued a separate Title V Air Operating Permit for the fossil units at Turkey Point and for the emergency diesel generators associated with the nuclear units. There are no operating limits for the emergency generators or diesel engines. Emergency diesel generators are limited to use ultra-low sulfur diesel fuel (0.0015% sulfur). NO_x emissions are regulated under Reasonably Available Control Technology (RACT) requirements in Rule 62-296.570(4) (b) 7 F.A.C., which limit NO_x emissions to 4.75 lb/MMBtu. The use of 0.05 percent sulfur diesel fuel and good combustion practices serve to keep NO_x emissions under this limit.

Regarding Turkey Point Units 6 & 7, the units will also minimize FPL system air pollutant emissions by using nuclear fuel to generate electric power. This includes avoiding emissions of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), carbon dioxide (CO_2), and volatile organic compounds (VOC). The circulating water cooling towers will be equipped with high-efficiency drift or mist eliminators to minimize emissions of PM to 0.0005 percent of the circulating water; which represents 99.99-percent control of potential drift emissions based on the circulating water flow.

The diesel engines necessary to support Turkey Point Units 6 & 7 and fire pump engines will be purchased from manufacturers whose engines meet the EPA's New Source Performance Standards (NSPS) Subpart IIII emission limits.

q. <u>Noise Emissions and Control Systems</u>

Field surveys and impact assessments of noise expected to be caused by activities associated with the Turkey Point Units 6 & 7 project were conducted. Predicted noise levels associated with these projects are not expected to result in adverse noise impacts in the vicinity of the site.

r. <u>Status of Applications</u>

The Turkey Point Units 6 & 7 Site Certification Application (SCA), under the Florida Electrical Power Plant Siting Act, was filed in June 2009 and a final order is anticipated in mid-2014. The FPSC issued the final order approving the need for this additional nuclear capacity in April 2008.

A Combined License Application for Units 6 & 7 was submitted to the NRC in June 2009. There are two components to that application; one is the Environmental Assessment (EA) and the other is the Safety component. The Application is still in process.

Besides the certification and the license, additional approvals have been issued for Turkey Point Units 6 & 7 including Miami-Dade County Unusual Use approvals that were issued in 2007 and 2013 and a Land Use Consistency Determination that was issued in 2013. The Prevention of Significant Deterioration (Air permit) was issued in 2009. In addition, a permit to construct an exploratory well and a dual zone monitoring well, under the Underground Injection Control Program, was issued in 2010, and a permit to convert the exploratory well, to an injection well and to operationally test the system, was issued in 2013. Permits from the Federal Aviation Administration (FAA) for the containment structure were originally issued in 2009 and renewed in 2012.

The western transmission lines associated with Units 6 & 7 (2 500 kV New Clear Sky Substation – Levee Substation and 1 230 kV New Clear Sky Substation – Pennsuco Substation) will utilize the existing approximately 40-mile-long transmission line right-of-way acquired by FPL in the 1960s and early 1970s between the Turkey Point plant property and Levee Substation. A 7.4 mile long segment of that existing right-of-way became surrounded by the Everglades National Park in 1989 when the East Everglades Expansion Area south of Tamiami Trail (US-41) was added to the Park. The National Park Service and several other federal, state and local agencies entered into contingent agreements in 2008 to exchange

FPL's fee-owned property within the Park for an alternative right-of-way along the Park's eastern boundary (the Exchange Right-of-Way). That land exchanges was authorized by the U.S. Congress in the 2009 Omnibus Public Lands Management Act, and the National Park Service is currently engaged in a National Environmental Policy Act (NEPA) review of the proposed exchange. The Recommended Order to be considered by the Siting Board in 2014 recommends for approval FPL's West Preferred Corridor, which includes the Exchange Right-of-Way, as a back-up western transmission line corridor to another corridor. The primary western corridor recommended for approval is the West Consensus Corridor (comprising an alternate corridor proposed by the Miami-Dade Limestone Products Association and a portion of FPL's West Preferred Corridor). Both of those western transmission line corridors recommended for certification use the Exchange Right-of-Way. In the event the pending land exchange with the National Park Service and other agencies is not consummated on a timely basis, FPL will need to evaluate other potential western corridors for the western transmission lines associated with Units 6 & 7, including its existing fee-owned right-of-way in the Park, and seek necessary approvals for construction of the required transmission facilities.

IV.F.2 <u>Potential Sites for Generating Options</u>

Four (4) sites are currently identified as Potential Sites for future generation additions to meet FPL's projected capacity and energy needs.[6] These sites have been identified as Potential Sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies, including both renewable energy and non-renewable energy technologies for various sites.

Each of these Potential Sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that will require further definition and attention.

Permits are presently considered to be obtainable for each of these sites. No significant environmental constraints are currently known for any of these sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time, FPL considers each site to be equally viable.

[6] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other Greenfield sites. Greenfield sites that FPL currently does not own, or for which FPL has not currently secured the necessary rights to, are not specifically identified as Potential Sites in order to protect the economic interests of FPL and its customers.

Potential Site # 1: Babcock Ranch, Charlotte County

This site is located within the proposed Babcock Ranch Community on the north side of Tuckers Grade, approximately 10.5 miles north of the intersection of SR-80 and SR-31 and 1.1 miles east of SR-31. The project is bordered on the north by the Babcock Ranch Preserve owned by the State of Florida. This site is a possibility for an FPL PV facility. FPL has received all permits necessary to construct a 74 MW PV facility at this location.

a. U.S. Geological Survey (USGS) Map

A map of this site is found at the end of this chapter.

b. Land Uses

Existing land use on the site is the Babcock Ranch Overlay District, and it is zoned as the Babcock Ranch Overlay Zoning District. This land use and zoning allows for solar facilities.

c. Environmental Features

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

d. Water Quantities

Minimal amounts of water, if any, would be required for a PV facility.

e. Supply Sources

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water may be brought to the site by truck.

Potential Site # 2: DeSoto Solar Expansion, DeSoto County

The DeSoto site is located at 4051 Northeast Karson Street which is approximately 0.3 miles east of U.S. Highway 17 and immediately north of Bobay Road in Arcadia, Florida. The site is located in Sections 26, 27, & 35, Township 36 South, and Range 25 East. FPL owns an approximate 13,000 acre parcel in DeSoto County. FPL has designated approximately 5,177 acres for development of a PV facility.

The DeSoto site is home to a 25 MW PV facility that has been operational since 2009. Up to an additional 275 MW of PV generation could be constructed in phases on the remaining undeveloped land. FPL has initiated permitting for the additional PV facilities.

a. U.S. Geological Survey (USGS) Map

A map of this site is found at the end of this chapter.

b. Land Uses

Existing land use on the site is agricultural. The future land use is Electric Generating Facility.

c. Environmental Features

There are no significant environmental features on the site.

d. Water Quantities

Minimal amounts of water would be required for a future expansion of the existing PV facility.

e. Supply Sources

Minimal water would be required for an expanded PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall. Potable water will be required in the administration building and maintenance building. FPL would propose to utilize existing wells onsite to accommodate water needs.

Potential Site # 3: Manatee Plant Site, Manatee County

The existing FPL Manatee Plant 9,500-acre site is located in unincorporated north-central Manatee County. The existing power generating facilities are located in all or portions of Sections 18 and 19 of Township 33S, Range 20-E. The plant site lies approximately 5 miles east of Parrish, Florida. It is approximately 5 miles east of U.S. Highway 301 and 9.5 miles east of Interstate Highway 75 (I-75). The existing plant is approximately 2.5 miles south of the Hillsborough-Manatee County line. A portion of the north property boundary of the plant site abuts the county line. State Road 62 (SR 62) is about 0.7 mile south of the plant, with the plant entrance road going north from that highway. This site is a possible location for an FPL PV facility. FPL has received the federal and state permits required to construct approximately 50 MW of PV at this location.

a. U.S. Geological Survey (USGS) Map

A map of the site is found at the end of this chapter.

b. Land Uses

Existing land use on the site is agricultural. The property is zoned Planned Development / Public Interest (PD-PI), which will allow for electrical generation.

c. Environmental Features

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

d. Water Quantities

Minimal amounts of water would be required for a PV facility.

e. Supply Sources

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall. Panel cleaning water source may be existing potable water or water tank trucked to the site.

Potential Site # 4: Martin County, Martin County

FPL is currently evaluating potential sites in Martin County for a future PV facility. No specific locations have been selected at this time.

a. U.S. Geological Survey (USGS) Map

A USGS map of the county has been included at the end of this chapter.

b. Land Uses

This information is not available because a specific site has not been selected at this time.

c. Environmental Features

This information is not available because a specific site has not been selected at this time.

d. Water Quantities

Minimal amounts of water would be required for a PV facility.

e. Supply Sources

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall.

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CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information." These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints: external limitations and internal limitations. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important since they affect the development of assumptions for the amount of external assistance that is available to the FPL system as well as the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In the loss of load probability (LOLP) portion of its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new generating units that minimize adverse impacts to the flow of electricity within FPL's system. The internal transmission limitations are also addressed by developing the direct costs for siting new units at different locations, by evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system, and/or by evaluating the costs of transmission additions that may be needed to address regional concerns regarding an imbalance between load and generation in a given region. Both of these site- and system-related transmission costs are developed for each different unit/unit location option or groups of options. When analyzing DSM portfolios, such as in a DSM Goals docket, FPL also examines the potential of utility DSM energy efficiency programs to avoid/defer regional transmission expenditures that would otherwise be needed to import power into that region by lowering electrical load in Southeastern Florida. In addition, transfer limits for capacity and energy that can be

imported into the Southeastern Florida region (Miami-Dade and Broward Counties) of FPL's system are also developed for use in FPL's production costing analyses. (A further discussion of the Southeastern Florida region of FPL's system, and the need to maintain a regional balance between generation and transmission contributions to meet regional load, is found in Chapter III.)

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's planned transmission facilities to interconnect and integrate generating units in FPL's resource plans, including those transmission facilities that must be certified under the Transmission Line Siting Act, are presented in Chapter III.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements for the FPL system.[7]

The load forecast that is presented in FPL's 2014 Site Plan was developed in October 2014. The only load forecast sensitivities analyzed during 2013/early 2014 were high load forecast sensitivities developed to analyze FPL's potential future natural gas needs and to analyze the quality of FPL's future reserves.

[7] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis (i.e., when only new generating options are considered), the lowest electric rate basis approach and the lowest system cumulative present value of revenue requirements basis approach yield identical results in terms of which resource options are more economic. In such cases FPL evaluates resource options on the simpler-to-calculate (but equivalent) lowest cumulative present value system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its fuel price forecasts are discussed in Chapter III of this document. FPL used three fuel cost, and three environmental compliance cost, forecasts in analyses supporting its 2013 nuclear cost recovery filing. Also, in response to a request from the FPSC Staff, FPL used three fuel cost forecasts in sensitivity case analyses for the 2014 DSM Goals docket.

A Medium fuel cost forecast is developed first. Then the Medium fuel cost forecast is adjusted upwards (for the High fuel cost forecast), or downwards (for the Low fuel cost forecast), by multiplying the annual cost values from the Medium fuel cost forecast by a factor of (1 + the historical volatility in the 12-month forward price, one year ahead) for the High fuel cost forecast, or by a factor of (1 – the historical volatility of the 12-month forward price, one year ahead) for the Low fuel cost forecast.

The resource plan presented in this Site Plan is based, in part, on those prior analyses. For that reason, this resource plan has not been further tested for different fuel cost forecasts.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item # 3, FPL used up to three fuel cost forecasts in its 2013/early 2014 resource planning analyses. While these forecasts did not represent a constant cost differential between oil/gas and coal, a variety of fuel cost differentials were represented in these forecasts.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 in Chapter I and Schedule 8 in Chapter III present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options in its resource planning work. A summary of this information for the new capacity options FPL currently projects to add over the reporting horizon for this document is presented on the Schedule 9 forms in Chapter III.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

During 2013, FPL used the following financial assumptions: i) a capital structure of 40.38% debt and 59.62% equity; (ii) a 4.79% cost of debt; (iii) a 10.5% return on equity; and (iv) an after-tax discount rate of 7.45%. In early 2014, the cost of debt and the after-tax discount rate changed slightly to 5.14% and 7.54%, respectively. The other assumptions did not change. No sensitivities of these financial assumptions were used in FPL's 2013/early 2014 resource planning work.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item # 2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective yield identical results in terms of which resource options are more economic when DSM levels are unchanged between competing resource plans. Therefore, in planning work in which DSM levels were unchanged, the equivalent, but simpler-to-calculate, cumulative present value of revenue requirements perspective was utilized.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses three system reliability criteria in its resource planning work that addresses generation, purchase, and DSM options. One criterion is a minimum 20% Summer and Winter reserve margin. Another reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). The third criterion is a minimum 10% generation-only reserve margin (GRM) criterion. These three reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability analysis work, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the Reliability Standards established by the North American Electric Reliability Council (NERC). The *NERC Reliability Standards* are available on the internet site (http://www.nerc.com/).

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Facility Rating Methodology* document that are also available on the internet under the Interconnection Request Information, and FPL Facility Ratings Methodologies, directories respectively at https://www.oatioasis.com/FPL/index.html.

Generally, FPL limits its transmission facilities to 100% of the applicable thermal rating. The normal and contingency voltage criteria for FPL stations are provided below:

	Normal/Contingency	
Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09
Turkey Point (*)	1.01/1.01	1.06/1.06
St. Lucie (*)	1.00/1.00	1.06/1.06

(*) Voltage range criteria for FPL's Nuclear Power Plants

There may be isolated cases for which FPL may have determined that it is acceptable to deviate from the general criteria stated above. There are several factors that could influence these criteria, such as the overall number of potential customers that may be impacted, the probability of an outage actually occurring, or transmission system performance, as well as others.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The projected impacts of FPL's DSM programs on demand and energy consumption are revised periodically. Engineering models, calibrated with current field-metered data, are updated at regular intervals. Participation trends are tracked for all of FPL's DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants. For its load management programs, FPL conducts periodic tests of the load control equipment to ensure that the equipment is functioning correctly. These tests, plus actual, non-test load management events, also allows FPL to gauge the MW reduction capabilities of its load management programs on an on-going basis.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The Executive Summary and Chapter III provide a discussion of a variety of system concerns/issues that influence FPL's resource planning process. Please see those chapters for a discussion of those concerns/issues.

In addition to these system concerns/issues, there are other strategic factors FPL typically considers when choosing between resource options. These include the following: (1) technology risk; (2) environmental risk, and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology, which has not achieved general commercial acceptance, has a higher risk than a technology in wide use and, therefore, assuming all else equal, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the FPL system, including environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for FPL's resource plan are those which minimize environmental impacts for the FPL system as a whole through highly efficient fuel use, state of the art environmental controls, generating technologies that do not utilize fossil fuels (such as nuclear and solar), etc.

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decision-making, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As shown in this 2014 Site Plan, FPL's resource plan currently reflects the following major supply-side resource additions: the on-going modernization at Port Everglades, on-going upgrading of CTs in several CCs throughout FPL's system, the projected addition of CTs at FPL's Lauderdale plant site, the implementation of the previously executed EcoGen PPA, a projected new CC unit (at a site that has not yet been selected), and the projected Turkey Point Units 6 & 7.

In regard to the above capacity additions for which a need determination has already been granted, Turkey Point Units 6 & 7, did not lend themselves to a request for proposal (RFP) approach involving bids from third parties who would build new nuclear generation capacity. In addition, nuclear capacity additions are exempted from the Commission's Bid Rule by section 403.519 (4) (c). For nuclear projects, FPL's procurement activities are conducted to ensure the best combination of quality and cost for the delivered products. In regard to the modernization project at Port Everglades, the project received a Commission waiver from the Bid Rule due to attributes specific to the Port Everglades site and to modernization projects in general (such as use of existing land, water, transmission, etc.) plus other economic benefits to FPL's customers. This waiver from the Bid Rule was granted in Order No. PSC-11-0360-PAA-EI for Port Everglades.

CT upgrades are currently taking place at several CC units throughout the FPL system. FPL was approached by the original equipment manufacturer (OEM) of the CTs regarding the possibility of upgrading these units. Following negotiations with the OEM, and economic analyses that showed that upgrading was cost-effective for FPL's customers, the decision was made to proceed with the CT upgrades. That process is underway and is scheduled to be completed in 2015.

In regard to the addition of five new CTs at FPL's Lauderdale plant site, FPL anticipates selecting the CTs through negotiations with, and/or competitive solicitation of, CT manufacturers. The EcoGen PPA, which was approved by the Commission in Order No. PSC-13-0205-CO-EQ dated 5/21/13, was the result of negotiations between EcoGen and FPL.

Identification of projected self-build options, beyond those units already approved by the FPSC and Governor and Siting Board or units, such as the 2019 CC unit presented in this Site Plan, is required of FPL in its Site Plan filings and represents FPL's current view of alternatives that appear to be FPL's best, most cost-effective self-build options at present. FPL reserves the right to refine its planning analyses and to identify and evaluate other options before making decisions regarding future capacity additions. Such refined analyses have the potential to yield a variety of self-build options, some of which might not require an RFP. If an RFP is issued for Supply options, FPL reserves the right to choose the best alternative for its customers, even if that option is not an FPL self-build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

(1) FPL has identified the need for a new 230 kV transmission line that required certification under the Transmission Line Siting Act which was issued in April 2006. The new line is to be completed in two phases connecting FPL's St. Johns Substation to FPL's Pringle Substation (shown on Table III.E.1 in Chapter III). Phase 1 was completed in May 2009 and consisted of a new line connecting Pringle to a new Pellicer Substation. Phase 2 is planned to connect St. Johns to Pellicer and is scheduled to be completed by December 2018. The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

(2) FPL has identified the need for a new 230 kV transmission line (by December 2014) that required certification under the Transmission Line Siting Act which was issued on November 2008. The new line will connect FPL's Manatee Substation to FPL's proposed Bob White Substation (also shown on Table III.E.1 in Chapter III). The construction of this line, scheduled to be completed in 2014, is necessary to serve existing and future customers in the Manatee and Sarasota areas in a reliable and effective manner.

APPENDIX B

Power Purchase Agreement Key Conditions

Attachment B

Power Purchase Agreement Key Conditions

These Power Purchase Agreement Key Conditions supplement Florida Power & Light Company's ("FPL") 2015 Request for Proposals to Meet Generation Capacity Needs Beginning in 2019 (the "RFP") and sets forth certain minimum conditions (the "Conditions") that will be incorporated in any Power Purchase Agreement (the "Contract") that would be executed by and between a Proposer and FPL. The Conditions are specified below and are in addition to any other RFP requirements that a Proposer in the RFP (the "Proposer") must satisfy. Satisfaction of the Conditions, standing alone, does not ensure a Proposer's eligibility for participation in the RFP, other RFP eligibility requirements specified in the RFP must also be satisfied. (Note: In the text below, the term "Facility" refers, as applicable, to both an individual generating unit, and a system of generating units, upon which the Proposal is based.)

I. Conditions Precedent

- The Florida Public Service Commission ("FPSC") shall have issued a final Determination of Need for the Facility (if applicable), which order is not subject to appeal.
- The FPSC shall have issued a final order approving the Contract and finding that FPL is entitled to recover all costs under the Contract from its customers, which order is not subject to appeal.
- The Federal Energy Regulatory Commission ("FERC") shall have issued a final order authorizing the Proposer to make the sales contemplated by the Contract, which order is not subject to appeal.
- Each Governmental Authority having jurisdiction over the Contract shall have issued a final order of approval, which order is no longer subject to appeal.

II. Completion Security, Performance Security

- Proposer shall provide Completion Security and Performance Security in the amount, form, and in accordance with the schedule set forth in the RFP.

III. Capacity Payment

- Capacity Payments will be on a sliding scale, based upon the Facility's annual capacity billing Factor ("ACBF").
- The Facility's ACBF will be determined by FPL and calculated based on (i) the Facility's availability measured on a rolling twelve month average, and (ii) weighted based on the Facility's Peak Period availability (60%) and Non-Peak

availability (40%). "Peak Period" means those hours (i) from 12:00 p.m. to 9:00 p.m. during the months of April through October, and (ii) from 6:00 am to 10:00 am and from 6:00 pm to 10:00 pm during the months January through March and November and December. "Non-Peak" means all other hours. Additionally, the average Peak Period availability will be weighted 70% for the months of December through February and June through September, with all other months weighted 30%.

- Within a band of 94% to 70% ACBF, for each 1% that the Facility's ACBF drops below 94%, then the Capacity Payment with respect to the Facility will be reduced by 4% (*i.e.*, for each 1% drop in ACBF the Capacity Payment is reduced by 4%).
- If the Facility's AFBC falls below the 70% band, no Capacity Payment shall be made with respect to the Facility.

IV. Step-In Rights, FPL's First Lien

- In addition to FPL's other remedies under the Contract, upon failure of the Proposer to meet any agreed upon milestone date, or upon any event of default by the Proposer (and failure by the Proposer to cure such default), FPL or its designee shall have the right, but not the obligation, to enter upon and complete the licensing, permitting, construction, start-up, testing, and commissioning, or operate and maintain the Facility as agent for the Proposer. FPL's step-in right shall continue until the earlier of (i) the Proposer demonstrating to FPL's reasonable satisfaction that reasons for Proposer's failure no longer applies; (ii) FPL elects in its sole discretion to cease exercising Step-In rights, or (iii) expiration or termination of the Contract.
- As security for Proposer's performance of its obligations, Proposer or FPL shall execute and record a Mortgage and Security Agreement to provide FPL with a fully perfected subordinated security interest and mortgage lien in any and all real and personal property, contractual rights, or other rights the necessary for the development, procurement, construction, operation, and maintenance of the Facility.

V. Exclusivity, Payment

- Proposer shall have no right to sell energy, capacity, or ancillary services (the "Products") generated by or attributable to the Facility to any entity except FPL during the term of the Contract. Payments under the Contract will represent a combined charge for the sale of all Products of any type provided by the Facility.

VI. Testing, Capacity Rating, Heat Rate

- In addition to a required capacity test to demonstrate Commercial Operation, FPL has the right, but not the obligation, to require Proposer to perform a capacity test once per each Summer Period, and once per each Winter Period, at FPL's sole discretion. Additionally, a capacity test will be required if Proposer is unable to comply with any material obligation under the Contract for a period of 30 days or more as a consequence of an event of Force Majeure, or at any time when the Proposer fails two consecutive times to satisfy the operating levels set by FPL dispatch instructions. Upon completion of a capacity test, the Available Capacity will be set at a level not less than the Minimum Capacity and not more than the lower of the Committed Capacity or the Continuous Capability demonstrated in the most recent capacity test.

- Consistent with the RFP, (i) the Proposer will guarantee the Facility's heat rate levels reflected in its proposal, (ii) the Facility will be subject to heat rate testing administered by FPL, and (iii) a heat rate adjustment payment will be due from Proposer in the event the Facility fails to achieve the guaranteed heat rate levels.

VII. Dispatch, Control, Operation, and Maintenance of the Facility

- Proposer shall at all times operate the Facility consistent with FPL's dispatch and control rights. Control shall be either by Proposer's manual control pursuant to FPL's oral or written directions, or by Automated Generation Control by FPL's system control center, as determined by FPL.

- During the term, Proposer shall employ qualified and trained personnel for managing, operating, and maintaining the Facility and shall ensure that such personnel are on-duty 24 hours per day, each day, throughout the term of the Contract.

- Proposer shall be responsible for compliance with all applicable NERC regulations and requirements.

- Proposer shall operate and maintain the Facility in accordance with good engineering and operating practices, including compliance with all environmental laws, regulations, and permits. Proposer shall operate the Facility with all automatic controls (except Automatic Generation Control) and protection equipment in service whenever the Facility is connected to or operating in parallel with FPL's system. Automatic Generation Control shall be operated by FPL's system control center as determined by FPL.

- Key replacement and maintenance components (Gas Turbine hot path components, for example) may be obtained only from the Original Equipment Manufacturer.

- On an annual basis, the Proposer shall submit preliminary desired outage schedules for the following five years and a detailed plan for the next year. FPL shall notify Proposer if the outage schedule is accepted, or cooperate reasonably with Proposer to agree upon an acceptable schedule. Under no circumstances will outages be scheduled during the Peak Months.

VIII. Regulatory Out

- Notwithstanding anything contrary in the Contract, if at any time FPL fails to obtain, or is denied, the authorization of the FPSC or any other legislative, judicial, or regulatory body which now has, or may have in the future, jurisdiction over FPL's rates and charges, to recover from its customers all of the payments required to be made under the terms of this Contract, or any amendment thereto, FPL may, at its sole discretion, adjust the payments made under the Contract to the amounts which FPL is authorized to recover from its customers. In this event, Proposer shall have the option to terminate the Contract upon ninety days' notice to FPL.

IX. Variable Interest Entity (VIE)

- From the effective date through the end of the term of the contract, Proposer shall covenant that from its perspective and due to any of its actions, FPL will not be required by any legal requirement or an accounting standard to consolidate Proposer or any of its affiliates or permitted assigns as a VIE in FPL's or any of its affiliates' financial statements. Proposer shall promptly notify FPL following any determination made by Proposer or its independent auditor that Proposer constitutes a VIE for which FPL is the primary beneficiary as a result of the Contract. At the time of execution of the Contract and annually thereafter, Proposer shall provide certification of compliance with this provision by the chief financial officer of the Proposer.

- If a Proposer fails to provide the required certification, or if at any time Proposer becomes a VIE and FPL becomes the Primary Beneficiary, such an event shall constitute an event of default under the Contract.

X. Greenhouse Gas (GHG) Emission Costs

- Whether FPL would pay the Proposer for their proposed unit's (or system's) share of "annual GHG emission costs for FPL total energy" calculated as reflected in the proposal evaluation would be a subject of PPA negotiations. However, FPL and its customers will not agree to pay the Proposer for any GHG emission costs due to GHG emission rates higher than submitted by the Proposer.

- In the event of a future change in law or regulation that would have the effect of shifting to or imposing upon FPL GHG emission costs not agreed to in the PPA, FPL would have the right to terminate the PPA if such additional costs were not found to be prudent and approved for FPL cost recovery by the FPSC.

APPENDIX C

Forms for Proposers

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Forms for Proposers

A. Overview of the Required Ten (10) Forms

There are ten (10) forms that all Proposers must complete and return to FPL's RFP Contact Person by 4:00 p.m. EDT on the Proposal Due Date. These completed forms, requested attachments to these forms, and RFP Evaluation Fee will, collectively, represent a proposal. If a Proposer is submitting more than one proposal, a separate set of forms and the appropriate RFP Evaluation Fee must be submitted for each proposal. These ten forms are described in the remainder of this Appendix. If a Proposer is also submitting a variation of a proposal in which a different price and/or term (but no changes in any other attributes) is offered for a proposal, then Form # 1, Form # 4 (page 3 of 14), Form # 5 (pages 1 of 4 and 2 of 4, or 3 of 4, as appropriate), Form # 9, and Form # 10 must be completed and submitted (along with the Variation Fee).

The Proposer must submit five (5) bound hard copies of each proposal that contains the forms and requested information, and an electronic copy of the completed forms on a CD, along with the RFP Evaluation Fee and, if applicable, the Variation Fee.

As discussed in Section II.C.2 of the RFP document, FPL will treat as confidential all information contained in proposals which is clearly identified as Proprietary and Confidential except for the information to be submitted on Form # 1, Public Information Regarding Proposal. To clearly identify confidential information, the Proposer must (1) stamp each such page with "**Confidential Information**" <u>and</u> (2) highlight/shade the specific confidential information on the pages stamped "**Confidential Information**". (A blanket statement that an entire page, or the entire proposal, is proprietary and confidential will <u>not</u> be considered clear identification.)

Please refer to Section II.C.2 of the RFP document for a full discussion of Proposal Confidentiality.

B. Form # 1: Public Information Regarding Proposal

In order to provide general information to the public about the proposals received in response to this RFP, FPL requires that all proposal submittals include a completed Public Information Regarding Proposal form that includes a list of projects undertaken (constructed and/or operated) by the Proposer that are similar to the project now being proposed. The information contained in this form will be treated as non-confidential and non-proprietary and may be released to the public at the sole discretion of FPL.

C. Form # 2: Executive Summary of the Proposal

A one (1) page summary of the proposed project and the Proposer is sought on this form. This executive summary should highlight any major value-added features of the proposal.

D. Form # 3: Financial Information

To mitigate risk, FPL will examine the Proposer's and, if applicable, the parent/affiliate guarantor's credit/corporate profile and financial guarantees. The credit/corporate profile information includes the corporate bond rating, the commercial paper rating, and the Dunn & Bradstreet Credit Appraisal Rating.

If a Proposer will be relying on any parent/affiliate guarantees, the Proposer shall also include a description of the corporate relationship between the Proposer and the guarantor and provide a description regarding the proposed guarantor's willingness to guarantee the Proposer's obligations and the terms of the guarantee.

In addition, the proposal shall include audited financial statements for the last two years for the Proposer and, if the Proposer is relying on any parent/affiliate guarantees, for the guarantor.

E. Form # 4: Operations & Engineering Information

Form # 4 requests a variety of information that will be used in the economic evaluation and/or non-economic evaluation of proposals. The requested information is to be filled in, as applicable, on the following 9 information categories of this form:

1. Power Generation Proposal Type
2. Technology/Configuration
3. Operational Considerations: Availability, Reliability, & Operating Time Limitations
4. Fuel Information & Barometric Pressure
5. Guaranteed Firm Capacity
6. Guaranteed Heat Rates
7. Emission Rate Information[1]

[1] If the proposal is based on a system sale, the emission rate information in section 7 is to be provided for each year in the proposed term of service by attaching a separate page(s) to the Proposal.

8. Natural Gas Pipeline Connection(s)
9. Generating Units' Operating & Maintenance Experience/Performance

In response to this capacity RFP, FPL envisions that it may receive power purchase agreement (PPA) proposals based on a specific existing generating unit(s) or a new generating unit(s). In either of these cases, FPL is requesting specific information regarding the following four aspects of the proposal:

- OEM replacement parts for hot gas path (HGP) components
- Availability and reliability
- Guaranteed capacity
- Guaranteed heat rates

For proposals based on an existing generating unit, FPL is seeking the following information regarding the above mentioned four aspects of the proposal:

a) OEM: Proposers will be required to state to what extent OEM parts have been used in the "proposal" unit to-date. Proposers will be required – as part of their proposal – to explicitly state that, if selected, the proposed unit will install and continue to use OEM replacement parts for such components, and that OEM maintenance schedules will be observed. A selected Proposer will have to annually obtain from the OEM a certification that OEM replacement parts have been installed and have been maintained in accordance with the OEM schedules. If a selected Proposer fails to install, use, and properly maintain OEM parts, or fails to obtain the OEM's certification, it will be in default, and will have 120 days to cure; if not cured, FPL may terminate the PPA and/or collect damages as specified in the PPA.

b) Availability & Reliability, Peak Capacity, and Heat Rates: Proposers will be required to state to what extent the proposed unit has achieved the availability and reliability, peak capacity, and heat rate levels reflected in the proposal during the last five years, and provide evidence that demonstrates that such availability and reliability, peak capacity, and heat rate levels have been achieved (such as through the results of annual heat rate tests, capacity tests, etc.) If selected, the Proposer must guarantee in the PPA that the proposed unit will continuously achieve the availability and reliability, peak capacity, and heat rate levels reflected in the proposal. If the unit in a selected proposal fails to achieve the availability and reliability, peak capacity, and/or heat rate levels reflected in the proposal and guaranteed in the PPA, the Proposer would be subject to liquidated damages. The selected Proposer will have 120 days to cure the problem. If not cured, FPL may terminate the PPA.

c) In regard to Availability & Reliability: If the average actual or proposed (as per the calculation performed in Form # 4) EAF for a proposal based on an existing combined cycle unit is less than 80% for any year, or if the average actual (or proposed as per the calculation performed in Form # 4) EFOR for a proposal based on an existing combined cycle unit is more than 4.2% for any year, or if the average actual or proposed (as per the calculation performed in Form # 4) FOF for a proposal based on an existing combustion turbine is more than 2.6% for any year, as applicable, the proposal will be rejected.

d) In regard to Heat Rates: If a heat rate test has not been performed within the last two years, the Proposer must perform a new test and submit the results as part of the proposal.

For proposals based on a new generating unit, FPL is seeking the following information regarding the above mentioned four aspects of the proposal:

a) OEM: Proposers will be required to state to what extent OEM parts have been used in existing units operated by the Proposer. Proposers will be required – as part of their proposal – to explicitly state that, if selected, the proposed unit will use OEM replacement parts for such components, and that OEM maintenance schedules will be observed. A selected Proposer will have to annually obtain from the OEM a certification that OEM replacement parts have been installed and have been maintained in accordance with the OEM schedules. If a selected Proposer fails to install, use, and properly maintain OEM parts, or fails to obtain the OEM's certification, it will be in default, and will have 120 days to cure; if not cured, FPL may terminate the PPA and/or collect damages as specified in the PPA.

b) Availability & Reliability, Peak Capacity, and Heat Rates: Proposers will be required to state to what extent the Proposer's similar existing units have achieved the availability and reliability, peak capacity, and heat rate levels reflected in the proposal during the last five years, and provide evidence that demonstrates that such availability and reliability, peak capacity, and heat rate levels have been achieved (such as through the results of annual heat rate tests or capacity tests). If selected, a Proposer must guarantee in the PPA that the proposed unit will continuously achieve the availability and reliability, peak capacity, and heat rate levels reflected in the proposal. If the unit in a selected proposal fails to achieve the availability and reliability, peak capacity, and/or heat rate levels reflected in the proposal and guaranteed in the PPA, the Proposer would be subject to liquidated damages. The selected Proposer will have 120 days to cure the problem. If not cured, FPL may terminate the PPA.

c) In regard to Availability & Reliability: If the proposed (as per the calculation performed in Form # 4) EAF for a proposal based on a new combined cycle unit is less than 80% for any year, or if the proposed (as per the calculation performed in Form # 4) EFOR for a proposal based on a new combined cycle unit is more than 4.2% for any year, or if the proposed (as per the calculation performed in Form # 4) FOF for a proposal based on a new combustion turbine is more than 2.6% for any year, as applicable, the proposal will be rejected.

d) In regard to Heat Rates: If selected, a winning Proposer must guarantee in the PPA to provide results of annual heat rate tests for the proposed unit.

For purposes of the RFP evaluation, FPL is using the following formulae for calculating availability and reliability of proposals and the NPGU:

- Availability = (8760 - POH – FOH)/8760

- EFOR = FOH/(Service Hours + FOH) in which Service Hours are calculated based on the type of proposed unit. For example, a CC unit's Service Hours are calculated to be 8760 hours x 0.80 and a CT unit's Service Hours are calculated to be 8760 hours x 0.15.

- FOF = FOH/8760

F. Form # 5: Pricing Information for Purchased Power or System Sale Proposals

Pricing for firm capacity and energy proposals that offer power purchases or system sales must be presented on Pricing Information Form # 5. **(Note that Proposers should not include projected greenhouse gas (GHG) costs in their proposal payment values. GHG cost values, in the form of FPL's projected CO2 annual cost values in $/ton, will be addressed in FPL's evaluation based upon CO2 emission rates provided in each proposal. This evaluation approach is discussed further in Appendix D.)**

Note that FPL requires actual prices to be filled in for each year of the proposed term-of-service. Proposals indicating a first-year price followed only by a note stating that a formula is to be used for escalating that price from year-to-year are not acceptable and constitute grounds for declaring a proposal ineligible. Please refer to Section F.5 (below) for an explanation of acceptable pricing approaches a Proposer may utilize in developing the annual price values to be presented on Form # 5.

1) Guaranteed Capacity Payments

The Proposer must provide Guaranteed Capacity Payment values for the term of the proposed contract on Form # 5, page 1 of 5. Guaranteed Capacity Payment values in terms of $/kw-month must be supplied for each operational mode (*e.g.,* base operation, Incremental Level 1, or Incremental Level 2, etc.) as specified on Form # 4. Proposals must include all costs of delivering capacity and energy to the FPL System including delivery over intervening transmission systems and the cost of gas pipeline laterals, if applicable, connecting the generator to the appropriate natural gas pipeline. Proposals must utilize the Guaranteed Firm Capacity rating for Summer (temperature of 95 degrees F.), the relative humidity specified, and the appropriate barometric pressure value from the chart supplied on Form # 4 in developing the denominator for the $/kw–month values.

2) <u>Guaranteed Energy Pricing & Payments</u>

a) Fuel Prices (for Non-System sales) & Energy Charges (for System Sales)

<u>For Proposals Not Based on System Sales:</u>
On Form # 5, page 2 of 5, the Proposer may submit a Guaranteed Fuel Transportation Reservation Price ($/mmBTU per Day) for the proposed term of the contract. The Proposer must designate the pipeline (FGT, Gulfstream, Sabal Trail, Sabal Trail / Florida Southeast Connection, etc.) that will serve the facility. FPL will base the variable costs and fuel on the current (or proposed as in the case of Sabal Trail and Sabal Trail / Florida Southeast Connection) tariff rates of the pipeline selected by the Proposer. If the Proposer does not wish to provide Guaranteed Fuel Transportation Reservation Prices, and the project can be connected to Sabal Trail or Florida Southeast Connection, FPL will use its own fuel transportation cost projections (which are based on Sabal Trail and Florida Southeast Connection), plus the Proposer's lateral and meter costs (provided on Form # 5, page 5 of 5), for the purposes of proposal evaluation. If the project must be connected to FGT, Gulfstream, etc., FPL will evaluate the cost of securing additional transportation capacity on those pipelines and incorporate that cost in the evaluation of the proposal.

If the Proposer has elected to submit a Guaranteed Fuel Transportation Reservation Price, the Proposer must also submit a Guaranteed Fuel Transportation Quantity (mmBTU/day) for the proposed term of the contract. For proposals with no Guaranteed Fuel Transportation Reservation Price, FPL will base its evaluation on the value for gas quantity that must be obtained on a firm basis as identified in Form # 4, page 13 of 14, in item (8) (f).

If the Proposer has elected to submit a Guaranteed Fuel Transportation Reservation Price, the Proposer may choose to submit a Guaranteed Fuel Commodity Price ($/mmBTU per Day) for the proposed term of the contract. If the Proposer elects to not provide Guaranteed Fuel Commodity Prices, FPL will use its own fuel commodity cost projections.

FPL's projected fuel commodity costs that will be used in the RFP economic evaluations will be presented on FPL's RFP website once this RFP is issued.

For Proposals Based on System Sales:
In regard to proposals based on system sales, the Proposer must submit a Guaranteed Energy Price value for each year of the proposed term-of-service. Actual annual values must be entered on Form 5, page 3 of 5. These annual values may be based on a formula based on FPL's projected fuel commodity price forecast that is discussed above. **The formula(e) applied by the Proposer to develop the energy charge payment values must be provided and fully described on a page to be developed by the Proposer and attached to Form # 5**. This formula, combined with future actual values for each forecasted fuel cost used in the formula, will be the basis for payments that the Proposer would receive if the proposal is selected.

b) Variable O&M Payments

In addition, the Guaranteed Variable O&M Prices (in $/MWh) of the proposal for each year of the proposed term-of-service for the base operational mode and for any other operational mode must be provided for all types of proposals. This information is to be provided on Form # 4, page 2 of 5 (for non-system sale proposals) or page 3 of 5 (for system sale proposals).

In calculating these values, assume an annual capacity factor of 80% for a system sale or a baseload generating proposal and 15% for peaking capacity proposals.

3) Startup Fuel Amounts and Startup Costs

The amount of fuel needed per startup (mmBTU per startup) must be provided on Form # 5, page 4 of 5.

Startup costs (other than fuel needed for startup as discussed above) should be included, at the Proposer's choice, in either of the Proposer's Guaranteed Capacity Payments or Variable O&M Payments, and are not to be entered separately on Form # 5.

4) Costs and Information Included in the Payments

Proposals that are based on generators that need to be constructed and connected to the transmission system must include transmission interconnection costs in their Guaranteed Capacity Pricing in Form # 5, page 1 of 5.

These proposals, plus proposals that are based on existing generating units, must also include the cost of third party transmission service (if applicable) for delivery to the FPL Receipt Point, including the impact of third party transmission service losses, if appropriate, in their Guaranteed Capacity Pricing on Form # 5, page 1 of 5.

On Form # 5, page 4 of 5, each Proposer must also separately provide the specific costs of transmission interconnection that are the basis for these transmission-related costs that are included in the Guaranteed Capacity Pricing values. The Proposer must also provide information related to third party transmission service (if applicable). The Proposer must also separately provide the specific costs of the gas pipeline lateral and meter, if applicable, regarding the connection of the generator to the appropriate natural gas pipeline on Form # 5, page 5 of 5.

The information that follows pertains to these transmission interconnection costs, third party transmission service information, and the costs of the gas pipeline lateral.

a) Transmission Interconnection Costs:

- All proposals that are based on generators that need to be constructed and connected to the transmission system must demonstrate that they have a valid completed application for Generator Interconnection Service (GIS) in the FPL GIS Queue, or with the applicable third party to the extent the new generator is connected to a third party's transmission system.

- The process for requesting GIS and having a completed GIS application on the FPL system is delineated on FPL's Open Access Transmission Tariff (OATT).

- To the extent the generator(s) is connecting to the FPL system, and a transmission interconnection study has been performed and completed by FPL Transmission providing cost estimates is available, the Proposer shall provide an interconnection cost estimate based on the transmission interconnection study, along with a copy of this study. This cost estimate shall include all materials, labor, land, permitting, and overhead adders associated with upgrades of existing facilities and construction of incremental facilities required as a result of the connection, plus thermal, short circuit, and stability impacts on the transmission system. Note that if a new transmission switchyard must be constructed to connect the proposed generator(s), the cost of the transmission switchyard, including land, all necessary permits, filling, and grading must be included in the cost estimate.

To the extent a completed transmission interconnection study is not available, and the generator(s) for which the capacity is being offered is to be connected to the FPL system, the Proposer must provide a cost estimate for the interconnection along with a written explanation of the basis for this estimate. Such cost estimate shall include all materials, labor, land, permitting, and overhead adders associated with upgrades of existing facilities and construction of incremental facilities required as a result of the connection, and short circuit and stability impacts on the transmission system. Note that if a new transmission switchyard must be constructed to connect the proposed generator(s), the cost of the transmission switchyard, including land, all necessary permits, filling, and grading, must be included in this cost estimate.

Form # 5, page 4 of 5, instructs proposers to provide the "basis for this (interconnection cost) estimate". FPL reserves the right to review such cost estimates for reasonableness. To the extent that FPL determines that this cost estimate is materially incorrect or incomplete, FPL reserves the right to adjust this cost estimate as it deems necessary during the evaluation process in order to reflect an acceptable interconnection arrangement. (The actual cost of connecting the generator to the FPL system would be based on the specific GIS Queue process and the attendant studies. These actual costs will need to be addressed if the Proposer is ultimately selected.)

- To the extent the generator(s) for which the capacity is being offered is not directly connected to the FPL system, the Proposer shall provide the best available cost estimate and a written explanation of the assumptions or studies upon which this cost estimate was based on Form # 5, page 4 of 5. Such cost estimate shall include all materials, labor, land, permitting, and overhead adders associated with upgrades of existing facilities and construction of incremental facilities required as a result of the connection, plus thermal, short circuit, and stability impacts on the transmission system.

b) **Third Party Transmission Service Information:**

To the extent the generator(s) is connected to the transmission system of a third party, the Proposer shall state whether third party transmission rights have been requested and/or already procured for a portion of or all of the generation capacity being offered. To the extent a request for such long-term firm transmission right have been requested, but not yet procured, provide all available studies associated with the request.

c) **Transmission Losses:**

On Form # 5, page 5 of 5, provide the projected transmission losses (MW) associated with the third party transmission service that are accounted for in the Total Guaranteed Firm Capacity values on Form # 4.

d) **Gas Pipeline Lateral and Meter Costs:**

On Form # 5, page 5 of 5, provide the total cost of the lateral pipeline and meter station for the lateral that connects the generator to the appropriate natural gas pipeline. (This cost is to be included in the Guaranteed Capacity Payment values provided on Form # 4.)

5) **Guidance for Developing Annual Capacity Payment and Variable O&M Payment Values for Form # 5**

a) **Background**

FPL's 2015 RFP requires potential Proposers to provide annual values for Capacity Payments (that inherently may include a fixed O&M component) and Variable O&M Payments. These annual values may reflect assumed escalation over the term of a proposed contract. Proposers may either submit fixed annual values or have components of their proposal prices be subject to escalation.

In the former instance, the Proposer would be guaranteeing the actual prices for each year (*i.e.*, those are the set annual prices that would be incorporated directly into a PPA if the Proposer were selected by FPL). In so doing, a Proposer would be choosing to assume the risk/benefit of costs deviating from the annual values provided.

In the latter case, a Proposer may submit prices that are subject to future adjustment based on a formula that includes one or more of three approved indices (described below). For example, a Proposer might propose a Variable O&M charge that entails a 2019 starting value that escalates thereafter at some portion or all of the actual change in a specific index. In summary, Proposers can choose the level of risk they would assume by applying a formulaic approach or guaranteeing specific annual values.

The following describes how this can be accomplished by Proposers in response to FPL's 2015 RFP (and how FPL developed, in part, the fixed O&M and variable O&M values for its NPGU.)

b) Process

The following is provided to clarify requirements for data submitted in response to FPL's 2015 RFP as pertains to proposal pricing components that may be either fixed or subject to escalation. The approach offers Proposers the opportunity to declare the annual values that will be used to evaluate their proposal and (if the proposal is subject to escalation) the method of applying FPL-authorized indices to develop the values to be evaluated.

A Proposer must submit payment <u>values</u>, not formulae, for all years for Capacity Payment and Variable O&M Payment as described in FPL's 2015 RFP. Thus, even if a Proposer decides to base a price component on a formula/index, the Proposer must still calculate and populate the RFP Form # 5 with specific annual values (so that the proposal evaluation team can verify its understanding of the Proposer's formula) and utilize the Proposer's own values in its evaluation.

Fixed Price Procedure

If the values on Form # 5 represent fixed, guaranteed payment values, then simply completing the RFP forms as described in the RFP is sufficient. These firm, guaranteed annual payment values would be used in the evaluation and then included unchanged in the PPA should the proposal be selected.

Formulaic/Indexing Procedure for Guaranteed Capacity and Variable O&M Payments

If a Proposer chooses to develop payment values based on the use of FPL-authorized indices, and desires this method to be the basis of the evaluation and a potential PPA with FPL, the Proposer must use the following approach.

For actual payment purposes if a proposal is selected, FPL's authorized indices for the Guaranteed Capacity Payments and Variable O&M Payments are from IHS Global Insight (Global Insight), a leading economic forecasting firm. The authorized indices are presented in Table C – 1 below and consist of:

- The Global Insight escalation index for Consumer Price Index – All Urban Consumers (CPI).
- The Global Insight escalation index for Producer Price Index – All Commodities (PPI); and,
- The Global Insight escalation index for Compensation Per Hour – Non-Farm Business Sector (CPH)

Or, alternatively, a Proposer may use a formula for these two payment values based on:

- A constant escalation rate per year.

Only the indices in Table C – 1, or a formula based on a constant escalation rate, are authorized for use in submitting formulaic/indexed prices for Guaranteed Capacity Payments and Variable O&M Payments in response to this RFP.

The formula(e) applied by the Proposer to develop the payment values must be provided and fully described on an attached page to Form # 5. This formula, combined with future actual values for each index from Table C – 1 used in the formula, will be the basis for payments that the Proposer would receive if the proposal is selected. **Note that if a constant escalation rate is used in a formulaic approach, the annual values supplied in the Proposal will then be included unchanged in the PPA should the proposal be selected (*i.e.*, this formulaic approach becomes a Fixed Price Procedure as previously described).**

A Proposer may also deem that some portion of a payment is not indexed, while another segment of the payment is. For example, a Proposer's Guaranteed Capacity Payment may entail one portion that is fixed (or that escalates at a set percentage) throughout the term of the contract while another portion (*i.e.*, a fixed O&M component) may be subject to annual adjustment based on a formula that includes one or more of the FPL-authorized indices or a constant escalation rate.

In addition to a thorough description of the formula/indexing process that is proposed, a Proposer must fill out the annual values for every year of the proposed transaction

Note that if a proposal that is based on a formulaic/indexing approach using the indices presented in Table C – 1 is selected, the Proposer will not be bound by these specific annual values that will be supplied on Form # 5 – only by the formulaic/indexing process behind them. However, the annual values are essential and will be used to confirm that the proposal evaluation team understands and correctly applies the Proposer's formula/indexing process.

Formulaic/Indexing Procedure for Energy Pricing of System Sale Proposals

Similar to the discussion above, the Proposer must provide annual values for each year of the proposed term-of-service for Guaranteed Energy Pricing Payments for system sale-based proposals. These annual values may be based on formulaic approach using one or more of the FPL Fuel Commodity Cost forecast that will be posted on the RFP website once the RFP is issued. The Proposer is required to provide an explanation of this formulaic approach.

Note that if such a proposal is selected, the Proposer will not be bound by these specific annual values that will be supplied on Form # 5 – only by the formulaic/indexing process behind them. However, the annual values are essential and will be used to confirm that the proposal evaluation team understands and correctly applies the Proposer's formula/indexing process.

c) FPL's Methodology for Developing NPGU Costs

In its NPGU analyses, FPL used projections of specific annual costs for Fixed O&M (FOM), Variable O&M (VOM), and Capital Replacement. The annual values for each of these three cost categories are presented in in Table VI.B-2 in the main body of the RFP document. The FOM, VOM and capital replacement are projections from a model that utilizes as inputs constant annual escalation rates of 2.5% for FOM and VOM, and 2.0% for Capital Replacement.

Table C - 1

Price Indices
(based on Global Insight's July & August 2014 Forecasts)

Year	Consumer Price Index (CPI) (Urban All Consumers)	% Change	Producer Price Index (PPI) (All Commodities)	% Change	Compensation per Hour (Nonfarm Business Sector)	% Change
2000	1.7267	---	1.3277	---	0.7398	---
2001	1.7723	2.6%	1.3421	1.1%	0.7728	4.5%
2002	1.8032	1.7%	1.3112	-2.3%	0.7905	2.3%
2003	1.8426	2.2%	1.3812	5.3%	0.8200	3.7%
2004	1.8940	2.8%	1.4665	6.2%	0.8572	4.5%
2005	1.9585	3.4%	1.5737	7.3%	0.8884	3.6%
2006	2.0193	3.1%	1.6473	4.7%	0.9233	3.9%
2007	2.0807	3.0%	1.7268	4.8%	0.9631	4.3%
2008	2.1524	3.4%	1.8956	9.8%	0.9895	2.7%
2009	2.1499	-0.1%	1.7297	-8.8%	1.0002	1.1%
2010	2.1841	1.6%	1.8480	6.8%	1.0195	1.9%
2011	2.2548	3.2%	2.0108	8.8%	1.0421	2.2%
2012	2.2993	2.0%	2.0218	0.5%	1.0706	2.7%
2013	2.3321	1.4%	2.0341	0.6%	1.0827	1.1%
2014	2.3782	2.0%	2.0679	1.7%	1.1204	3.5%
2015	2.4124	1.4%	2.0931	1.2%	1.1576	3.3%
2016	2.4507	1.6%	2.1189	1.2%	1.1998	3.6%
2017	2.4961	1.9%	2.1639	2.1%	1.2460	3.9%
2018	2.5471	2.0%	2.2079	2.0%	1.2955	4.0%
2019	2.5976	2.0%	2.2371	1.3%	1.3469	4.0%
2020	2.6506	2.0%	2.2789	1.9%	1.3991	3.9%
2021	2.7093	2.2%	2.3238	2.0%	1.4526	3.8%
2022	2.7678	2.2%	2.3715	2.1%	1.5072	3.8%
2023	2.8271	2.1%	2.4212	2.1%	1.5643	3.8%
2024	2.8856	2.1%	2.4889	2.8%	1.6240	3.8%
2025	2.9445	2.0%	2.5460	2.3%	1.6856	3.8%
2026	3.0046	2.0%	2.5837	1.5%	1.7500	3.8%
2027	3.0647	2.0%	2.6266	1.7%	1.8160	3.8%
2028	3.1244	1.9%	2.6668	1.5%	1.8831	3.7%
2029	3.1838	1.9%	2.7074	1.5%	1.9519	3.7%
2030	3.2432	1.9%	2.7423	1.3%	2.0230	3.6%
2031	3.3056	1.9%	2.7877	1.7%	2.0954	3.6%
2032	3.3703	2.0%	2.8317	1.6%	2.1700	3.6%
2033	3.4384	2.0%	2.8755	1.5%	2.2465	3.5%
2034	3.5069	2.0%	2.9163	1.4%	2.3254	3.5%
2035	3.5770	2.0%	2.9693	1.8%	2.4083	3.6%
2036	3.6489	2.0%	3.0123	1.4%	2.4947	3.6%
2037	3.7230	2.0%	3.0586	1.5%	2.5830	3.5%
2038	3.7998	2.1%	3.1059	1.5%	2.6754	3.6%
2039	3.8787	2.1%	3.1541	1.6%	2.7711	3.6%
2040	3.9588	2.1%	3.2018	1.5%	2.8694	3.5%
2041	4.0406	2.1%	3.2495	1.5%	2.9713	3.6%
2042	4.1240	2.1%	3.2991	1.5%	3.0771	3.6%
2043	4.2092	2.1%	3.3501	1.5%	3.1870	3.6%
2044	4.2962	2.1%	3.4035	1.6%	3.3021	3.6%
2045	4.3849	2.1%	3.4578	1.6%	3.4214	3.6%
2046	4.4755	2.1%	3.5129	1.6%	3.5449	3.6%
2047	4.5679	2.1%	3.5689	1.6%	3.6729	3.6%
2048	4.6623	2.1%	3.6257	1.6%	3.8056	3.6%
2049	4.7586	2.1%	3.6835	1.6%	3.9430	3.6%

G. Form # 6: Environmental & Permitting Information

In order to fully evaluate the environmental and permitting aspects of proposals, Form # 6 requests a variety of information from 12 major categories that will be used to evaluate proposals. Each Proposer should be more inclusive rather than exclusive when responding to the information requested. If the category or information requested does not apply to the proposal, an explanation must be provided. The following are the 12 major information categories of this form:

1. Proposed Community Outreach Activities and Experience
2. Required Permits or Approvals to License or Permit the Facility
3. Description of Air Pollution Control Equipment
4. PSD/NSR Permitting
5. Water Supply Strategy
6. Water Discharge Strategy
7. Strategy to Address Land Use Issues
8. Solid/Hazardous Waste / Material Management Strategy
9. Other Infrastructure Needs or Requirements
10. Protected Species Impacts
11. Permitting Experience in Florida of Proposer and Environmental Support Contractors and Consultants
12. Proposer Compliance History (Last 5 years, i.e., 2010 – 2014)

H. Form # 7: Key Milestones

FPL's ability to maintain a certain level of system reliability for its customers will be dependent upon a selected Proposer's ability to meet the contracted Capacity Delivery Date (CDD). Because there is a possibility that the Proposer will not meet this date, FPL may have to make alternate arrangements to cover the capacity and energy shortfall. This will require FPL to monitor the Proposer's progress. Therefore, the Proposer must provide the expected completion dates for certain key project milestones on this form. When providing these key project milestones, a Proposer should carefully review the Minimum Requirements regarding Project Milestone Schedule for the specific milestones listed in Section III, part 20, of the main body of the RFP document.

A proposal that requires new power plant construction falling under the Siting Act will have to demonstrate permitting, construction, etc. schedules that allow the new plant to be in-service on or before FPL's needed in-service date of June 1, 2019.

I. Form # 8: Receipt Point(s) to FPL

Information on this form will identify the location of the receipt point(s) of each proposed capacity source(s) including a listing of the nearest substation(s).

The Proposer must also attach a readable transmission map (8.5 x 11 inches) highlighting the receipt point(s) identified above.

J. Form # 9: Proposer Exceptions

All Proposers must complete and return this Proposer Exceptions form as part of their proposal submittal. On this form, the Proposer must either indicate that they take no exceptions to any of the terms, conditions, or other facets of the RFP or must indicate that they do take exception(s). In the case in which one or more exception is taken, then for each term, condition, or other facets of the RFP to which an exception is taken, the Proposer must provide their desired revised language.

FPL will consider the number and significance of exceptions in its non-economic evaluation. FPL will not consider proposed exceptions to the RFP's Minimum Requirements for Proposals or Minimum Requirements Pursuant to Purchase Agreement.

K. Form # 10: Proposal Certification

All Proposers must complete and return this Proposal Certification form as part of their proposal submittal. An Officer of the proposing company is to certify that: (i) all information contained in the Proposer's proposal is complete and accurate and that the pricing contains all applicable costs for the proposed full term of service; (ii) that the terms, conditions, and other facets of the RFP are acceptable, except as specifically noted by the Proposer on Form # 9; (iii) the Completion Security and Performance Security described in Section IV of the main body of the RFP document are acceptable and there are no pending legal or civil actions that would affect the ability of the Proposer and/or its guarantor to maintain these security amounts; (iv) the proposal has been submitted in the legal name of the entity which would be bound by any resulting contract; (v) and that the proposal is binding, definitive, and firm and will remain open for 180 days from the Proposal Due Date.

The copies of this form that are included in the five (5) bound hard copies of the proposal must each be signed by an Officer of the proposing company.

M. Proposer's Forms

The forms that follow on the remaining pages of this Appendix are the required forms which must be completed by all Proposers for each individual proposal they wish to offer. If a variation to a proposal is offered, in which either price or term only is offered, then only forms applicable to this variation may be presented.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 1: Public Information Regarding Proposal

Facility Name: ______________________________

1) **Name of Proposing Company:** ______________________________

2) **Type of Generating Unit:** ______________________________

3) **Type of Project (Select One):**
Purchased Power from Existing Unit: __________
Purchased Power from New Unit: __________
System Sale: __________
Qualifying Facility: __________
Other(Specify): __________

4) **Generating Facility Location (City/Co./State):** ______________________________

5) **Fuel:**
Primary: ____________________
Secondary/Backup: ____________________

6) **Proposer Classification (Select One):**
Utility (retail serving): __________
Independent Power Producer: __________
Small Power Producer: __________
Cogenerator: __________
Other (explain): __________

7) **Proposed Total Guaranteed Firm Capacity (Net MW) Delivered to FPL system** (must match information on Form # 4, item 5, Guaranteed Firm Capacity, MW):

Summer (95F): ____________ Winter (35F): __________

8) **Proposed Capacity Delivery Start Date:** __________________ (Month/Day/Year)

9) **Proposed Capacity Delivery End Date:** __________________ (Month/Day/Year)

10) **Use the space below, or a separate sheet, to list all major projects undertaken (constructed and/or operated) by the Proposer or Proposer's affiliates/parent company during the last five (5) years which are similar to the project being proposed by the Proposer in response to FPL's RFP.**

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 2: Executive Summary of the Proposal

Facility Name: ____

Please provide a one (1) page summary of the proposed project and the Proposer.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 3: Financial Information

Facility Name: ______________________________

1) **Proposer's Legal Name:** ______________________________

2) **Physical Address:** ______________________________
____

3) **Financial/Credit Contact Person:**

Name: ______________________________
Position Title: ______________________________
Telephone: ______________________________
Fax: ______________________________
E-Mail: ______________________________

4) **Federal Tax Identification Number:** ______________________________

5) **Proposer is (Select all that apply):**

________ Corporation	________ Sole Proprietorship
________ Partnership	________ Limited Liability Company
________ Joint Venture	________ Limited Liability Partnership
	________ Other (attach description)

6) **State in which Proposer is incorporated or organized:** ______________________________

7) **Proposer Information:**

a) Dunn & Bradstreet Identification Number: ______________________________

b) Corporate Bond Ratings: ________ Sources: ____________
________ ____________

c) Commercial Paper Ratings: ________ Sources: ____________
________ ____________

d) Dunn & Bradstreet Credit Appraisal Rating: ____________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 3: Financial Information

Facility Name: ____

8) **(If applicable) Parent/Affiliate Guarantor Information:**

a) Name of parent/affiliate guarantor: ______________________

b) Dunn & Bradstreet Identification Number: ______________________

c) Corporate Bond Ratings: __________ Sources: __________
__________ __________

d) Commercial Paper Ratings: __________ Sources: __________
__________ __________

e) Dunn & Bradstreet Credit Appraisal Rating: ______________

9) **If Proposer is relying on any parent/affiliate guarantees, use the space below to describe the corporate relationship between the Proposer and the guarantor. Also, provide a statement regarding the proposed guarantor's willingness to guarantee the Proposer's obligation pursuant to the form of guarantee that is to be attached to the PPA.**

____
____
____
____
____
____

10) **Provide audited financial statements for the last two years for the Proposer and, if applicable, the proposed guarantor.**

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ________________________________

1) **Power Generation Proposal Type: (Select one):**

a) Purchased Power from Existing Unit: _____
b) Purchased Power from New Unit: _____
c) System Sale: _____ Provide an attachment detailing the proposed system sale including an explanation of how the proposing utility will maintain its reserve margin/reliability requirements in regard to commitments to its Public Service Commission.

d) Qualifying Facility: _____
e) Other: _____ Provide details:

____

____

2) **Technology/Configuration:**

a) Type of Generating Unit: Select Appropriate Number from the List Below: 1
Combined Cycle = 1
Combustion Turbine = 2
All Other = 3
(Note: if "All Other = 3" is chosen, FPL will develop Proposal-specific values for calculating EFOR and EAF on Form # 4, page 3 of 14)

b) Configuration:(*e.g Combined Cycle Unit with 2 CTG/HRSG trains w/duct firing and 1 Steam Turbine, Cooling Tower with makeup water from Source A; etc):*

____

____

c) Major Equipment Technology, Supplier, Model: (*Combustion Turbine, Steam Turbine; Boiler/HRSG/Catalyst Systems):*

____

____

d) Generation/Operation Modes: (*Specify/describe basis for proposed Generation/Operation Mode(s)):*
Base Operation: ________________________________
Incremental Level 1: ________________________________
Incremental Level 2: ________________________________
Other(s): ________________________________

e) Design/Operational capabilities for extreme events (e.g. hurricanes)
Design Criteria:
i) Building Code ________________________________
ii) Wind Speed: ________________
iii) Importance Factor: ________________
Operating Criteria - specificy the maximum wind speed above which the Operator(s) will shut down the generating unit: ________________________________
Special Design/Operational Features - identify plant system(s) and capabilities
i) safe shutdown of unit with readiness for rapid restart: ________________________________
ii) blackstart unit w/o offsite power: ________________________________

____

f) General Equipment Specifications
Nominal Ratings (at rated temperature and pressure of the generator cooling medium):

____
Capability Curves (at rated temperature and pressure of the generator cooling medium): Provide as an attachment.
Nominal Power Factor: ________________________________
GSU Transformer impedances: ________________________________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

2) Technology/Configuration (Continued):

g) Existing Unit(s) and OEM Replacement Parts for Hot Gas Path Components:

- For a proposal based on an existing generating unit(s), please explain to what extent OEM replacement parts for hot gas path (HGP) components have been used in the unit(s):

____

____

- If the proposal is accepted, the winning Proposer must install OEM replacement HGP parts prior to the start of delievery of capacity and energy to FPL, then continue to utilize OEM replacement HGP parts for the duration of the PPA, and agree in the PPA to annually obtain from the OEM a certification that OEM replacement have been installed and have been maintained in accordance with the OEM schedules. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

h) Proposed New Unit(s) and OEM Replacement Parts for Hot Gas Path Components:

- For a proposal based on a new generating unit(s), please explain to what extent OEM replacement parts for hot gas path (HGP) components have been used in existing unit(s) operated by the Proposer:

____

____

- If the proposal is accepted, the winning Proposer must utilize OEM replacement HGP parts for the duration of the PPA, and agree in the PPA to annually obtain from the OEM a certification that OEM replacement have been installed and have been maintained in accordance with the OEM schedules. (Check One):

Agree ________ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

i) Historical Outage Hours for Existing Unit(s) Operated by Propser that are Similar to the New Unit being proposed:
(Provide requested data below for all such existing units)

	Base Operational Mode		Other Operational Modes	
Year	Actual Annual Planned Outage Hours	Actual Annual Forced Outage Hours	Actual Annual Planned Outage Hours	Actual Annual Forced Outage Hours
2010				
2011				
2012				
2013				
2014				

Note: Do not include Maintenance Outage Hours in these projections.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____________________

1	= Type of Generating Unit (from Form 4_1).
0.85	= Projected service hours for purposes of projecting EFOR and FOF.

3) Operational Considerations: Availability, Reliability, & Operating Time Limitations;

a) Outage Hours:

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Base Operational Modes					Other Operational Modes				
			FPL Calculations for RFP Analyses					FPL Calculations for RFP Analyses		
Contract Year	Annual Forced Outage Hours	Annual Planned Outage Hours	EAF (%)	EFOR (%)	FOF (%)	Annual Forced Outage Hours	Annual Planned Outage Hours	EAF (%)	EFOR (%)	FOF (%)
2019			100%	0.00%	0.00%			100%	0.00%	0.00%
2020			100%	0.00%	0.00%			100%	0.00%	0.00%
2021			100%	0.00%	0.00%			100%	0.00%	0.00%
2022			100%	0.00%	0.00%			100%	0.00%	0.00%
2023			100%	0.00%	0.00%			100%	0.00%	0.00%
2024			100%	0.00%	0.00%			100%	0.00%	0.00%
2025			100%	0.00%	0.00%			100%	0.00%	0.00%
2026			100%	0.00%	0.00%			100%	0.00%	0.00%
2027			100%	0.00%	0.00%			100%	0.00%	0.00%
2028			100%	0.00%	0.00%			100%	0.00%	0.00%
2029			100%	0.00%	0.00%			100%	0.00%	0.00%
2030			100%	0.00%	0.00%			100%	0.00%	0.00%
2031			100%	0.00%	0.00%			100%	0.00%	0.00%
2032			100%	0.00%	0.00%			100%	0.00%	0.00%
2033			100%	0.00%	0.00%			100%	0.00%	0.00%
2034			100%	0.00%	0.00%			100%	0.00%	0.00%
2035			100%	0.00%	0.00%			100%	0.00%	0.00%
2036			100%	0.00%	0.00%			100%	0.00%	0.00%
2037			100%	0.00%	0.00%			100%	0.00%	0.00%
2038			100%	0.00%	0.00%			100%	0.00%	0.00%
2039			100%	0.00%	0.00%			100%	0.00%	0.00%
2040			100%	0.00%	0.00%			100%	0.00%	0.00%
2041			100%	0.00%	0.00%			100%	0.00%	0.00%
2042			100%	0.00%	0.00%			100%	0.00%	0.00%
2043			100%	0.00%	0.00%			100%	0.00%	0.00%
2044			100%	0.00%	0.00%			100%	0.00%	0.00%
2045			100%	0.00%	0.00%			100%	0.00%	0.00%
2046			100%	0.00%	0.00%			100%	0.00%	0.00%
2047			100%	0.00%	0.00%			100%	0.00%	0.00%
2048			100%	0.00%	0.00%			100%	0.00%	0.00%
2049			100%	0.00%	0.00%			100%	0.00%	0.00%

Notes: 1) The specified forced outage hour values **must** reflect realistic values **over the life of the proposed capacity, not**"new & clean" unit values for all years.
2) If the EAF, EFOR, or FOF values are worse than the respective values discussed in Appendix C, Section E in any year, the bid will be rejected.

b) Operating Time Limitations:

- Provide explanation (s) for any operating time limitations attributable to facility design, permits, environmental regulations, maintenance, and/or other factors.
- Note that FPL requires that the Guaranteed Firm Capacity value quoted on Form 4_7 be capacity without run-time limitations.

Generation Operation Mode	Run-Time Limitations (e.g. hrs/yr.)	Explanation
Base Operation:		
Incremental Level 1:		
Incremental Level 2:		
Other(s):		

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

3) **Operational Considerations: Availability & Reliability (Continued):**

c) Existing Unit(s) and Availability & Reliability:

- For a proposal based on an existing generating unit(s), please state to what extent this generating unit(s) has achieved the outage hours reflected in the proposal during the last five years (and provide evidence that demonstrates that these outage hour levels have been achieved.)

____

- If the proposal is accepted, the winning Proposer must guarantee in the PPA that the unit will achieve outage hour levels reflected in the proposal so that the calculated EA, EFOR, and FOF levels are no worse than those projected on Form # 4, page 3 of 14. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

d) Proposed New Unit(s) and Availability & Reliability:

- For a proposal based on a new generating unit(s), please state to what extent existing units operated by the Proposer have achieved the calculated EA, EFOR, and FOF levels projected during the past five years (and provide evidence that demonstrates that such availability and reliability levels have been achieved).

____
____

- If the proposal is accepted, the winning Proposer must guarantee in the PPA that the unit will achieve EA, EFOR, and FOF levels equal to, or better, than those calculated on Form # 4, page 3 of 14. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the bid will be rejected.)*

4) **Fuel Information and Barometric Pressure:**

a) Primary Type of Fuel: ______________

b) Secondary/Backup Type of Fuel: ______________

c) Total operating time that unit can run at full capacity using actual on-site Secondary/Backup fuel without this stored fuel being replenished. = ______________ Hrs.
(See Minimum Requirements for Proposals, Section III)

d) Total Quantity of Secondary/Backup Fuel Stored On-Site:
Storage capacity = ______________________________
Typical On-Site Inventory for Operations = ______________________________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ______________________________

4) Fuel Information and Barometric Pressure (continued):

c) Natural Gas Fuel -Typical Properties *(for specifying unit performance values)*

Proposer's facility shall be designed to handle the expected range of fuels from its source(s). However, all specified unit performance values provided by Proposer shall be based on the "Average Fuel Analysis" that follows below:

Wide Range Fuel Data - Natural Gas

Property Constituents (Mole%)	Average
Methane	93.56%
Ethane	3.90%
Propane	1.00%
Normal Butane	0.23%
Iso Butane	0.23%
Normal Pentane	0.05%
Iso Pentane	0.03%
Hexane	0.10%
Carbon Dioxide	0.50%
Nitrogen	0.40%
TOTAL (MOLE %)	100%
Specific Gravity	0.601
Wobbe Index	1,376.7
Btu/SCF (HHV)	1,067
Btu/SCF (LHV)	962
HHV/LHV Ratio	1.109

Notes:
1 The constituent mole % values are normalized from the AVERAGE.
2 All constituent heating values are from the 1981 GPSA Engineering Data Book.
3 FPL does not warrant or guarantee that this fuel information is the actual that will be received during operation.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____________________

4) Fuel Information and Barometric Pressure (continued):

d) Barometric Pressure Conditions (for specifying performance values):

The generating unit performance values specified hereinafter shall be based on barometric pressure conditions as follows:

Ambient Barometric Pressure Chart

Centerline of CTG inlet bell mouth elevation (ft.)	Barometric Pressure (PSIA)
Sea Level	14.696
25	14.687
50	14.674
75	14.661
100	14.648
150	14.622
200	14.596
250	14.5704
300	14.5445

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ______________________________

5) **Guaranteed Firm Capacity** **(Net MW @ GSU Transformer High Side unless otherwise noted *):**

a) On Primary Fuel

Ambient Conditions	Generation/Operation Mode: Base Operation **	Incremental Level 1 *,***	Incremental Level 2 *,***	Other(s) (Specify) *,***	Total Guaranteed Firm Capacity
95F,50%RH					
35F,60%RH					
95F,50%RH ***					
35F,60%RH ***					

b) On Secondary Fuel

Ambient Conditions	Generation/Operation Mode: Base Operation **	Incremental Level 1 *,***	Incremental Level 2 *,***	Other(s) (Specify) *,***	Total Guaranteed Firm Capacity
95F,50%RH					
35F,60%RH					
95F,50%RH ***					
35F,60%RH ***					

* As delivered to FPL's system adjusted for any 3rd Party transmission system losses (if applicable).

** Guaranteed firm capacity must be capacity without run-time limitations

*** Generation/Operation Mode: "Incremental Level 1" values shall be specified as incremental to "Base Operation" values; "Incremental Level 2" values shall be specified as incremental to "Incremental Level 1 values; and so forth. (Example: Base Operation may be combined cycle w/o HRSG duct burners in operation. "Incremental 1" may be the incremental performance from use of HRSG duct burners.)

Note: The guaranteed capcity values shown above **must reflect "average" capacity values over the proposed term-of-service to FPL, not** "new & clean" unit values.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

5) **Guaranteed Firm Capacity (Continued):**

c) Existing Unit(s) and Guaranteed Firm Capacity:

- For a proposal based on an existing generating unit(s), please state to what extent this generating unit(s) has achieved the peak capacity levels reflected in the proposal during the last five years (and provide evidence that demonstrates that such peak capacity levels have been achieved.)

____

____

- If the proposal is accepted, the winning Bidder must guarantee in the PPA that the unit will continuously achieve the peak capacity levels reflected in the bid and provide results on annual tests of capacity. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the bid will be rejected.)*

d) Proposed New Unit(s) and Guaranteed Firm Capacity:

- For a proposal based on a new generating unit(s), please explain to what extent existing units operated by the Proposer have achieved the peak capacity levels reflected in the proposal during the past five years (and provide evidence that demonstrates that such peak capacity levels have been achieved).

____

____

- If the proposal is accepted, the winning Proposer must guarantee in the PPA that the unit will continuously achieve the peak capacity levels reflected in the proposal and provide results on annual tests of capacity. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

6) **Guaranteed Heat Rates (BTU/kWh (HHV) @ Guaranteed Firm Capacity as delivered to FPL system adjusted for any 3rd Party transmission system losses):**

a) On Primary Fuel:

	Generation/Operation Mode			
Ambient Conditions	Base Operation	Incremental Level 1 *	Incremental Level 2 *	Other(s) (Specify)*
95F,50%RH				
75F,60%RH				

b) On Secondary Fuel:

	Generation/Operation Mode			
Ambient Conditions	Base Operation	Incremental Level 1 *	Incremental Level 2 *	Other(s) (Specify)*
95F,50%RH				
75F,60%RH				

* Generation/Operation Mode: "Incremental Level 1" values shall be specified as incremental to "Base Operation" values; "Incremental Level 2" values shall be specified as incremental to "Incremental Level 1 values; and so forth. (Example: Base Operation may be combined cycle w/o HRSG duct burners in operation. "Incremental 1" may be the incremental performance from use of HRSG duct burners.)

Note: The guaranteed heat rates values shown above **must reflect "average" values over the proposed term-of-service to FPL, not** "new & clean" unit values.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

6) Guaranteed Heat Rates (Continued):

c) Existing Unit(s) and Guaranteed Heat Rates:

- For a proposal based on an existing generating unit(s), please state to what extent this generating unit(s) has achieved the heat rate levels reflected in the proposal during the last five years (and provide evidence that demonstrates that such heat rate levels have been achieved.)

____

____

- In regard to this evidence of actual heat rates, if a heat rate test acceptable to FPL has not been performed within the last two years, the Proposer must perform a new test and submit the results as part of the proposal. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

- If the proposal is accepted, the winning Proposer must guarantee in the PPA that the unit will achieve the heat rate levels reflected in the proposal and provide results of annual heat rate tests (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

d) Proposed New Unit(s) and Guaranteed Heat Rates:

- For a proposal based on a new generating unit(s), please explain to what extent similar existing units operated by the Proposer have achieved the heat rate levels reflected in the proposal during the past five years (and provide evidence that demonstrates that such peak capacity levels have been achieved).

____

- In regard to this evidence of actual heat rates, if a heat rate test acceptable to FPL has not been performed for such existing units within the last two years, the Proposer must perform a new test(s) and submit the results as part of the proposal. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

- If the proposal is accepted, the winning Proposer must guarantee in the PPA that the unit will achieve the heat rate levels reflected in the proposal and provide results of annual heat rate tests (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

7) **Emission Rate Information:** **(For System Sales, please see directions in the Appendix C text on page C-4.)**

Provide the emission rate information requested below for the incremental MW supplied by each applicable operational mode on both the primary and secondary fuel.

a) On Primary Fuel

	Base Operation @ Full Load	Incremental Level 1	Incremental Level 2	Other
NO_x emission rate: lbs./mmBTU =				
SO_2 emission rate:lbs./mmBTU =				
PM_{10} emission rate:lbs./mmBTU =				
CO emission rate:lbs./mmBTU =				
CO_2 emission rate:lbs./mmBTU =				
Hg emission rate:lbs./trillion BTU =				

b) On Secondary Fuel

	Base Operation @ Full Load	Incremental Level 1	Incremental Level 2	Other
NO_x emission rate: lbs./mmBTU =				
SO_2 emission rate:lbs./mmBTU =				
PM_{10} emission rate:lbs./mmBTU =				
CO emission rate:lbs./mmBTU =				
CO_2 emission rate:lbs./mmBTU =				
Hg emission rate:lbs./trillion BTU =				

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____________________

7) **Emission Rate Information (Continued):**

Provide the emission rate information requested below for the incremental MW supplied by each applicable operational mode on both the primary and secondary fuel.

a) On Primary Fuel

	Base Operation @ Full Load	Incremental Level 1	Incremental Level 2	Other
NO_x (ppmvd @ 15% oxygen) =				
CO (ppmvd @ 15% oxygen) =				
VOC (ppmvd @ 15% oxygen) =				
SO_2 (ppmvd @ 15% oxygen) =				
SO_2 (lbs per hour) =				
PM (lbs per hour) =				
PM_{10} (lbs per hour) =				
$PM_{2.5}$ (lbs per hour) =				
H_2SO_4 mist (lbs per hour) =				

b) On Secondary Fuel

	Base Operation @ Full Load	Incremental Level 1	Incremental Level 2	Other
NO_x (ppmvd @ 15% oxygen) =				
CO (ppmvd @ 15% oxygen) =				
VOC (ppmvd @ 15% oxygen) =				
SO_2 (ppmvd @ 15% oxygen) =				
SO_2 (lbs per hour) =				
PM (lbs per hour) =				
PM_{10} (lbs per hour) =				
$PM_{2.5}$ (lbs per hour) =				
H_2SO_4 mist (lbs per hour) =				

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

8) **Natural Gas Pipeline Connection(s):**

a) Identify the projected source of natural gas supply (FGT, Gulfstream, Sabal Trail, or Sabal Trail / Florida Southeast Connection, etc.)

____

b) Designate the power generating facility, proposed gas pipeline delivery point, and any proposed lateral line facilities on a hard copy submittal of marked-up U.S. Geological Survey Map(s) indicating the Section(s), Township(s) and Range(s). Include one hard copy of this USGS map(s) in each of the five bound hard copies of these completed forms.

c) Provide a written description of these proposed lateral line and metering facilities to connect the interstate or intrastate gas pipeline to the generating facility, including the size of the pipe and the distance (in miles) of the generating facility from the appropriate natural gas interstate or intrastate mainline (name the mainline) that will supply the facility's gas and a detailed description of the metering facilities.

____

____

____

____

d) Provide the minimum acceptable natural gas delivery pressure at each of the following locations: (i) at the interconnection with the interstate gas pipeline, (ii) at the end of the proposed lateral line, and (iii) at the generating facility inlet.

e) Provide the Maximum Daily Natural Gas Consumption Requirement at Generating Facility:
____________________ (mmBTU/day)

f) Provide the portion of the Maximum Daily Natural Gas Consumption Requirement identified in e) above that must be obtained on a firm basis: _________ (mmBTU/day)

g) Provide the Maximum Hourly Natural Gas Consumption Requirement at Generating Facility:
____________________ (mmBTU/hour)

h) Provide the portion of the Maximum Hourly Natural Gas Consumption Requirement identified in g) above that must be obtained on a firm basis: _________ (mmBTU/hour)

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

9) **Generating Units' Operating & Maintenance Experience/Performance:**

Use attachment(s) to specify the name, address, etc. of the responsible Operating & Maintenance Group/ Company and pertinent U.S. experience/performance information (i.e., Actual Performance Track-Record):

For all generating plants in its U.S. domestic portfolio, provide a listing of individual generating unit names, location, state, guaranteed/demonstrated MW capacity, in-service year, technology type, primary fuel, start year of Operating Entity experience with the unit. From these, provide composite experience summaries as follows:

General - Cumulative MW-years of experience through December 2014 with ALL present generating capacity

Specific - Cumulative MW-years of experience through December 2014 with SPECIFIC generating technologies being proposed (e.g. Combined Cycle, Peaking CT/GT, Coal-Steam).

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 5: Pricing Information for Purchased Power or System Sale Proposals

Facility Name: ______________________________

1) **Guaranteed Capacity Payments: *,****

Provide guaranteed total capacity pricing for each operational mode identified on Form # 4. Please insert "NA" for operational modes that are not applicable to your proposal.

	for: Base Operational Mode	for: Incremental Level 1 Operational Mode	for: Incremental Level 2 Operational Mode	for: Other (specify) Operational Mode
Contract Year	Guaranteed Capacity Payment **($/kw-month)**	Guaranteed Capacity Payment **($/kw-month)**	Guaranteed Capacity Payment **($/kw-month)**	Guaranteed Capacity Payment **($/kw-month)**
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				
2039				
2040				
2041				
2042				
2043				
2044				
2045				
2046				
2047				
2048				
2049				

* Guaranteed capacity pricing values must include all proposed payments for at least the following:
- generation capital, fuel delivery capital including lateral from the appropriate natural gas pipeline, and infrastructure capital;
- fixed O&M and capital replacement;
- transmission interconnection and 3rd party transmission service (as applicable) over another utility system(s). (See pages 3 of 4 and 4 of 4 of this form.)

**** Please refer to instructions in Section F of this Appendix.**

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 5: Pricing Information for Non-System Sale Proposals

Facility Name: ____________________

2) **Guaranteed Energy Pricing Payments:**

Pipeline: ______________ *

Contract Year	Guaranteed Fuel Transportation Reservation Price (if applicable) ** **($/mmBTU per Day)**	Guaranteed Fuel Transportation Quantity (if applicable) *** **(mmBTU per Day)**	Guaranteed Fuel Commodity Price (if applicable) **** **($/mmBTU per Day)**	(for Base Operational Modes) Guaranteed Variable O&M Payment ***** **($/MWH)**	(for all Other Operational Modes) Guaranteed Variable O&M Payment ***** **($/MWH)**
2019					
2020					
2021					
2022					
2023					
2024					
2025					
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					
2036					
2037					
2038					
2039					
2040					
2041					
2042					
2043					
2044					
2045					
2046					
2047					
2048					
2049					

* In regard to the "Pipeline" entry, please fill in the blank with one of the following: "FGT", "Gulfstream", "Sabal Trail", or "Sabal Trail / Florida Southeast Connection (FSC)".

** If $/mmBTU per Day values are not entered for each year, FPL will use its own fuel transportation forecast, plus any incremental lateral costs, for evaluation purposes for any project capable of connecting to Sabal Trail or FSC. For projects which must be connected to FGT or Gulfstream, FPL will have to evaluate the cost of acquiring additional capacity on the applicable pipeline. If $/mmBTU per Day values are entered, FPL will use those values for evaluation purposes and will use the applicable pipeline's tariff to determine the appropriate variable costs and fuel per mmBTU per Day.

*** A Guaranteed Fuel Transportation Quantity must be included for proposals with a Guaranteed Fuel Transportation Reservation Price.

**** If left blank, FPL will use its own fuel price forecast for purposes of proposal evaluation.

***** **Please refer to instructions in Section F of this Appendix.**

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 5: Pricing Information for System Sale Proposals

Facility Name: ______________________________

2) Guaranteed Energy Pricing Payments:

Contract Year	Guaranteed Variable O&M Payment * (\$/MWH)	Guaranteed Energy Payment * (\$/MWH)
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		
2046		
2047		
2048		
2049		

* Please refer to instructions in Section F of this Appendix.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 5: Pricing Information for Purchased Power or System Sale Proposals

Facility Name: ____

3) **Startup Fuel Amount Required:**

______________________ **(mmBTU per startup)**

4) **Costs and Information Included in the Payments:**

a) (For proposals that are based partially or totally on generators that need to be constructed and connected to the transmission system) Attach a copy of the completed and submitted application for Generator Interconnection Service (GIS) in the FPL GIS Queue, or which the applicable third party if the new generator is to be connected to a third party's transmission system.

b) Transmission Interconnection Costs:

Total transmission interconnection cost included in the Guaranteed Capacity Payment values provided on page 1 of 4 of this form = ______________________ (millions, 2019$)

Basis for this cost estimate is : ____

____

____

____

c) Third Party Transmission Service Information:

State whether third party transmission service rights have been requested and/or already procured for a portion of or all of the generation capacity being offered. To the extent a request for such long-term firm transmission rights have been requested, but not yet procured, provide all available studies associated with such requests.

____

____

____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 5: Pricing Information for Purchased Power or System Sale Proposals

Facility Name: ____

4) **Costs and Information Included in the Payments (Continued):**

d) Transmission Losses:

Transmission losses (MW) associated with the third party transmission service (which are accounted for in developing the Total Guaranteed Firm Capacity (As Delivered to FPL's System) values on Form # 4):

____

____

____

____

e) Gas Pipeline Lateral and Meter Costs:

Total lateral pipeline and meter cost = ______________ (millions, 2019$).

Are the lateral pipeline and meter station cost included in the Guaranteed Capacity Payment values provided on page 1 of 4 of this form or, if applicable, in the Guaranteed Fuel Transportation Reservation Price provided on page 2 of 4 of this form? Please indicate below with an "X":

In the Guaranteed Capacity Payment ________
In the Guaranteed Fuel Transportation Reservation Price ________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

1) **Proposed Community Outreach Activities and Experience:**

Describe experience with Community Outreach Plans, identify community benefits, and identify the proposed outreach activities for the proposed facilities.

____
____
____

2) **Required Permits or Approvals to License or Permit the Facility:**

Provide a listing of all required permits or approvals (federal, state, and local) to license or permit the construction and operation of the facility.
Include a major milestone permitting schedule *:

____
____
____

* FPL is requiring that a Proposer's Site Certification Application must be filed within 39 months of the proposed Capacity Delivery Date. **(See Section III of the RFP document.)**

Identify any studies, surveys, and/or analyses necessary to support the permititng, licensing, and certification of the facility:

____
____
____

Identify the need for any Variances or Exceptions to substantive standards and other requirments along with the strategy to obtain same:

____
____
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

3) **Description of Air Pollution Control Equipment:**
Provide sufficient detail to characterize pollution reduction effectiveness and maturity at size/scale proposed, e.g. mature, emerging, or new application):

____
____
____

a) Industry Experience:
# of Units in operation: ________
Years Experience: ________
Operational Issues: ______________________________
____
Other: ______________________________
____

b) Proposer Experience:
# of Units in operation: ________
Years Experience: ________
Operational Issues: ______________________________
____
Other: ______________________________
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

4) **PSD/NSR Permitting:**

Provide anticipated emission rates for each regulated pollutant or emission emitted from the facility (including CO_2).

Lbs./hr ________
Lbs./mmBTU ________
ppm ________
TPY ________

Describe the overall strategy for permitting the proposed Pollution Control Technology for all regulated pollutants.

____
____
____

Describe the emissions credit strategy (if applicable):

____
____
____

Describe the basis for all regulated pollutant emission rates (e.g., vendor guarantee, EPA emissions factor, operating experience, etc.):

____
____
____

Provide the expected cooling tower emission rates for regulated pollutants (lbs.hr. & TPY):

____
____
____

Describe treatment/maintenance chemicals (including cycles of concentration):

____
____
____

Describe compliance with applicable AAQS, PSD increments and AQRVs:

____
____
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

5) **Water Supply Strategy:**

Identify source(s), quantity, and quality (monthly or seasonal differences):

____

____

Describe agreement(s) or authorization status (timetable or plan to acquire water supply):

____

____

Identify any conflicts with regional Water Management District (WMD), or other local water authority, goals or plans:

____

____

6) **Water Discharge Strategy:**

Location(s) of discharge(s) - water body, city/town, and latitude and longitude:

____

____

Quality and quantity (monthly or seasonal differences):

____

____

List of any required agreements or permits and provide status (timetable or work plan to acquire same):

____

____

Identify any conflicts with WMD goals and FDEP rules:

____

____

Wetlands Impacts:

____

____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

6) **Water Discharge Strategy (Continued):**

TMDLs (if applicable):

____
____
____

Surface Water Impacts

____
____
____

Groundwater Water Impacts

____
____
____

7) **Strategy to Address Land Use Issues:**

Comprehensive Plan/Amendment (current and proposed changes, if any; status or work plan required):

____
____
____

Identify the need for Variances or Exceptions and the strategy to obtain same:

____
____
____

Compatibility with adjacent land uses:

____
____
____

Distance and direction of nearest residence to plant boundary:

____
____
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

7) **Strategy to Address Land Use Issues (Continued):**

Describe the strategy for compliance with noise standards:

____
____
____

Describe the strategy for compliance with other standards:

____
____
____

Identify any zoning issues, the need for Variances or Exceptions, and the strategy to obtain same:

____
____
____

Summary of Phase I/Phase II environmental site assessment findings, if any; and status of required work plan.

____
____
____

Description of Archaeological or Historic Site Impacts, if any;
status of work plan required:

____
____
____

8) **Solid/Hazardous Waste/Material Management Strategy:**

____
____
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

9) **Other Infrastructure Needs or Requirements:**

Water supply or discharge line Right of Way (ROW) and easements - and the strategy to obtain same:

____
____
____

Fuel supply ROW and easements - and the strategy to obtain same:

____
____
____

Transmission line ROW and easements - and the strategy to obtain same:

____
____
____

Transportation access ROW & easements - and strategy to obtain same:

____
____
____

10) **Protected Species Impacts:**

____
____
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

11) **Permitting Experience in Florida of Proposer and Environmental Support Contractors and Consultants:**

____
____
____
____
____
____

12) **Proposer Compliance History (Last 5 years, i.e., 2010-2014):**

Total and type of violation/non-compliance: ____________________
____

Total dollars in:
Fines: ________________
Penalties: ________________
Payments or other in-kind contribution for settlement: ________________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 7: Key Milestones

Facility Name: ____

Key Milestones (as applicable):	**Projected Date:**
a) Site Certification Application Filed	____________
b) Air Permit Application Filed	____________
c) Interconnection Application Filed	____________
d) Granted Site Certification	____________
e) Granted Air Permit	____________
f) Irrevocable Order Placed for All Major Equipment	____________
g) Firm Fuel Transportation Arrangement(s) Executed	____________
h) Contractor Mobilized, Financing Closed	____________
i) Construction Start	____________
j) Major Equipment Deliveries (specify all)	____________
k) Acceptance Testing (specify all)	____________
l) Capacity Delivery Date	____________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 8: Receipt Point(s) to FPL

Facility Name: ____

1) State the receipt point(s) to the FPL system including nearest substation(s):

____

____

____

2) Attach a readable transmission map (8.5x11) highlighting the receipt point(s) listed above.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 9: Proposer Exceptions *

Facility Name: ____

*** Note: FPL will not consider proposed exceptions to the RFP's Minimum Requirements for Proposals or to the Minimum Requirements Pursuant to Puchase Agreement.**

1) With regard to this proposal, the Proposer takes no exception to terms, conditions, or other facets of the RFP (Check One): _________ Agrees _________ Disagrees

2) If the answer to item (1) above is "Disagrees", then for each term, condition, or other facet of the RFP which the Proposer takes exception to, use the space below to:

   a) identify the language (citing page and paragraph) in the RFP for which an exception is made; and,

   b) write out the Proposer's desired revised language.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 10: Proposal Certification

Facility Name: ____

The undersigned certifies that: (i) all of the information submitted in its proposal to FPL is complete and accurate, and that the pricing includes all of the following applicable costs for the proposal for the proposed full term of service including, but not limited to, the following costs:

- generator construction;
- generator operation and maintenance;
- transmission interconnection and 3rd party transmission service;
- gas pipeline interconnection including lateral pipeline (or other fuel delivery capital and O&M costs); and
- cost of fuel (as applicable);

(ii) the terms, conditions, and other facets of the RFP are acceptable, except as specifically noted on Form # 9; (iii) the Completion Security and Performance Security described in Section IV of the RFP document are acceptable and there are no pending legal or civil actions that would affect the ability of the Proposer and/or it guarantor to maintain these security amounts; (iv) the proposal has been submitted in the legal name of the entity which would be bound by any resulting contract; and (v) the proposal is binding, definitive, and firm and will remain open for 180 days from the Proposal Due Date.

Name of Legal Entity: ____

State of Incorporation: ____

Business Address: ____

Name of Person Certifying Proposal: ______________________________

Title: ____

Date: ____

Telephone: ____

Signature:* ____

E-Mail: ____

(* An Officer of the proposing company must sign a copy of this form which is included in each of the five (5) bound hard copies of the proposal.)

APPENDIX D

D.1 Evaluation Methodology – Overall Process

D.2 Transmission Integration & Losses

D.3 Net Equity Adjustment

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D.1. Evaluation Methodology - Overall Process

A. Overview

The objective of the evaluation methodology is to determine the best generation capacity option(s) that meet the RFP eligibility requirements and FPL's RFP capacity need requirements that start in June 2019. The determination will be made after analyses of eligible proposals received in response to this RFP and FPL's next planned generating unit (NPGU) that is presented in the main body of this RFP.

An individual proposal may meet the 2019 need requirement by itself (as FPL's NPGU will do). Individual proposals that only partially satisfy the 2019 need requirement may be paired with other proposals in a portfolio of proposals that together meet the 2019 need requirement. Once portfolios have been developed that each meet FPL's 2019 need requirement, the next step is to develop multi-year resource plans. Each resource plan will incorporate: an individual proposal that fully meets FPL's 2019 resource need, FPL's NPGU that also fully meets FPL's 2019 resource need, or one of the portfolios of smaller proposals. Filler units will then be added in each resource plan to meet FPL's projected annual resource needs after 2019.

These resource plans will then be evaluated using a multi-year analysis approach that allows examination of both short-term and long-term impacts to FPL's system from the generation options. These analyses will utilize both economic and non-economic perspectives.

The economic analyses will provide a total system perspective including economic impacts related to: new generation costs, system fuel costs, transmission costs, environmental compliance costs, and FPL's cost of capital. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the intent of minimizing FPL's levelized system average rate (*i.e.*, a Rate Impact Measure or RIM methodology). However, in cases such as a generation-only RFP evaluation in which FPL's demand side management (DSM) plans are unchanged, comparisons of competing resource plans' impacts on a levelized system average electric rate basis and on a cumulative present value system revenue requirements (CPVRR) basis will yield identical rankings of the options being evaluation. For this reason, and because it is a simpler process to perform CPVRR-based analyses than it is to perform levelized system average electric rate analyses, the economic analyses for this RFP competing resource plans evaluated in the RFP analyses will be evaluated on a CPVRR basis.

The economic analyses of proposals received in response to this capacity RFP will use a similar process to that used in analyses that led to the identification of FPL's NPGU. In its economic evaluation, FPL plans to use the UPLAN production costing model for detailed production costing work. If a large number of eligible proposals are received in response to this RFP, FPL may also use the EGEAS optimization model to perform rankings of the resource plans. The highest ranking (*i.e.*, lowest CPVRR cost) resource plans would then be evaluated using the UPLAN production costing model and FPL's Fixed Cost Spreadsheet. The Fixed Cost Spreadsheet is used to develop the fixed costs associated with each of the resource plans. These fixed costs include costs (as applicable) for: capital for new generation, fixed O&M, capital replacement, firm gas transportation, capacity payments, etc. If the number of eligible proposals received is relatively small, FPL may elect to not utilize the EGEAS model. In addition, the analyses will also utilize various spreadsheets that are discussed later in this Appendix.

All economic analyses steps will use consistent assumptions regarding fuel costs, environmental compliance costs, load growth, and generation expansion plan addition options. A designated FPL Fossil Fuel Price Forecast and the FPL Environmental Compliance Cost Forecast will be utilized in these economic analyses. (The FPL Fossil Fuel Price Forecast and the FPL Environmental Compliance Cost Forecast will be posted on the RFP website once the RFP document is issued.) In addition, load growth will be modeled using FPL's current Load Forecast and FPL's approved DSM Goals. The resulting projected firm peak load growth will require additional generation beginning in 2019, and in years beyond 2019, to maintain FPL's required reserve margin levels.

Some of the forecasts and assumptions that will be utilized in the economic analyses are different from those presented in, and utilized in the development of FPL's 2014 Ten Year Site Plan (Site Plan). Appendix E presents a list of some of the key forecasts that have changed from those used in developing the resource plan that was previously presented in the 2014 Site Plan. (FPL will file its 2015 Site Plan on April 1, 2015, *i.e.*, after the release of this RFP.) Largely as a result of these updated forecasts, FPL's current resource plan is different from that presented in the 2014 Site Plan. Appendix E also discusses key changes in FPL's resource plan through the year 2019.

Non-economic analyses will be performed to evaluate certain risks for each portfolio. These analyses will include, but not necessarily be limited to, examining the following: 1) risks associated with an eligible proposal, 2) projected FPL system emissions for each portfolio, and 3) projected FPL system fuel mix for each portfolio. The results of the non-economic analyses will then be combined with the results of the economic analyses in order to determine the best overall portfolio with which to serve FPL's customers.

The economic analysis will be coordinated and largely conducted by FPL's Resource Assessment & Planning Department. An external consultant, Sedway Consulting (Sedway), will serve as an Independent Evaluator and conduct parallel economic evaluations using a different model(s). Both FPL and Sedway will evaluate FPL's NPGU and eligible proposals received in response to the RFP. Other external consultants may be used in analyzing impacts or costs regarding transmission integration, transmission losses, and/or natural gas delivery aspects of the evaluation depending upon the number and/or complexity of the proposals received.

The non-economic analysis will be conducted by several FPL departments which may also utilize other independent consultants in their assessments. The coordination of the non-economic analysis work, and the integration of the results of the economic and non-economic analyses, will be performed by FPL's Resource Assessment & Planning Department.

The evaluation of eligible proposals, the NPGU, and the resulting resource plans will be conducted using an eight (8) step process that is summarized below.

Step 1: Initial Screening for Eligibility

This initial step determines whether proposals satisfy the Minimum Requirements for Proposals and the Minimum Requirements Pursuant to Purchase Agreement (Sections III and IV, respectively, of the main body of the RFP). Proposals that do not satisfy these Minimum Requirements will be deemed ineligible and will be returned to the Proposer, along with 50% of the RFP Evaluation Fee, and will not be evaluated further.

Step 2: Economic Evaluation of Individual Proposals (if applicable)

In order to assist in the analysis of a potentially large number of eligible proposals that might be received in response to this RFP, an economic ranking of individual eligible proposals may be made based on their individual impact to the FPL system. The results of such an analysis would be used to rank proposals based on their individual economic merit. If there are significant differences in the projected economic impacts to the FPL system among the proposals, these results may be used to reduce the number of proposals that are carried forward to the next steps of the economic evaluation. Proposals that are not evaluated beyond this step will have been shown to be non-competitive by comparison of their results to the results of other proposals that do proceed in the evaluation.

The Step 2 analyses, if applicable, will likely be performed utilizing the EGEAS optimization model. These analyses of individual proposals will address FPL system cost impacts such as capital, capacity payments, fixed and variable O&M, capital replacement, firm gas transportation, system fuel, system environmental compliance costs, and other impacts effects from a resource plan perspective, including the ability of a proposal to help meet post-2019 resource needs.

If there are a relatively small number of eligible proposals, FPL may choose to forego this step of evaluating individual proposals and proceed to the creation and evaluation of portfolios and/or resource plans.

Step 3: Creation and Initial Evaluation of Portfolios and/or Resource Plans

Eligible proposals that remain after Step 1 (and, if applicable, Step 2) will then be incorporated into resource plans for further analyses. If a proposal is large enough by itself to meet FPL's 2019 resource needs, this proposal will be the only generation addition assumed to be added in 2019. Smaller proposals that cannot, by themselves, fully meet FPL's 2019 resource needs, would be combined, if possible, into a portfolio of proposals that in combination meets the 2019 resource need. Then large proposals and portfolios of smaller proposals will be incorporated into separate multi-year resource plans that address 30 years beyond 2019. In addition, a separate resource plan will assume the NPGU alone is added in 2019.

Each resource plan will then be evaluated for all system cost impacts, such as capital and other fixed costs, fuel and other variable costs, transmission interconnection and integration costs, system losses, and system environmental costs. These analyses will be performed utilizing FPL's Fixed Cost Spreadsheet and the UPLAN production costing model. FPL will utilize its Fixed Cost Spreadsheet to develop the fixed costs associated with each of the resource plans. These fixed costs include costs for: capital, fixed O&M, capital replacement, firm gas transportation, and capacity payments.

The UPLAN production costing model will be used to develop the variable annual costs of system operation for the resource plans. (The UPLAN model will be used by FPL in FPL's fuel cost recovery filings beginning in 2015, as well as in other production cost applications, and was used in the identification of FPL's NPGU for this capacity RFP.) This detailed, hourly production costing model will develop the projected annual fuel and variable O&M costs for each of the resource plans. This production costing model will also account for limitations on the amount of power that can be imported into the Southeastern Florida area and the corresponding impacts on the operation of FPL generating units located in Southeastern Florida. The UPLAN model, and potentially additional spreadsheet analysis, will be used to develop the environmental compliance costs of each portfolio.

Step 4: Development of Additional System Costs for Resource Plans

At the conclusion of Step 3, competitive resource plans will then undergo additional economic analyses as well as a non-economic evaluation. In Step 4, four additional system cost areas will be specifically developed for each resource plan, as applicable. These system costs are: (a) transmission-related costs, (b) fuel system-related costs, (c) greenhouse gas (GHG) emission-related costs, and (d) the net impact on FPL's cost of capital. In regard to the first two of these cost items, the specific siting of the proposed generation will be a key factor.

4a. Transmission-Related Costs

The following transmission-related costs will be calculated:
- transmission integration costs;
- costs related to system capacity (MW) losses at FPL's system peak hour and costs related to system annual energy (MWh) losses; and,
- impacts of the resource plans on maintaining a balance between load and generation in the Southeastern Florida region (*i.e.*, Miami-Dade and Broward counties).

The transmission integration facilities that are needed for each resource plan will be determined first. Next, costs for these integration facilities will be calculated. A transmission system analysis will then be conducted of each resource plan assuming that these integration facilities are in place. This analysis will serve as the basis to estimate the transmission system capacity losses at the system peak hour and annual energy losses associated with the resource plan. Costs will be assigned to these projected losses. In addition, the location of proposed generation capacity in each resource plan will be evaluated in regard to how it is projected to affect FPL's ability to maintain a balance between load and generation in the Southeastern Florida region consisting of Miami-Dade and Broward counties. Proposed generation capacity that is located in that region may be credited with the benefit of avoiding/deferring the costs of transmission projects projected to maintain this balance. (In addition, the production costing analyses will automatically account for the impact of the location of proposed generation capacity on the dispatch of FPL's generation system.)

Other transmission-related costs, including transmission interconnection costs and the costs of 3rd party transmission services (if applicable), are to be included in the price provided for each individual proposal. These items are discussed in more detail in Section D.2. below. (The cost of the NPGU presented in the main body of this RFP includes both transmission interconnection and integration costs.)

4b. Fuel System-Related Costs

As applicable, a more detailed analysis of the fuel system-related costs for each resource plan will be developed. Such an analysis will utilize the specific location of the generator(s) contained in the portfolio and the designated natural gas pipeline(s) to provide a more definitive estimate of the firm fuel transportation costs required to provide the necessary firm transportation at the appropriate pressures and volume to the portfolio consistent with FPL's normal fuel system management practices.

In addition, FPL will be evaluating the portfolio and resource plan to identify if "upstream" capital costs associated with additional natural gas pipeline and/or compression facilities will be needed to supply the proper volume and pressure of natural gas to the units in the portfolio.

4c. GHG Emission-Related Costs

For evaluation purposes, carbon dioxide (CO2) emission will serve to represent GHG emissions. All proposals will be required to provide the CO2 emission rates (lbs/MMBtu) of each proposed individual unit or, in the case of a system sale, the projected annual system emission rates (tons/MWh), for CO2 emissions. FPL will use these emission rates to calculate FPL's total projected annual system CO2 system emissions (tons) for each resource plan that includes one or more proposals. This approach will also apply to the resource plan with the NPGU. FPL and Sedway will then apply FPL's current projection of annual CO2 emission costs ($/ton) to these annual CO2 emissions so that the total annual emission costs that could be attributable to all energy generated to meet FPL customers' needs ("annual CO2 emission costs for FPL total energy") are calculated for each resource plan. FPL's projection of annual CO2 emission costs ($/ton) will be posted on the RFP website once the RFP is issued. From these annual CO2 emission costs, FPL will calculate a CPVRR CO2 emission cost value for the length of the analysis period for each resource plan. This CPVRR CO2 emission cost value will then be added to the projected fixed and variable CPVRR cost for the resource plan in the same way that CPVRR costs for transmission integration, losses, and net equity adjustment (see below) will be added. Together, the sum of all of these CPVRR costs will represent the total CPVRR cost for the resource plan.

4d. Net Equity Adjustment

FPL will also estimate the impact to FPL's cost of capital associated with entering into a new purchased power agreement(s). The costs of the resulting impact on FPL's capital structure are referred to as an equity adjustment. It is also recognized that a power purchase agreement also has the potential to mitigate completion and/or performance risks that would otherwise be borne by FPL if FPL were to construct a new generating unit. FPL assigns a cost savings to these "mitigating factors" and subtracts these values from the equity adjustment amount to derive a net equity adjustment. An explanation of the net equity adjustment evaluation, including an example calculation, is presented in Section D.3. below.

Step 5: Detailed Evaluation of Total System Costs

In Step 5, the CPVRR costs for each resource plan calculated in Step 3 are added to the additional system costs developed in Step 4 to produce a total system CPVRR cost for each resource plan. This total cost value represents the result of the full economic evaluation for each resource plan. The results for each resource plan, presented in CPVRR form, will be compared to the results for all other resource plans.

Step 6: Non-Economic Evaluation of Portfolios

A non-economic evaluation will be conducted on parameters that, by their nature, are unable to be integrated into the economic evaluation. These parameters describe factors that represent elements of risk that FPL must evaluate in all generation addition scenarios as well as other non-economic factors such as projections of system emissions and system fuel mix. Detailed information requirements designed to assist FPL in certain aspects of the non-economic evaluation are outlined in the submittal forms in this RFP that are presented and discussed in Appendix C. These submittal forms will be used to evaluate specific risk-related parameters that can be summarized as falling into one or more of the following three areas:

6a. Environmental Area

- Items related to the Proposer's ability to successfully complete the permitting and siting aspects of the project as proposed and maintain compliance with applicable rules and regulations.

6b. Technical/Operational Area

- Items related to the long-term operational performance, reliability, and maintainability of the proposed generating alternatives.

6c. Project Execution Area

- Items related to the exceptions stated to the RFP and the impact of those exceptions.
- Items that relate to the Proposer's ability to complete the development, construction, and operational aspects of the project as proposed.

Proposals that exhibit strong potential in the economic evaluation, but are unclear in certain non-economic evaluation areas, may be considered for a Panel Review. The Panel Review, if necessary, would provide for an exchange between the Proposer(s) and FPL panelists regarding the non-economic evaluation areas. This would allow for a more complete exchange of information in the important areas. Proposers will be notified individually if a need for a Panel Review is indicated, and a mutually convenient time will be arranged.
The specific key parameters for each of these 3 areas are presented in Tables D.1 - 1 through D.1 – 3 that follow.

Table D.1 - 1 Environmental Area Parameters

Compliance Experience
Control Technology
Violation/Non - Compliance
Proposed Project
Licensing/Permitting
PPSA/Permitting Issues
PSD/NSR Issues
Land Use Issues
Protected Species Issues
Zoning Issues
Variance Required
Exceptions Required
Community Outreach Plan
Water Supply Strategy
Water Discharge Strategy
FL Permitting Experience
PPSA
Non - PPSA
Other Infrastructure
Water Supply or Discharge Easements
Transportation Access
Fuel Supply Easements
Transmission Line Easements

Table D.1 - 2 Technical/Operational Area Parameters

Technology
Configuration
Operational Limitations
Fuel
Guaranteed Firm Capacity
Guaranteed Heat Rate
Commercial Availability
Generating Units' Operating & Maintenance Experience

Table D.1 - 3 Project Execution Area Parameters

Nature of Exceptions
Impact to Risk Profile
Departure from Scope
Probability of Resolution
Development Experience
Design/Construct Experience
Operational Experience

Step 7: Best and Final Offer Evaluation

After the economic results from Step 5 and the non-economic results from Step 6 are developed, the overall economic and non-economic profile of each resource plan based on a single proposal or portfolio of proposals will be examined and compared to the resource plan that includes FPL's NPGU. At that time, FPL will decide whether it will select a Short List of Proposers. If so, FPL may request from these Short Listed Proposers a Best and Final Offer ("BAFO"). In this case, FPL would then evaluate these BAFOs to develop the final economic and non-economic evaluations.

If the results of the evaluation indicate that the additional step of selecting a Short List of Proposers is not necessary or appropriate, FPL will base its decision on the evaluation (economic and non-economic) performed on the original proposals.

Step 8: Final Selection

The results of FPL's economic and non-economic evaluation will be presented to an FPL Management Review Team. The Management Review Team will then make a selection based on sound business practices and the best interests of FPL's customers.

D.2 Transmission Integration and Losses

A. Overview

In its evaluation of proposals received in response to this RFP, FPL will be evaluating five transmission-related costs associated with FPL's transmission system for individual proposals or for portfolios of proposals. These five costs are:

1) transmission interconnection costs (as applicable);
2) third party transmission service costs (as applicable);
3) transmission integration costs;
4) costs of transmission system losses; and
5) cost impacts of the resource plans on maintaining a balance between load and generation in the Southeastern Florida region (*i.e.*, Miami-Dade and Broward counties).

Noting that the transmission interconnection and third party transmission service costs are to be provided by each Proposer for their individual proposal(s), each of these 5 categories of transmission-related costs are discussed below.

1. Transmission Interconnection Costs (as applicable)

As discussed in Appendix C, Form # 5, a Proposer whose proposal is based partially or totally on generators that need to be constructed and connected to a transmission system must include all costs of this interconnection in the proposal's Guaranteed Capacity Payment. In addition, these interconnection costs must be separately broken out on Form # 5 so that FPL may judge the reasonableness of this estimate. FPL reserves the right to review and, if it deems necessary, to adjust this estimate accordingly to provide a more accurate interconnection cost based on FPL's knowledge and experience with the transmission system. Proposers will be notified of any such adjustments affecting their proposal(s).

All proposals that are based partially or totally on generators that need to be constructed and connected to the transmission system must also demonstrate per instructions on Form # 5 that they have a valid completed application for Generator Interconnection Service ("GIS") in the FPL GIS Queue, or with the applicable third party if the new generator is to be connected to a third party's transmission system.

The process for requesting GIS and having a completed GIS application on the FPL system is delineated in FPL's Open Access Transmission Tariff.

2. Third Party Transmission Service Costs (as applicable)

As discussed in Appendix C, regarding Form # 5, to the extent the generator(s) is connected to the transmission system of a third party, the Proposer shall include any and all third party transmission service costs in the Guaranteed Capacity Payment.

In addition, the Proposer shall state on Form # 5 whether such long-term transmission rights for third party transmission service has been requested and/or already procured for a portion of or all of the generation capacity being offered. To the extent a request for such long – term firm transmission rights has been made, but not yet procured, the Proposer shall provide all available studies and information associated with such request(s).

Finally, the Proposer shall also state on Form # 5 the transmission losses associated with the third party transmission service which are accounted for as the Proposer developed the Total Guaranteed Firm Capacity (as delivered to FPL's system) values on Form # 4.

3. Transmission Integration Costs

The transmission integration costs are based on all modifications (new facilities and facility upgrades) to the FPL transmission system that are necessary to physically transfer the proposed power from the FPL System Receipt Point to the load center consistent with reliability standards for 2019 conditions. The latest available Florida Reliability Coordinating Council (FRCC) peak load flow case representing the year 2019 (updated as necessary to reflect the latest available information) will be used as the basis for determining the transmission integration modifications needed. Once these modifications are determined, costs for these modifications will be estimated. These costs will then be assigned to the resource plan in question. The process of determining the needed transmission integration modifications generally consists of three steps.

Integration Cost Step 1: Identify Needed New/Upgraded Facilities

The first step is to perform screening studies to identify new facilities and facility upgrades that would be needed to integrate the proposals, portfolios of proposals, and/or the NPGU in each resource plan into the transmission system as a network resource for FPL. The type of studies that will be performed are considered screening type studies since they are not as comprehensive as studies that are normally performed for a specific request for transmission service. However, the screening type studies are sufficient to provide a reasonable estimate of the upgrades and facilities necessary to integrate each portfolio into the FPL system meeting the same reliability standards for comparison purposes. The analysis will assure that the FPL transmission system is planned with sufficient capability such that FPL can serve its customers and meet its transmission service obligations beginning in the year 2019 consistent with NERC, FRCC, and FPL standards.

Each of the resource plans will be subjected to contingency screening of all transmission elements and generators, and the transmission system is monitored for violations of NERC, FRCC, and FPL standards. Contingency screening tests will be performed at summer peak load conditions with all FPL generators/facilities assumed available and economically dispatched. Further, the generator deemed most critical to that case will be assumed to be unavailable, and the remaining FPL generators will be dispatched to mitigate, if practicable, violation of reliability criteria for all contingencies tested. Violations of reliability criteria found on the FPL system are resolved by acceptable remedial action (*e.g.*, switching), facility upgrades, or by new facilities, as appropriate. All proposed solutions will be subsequently introduced into the appropriate case and tested in order to verify the completeness of the solution.

During these studies, potential violations may be noticed on third party transmission systems. Should that occur, the following actions will be taken. The observance of such potential violations and the details surrounding these events will be communicated to the Proposer whose proposal is associated with the third party transmission system in question. Since the mitigation measures employed for the potential violations on third party systems will be at the discretion of, and based on the expertise of, third parties for their own transmission systems, identified potential violations will need to be communicated by the Proposer to the third party transmission system owner. Resolution of potential violations will be necessary if the proposal is selected to potentially meet FPL's need. As a result, any upgrades or facilities required on a third party system and attendant costs must be developed and provided by the Proposer so that they may be taken into consideration in the final evaluation. It is possible that a potential violation could be attributable in part to the portfolio combination of proposals being reviewed (*e.g.*, violation on transmission system X of Proposal A is aggravated by existence of Proposal B on FPL system). Analysis of this type would require a coordinated effort and the involvement of multiple parties.

Integration Cost Step 2: Determine Total Cost of Needed Facilities

Once a list of new facilities and upgrades on the FPL system required for integration is identified, the second step of the evaluation process of developing cost estimates for the new and upgraded transmission facilities commences. Based on the need for incremental transmission facilities identified in each resource plan, a cost estimate for the facilities is developed in a consistent manner for each resource plan. The estimates will be based on engineering judgment and readily available cost information, including cost information previously obtained from equipment manufacturers for transmission reinforcements of the type and capacity required. The estimates do not involve any field inspections, or detailed analysis of the type that would be performed in response to a specific request for interconnection or transmission service, but are adequate for their intended purpose.

Integration Cost Step 3: Develop Monthly Cash Flows

The final step in the process involves transforming the total transmission integration cost for resource plan developed in Step 2 into an estimated monthly cash flow (including AFUDC, as appropriate) of the costs for the transmission projects. This will allow projected annual integration costs to be accounted for each resource plan.

4. Costs of Transmission System Losses

Each proposal, portfolio of proposals, and/or the NPGU in the resource plans will contain capacity additions at specific locations in relation to the FPL transmission system. Therefore, each resource plan will present a unique transmission loss impact when combined with the existing FPL transmission system. The difference in the economic impacts between resource plans related to losses will be estimated and applied in the economic comparison of resource plans.

There are two types of losses that comprise total transmission losses for the system. In the analysis of the first type of loss, the generation capacity required to compensate for transmission losses is based on losses during peak load conditions. The second type of loss, energy losses that occur over the entire year, will be estimated based on losses during peak load and average system load conditions.

Transmission losses will vary from year-to-year with load growth, transmission system additions, and resource additions. It is not practicable to predict the amount of such variations due to the almost infinite combinations of future scenarios. It is, however, both certain and practical to assess the impact each portfolio would have in the 2019 time frame of operation. Losses for all future years are calculated based on expected 2020 system conditions, while only accounting for term-of-service-related changes in a particular resource plan over time as discussed below.

The losses for a given resource plan are determined, and costs are assigned to these losses, in a 3-step procedure discussed below. This discussion utilizes a hypothetical example to explain the loss evaluation and cost assignment methodologies. In this example, it is assumed that a hypothetical resource plan has a 1,200 MW proposed purchase for 20 years starting in 2019. At the end of the 20-year purchase term, the proposed 1,200 MW purchase capacity is replaced by filler units.

Cost of Losses Step 1: Calculation of Peak Load and Average Load Losses

a) <u>Peak Load Losses</u>

The required FPL transmission system integration upgrades will be incorporated into the FRCC load flow base case (updated with the latest available information), resulting in a modified, resource plan-specific load flow case. The modified load flow case is set up with the proposal, portfolio of proposals, and/or the NPGU on-line at full output, and the remaining system resources are dispatched economically. The losses (MW) <u>at the peak load hour</u> on the FPL transmission system (Peak Load Losses) are then calculated.

The resource plan associated with the lowest system Peak Load Losses for the year 2019 will be designated as the "reference" resource plan for both the 2019 Peak Load Losses and Average Load Losses analyses. The difference between system Peak Load Losses associated with each resource plan and with the reference resource plan will be calculated for 2019.

Starting with the year 2019, the total losses will remain constant for each resource plan for the 2019 – on time period until one of the components (proposal, portfolio of proposals, and/or the NPGU) reaches the end of its proposed term-of-service. If there are no changes to the reference resource plan during this period, the difference in transmission losses between the specific resource plan being evaluated and the reference resource plan will also be unchanged over this period.

In the example, the MW differences in system Peak Load Losses associated with the hypothetical resource plan and with the reference resource plan can be seen in Column (8) of Table D.2 – 1 below.

For resource plans (including the actual reference resource plan) that have components whose proposed terms-of-service end prior to the end of the analysis period (as is the case with this hypothetical resource plan), the resource plan-specific load flow case mentioned above will be further modified. This additional modification will reflect the termination of a specific component along with a corresponding adjustment to the FPL load. The system Peak Load Losses associated with only the resource plan's remaining components are first calculated. Then, in order to compensate for the loss of the expired component's capacity, an equal amount of Filler unit capacity and load is introduced. This Filler unit capacity is assumed to have losses equal to FPL's current system average transmission losses (1.85%).[1]

The losses associated with the reference resource plan are subtracted from the system Peak Load Losses associated with the remaining resource plan components, plus the Filler unit losses. The resulting system Peak Load Loss value associated with the resource plan is carried forward until another component of the resource plan reaches the end of its proposed term-of-service (if applicable).

[1] Note that the FPL system average transmission losses mentioned here are not the same as the Average Load Losses discussed later in this section.

Table D.2 - 1

Peak Load Losses Calculation for:

Example: For 2019, a 1,200 MW proposal for 20 years

	Year	(1) Proposal 1 (1200 MW)	(2) Filler Capacity Needed to replace Resource Plan's Expired Components (MW)	(3) Filler Capacity Losses (%)	(4) = (2) * (3) Filler Capacity Losses (MW)	(5) FPL Transmission System Losses with Resource Plan's Remaining Components (MW)	(6) = (4) + (5) FPL Transmission System Losses with Resource Plan's Remaining Components + Filler Capacity Losses (MW)	(7) FPL Transmission System Losses with the Reference Resource Plan (MW)	(8) = (6) - (7) Difference in FPL Transmission System Losses between Resource Plan In Question and Reference Resource Plan (MW)
1	2019	1,200	-	1.85%	0	475	475	466	9
2	2020	1,200	-	1.85%	0	494	494	474	20
3	2021	1,200	-	1.85%	0	486	486	483	3
4	2022	1,200	-	1.85%	0	514	514	507	7
5	2023	1,200	-	1.85%	0	567	567	546	21
6	2024	1,200	-	1.85%	0	567	567	574	(7)
7	2025	1,200	-	1.85%	0	567	567	574	(7)
8	2026	1,200	-	1.85%	0	567	567	574	(7)
9	2027	1,200	-	1.85%	0	567	567	574	(7)
10	2028	1,200	-	1.85%	0	567	567	574	(7)
11	2029	1,200	-	1.85%	0	567	567	574	(7)
12	2030	1,200	-	1.85%	0	567	567	574	(7)
13	2031	1,200	-	1.85%	0	567	567	574	(7)
14	2032	1,200	-	1.85%	0	567	567	574	(7)
15	2033	1,200	-	1.85%	0	567	567	574	(7)
16	2034	1,200	-	1.85%	0	567	567	574	(7)
17	2035	1,200	-	1.85%	0	567	567	574	(7)
18	2036	1,200	-	1.85%	0	567	567	574	(7)
19	2037	1,200	-	1.85%	0	567	567	574	(7)
20	2038	1,200	-	1.85%	0	567	567	574	(7)
21	2039	-	1,200	1.85%	22	567	589	574	16
22	2040	-	1,200	1.85%	22	567	589	574	16
23	2041	-	1,200	1.85%	22	567	589	574	16
24	2042	-	1,200	1.85%	22	567	589	574	16
25	2043	-	1,200	1.85%	22	567	589	574	16
26	2044	-	1,200	1.85%	22	567	589	574	16
27	2045	-	1,200	1.85%	22	567	589	574	16
28	2046	-	1,200	1.85%	22	567	589	574	16
29	2047	-	1,200	1.85%	22	567	589	574	16
30	2048	-	1,200	1.85%	22	567	589	574	16
31	2049	-	1,200	1.85%	22	567	589	574	16

b) Average Load Losses

Another separate set of load flow cases is then created for each resource plan. This second set of load flow cases represent specific portfolios in 2019 - on, under FPL's average system load (*i.e.*, 60% of peak) and typical operation of FPL's system (*e.g.*, peaking generation type components off-line). For each resource plan, the transmission system is modified to include the same transmission upgrades required for that resource plan as applied to the load flow cases used for the Peak Load Losses evaluation. This system representation is used to calculate the transmission system losses on the FPL system at average system load (Average Load Losses) for each resource plan including the reference resource plan defined in the Peak Load Losses calculations for years 2019 - on.

The difference between system Average Load Losses of each evaluated resource plan and the reference resource plan will be calculated for 2019. Thereafter, the difference amount is carried forward for each year until one of the components making up the resource plan (or one of the components in the reference resource plan) reaches the end of its proposed term-of-service.

In the example, the differences between the system Average Load Losses associated with the hypothetical resource plan and with the reference resource plan can be seen in Column (8) of Tables D.2 – 2 below.

For resource plans that have components whose proposed terms-of-service end prior to the end of the analysis period, and which would have been on-line in the typical operation of the system at FPL's system average load, that component would be replaced with Filler unit capacity. The loss calculations in these instances will be based on the same 2019 load flow case, but with the FPL load reduced by the amount of expired capacity and the existing FPL resources and the remaining resource components dispatched to represent typical operation of FPL's system (*e.g.*, peaking type components off-line at this load level). In those circumstances in which a component is not typically in operation at FPL's average system load and whose term-of-service ends prior to the end of the analysis period, no Filler unit capacity is introduced for this analysis.

Table D.2 - 2

Average Load Losses Calculation for:

Example: For 2019, a 1,200 MW proposal for 20 years

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
					= (2) * (3)		= (4) + (5)		= (6) - (7)
	Year	Proposal 1 (1200 MW)	Filler Capacity Needed to replace Resorce Plan's Expired Components (MW)	Filler Capacity Losses (%)	Filler Capacity Losses (MW)	FPL Transmission System Losses with Resource Plan's Remaining Components (MW)	FPL Transmission System Losses with Resource Plan's Remaining Components Filler Capacity Losses (MW)	FPL Transmission System Losses with the Reference Resource Plan (MW)	Difference in FPL Transmission System Losses between Resource Plan in Question and Rdference Resource Plan (MW)
1	2019	1,200	-	1.85%	0	248	248	238	10
2	2020	1,200	-	1.85%	0	248	248	248	0
3	2021	1,200	-	1.85%	0	248	248	241	7
4	2022	1,200	-	1.85%	0	246	246	251	(5)
5	2023	1,200	-	1.85%	0	246	246	272	(26)
6	2024	1,200	-	1.85%	0	246	246	273	(27)
7	2025	1,200	-	1.85%	0	246	246	273	(27)
8	2026	1,200	-	1.85%	0	246	246	273	(27)
9	2027	1,200	-	1.85%	0	246	246	273	(27)
10	2028	1,200	-	1.85%	0	246	246	273	(27)
11	2029	1,200	-	1.85%	0	246	246	273	(27)
12	2030	1,200	-	1.85%	0	246	246	273	(27)
13	2031	1,200	-	1.85%	0	246	246	273	(27)
14	2032	1,200	-	1.85%	0	246	246	273	(27)
15	2033	1,200	-	1.85%	0	246	246	273	(27)
16	2034	1,200	-	1.85%	0	246	246	273	(27)
17	2035	1,200	-	1.85%	0	246	246	273	(27)
18	2036	1,200	-	1.85%	0	246	246	273	(27)
19	2037	1,200	-	1.85%	0	246	246	273	(27)
20	2038	1,200	-	1.85%	0	246	246	273	(27)
21	2039	-	1,200	1.85%	22	246	268	273	(5)
22	2040	-	1,200	1.85%	22	246	268	273	(5)
23	2041	-	1,200	1.85%	22	246	268	273	(5)
24	2042	-	1,200	1.85%	22	246	268	273	(5)
25	2043	-	1,200	1.85%	22	246	268	273	(5)
26	2044	-	1,200	1.85%	22	246	268	273	(5)
27	2045	-	1,200	1.85%	22	246	268	273	(5)
28	2046	-	1,200	1.85%	22	246	268	273	(5)
29	2047	-	1,200	1.85%	22	246	268	273	(5)
30	2048	-	1,200	1.85%	22	246	268	273	(5)
31	2049	-	1,200	1.85%	22	246	268	273	(5)

Cost of Losses Step 2: Calculation of Peak Hour Capacity Loss Costs:

The cost of peak hour capacity losses associated with a resource plan is the product of the annual difference in the Peak Load Losses between a resource plan and the reference resource plan (calculated in Step 1) multiplied by a proxy purchase cost ($5/kw-month), and then escalated annually throughout the analysis period. This proxy purchase cost represents the economic value needed to bring this reference plan into equivalence with the reference resource plan.

An example of this calculation for the hypothetical resource plan is shown below in Table D.2 – 3.

An annual peak hour capacity loss cost is calculated for all years starting in 2019 and the annual costs are then present valued and summed. The sum of these present valued costs represents the difference in CPVRR cost of peak hour capacity losses associated with the resource plan relative to the reference resource plan.

Cost of Losses Step 3: Calculation of Annual Energy Loss Costs:

Both the differences for the Peak Load Losses and Average Load Losses between a resource plan and the reference resource plan (calculated in Step 1) are first converted to energy (MWh) values. The Peak Load Loss value is multiplied by 876 hours each year (representing 10% of the annual 8,760 hours) to derive an "on-peak" energy loss (MWh) value. These on-peak MWh values are then multiplied by projected on-peak marginal energy prices to derive on-peak energy loss costs for each resource plan relative to the reference resource plan.

Similarly, the Average Load Losses value is multiplied by an appropriate (to the type of capacity being offered in the resource plan) number of hours to derive an "off-peak" energy loss (MWh) value. These off-peak MWh values are then multiplied by projected off-peak marginal energy prices to derive off-peak energy loss costs for each resource plan relative to the reference resource plan.

These annual on-peak and off-peak energy loss costs are then summed to derive a total annual energy loss cost for each resource plan relative to the reference resource plan. This total annual energy loss cost is calculated for all years starting in 2020. These annual costs are then present valued and summed. The sum of these present valued costs represents the difference in the CPVRR cost of energy losses associated with the resource plan relative to the reference resource plan.

Tables D.2 – 3 and D.2 - 4 present an example of this calculation for the hypothetical resource plan. In Table D.2 – 4, a set of marginal energy costs based on FPL's designated Fossil Fuel Price Forecast is used in this example.

Table D.2 - 3

Calculation of Costs for Peak Hour Capacity Losses (MW) for:

Example: For 2019, a 1,200 MW Proposal for 20 years

Discount Rate =	7.51%
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	2.5%

		(1)	(2)	(3)	(4)	(5)
					=(1)*(3)*12	=(2)*(4)
	Year	Proxy Purchase Cost ($/kw-mo)	Discount Factor	Peak Load Loss (MW)	Peak Hour Capacity Loss Cost Nominal ($ 000)	Peak Hour Capacity Loss Cost NPV ($ 000)
	2015	$0.00	1.000	0	$0	$0
	2016	$0.00	0.930	0	$0	$0
	2017	$0.00	0.865	0	$0	$0
	2018	$0.00	0.805	0	$0	$0
1	2019	$5.00	0.749	9	$553	$414
2	2020	$5.13	0.696	20	$1,215	$846
3	2021	$5.25	0.648	3	$196	$127
4	2022	$5.38	0.602	7	$463	$279
5	2023	$5.52	0.560	21	$1,403	$786
6	2024	$5.66	0.521	(7)	($441)	($230)
7	2025	$5.80	0.485	(7)	($452)	($219)
8	2026	$5.94	0.451	(7)	($464)	($209)
9	2027	$6.09	0.419	(7)	($475)	($199)
10	2028	$6.24	0.390	(7)	($487)	($190)
11	2029	$6.40	0.363	(7)	($499)	($181)
12	2030	$6.56	0.337	(7)	($512)	($173)
13	2031	$6.72	0.314	(7)	($525)	($165)
14	2032	$6.89	0.292	(7)	($538)	($157)
15	2033	$7.06	0.272	(7)	($551)	($150)
16	2034	$7.24	0.253	(7)	($565)	($143)
17	2035	$7.42	0.235	(7)	($579)	($136)
18	2036	$7.61	0.219	(7)	($593)	($130)
19	2037	$7.80	0.203	(7)	($608)	($124)
20	2038	$7.99	0.189	(7)	($623)	($118)
21	2039	$8.19	0.176	16	$1,544	$271
22	2040	$8.40	0.164	16	$1,582	$259
23	2041	$8.61	0.152	16	$1,622	$247
24	2042	$8.82	0.142	16	$1,662	$235
25	2043	$9.04	0.132	16	$1,704	$224
26	2044	$9.27	0.122	16	$1,746	$214
27	2045	$9.50	0.114	16	$1,790	$204
28	2046	$9.74	0.106	16	$1,835	$194
29	2047	$9.98	0.099	16	$1,881	$185
30	2048	$10.23	0.092	16	$1,928	$177
31	2049	$10.49	0.085	16	$1,976	$168
					NPV Total ($000) =	$2,308
					NPV Total ($millions) =	$2.31

Table D.2 - 4

Calculation of Costs for Annual Energy Losses (MW) for:

Example: For 2019, a 1,200 MW Proposal for 20 years

On-Peak Hours =	876	(or 10% of all hours)
Off-Peak Hours =	6,570	
Discount Factor =	7.51%	

		(1)	(2)	(3)	(4)	(5) = (4)*On-Peak Hours	(6) = (1)*(5)/1000	(7)	(8) = (7)*Off-Peak Hours	(9) = (2)*(8)/1000	(10) = (6) + (9)	(11) = (3)*(10)
	Year	On-Peak Marginal Energy Cost ($/mwh)	Off-Peak Marginal Energy Cost ($/mwh)	Discount Factor	Peak Load Loss from Table D.2-1 (MW)	On - Peak Hours Annual Energy Loss (MWH)	On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Average Load Loss from Table D.2-2 (MW)	Off - Peak Hours Annual Energy Loss (MWH)	Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost NPV ($ 000)
	2015	0	0	1.000	0	0	$0	0	0	$0	$0	$0
	2016	0	0	0.930	0	0	$0	0	0	$0	$0	$0
	2017	0	0	0.865	0	0	$0	0	0	$0	$0	$0
	2018	0	0	0.805	0	0	$0	0	0	$0	$0	$0
1	2019	$55.94	$35.12	0.749	9	8,077	$452	10	64,715	$2,273	$2,725	$2,039
2	2020	$49.82	$40.20	0.696	20	17,301	$862	0	1,708	$69	$931	$648
3	2021	$55.81	$41.42	0.648	3	2,724	$152	7	47,895	$1,984	$2,136	$1,383
4	2022	$63.48	$47.75	0.602	7	6,272	$398	(5)	(35,281)	($1,685)	($1,286)	($775)
5	2023	$70.21	$50.90	0.560	21	18,554	$1,303	(26)	(173,645)	($8,838)	($7,536)	($4,222)
6	2024	$62.85	$48.98	0.521	(7)	(5,694)	($358)	(27)	(178,967)	($8,766)	($9,124)	($4,755)
7	2025	$63.53	$50.28	0.485	(7)	(5,694)	($362)	(27)	(180,018)	($9,050)	($9,412)	($4,562)
8	2026	$58.11	$50.38	0.451	(7)	(5,694)	($331)	(27)	(180,018)	($9,068)	($9,399)	($4,238)
9	2027	$60.67	$51.82	0.419	(7)	(5,694)	($345)	(27)	(180,018)	($9,328)	($9,673)	($4,057)
10	2028	$58.85	$51.01	0.390	(7)	(5,694)	($335)	(27)	(180,018)	($9,183)	($9,518)	($3,713)
11	2029	$62.76	$52.04	0.363	(7)	(5,694)	($357)	(27)	(180,018)	($9,367)	($9,725)	($3,528)
12	2030	$66.32	$59.18	0.337	(7)	(5,694)	($378)	(27)	(180,018)	($10,653)	($11,030)	($3,723)
13	2031	$68.73	$62.46	0.314	(7)	(5,694)	($391)	(27)	(180,018)	($11,243)	($11,634)	($3,652)
14	2032	$70.61	$65.36	0.292	(7)	(5,694)	($402)	(27)	(180,018)	($11,766)	($12,169)	($3,553)
15	2033	$74.01	$69.32	0.272	(7)	(5,694)	($421)	(27)	(180,018)	($12,478)	($12,900)	($3,504)
16	2034	$76.25	$71.98	0.253	(7)	(5,694)	($434)	(27)	(180,018)	($12,957)	($13,391)	($3,383)
17	2035	$78.95	$74.66	0.235	(7)	(5,694)	($450)	(27)	(180,018)	($13,441)	($13,890)	($3,264)
18	2036	$83.21	$78.73	0.219	(7)	(5,694)	($474)	(27)	(180,018)	($14,174)	($14,647)	($3,201)
19	2037	$85.80	$82.38	0.203	(7)	(5,694)	($489)	(27)	(180,018)	($14,831)	($15,319)	($3,114)
20	2038	$89.87	$85.82	0.189	(7)	(5,694)	($512)	(27)	(180,018)	($15,448)	($15,960)	($3,018)
21	2039	$92.94	$89.87	0.176	16	13,753	$1,278	(5)	(34,164)	($3,070)	($1,792)	($315)
22	2040	$97.35	$94.34	0.164	16	13,753	$1,339	(5)	(34,164)	($3,223)	($1,884)	($308)
23	2041	$100.71	$98.61	0.152	16	13,753	$1,385	(5)	(34,164)	($3,369)	($1,984)	($302)
24	2042	$105.53	$103.07	0.142	16	13,753	$1,451	(5)	(34,164)	($3,521)	($2,070)	($293)
25	2043	$110.41	$108.38	0.132	16	13,753	$1,518	(5)	(34,164)	($3,703)	($2,184)	($288)
26	2044	$115.07	$113.55	0.122	16	13,753	$1,583	(5)	(34,164)	($3,879)	($2,297)	($281)
27	2045	$119.92	$118.96	0.114	16	13,753	$1,649	(5)	(34,164)	($4,064)	($2,415)	($275)
28	2046	$124.98	$124.63	0.106	16	13,753	$1,719	(5)	(34,164)	($4,258)	($2,539)	($269)
29	2047	$130.25	$130.57	0.099	16	13,753	$1,791	(5)	(34,164)	($4,461)	($2,669)	($263)
30	2048	$135.75	$136.80	0.092	16	13,753	$1,867	(5)	(34,164)	($4,674)	($2,807)	($257)
31	2049	$141.48	$143.32	0.085	16	13,753	$1,946	(5)	(34,164)	($4,896)	($2,951)	($252)
											NPV Total ($000) =	($59,295)
											NPV Total ($millions) =	($59)

5. Cost Impacts Regarding Maintaining a Balance Between Load and Generation in the Southeastern Florida Region

The location of proposed generation capacity in each resource plan will be evaluated in regard to how it is projected to affect FPL's ability to maintain a balance between load and generation in the Southeastern Florida region consisting of Miami-Dade and Broward counties. The analysis approach that will be used is the same as has been utilized in a number of FPL's filings over the last several years including nuclear cost recovery and DSM. The projected costs of maintaining this balance solely through new transmission expenditures will first be developed. Then each resource plan will be analyzed to determine if the proposed location of the generation resources would avoid/defer any of these projected transmission expenditures. If so, then the resource plan may be credited with the benefit of avoiding/deferring the costs of these transmission projects.

D.3 Net Equity Adjustment

A. Explanation of Equity Adjustment

In order to fairly evaluate the total cost of competing resource plans, FPL will consider the impact that the potential selection of each resource plan would have on FPL's overall capital structure. FPL's NPGU assumes financing of incremental costs at 59.62% equity, 40.38% debt, and these financing costs are included in the total cost of FPL's NPGU.

Consistent with that approach, an adjustment will be made to the total cost of other resource plans containing purchased power obligations to reflect the fact that such obligations draw upon the debt capacity of FPL and, all other things being equal, must be offset by increasing the ratio of equity in FPL's capital structure. This is necessary to ensure that resource plans are compared against one another in a manner that is neutral relative to FPL's capital structure. Rating agencies explicitly evaluate purchase power obligations and, based on that examination, the rating agencies attribute a portion of the net present value (NPV) of the obligations under each power purchase agreement to the utility's balance sheet as a debt equivalent. The effect of this adjustment is to increase the relative share of debt and debt-like instruments in the capital structure. Therefore, FPL will calculate the incremental cost of the equity required to rebalance the capital structure at 59.62% equity, 40.38% debt to obtain a complete assessment of the related costs to FPL associated with each resource plan.

Standard & Poor's ("S & P") methodology will be used to calculate the debt equivalent that would be added to FPL's capital structure. S & P begins by taking the NPV of the annual capacity payments over the life of the power purchase contract using a 7% discount factor. To determine the debt equivalent, the NPV is then multiplied by a risk factor. Based on the guidelines provided by S & P for utilities with a clause recovery mechanism (such as is the case for FPL), a 25% risk factor will be used to calculate the debt equivalent.

Once the debt equivalent has been determined, the amount of equity required to rebalance the capital structure will be calculated. The equity adjustment represents the net present value of the incremental cost of equity (versus debt) required to rebalance the capital structure. A detailed example of the calculation of the equity adjustment is presented in Table D.3 – 1 at the end of this section.

B. Mitigating Factors

While the S & P methodology takes a broad look at the debt equivalence of purchase power obligations, there may be other factors which may be considered as mitigating the effect of such purchased power obligations. The following subsections discuss those factors that, in FPL's review, may offer some mitigation and can be quantified. These factors will be reflected as credits in the development of a modified or net equity adjustment factor.

1) Mitigation Offered by Completion Security

When FPL enters into a purchased power agreement (PPA) associated with a new unit to be constructed, the Proposer will provide Completion Security to address the delivery risks associated with completing the project. Many of these risks can be combined and represented as the risk of delivering less capacity than that proposed, and upon which the selection was made and a PPA was executed. Under an FPL self-build option, there is some small probability that such an event might occur, and that impact might not be mitigated by FPL's contractual arrangements. If this occurred and it was determined by the FPSC that FPL was not imprudent, any incremental cost caused by such a delivery shortage may be allowed to be recovered from FPL's customers.

If this same sequence of events occurred under a PPA associated with a unit to be constructed, in the form contemplated by FPL, the Completion Security could mitigate the impact of those costs on FPL's customers. This would be the source of mitigation provided by the PPA Completion Security that is different from an FPL self-build option.

In order to assess a quantitative value that could be assigned to this mitigation, both the risk of occurrence and the economic magnitude of the occurrence of a delivery shortage must be estimated.

FPL reviewed the history of FPL self-build projects relevant to this RFP to determine the probability of a delivery shortage. These combined cycle projects represented approximately 6,745 MW of planned capacity. The data showed that some projects over-delivered while others under-delivered. As a conservative approach, overages were not allowed to offset shortages. On this basis, a total shortage of 14 MW was seen over the projected approximately 6,745 MW resulting in a probability of delivery shortage of 0.21%.

The economic impact of a delivery shortage can be identified as represented by the Completion Security amount established by FPL. It is noted that this amount could be mitigated by many factors for specific occurrences; *e.g.*, component performance guarantees, engineering - procurement - construction (EPC) guarantees and Liquidated Damages (LD's), but represents a "worst case" value that is conservatively derived and applied to the favor of the Proposer in developing the mitigation credit.

The value of the mitigation provided by a PPA would be the product of the probability of delivery shortage (risk) and the Completion Security amount (magnitude) identified in Section IV of the RFP document.

The following example demonstrates the Completion Security mitigating factor calculation for a proposal based on a new generating unit:

P_{DS} = Probability of FPL Delivery Shortage = 0.21%
CS = Completion Security = $200,000 per MW

CS Mitigation = CS * (P_{DS}) = $200,000* (0.0021) = $420 per MW (Nominal $)

2) Mitigation offered by Performance Security

FPL recognizes that PPA-based capacity, if selected instead of an FPL self-build option, has the potential to provide better performance than that projected for FPL's NPGU at certain times. Therefore, FPL has calculated a Performance Mitigating Factor that attributes an appropriate amount of credit to a PPA for this potential benefit.

The Performance Mitigating Factor is not dependent upon the type or nature of the PPA in question. Instead, it is based on the projected forced outage factor (FOF) of FPL's NPGU in this RFP compared to recent FPL experience with the type of new units installed and operated by FPL that are most similar to the NPGU of this RFP; *i.e.*, combined cycle units. The most recent FPL combined cycle units are: Martin units 3, 4, and 8, Manatee unit 3, Turkey Point unit 5, and West County units 1, 2, and 3.

The actual/projected annual average FOF for these units over their projected life is 1.56%. The projected average annual FOF for FPL's NPGU is 1.1%. Consequently, using the actual/projected annual average FOF for the previous FPL combined cycle units as a possible projection of the actual FOF for the similar, but different, technology of FPL's NPGU, yields a possible FOF annual differential of 0.46%.

This translates to approximately 40 hours per full year (8,760 hours/year x 0.0046 = 40 hours/year) in which the existing units on FPL's system might have to supply energy that is projected to be supplied by the NPGU. Then, using the same projection of FPL system marginal energy costs that is used in the calculation of the Costs of Transmission Losses in Section D.2 of this appendix, a calculation of the replacement energy costs for these 40 hours for each year is made. This annual nominal cost value is then present valued and added to the cumulative present value of these costs from prior years. This calculation is presented in Table D.3 – 2 at the end of this section.

As seen in Table D.3 – 2, the values calculated are on a per MW basis and can vary according to the proposed term of the PPA. The actual Performance Mitigating Factor that will be applied to a PPA will depend both upon the proposed capacity (MW) and the proposed term-of-service.

3) Application

Once the appropriate Performance Mitigating Factor is calculated for a PPA, this mitigating factor, plus the Completion Security Mitigating Factor discussed above, will be subtracted from the Equity Adjustment value to derive a Net Equity Adjustment value for the PPA. This net value will be included in the final economic evaluation of all resource plans that include this PPA.

An example application of the equity adjustment calculation, and the mitigating factors, to provide a net equity adjustment value is presented in the remainder of this section.

C. Example Net Equity Adjustment Calculations

The net equity adjustment calculations that FPL will use in its evaluation of purchased power Proposals received in response to this RFP are explained below using a hypothetical Proposal for 500 MW starting in June 2019 through the end of 2030 at a constant price of $60/kw-yr (or $5/kw-month).

Table D.3 -1 presents the equity adjustment calculation. This is preceded by an explanation by column of the values in Table D.3 - 1. The first of the two mitigating factors is then discussed. Then Table D.3 – 2 presents the calculation of the second of the two mitigating factors. The net equity adjustment value is then calculated.

Explanation of calculation by column:

Column [K] = Projected Annual Capacity Payments in $/kw-year (assuming a constant $5/kw-month payment.)

Column [L] = Projected Annual Capacity Payments in $000 (Projected Annual Capacity Payments in $/kw-year * Proposal's Firm Capacity (MW) * PPA's Firm Capacity Ratio) /12 * number of months capacity is delivered)

Column [M] = Net Present Value (NPV) of the total sum of remaining annual capacity payments with values discounted at the risk factor used by S&P's to value off-balance sheet purchase power obligations.

Example: For 2019: NPV of capacity payments for (2019-2030)
For 2020: NPV of capacity payments for (2020 – 2030)
For 2021: NPV of capacity payments for (2021 – 2030)
Etc:

Column [N] =Total imputed asset value (NPV of capacity payments in Column [3]* S&P Adjustment Factor)

Column [O] =Equity Replaced to Rebalance (Total imputed asset value in Column [4] * Equity ratio)

Column [P] = Equity Adjustment (Column [5]* Equity vs. Debt Cost Difference)
(Where Equity vs. Debt Cost Difference = ((Cost of Equity)/(1- Effective Tax Rate)) – Cost of Debt)

NPV Total is discounted back to the current year (2015 in this example) using the after tax cost of capital discount rate.

Table D.3 - 1

Equity Adjustment Calculation - Example Purchase

	Notes			Notes	
Adjustment Factor	A	25.00%	Disc Rate for Equity Adj (FPL 2014 WACC)	G	7.51%
Target Equity Ratio	B	59.62%	Equity vs. Debt Pre-Tax Cost Difference	H	12.0%
Effective Tax Rate	C	38.58%	Nameplate Capacity (MW)	I	500
Cost of Debt	D	5.05%	PPA Firm Capacity Ratio	J	100.0%
Discount Rate Applied to Capacity Charges	E	7.00%			
Cost of Equity (Allowed ROE)	F	10.50%			

Equity Adjustment Calculation

Period	K Projected Capacity Chg ($/kw-yr)	L = I x J x K Projected Annual Capacity Payments ($000)	M NPV Capacity Payments @ 7% (E) ($000)	N = M x A Total Imputed Asset Value ($000)	O = N x B Equity Replaced to Rebalance ($000)	P = O x H Equity Adjustment ($000)
2015	-	-	-	-	-	-
2016	-	-	-	-	-	-
2017	-	-	-	-	-	-
2018	-	-	-	-	-	-
2019	60	17,500	226,598	56,650	33,774	4,068
2020	60	30,000	224,960	56,240	33,530	4,038
2021	60	30,000	210,707	52,677	31,406	3,783
2022	60	30,000	195,457	48,864	29,133	3,509
2023	60	30,000	179,139	44,785	26,701	3,216
2024	60	30,000	161,679	40,420	24,098	2,902
2025	60	30,000	142,996	35,749	21,314	2,567
2026	60	30,000	123,006	30,751	18,334	2,208
2027	60	30,000	101,616	25,404	15,146	1,824
2028	60	30,000	78,729	19,682	11,735	1,413
2029	60	30,000	54,241	13,560	8,085	974
2030	60	30,000	28,037	7,009	4,179	503
			CPVRR Equity Adjustment @ WACC (2015 $s) @ 59.6% =			**$17,810**

Notes:

A) Per Standard & Poor's methodology for utilities, such as FPL, that have a clause recovery mechanism
B) FPL target equity ratio
C) FPL effective tax rate
D) FPL average cost of debt
E) Discount applied to Capacity Charges per S&P
F) FPL's allowed ROE
G) FPL incremental WACC (based on B,C,D,F above)
H) Difference between FPL's pre-tax cost of equity and debt
I) Sum of capacity of PPA portfolio
J) Firm capacity ratio of PPAs
K) Annual capacity payments calculated by multiplying the capacity charge, by the project namplate capacity and the firm capacity ratio of 100%
L) Annual capacity payments of PPA's
M) PV of net capacity payments discounted at FPL's average cost of debt
N) Per S&P methodology, apply a 25% adjustment factor for utilities with clause recovery mechanisms to the NPV of capacity payments
O) Equity required to rebalance due to the additional imputed debt is calculated by multiplying the debt equivalence by the target equity ratio
P) The equity adjustment is calculated as the equity replaced to rebalance, multiplied by the difference between the cost of equity and the pre-tax debt cost
Q) The CPVRR of the equity adjustments discounted at WACC. Represents the additional equity required to maintain the capital structures ratio considering the PPA as debt.

Completion Security Mitigation Example:

The Completion Security Mitigating Factor would be credited by applying the amount previously calculated:

CS mitigation/MW * Capacity * Net Present Value Factor for the year 2019 = Completion Security Mitigation Factor

$420/MW * 500 MW = $210,000 (Nominal $) or
$210,000 * 0.749 = $157,290 (NPV $)

Performance Mitigation Example:

The Performance Mitigation value, in terms of $ per MW, is presented in the following table.
In the table above, a 500 MW PPA with an in-service date of 2019 and a term through the end of 2030 would have a Performance Mitigation amount of:

500 MW * $11,537/MW = $ 5,768,500 (NPV $)

Net Equity Adjustment Example:

In this example, the Completion Security Mitigation amount and the Performance Mitigation amount would be subtracted from the Equity Adjustment to yield a Net Equity Adjustment value for a resource plan that included this PPA of:

$17,810,000 - $157,290 - $5,768,500 = $11,884,210 (NPV $)

Table D.3 - 2

Performance Mitigating Factor Calculation: for Bid with 2019 In-Service Date
(Note: Values shown are "per MW" values)

Assumptions:

Capacity level (MW) =	1
Historical Average FOF value for CC units =	1.56%
Projected Annual FOF value for NPGU =	1.10%
Average Annual FOF "overage" for FPL CCs =	0.46%

		(1)	(2)	(3)	(4) = (2) x (3)	(5) = (1) x (3)	(6)
	Year	Discount Factor 7.51%	Average Annual Forced Outage "Overage" (MWH per MW)	Average Marginal Energy Cost ($/MWH)	Nominal Replacement Energy Cost ($/MW)	Annual NPV Replacement Energy Cost ($/MW)	Cumulative NPV Replacement Energy Cost ($/MW)
	2015	1.000	0	$31.55	$0	$0	$0
	2016	0.930	0	$35.50	$0	$0	$0
	2017	0.865	0	$31.44	$0	$0	$0
	2018	0.805	0	$33.90	$0	$0	$0
1	2019	0.749	23	$33.30	$781	$585	$585
2	2020	0.696	40	$39.64	$1,598	$1,113	$1,697
3	2021	0.648	40	$43.01	$1,729	$1,120	$2,817
4	2022	0.602	40	$45.94	$1,847	$1,113	$3,930
5	2023	0.560	40	$48.39	$1,945	$1,090	$5,020
6	2024	0.521	40	$49.99	$2,015	$1,050	$6,070
7	2025	0.485	40	$52.38	$2,106	$1,021	$7,091
8	2026	0.451	40	$53.14	$2,136	$963	$8,054
9	2027	0.419	40	$54.06	$2,173	$911	$8,965
10	2028	0.390	40	$56.51	$2,278	$889	$9,854
11	2029	0.363	40	$58.93	$2,369	$860	$10,714
12	2030	0.337	40	$60.69	$2,440	$823	$11,537
13	2031	0.314	40	$62.57	$2,516	$790	$12,327
14	2032	0.292	40	$65.23	$2,630	$768	$13,095
15	2033	0.272	40	$68.08	$2,737	$743	$13,838
16	2034	0.253	40	$69.67	$2,801	$708	$14,546
17	2035	0.235	40	$70.99	$2,854	$671	$15,217
18	2036	0.219	40	$72.38	$2,918	$638	$15,854
19	2037	0.203	40	$74.58	$2,999	$610	$16,464
20	2038	0.189	40	$77.31	$3,108	$588	$17,052
21	2039	0.176	40	$79.28	$3,187	$561	$17,612
22	2040	0.164	40	$82.61	$3,330	$545	$18,157
23	2041	0.152	40	$85.92	$3,454	$526	$18,683
24	2042	0.142	40	$89.12	$3,583	$507	$19,190
25	2043	0.132	40	$92.47	$3,718	$489	$19,679
26	2044	0.122	40	$96.31	$3,883	$475	$20,155
27	2045	0.114	40	$100.30	$4,033	$459	$20,614
28	2046	0.106	40	$104.47	$4,200	$445	$21,059
29	2047	0.099	40	$108.81	$4,375	$431	$21,490
30	2048	0.092	40	$113.33	$4,569	$419	$21,909
31	2049	0.085	40	$118.03	$4,746	$405	$22,314

APPENDIX E

Changes in Key Forecasts and FPL's Resource Plan from FPL's 2014 Ten-Year Site Plan

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FPL's 2014 Ten-Year Site Plan (Site Plan) was filed with the Florida Public Service Commission (FPSC) in April 2014. This Site Plan, presented in Appendix A of this RFP document, addressed FPL's resource planning work during the year 2013 and the first quarter of 2014. Since the first quarter of 2014, a number of changes have occurred in regard to the forecasts that are used in FPL's resource planning work. Largely as a result of these changes to forecasts, FPL's current resource plan has also changed. The changes to these forecasts and FPL's resource plan will be presented in FPL's 2015 Site Plan that will be filed with the Florida Public Service Commission on April 1, 2015.

For the benefit of potential bidders to this capacity RFP, two tables are presented below. Table E - 1 summarizes changes in key forecasts from those used in the 2014 Site Plan work. Table E – 2 summarizes key changes in FPL's resource plan through the year 2019 (the year for which capacity proposals are being sought with this RFP).

Table E - 1

Key Changes in Forecasts		
Item	**Ten Year Site Plan**	**Current**
Date of Load Forecast	10/1/2013	10/14/2014
Vero Beach load	Included in FPL's load forecast	Not Included in FPL's load forecast
Date of Fuel Forecast	10/7/2013	11/3/2014
Below are the forecasted firm gas prices for 2019 from the two fuel forecasts:		
- 2019 FGT Firm Gas Price	$6.15/MMBTU	$4.70/MMBTU
- 2019 Gulfstream Gas Price	$6.13/MMBTU	$4.65/MMBTU
- 2019 New Pipeline Gas Price	$6.14/MMBTU	$4.69/MMBTU

As shown in Table E – 1, the October 2014 load forecast has now replaced the October 2013 load forecast that was used in the resource planning work that led to the 2014 Site Plan. The new load forecast no longer assumes that FPL will serve the electrical load of Vero Beach. In regard to the Summer 2019 peak load, the new October 2014 load forecast is approximately 150 MW higher than the October 2013 load forecast.

Similarly, the November 2014 fuel cost forecast has now replaced the October 2013 fuel cost forecast that was used in the resource planning work that led to the

2014 Site Plan. As shown in the comparison of forecasted natural gas values for the year 2019, projected natural gas prices are now lower than previously forecast.

In addition, FPL's resource plan has changed from that presented in its 2014 Site Plan. Table E – 2 presents the key changes in FPL's resource plan through the year 2019.

Table E - 2

Key Changes in FPL's Resource Plan Through 2019
(presented in approximate chronological order)

Item	2014 Site Plan	Current
FPL DSM Additions (approx. MW/year)	34	53
Existing GT Replacement	Occurs by the end of 2018; Net effect of approx. 255 MW capability reduction	Occurs by the end of 2016; Net effect of approx. 40 MW capability reduction
Cedar Bay Expiration Date (250 MW)	12/31/2024	12/31/2016
New Utility Scale Solar	No additional solar	3 - 74 MW (nameplate AC) PV facilities by the end of 2016.
2019 Unit (Summer MW)	1,269 MW CC	1,622 MW CC (FPL's NPGU)

FPL's resource plan now shows an increase in annual DSM implementation (in terms of Summer MW peak load reductions) from approximately 34 MW/year assumed in FPL's 2014 Site Plan to approximately 53 MW/year. This is consistent with the FPSC's decision in the 2014 DSM Goals docket.

In its 2014 Site Plan, FPL projected that, for environmental reasons, it would have to retire all of its existing gas turbines (GTs) in Broward County and replace part of that capacity with new combustion turbines (CTs) by the end of 2018. The projected impact of this would have been a net loss of 255 MW. FPL currently projects that it is cost-effective to retire most of its existing GTs at its two Broward County sites (Lauderdale and Port Everglades) and its Lee County (Ft. Myers) site, and partially replace this peaking capacity with new CTs at its

Lauderdale and Ft. Myers sites. In addition, FPL's two existing CTs at its Ft. Myers site will be upgraded to produce more capacity. All of this "GT replacement" work is projected to be completed by the end of 2016.
FPL anticipates terminating its existing power purchase agreement for 250 MW of coal-fired capacity from the Cedar Bay generating facility at the end of August 2015 as a result of a Purchase and Sale Agreement between FPL and Cedar Bay Generating Company, L.P. FPL would then own the unit starting on September 1, 2015. FPL currently anticipates that it will not need the unit for economic purposes after 2016 and, if that proves to be the case, would retire the unit at that time. FPL filed for FPSC approval of the Purchase and Sale Agreement in the first quarter of 2015.

FPL will be adding three new photovoltaic (PV) facilities by the end of 2016. Each of the PV facilities will be approximately 74.5 MW (nameplate rating, AC). The new PV installations are projected to be sited in Manatee, Charlotte, and DeSoto counties. The economics of these specific PV projects are aided by the fact that the sites are located close to existing electric infrastructure including tranmission lines and electric substations.

Finally, in its 2014 Site Plan, FPL projected the addition of a 1,269 MW (Summer) combined cycle (CC) unit as a placeholder in 2019 to meet capacity needs beginning in 2019. At the time the 2014 Site Plan was filed, this represented FPL's best self-build generating option for that year. FPL now projects that a 1,622 MW (Summer) CC unit to be its best self-build generating option for 2019. That CC unit is presented in this RFP as FPL's next planned generating unit (NPGU) which will be evaluated with all eligible proposals received in response to this RFP.

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Docket No. 15_______-EI
Projection of FPL's Resource Needs: 2015 through 2020
Exhibit SRS-2, Page 1 of 1

Projection of FPL's Resource Needs: 2015 through 2020

	(1)	(2)	(3)	(4) = (1) + (2) - (3)	(5)	(6)	(7) = (5) - (6)	(8) = (4) - (7)	(9) = (8) / (7)	(10) = ((7)*1.20)-(4)	(11) = ((4)-(5)) / (5)	(12) = ((5)*1.10)-(4)
August of the Year	Projected FPL Unit Capability * (MW)	Projected Firm Capacity Purchases * (MW)	Projected Scheduled Maintenance (MW)	Projected Total Capacity (MW)	Projected Peak Load (MW)	Projected Summer DSM Capability ** (MW)	Projected Firm Peak Load (MW)	Projected Summer Reserves (MW)	Projected Summer Total Reserve Margin w/o Additions in 2019 & 2020 (%)	**Projected Total MW Needed to Meet 20% Total Reserve Margin*** (MW)**	Projected Generation-Only Reserve Margin (GRM) w/o Additions in 2019 & 2020 (%)	**Projected Total MW Needed to Meet 10% GRM**** (MW)**
-----	-----	-----		-----	-----	-----	-----	-----	-----	-----	-----	-----
2015	25,008	2,015	0	27,022	23,286	1,951	21,335	5,688	26.7%	(1,421)	---	---
2016	25,585	837	0	26,421	23,778	2,000	21,779	4,643	21.3%	(287)	---	---
2017	26,002	837	0	26,838	24,252	2,046	22,207	4,632	20.9%	(190)	---	---
2018	26,023	1,044	0	27,067	24,648	2,092	22,555	4,512	20.0%	(1)	---	---
2019	26,043	455	0	26,498	25,045	2,140	22,905	3,593	15.7%	**988**	5.8%	**1,052**
2020	26,043	455	0	26,498	25,369	2,188	23,181	3,316	14.3%	**1,320**	4.4%	**1,409**

* MW values shown in Columns (1) & (2) include, but are not limited to, the following: the completion of the Port Everglades modernization project in 2016, the retirement of 44 of the 48 existing GTs in late 2016, the addition of 5 new CTs at the Lauderdale site and 2 CTs at the Ft.Myers site in late 2016, the addition of 116 MW of firm PV in late 2016, the upgraded capacity of Ft.Myers 3A & 3B in late 2016, and the addition of an unspecified one-year 207 MW PPA in 2018.

** The DSM values shown in Column (6) account for incremental DSM additions as per the 2014 DSM Goals docket for 2015 through 2020, and for projected annual participant attrition in FPL's existing residential load management program.

*** MW values shown in Column (10) represent new generating capacity needed to meet the 20% total reserve margin criterion.

**** MW values shown in Column (12) represent new generating capacity needed to meet the 10% generation-only reserve margin criterion (GRM) which must be met beginning in 2019.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 3
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Steven R. Sim SRS-2

Evaluation of FPL Self-Build Options: A Representative List of CC and CT Generating Options at Two Sites Evaluated in the First Stage of the Analyses

Site	Type of Generation	Manufacturer	Model of CT	With Duct Firing ?	Summer Capacity (MW)
-------	-------	-------	-------	-------	-------
Okeechobee	3 x 1 CC	GE	7HA.02	Yes	1,523
Okeechobee	4 x 1 CC	Mitsubishi	J	No	1,749
Okeechobee	3 x 1 CC	GE	7HA.02	No	1,424
Okeechobee	3 x 1 CC	Mitsubishi	J	Yes	1,411
Okeechobee	3 x 1 CC	Mitsubishi	J	No	1,311
Okeechobee	7 x 0 CT	GE	7FA.05	No	1,419
Okeechobee	6 x 0 CT	GE	7FA.05	No	1,216
Putnam	3 x 1 CC	GE	7HA.02	Yes	1,524
Putnam	3 x 1 CC	GE	7HA.02	No	1,424
Putnam	3 x 1 CC	Siemens	H	Yes	1,321
Putnam	3 x 1 CC	Siemens	H	No	1,220
Putnam	3 x 1 CC	Mitsubishi	J	No	1,312
Putnam	5 x 0 CT	GE	7FA.05	No	1,014

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 4
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Steven R. Sim SRS-3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 5
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Steven R. Sim SRS-4

Evaluation of FPL Self-Build Options: Results of Analyses of CC and CT Generating Options at Two Sites Evaluated in the First Stage of the Analyses

Site	Type of Generation	Manufacturer	Model of CT	With Duct Firing ?	Summer Capacity (MW)	Difference From Lowest Cost Resource Plan (CPVRR, millions)
-------	-------	-------	-------	-------	-------	-------
Okeechobee	3 x 1 CC	GE	7HA.02	Yes	1,523	---
Okeechobee	4 x 1 CC	Mitsubishi	J	No	1,749	$33
Okeechobee	3 x 1 CC	GE	7HA.02	No	1,424	$42
Putnam	3 x 1 CC	GE	7HA.02	Yes	1,524	$65
Okeechobee	3 x 1 CC	Mitsubishi	J	Yes	1,411	$73
Putnam	3 x 1 CC	GE	7HA.02	No	1,424	$81
Okeechobee	3 x 1 CC	Mitsubishi	J	No	1,311	$114
Okeechobee	7 x 0 CT	GE	7FA.05	No	1,419	$124
Putnam	3 x 1 CC	Siemens	H	Yes	1,321	$129
Putnam	3 x 1 CC	Mitsubishi	J	No	1,312	$238
Okeechobee	6 x 0 CT	GE	7FA.05	No	1,216	$259
Putnam	5 x 0 CT	GE	7FA.05	No	1,014	$265
Putnam	3 x 1 CC	Siemens	H	No	1,220	$322

Docket No. 15______-EI
Evaluation of FPL Self-Build Options: Results of Analyses of CC and CT
Generating Options at Two Sites Evaluated in the First Stage of the Analyses
Exhibit SRS-4, Page 1 of 1

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company	)	DOCKET NO. 150196-EI FILED: November 13, 2015

ERRATA SHEET OF DR. STEVEN R. SIM

September 3, 2015 Direct Testimony

PAGE #	LINE #	CORRECTION
26	8	Change “$42” to “$48”
26	22	Change “$6” to “$10”
27	2	Change “$157” to “$167”
27	3	Change “$42” to “$48”, “$6” to “$10”, and “$157” to “$167”
38	9	Change “$157” to “$167”
38	10	Change “$281” to “$291”

September 3, 2015 Exhibits

EXHIBIT #	PAGE #	Table #	CORRECTION
SRS-5	2 of 2	(2) Second Step:	Last column, change “$42” to “$48” and “$83” to “$90”
SRS-5	2 of 2	(3) Third Step:	Last column, change “$6” to “$10”

October 26, 2015 Rebuttal Testimony

PAGE #	LINE #	CORRECTION
24	1	Change “began” to “continued”

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 6
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Steven R. Sim SRS-5

Evaluation of FPL Self-Build Options: List of Generating Option Technologies Evaluated in the Second Stage of the Analyses and the Results of These Analyses

(1) First Step:

Site	CC Type	Manufacturer	Model of CT	With Duct Firing ?	Summer Capacity (MW)	Difference From Lowest Cost Resource Plan (CPVRR, millions)
-------	-------	-------	-------	-------	-------	-------
Okeechobee	3 x 1	GE	7HA.02	Yes	1,582	-
Okeechobee	3 x 1	GE	7HA.02	No	1,482	$103
Okeechobee	3 x 1	GE	7HA.02	Yes	1,523	$109
Okeechobee	3 x 1	Mitsubishi	J	Yes	1,418	$191
Okeechobee	2 x 1	GE	7HA.02	Yes	1,054	$193
Okeechobee	3 x 1	Mitsubishi	J	No	1,317	$220
Okeechobee	3 x 1	Siemens	H	Yes	1,322	$238
Okeechobee	3 x 1	Mitsubishi	JAC	Yes	1,350	$265
Okeechobee	3 x 1	Siemens	H	No	1,221	$265
Okeechobee	3 x 1	Mitsubishi	JAC	No	1,251	$294

Evaluation of FPL Self-Build Options: List of Generating Option Technologies Evaluated in the Second Stage of the Analyses and the Results of These Analyses

(2) Second Step:

Site	CC Type	Manufacturer	Model of CT	With Duct Firing ?	With Peak Firing and Wet Compression ?	Summer Capacity (MW)	Difference From Lowest Cost Resource Plan (CPVRR, millions)
-------	-------	-------	-------	-------	-------	-------	-------
Okeechobee	3 x 1	GE	7HA.02	No	Yes	1,586	-
Okeechobee	3 x 1	GE	7HA.02	Yes	No	1,582	$42
Okeechobee	3 x 1	GE	7HA.02	No	No	1,482	$83

(3) Third Step:

Site	CC Type	Manufacturer	Model of CT	With Duct Firing ?	With Peak Firing and Wet Compression ?	Summer Capacity (MW)	Difference From Lowest Cost Resource Plan (CPVRR, millions)
-------	-------	-------	-------	-------	-------	-------	-------
Okeechobee	3 x 1	GE	7HA.02	No	Yes	1,622	-
Okeechobee	3 x 1	GE	7HA.02	No	Yes	1,586	$6

FLORIDA POPULATION

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	273,721	1.7%
Based on 2014 TYSP (2015 to 2024)	268,995	1.3%
Based on 2015 TYSP (2015 to 2024)	277,262	1.3%

HISTORY

		Growth	
		Absolute	%
1990	12,938,071	390,341	3.1%
1991	13,258,732	320,661	2.5%
1992	13,497,541	238,809	1.8%
1993	13,730,115	232,574	1.7%
1994	14,043,757	313,642	2.3%
1995	14,335,992	292,235	2.1%
1996	14,623,421	287,429	2.0%
1997	14,938,314	314,893	2.2%
1998	15,230,421	292,107	2.0%
1999	15,580,244	349,823	2.3%
2000	15,982,824	402,580	2.6%
2001	16,305,100	322,276	2.0%
2002	16,634,256	329,156	2.0%
2003	16,979,706	345,450	2.1%
2004	17,374,824	395,118	2.3%
2005	17,778,156	403,332	2.3%
2006	18,154,475	376,319	2.1%
2007	18,446,768	292,293	1.6%
2008	18,613,905	167,137	0.9%
2009	18,687,425	73,520	0.4%
2010	18,801,332	113,907	0.6%
2011	18,905,070	103,738	0.6%
2012	19,074,434	169,364	0.9%
2013	19,259,543	185,109	1.0%
2014	19,507,369	247,826	1.3%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Absolute Growth	Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Monthly Rate	Absolute	%
2015	19,745,376	238,007	1.2%	19,769,010	261,641	1.3%	21,803	23,634	0.1%
2016	20,024,054	278,678	1.4%	20,051,547	282,537	1.4%	23,545	27,493	0.1%
2017	20,306,863	282,809	1.4%	20,338,444	286,897	1.4%	23,908	31,581	0.2%
2018	20,587,391	280,528	1.4%	20,622,557	284,113	1.4%	23,676	35,166	0.2%
2019	20,864,297	276,906	1.3%	20,906,670	284,113	1.4%	23,676	42,373	0.2%
2020	21,137,177	272,880	1.3%	21,185,476	278,806	1.3%	23,234	48,299	0.2%
2021	21,389,898	252,721	1.2%	21,460,260	274,784	1.3%	22,899	70,362	0.3%
2022	21,645,640	255,742	1.2%	21,731,097	270,837	1.3%	22,570	85,457	0.4%
2023	21,904,440	258,800	1.2%	21,998,833	267,736	1.2%	22,311	94,393	0.4%
2024	22,166,334	261,894	1.2%	22,264,368	265,535	1.2%	22,128	98,033	0.4%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 8
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Richard Feldman RF-2

TOTAL AVERAGE CUSTOMERS

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	64,584	1.7%
Based on 2014 TYSP (2015 to 2024)	65,543	1.3%
Based on 2015 TYSP (2015 to 2024)	67,178	1.3%

HISTORY

		Growth	
		Absolute	%
1990	3,158,817	94,381	3.1%
1991	3,226,455	67,638	2.1%
1992	3,281,238	54,783	1.7%
1993	3,355,794	74,556	2.3%
1994	3,422,187	66,393	2.0%
1995	3,488,796	66,609	1.9%
1996	3,550,747	61,951	1.8%
1997	3,615,485	64,738	1.8%
1998	3,680,470	64,985	1.8%
1999	3,756,009	75,539	2.1%
2000	3,848,350	92,341	2.5%
2001	3,935,281	86,931	2.3%
2002	4,019,805	84,523	2.1%
2003	4,117,221	97,416	2.4%
2004	4,224,509	107,289	2.6%
2005	4,321,895	97,386	2.3%
2006	4,409,563	87,667	2.0%
2007	4,496,589	87,027	2.0%
2008	4,509,730	13,141	0.3%
2009	4,499,067	-10,663	-0.2%
2010	4,520,328	21,261	0.5%
2011	4,547,051	26,723	0.6%
2012	4,576,449	29,398	0.6%
2013	4,626,934	50,486	1.1%
2014	4,708,829	81,895	1.8%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2015	4,782,469	73,640	1.6%	4,777,210	68,380	1.5%	-5,259	-0.1%
2016	4,852,827	70,358	1.5%	4,848,294	71,084	1.5%	-4,534	-0.1%
2017	4,922,918	70,090	1.4%	4,919,162	70,868	1.5%	-3,756	-0.1%
2018	4,991,659	68,741	1.4%	4,988,771	69,609	1.4%	-2,888	-0.1%
2019	5,058,945	67,286	1.3%	5,057,400	68,629	1.4%	-1,545	0.0%
2020	5,123,909	64,963	1.3%	5,124,436	67,036	1.3%	528	0.0%
2021	5,185,333	61,424	1.2%	5,190,185	65,748	1.3%	4,852	0.1%
2022	5,247,054	61,721	1.2%	5,254,820	64,635	1.2%	7,766	0.1%
2023	5,309,376	62,322	1.2%	5,318,608	63,788	1.2%	9,232	0.2%
2024	5,372,353	62,977	1.2%	5,381,815	63,207	1.2%	9,463	0.2%

REAL DISPOSABLE INCOME PER HOUSEHOLD (THOUSANDS 2009$)

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	0.94	1.2%
Based on 2014 TYSP (2015 to 2024)	1.36	1.4%
Based on 2015 TYSP (2015 to 2024)	2.00	2.0%

HISTORY

		Growth	
		Absolute	%
1990	67.1	-0.1	-0.2%
1991	66.4	-0.8	-1.2%
1992	67.2	0.9	1.3%
1993	68.4	1.2	1.8%
1994	69.3	0.9	1.3%
1995	71.0	1.6	2.4%
1996	71.4	0.4	0.5%
1997	72.1	0.8	1.1%
1998	75.2	3.1	4.2%
1999	76.1	0.9	1.2%
2000	78.2	2.1	2.7%
2001	79.2	1.1	1.4%
2002	80.6	1.4	1.7%
2003	81.9	1.4	1.7%
2004	84.7	2.8	3.4%
2005	86.6	1.8	2.2%
2006	90.1	3.5	4.1%
2007	90.8	0.7	0.8%
2008	89.7	-1.1	-1.2%
2009	86.9	-2.8	-3.2%
2010	88.7	1.9	2.2%
2011	88.8	0.0	0.1%
2012	89.4	0.7	0.7%
2013	89.1	-0.3	-0.4%
2014	89.7	0.6	0.7%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2015	91.9	2.1	2.4%	91.5	1.8	2.0%	-0.4	-0.4%
2016	93.9	2.0	2.2%	94.2	2.7	3.0%	0.4	0.4%
2017	96.1	2.2	2.3%	97.3	3.0	3.2%	1.2	1.2%
2018	97.5	1.4	1.5%	99.6	2.4	2.4%	2.1	2.2%
2019	98.9	1.4	1.4%	101.8	2.1	2.1%	2.9	2.9%
2020	99.9	1.0	1.0%	103.3	1.6	1.5%	3.5	3.5%
2021	100.7	0.8	0.8%	104.8	1.5	1.4%	4.1	4.1%
2022	101.6	0.9	0.9%	106.4	1.6	1.5%	4.8	4.7%
2023	102.7	1.1	1.1%	108.0	1.7	1.6%	5.3	5.2%
2024	104.1	1.4	1.4%	109.5	1.5	1.4%	5.4	5.2%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 10
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Richard Feldman RF-4

REAL PRICE OF GASOLINE LAGGED (CENTS/GALLON)

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	2.91	1.9%
Based on 2014 TYSP (2015 to 2024)	0.65	0.5%
Based on 2015 TYSP (2015 to 2024)	2.38	1.6%

HISTORY

		Growth	
		Absolute	%
1990	94.58	6.27	7.1%
1991	87.36	7.27	-7.6%
1992	87.04	-0.31	-0.4%
1993	80.31	-6.73	-7.7%
1994	79.50	-0.82	-1.0%
1995	82.05	2.56	3.2%
1996	84.64	2.59	3.2%
1997	80.99	-3.65	-4.3%
1998	69.40	-11.59	-14.3%
1999	77.49	8.09	11.7%
2000	93.18	15.69	20.2%
2001	87.88	-5.30	-5.7%
2002	83.34	-4.54	-5.2%
2003	90.04	6.71	8.0%
2004	104.58	14.54	16.1%
2005	133.50	28.92	27.7%
2006	143.00	9.50	7.1%
2007	139.22	-3.78	-2.6%
2008	178.64	39.41	28.3%
2009	116.50	-62.14	-34.8%
2010	127.41	10.91	9.4%
2011	162.84	35.44	27.8%
2012	161.91	-0.93	-0.6%
2013	156.49	-5.42	-3.3%
2014	149.90	-6.59	-4.2%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2015	139.64	-10.26	-6.8%	139.70	-10.20	-6.8%	0.06	0.0%
2016	140.85	1.21	0.9%	138.42	-1.28	-0.9%	-2.43	-1.7%
2017	142.30	1.45	1.0%	138.10	-0.32	-0.2%	-4.20	-2.9%
2018	143.98	1.68	1.2%	139.15	1.05	0.8%	-4.83	-3.4%
2019	145.20	1.22	0.8%	141.36	2.21	1.6%	-3.84	-2.6%
2020	145.79	0.59	0.4%	145.14	3.78	2.7%	-0.64	-0.4%
2021	145.99	0.21	0.1%	149.48	4.33	3.0%	3.49	2.4%
2022	145.80	-0.20	-0.1%	153.47	3.99	2.7%	7.67	5.3%
2023	145.58	-0.21	-0.1%	157.44	3.97	2.6%	11.85	8.1%
2024	145.45	-0.13	-0.1%	161.13	3.69	2.3%	15.68	10.8%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 11
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Richard Feldman RF-5

SUMMER PEAK LOAD (MW)

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	383	2.2%
Based on 2014 TYSP (2015 to 2024)	429	1.7%
Based on 2015 TYSP (2015 to 2024)	387	1.6%

HISTORY

		Growth Absolute	Growth %
1990	13,754	329	2.5%
1991	14,123	369	2.7%
1992	14,661	538	3.8%
1993	15,266	605	4.1%
1994	15,179	-87	-0.6%
1995	15,813	634	4.2%
1996	16,064	251	1.6%
1997	16,613	549	3.4%
1998	17,897	1,284	7.7%
1999	17,615	-282	-1.6%
2000	17,808	193	1.1%
2001	18,754	946	5.3%
2002	19,219	465	2.5%
2003	19,668	449	2.3%
2004	20,545	877	4.5%
2005	22,361	1,816	8.8%
2006	21,819	-542	-2.4%
2007	21,962	143	0.7%
2008	21,060	-902	-4.1%
2009	22,351	1,291	6.1%
2010	22,256	-95	-0.4%
2011	21,619	-637	-2.9%
2012	21,440	-179	-0.8%
2013	21,576	136	0.6%
2014	22,935	1,359	6.3%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2015	23,356	421	1.8%	23,286	351	1.5%	-70	-0.3%
2016	23,778	422	1.8%	23,778	493	2.1%	1	0.0%
2017	24,190	412	1.7%	24,252	474	2.0%	62	0.3%
2018	24,544	354	1.5%	24,648	395	1.6%	104	0.4%
2019	24,896	352	1.4%	25,045	397	1.6%	149	0.6%
2020	25,239	344	1.4%	25,369	324	1.3%	130	0.5%
2021	25,439	200	0.8%	25,497	128	0.5%	58	0.2%
2022	25,908	469	1.8%	25,833	336	1.3%	-75	-0.3%
2023	26,528	621	2.4%	26,286	453	1.8%	-242	-0.9%
2024	27,214	686	2.6%	26,771	485	1.8%	-444	-1.6%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 12
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Richard Feldman RF-6

RISK-ADJUSTED SUMMER PEAK FORECAST (MW)

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	383	2.2%
Base Case Forecast (2015 to 2024)	387	1.6%
Risk-Adjusted Forecast (2015 to 2024)	535	2.1%

HISTORY

		Growth Absolute	Growth %
1990	13,754	329	2.5%
1991	14,123	369	2.7%
1992	14,661	538	3.8%
1993	15,266	605	4.1%
1994	15,179	-87	-0.6%
1995	15,813	634	4.2%
1996	16,064	251	1.6%
1997	16,613	549	3.4%
1998	17,897	1,284	7.7%
1999	17,615	-282	-1.6%
2000	17,808	193	1.1%
2001	18,754	946	5.3%
2002	19,219	465	2.5%
2003	19,668	449	2.3%
2004	20,545	877	4.5%
2005	22,361	1,816	8.8%
2006	21,819	-542	-2.4%
2007	21,962	143	0.7%
2008	21,060	-902	-4.1%
2009	22,351	1,291	6.1%
2010	22,256	-95	-0.4%
2011	21,619	-637	-2.9%
2012	21,440	-179	-0.8%
2013	21,576	136	0.6%
2014	22,935	1,359	6.3%

FORECAST

	2015 TYSP Base Case Forecast	Growth Absolute	Growth %	2015 TYSP Risk-Adjusted Forecast	Growth Absolute	Growth %	Difference
2015	23,286	351	1.5%	23,735	800	3.5%	449
2016	23,778	493	2.1%	24,333	598	2.5%	555
2017	24,252	474	2.0%	24,922	589	2.4%	670
2018	24,648	395	1.6%	25,494	572	2.3%	847
2019	25,045	397	1.6%	26,188	694	2.7%	1,143
2020	25,369	324	1.3%	26,802	614	2.3%	1,433
2021	25,497	128	0.5%	27,127	325	1.2%	1,630
2022	25,833	336	1.3%	27,539	412	1.5%	1,707
2023	26,286	453	1.8%	28,042	502	1.8%	1,756
2024	26,771	485	1.8%	28,550	508	1.8%	1,779

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 13
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Richard Feldman RF-7

WINTER PEAK LOAD (MW)

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	146	0.9%
Based on 2014 TYSP (2015 to 2024)	249	1.1%
Based on 2015 TYSP (2015 to 2024)	141	0.7%

HISTORY

		Growth	
		Absolute	%
1990	13,988	1,112	8.6%
1991	11,868	-2,120	-15.2%
1992	13,319	1,451	12.2%
1993	12,964	-355	-2.7%
1994	12,594	-370	-2.9%
1995	16,563	3,969	31.5%
1996	18,096	1,533	9.3%
1997	16,490	-1,606	-8.9%
1998	13,060	-3,430	-20.8%
1999	16,802	3,742	28.7%
2000	17,057	255	1.5%
2001	18,199	1,142	6.7%
2002	17,597	-602	-3.3%
2003	20,190	2,593	14.7%
2004	14,752	-5,438	-26.9%
2005	18,108	3,356	22.7%
2006	19,683	1,575	8.7%
2007	16,815	-2,868	-14.6%
2008	18,055	1,240	7.4%
2009	20,081	2,026	11.2%
2010	24,346	4,265	21.2%
2011	21,126	-3,220	-13.2%
2012	17,934	-3,192	-15.1%
2013	15,931	-2,003	-11.2%
2014	17,500	1,569	9.8%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2015	20,971	3,471	19.8%	21,136	3,636	20.8%	165	0.8%
2016	21,490	519	2.5%	21,369	233	1.1%	-122	-0.6%
2017	21,731	241	1.1%	21,485	116	0.5%	-246	-1.1%
2018	21,968	238	1.1%	21,598	113	0.5%	-370	-1.7%
2019	22,180	211	1.0%	21,792	194	0.9%	-388	-1.7%
2020	22,383	203	0.9%	21,965	173	0.8%	-418	-1.9%
2021	22,584	201	0.9%	22,096	131	0.6%	-488	-2.2%
2022	22,601	17	0.1%	22,026	-71	-0.3%	-575	-2.5%
2023	22,891	290	1.3%	22,202	176	0.8%	-689	-3.0%
2024	23,211	320	1.4%	22,408	206	0.9%	-803	-3.5%

Docket No. 15__________-EI
Calendar Net Energy for Load (GWH)
Exhibit RF-8, Page 1 of 1

CALENDAR NET ENERGY FOR LOAD (GWH)

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	1,852	2.0%
Based on 2014 TYSP (2015 to 2024)	1,472	1.2%
Based on 2015 TYSP (2015 to 2024)	1,507	1.2%

HISTORY

		Growth	
		Absolute	%
1990	71,528	1,229	1.7%
1991	73,426	1,897	2.7%
1992	73,321	-105	-0.1%
1993	76,074	2,753	3.8%
1994	80,673	4,599	6.0%
1995	84,546	3,873	4.8%
1996	85,028	482	0.6%
1997	87,056	2,028	2.4%
1998	92,802	5,747	6.6%
1999	91,683	-1,119	-1.2%
2000	96,313	4,630	5.1%
2001	98,612	2,299	2.4%
2002	104,657	6,045	6.1%
2003	108,214	3,557	3.4%
2004	108,122	-93	-0.1%
2005	111,443	3,321	3.1%
2006	113,406	1,963	1.8%
2007	114,532	1,126	1.0%
2008	111,100	-3,432	-3.0%
2009	111,237	137	0.1%
2010	114,604	3,366	3.0%
2011	111,542	-3,061	-2.7%
2012	110,866	-677	-0.6%
2013	111,655	790	0.7%
2014	115,968	4,312	3.9%

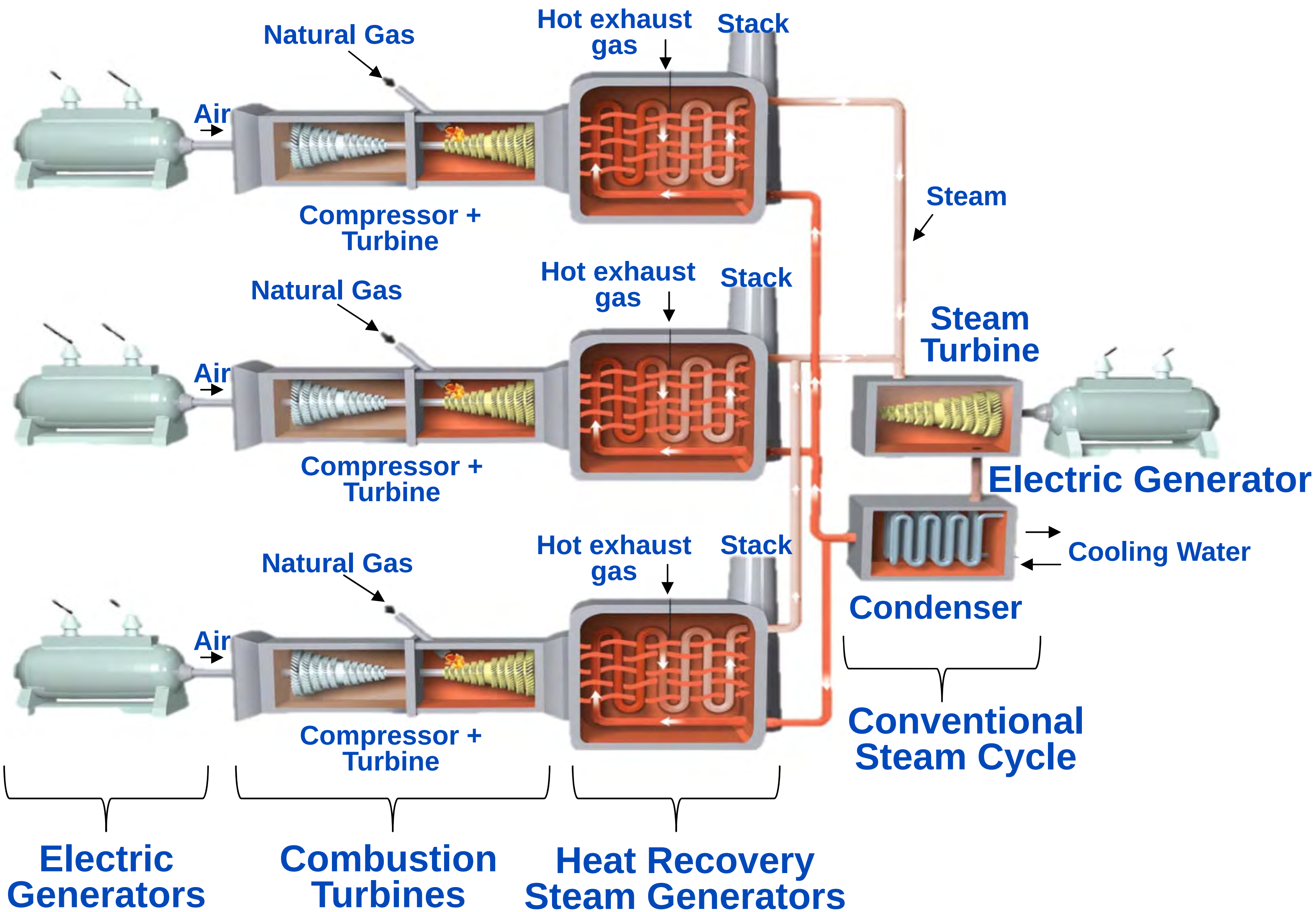
FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2015	121,606	5,638	4.9%	119,713	3,745	3.2%	-1,893	-1.6%
2016	123,943	2,337	1.9%	122,407	2,694	2.3%	-1,536	-1.2%
2017	124,914	971	0.8%	123,946	1,539	1.3%	-968	-0.8%
2018	126,399	1,485	1.2%	125,433	1,487	1.2%	-966	-0.8%
2019	127,673	1,274	1.0%	127,070	1,637	1.3%	-603	-0.5%
2020	129,187	1,514	1.2%	128,851	1,782	1.4%	-336	-0.3%
2021	129,454	267	0.2%	129,237	386	0.3%	-216	-0.2%
2022	130,517	1,064	0.8%	130,077	839	0.6%	-441	-0.3%
2023	132,357	1,840	1.4%	131,495	1,419	1.1%	-862	-0.7%
2024	134,849	2,492	1.9%	133,276	1,780	1.4%	-1,573	-1.2%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 14
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Richard Feldman RF-8

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 15
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Jacquelyn K. Kingston JKK-1

Typical 3x1 Combined Cycle Unit Schematic



Docket No. 15____-EI
Typical 3x1 Combined Cycle Unit Schematic
Exhibit JKK-1, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 16
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Jacquelyn K. Kingston JKK-2

FPL Operational Combined Cycle Power Plants

Facility[1]	In-Service Year	Technology	Summer Capacity (MW)
Riviera Beach Unit 5	2014	3x1 combined cycle	1,212
Cape Canaveral Unit 3	2013	3x1 combined cycle	1,210
West County Unit 3	2010	3x1 combined cycle	1,219
West County Unit 2	2009	3x1 combined cycle	1,219
West County Unit 1	2008	3x1 combined cycle	1,219
Turkey Point Unit 5	2007	4x1 combined cycle	1,192
Martin Unit 8	2005	4x1 combined cycle	1,135
Manatee Unit 3	2005	4x1 combined cycle	1,143
Sanford Unit 4	2003	4x1 combined cycle	1,005
Fort Myers Unit 2	2002	6x2 combined cycle	1,436
Sanford Unit 5	2002	4x1 combined cycle	1,005
Martin Unit 3	1994	2x1 combined cycle	469
Martin Unit 4	1994	2x1 combined cycle	469
Lauderdale Unit 4	1993	2x1 combined cycle	442
Lauderdale Unit 5	1993	2x1 combined cycle	442
TOTAL:			**14,817**

FPL Combined Cycle Power Plants in Construction

Facility[1]	Projected In-Service Year	Technology	Summer Capacity (MW)
Port Everglades Unit 5	2016	3x1 combined cycle	1,237
TOTAL:			**1,237**

[1]All facilities are located in Florida. The primary fuel for all facilities is natural gas.

History of FPL Combined Cycle Capital Construction Costs

Project	Approved Plan ($ Millions)	Actual/Projected Cost ($ Millions)
Martin Unit 8	$462.7	$391.2
Manatee Unit 3	$552.8	$476.8
Turkey Point Unit 5	$580.3	$552.4
West County Units 1 & 2[1]	$1,321.0	$1,320.8
West County Unit 3	$864.7	$842.4
Cape Canaveral Unit 3[2]	$1,114.7	$968.6
Riviera Beach Unit 5[3]	$1,275.6	$1,275.6

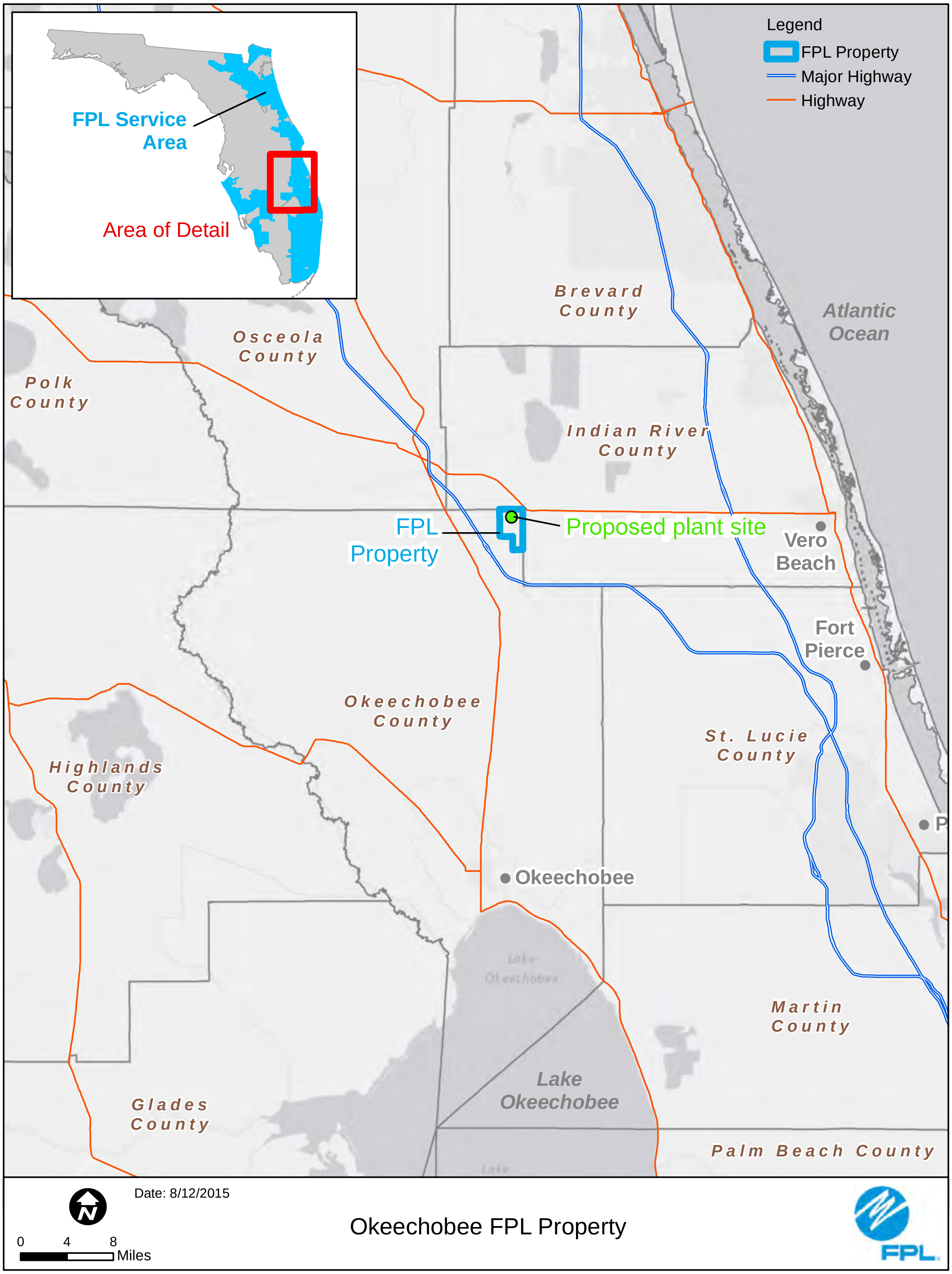
[1] FPL considers the combined costs to be the most meaningful way to evaluate project costs because it best aligns in practical terms with how the construction was actually managed.

[2] Construction on the units is complete; however, there are limited warranty activities still ongoing which are expected to be complete by year-end 2015.

[3] Construction on the units is complete; however, there are activities still ongoing which are expected to be completed by year-end 2015.

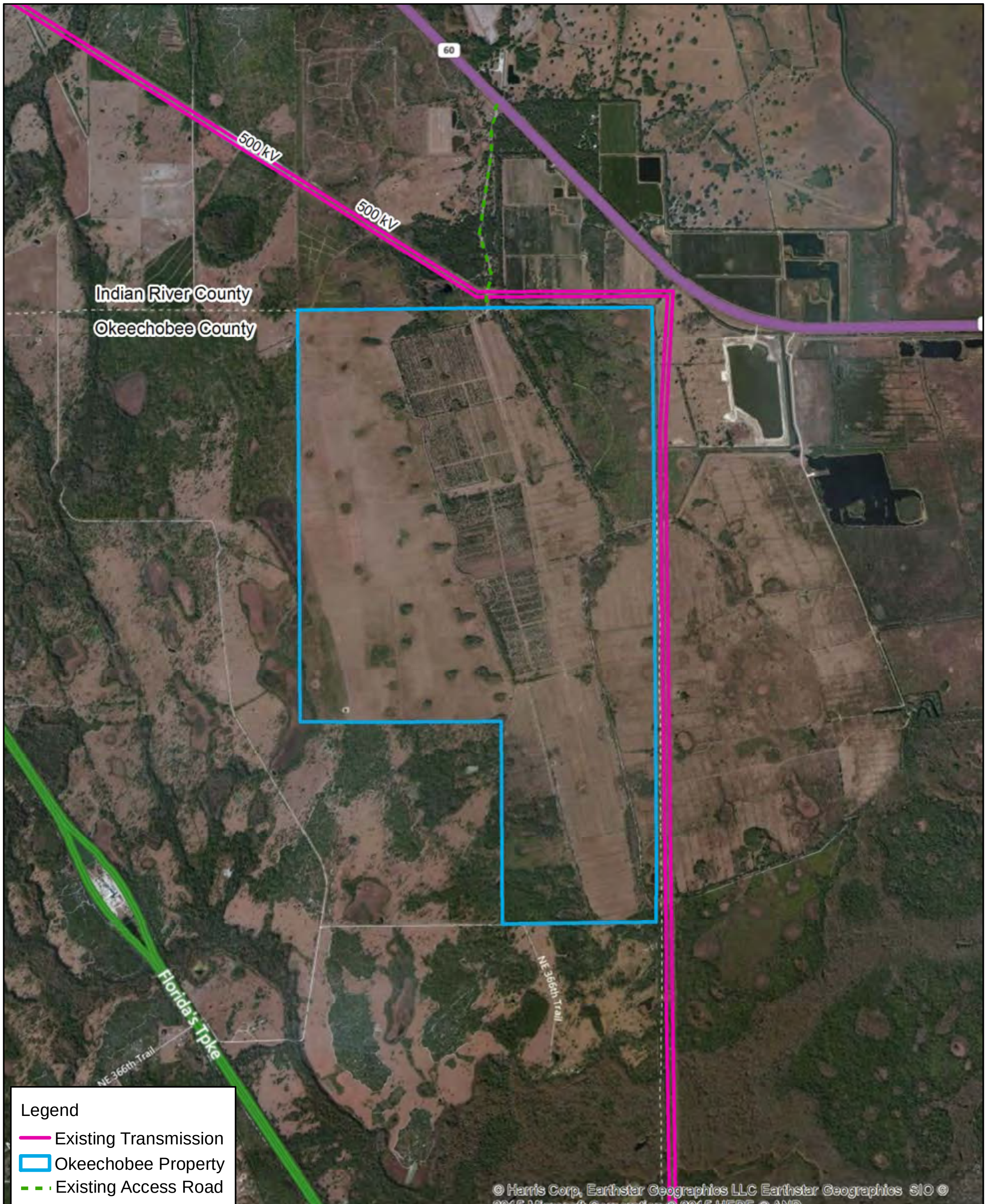
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 18
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Jacquelyn K. Kingston JKK-4

Docket No. 15__________-EI
OCEC Unit 1 Site Regional Map
Exhibit JKK-4, Page 1 of 1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 19
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Jacquelyn K. Kingston JKK-5

Docket No. 15__________-EI
OCEC Unit 1 Site Property Delineation
Exhibit JKK-5, Page 1 of 1



Date: 6/15/2015

0 0.25 0.5 Miles

Okeechobee FPL Property

FPL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 20
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Jacquelyn K. Kingston JKK-6

Aerial Photo of Okeechobee FPL Property (January 2015)
Looking Southeast

Docket No. 15______-EI
Aerial Photo of Okeechobee FPL Property
Exhibit JKK-6, Page 1 of 1

OCEC Unit 1 Proposed Site Plan Rendering

1. Cooling tower
2. Steam generators
3. Steam turbine
4. Combustion turbines
5. Collector yard
6. Maintenance work area
7. Switch yard
8. Power transmission lines
9. Storm water pond
10. Gas metering area
11. Contractor work area
12. Contractor parking
13. Employee parking
14. Administration & storage buildings
15. Back-up fuel tank
16. Demineralized water tank
17. Storm water ditch

Docket No. 15_____-EI
OCEC Unit 1 Proposed Site Plan Rendering
Exhibit JKK-7, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 21
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Jacquelyn K. Kingston JKK-7

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company)	DOCKET NO. 150196-EI FILED: November 20, 2015

ERRATA SHEET OF JACQUELYN K. KINGSTON

September 3, 2015 Direct Testimony

PAGE #	LINE #	CORRECTION
15	4	change “96.7%” to “95.5%”
15	5	change “1.1%” to “1.0%”
15	6	change “2.2%” to 3.5”
15	15	change “96.7%” to “95.5%”

September 3, 2015 Exhibits

EXHIBIT #	LINE #	CORRECTION
JKK-8	n/a	Planned Outage Factor change “2.2%” to “3.5%”
JKK-8	n/a	Forced Outage Factor change “1.1%” to “1.0%”
JKK-8	n/a	Equivalent Availability Factor change “96.7%” to “95.5%”

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 22
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Jacquelyn K. Kingston JKK-8

OCEC Unit 1 Plant Specifications

Generating Technology – "Three on One" (3x1) Combined Cycle Configuration:

- Three (3) Advanced Combustion Turbines with Evaporative Coolers
- Three (3) Heat Recovery Steam Generators with Selective Catalytic Reduction System for NO_X control
- One (1) Single-Reheat Steam Turbine

Expected Plant Peak Capacity:

• Summer (95°F / 50% Relative Humidity (RH))	1,622 MW
• Winter (35°F / 60% RH)	1,595 MW

Projected Unit Performance Data:

• Planned Outage Factor	2.2%
• Forced Outage Factor	1.1%
• Equivalent Availability Factor	96.7%
• Resulting Capacity Factor (%)	Approx. 80%
• Avg. Net Operating Heat Rate (Base operation @ 75°F, 100%)	6,304 Btu/kWh
• Annual Fixed O&M[1]	$16.89/kW-yr
• Variable O&M - excluding fuel[2]	$0.28/MWh

Fuel Type and Base Load Typical Usage @ 75°F:

• Primary Fuel	Natural Gas
• Natural Gas Consumption	9,432,429 scf/hr[3]
• On Site Back Up Fuel	Light Fuel Oil
• Light Fuel Oil Consumption	68,497 gal/hr

Expected Base Load Air Emissions Per Combustion Turbine/Heat Recovery Steam Generator @ 75°F (Baseload):

	Natural Gas	Light Fuel Oil
• NO_x (@15% O_2)	2 ppmvd[4]	8 ppmvd
• CO	5 ppmvd	10 ppmvd
• SO_2	< 0.0003 lb Sulfur/100 cubic feet	<0.0015% Sulfur

Water Balance:

- Primary Water Source – Floridan Aquifer

Linear Facilities:

- One (1) new natural gas pipeline lateral
- No new linear transmission facilities – connect into adjacent 500 kV corridor

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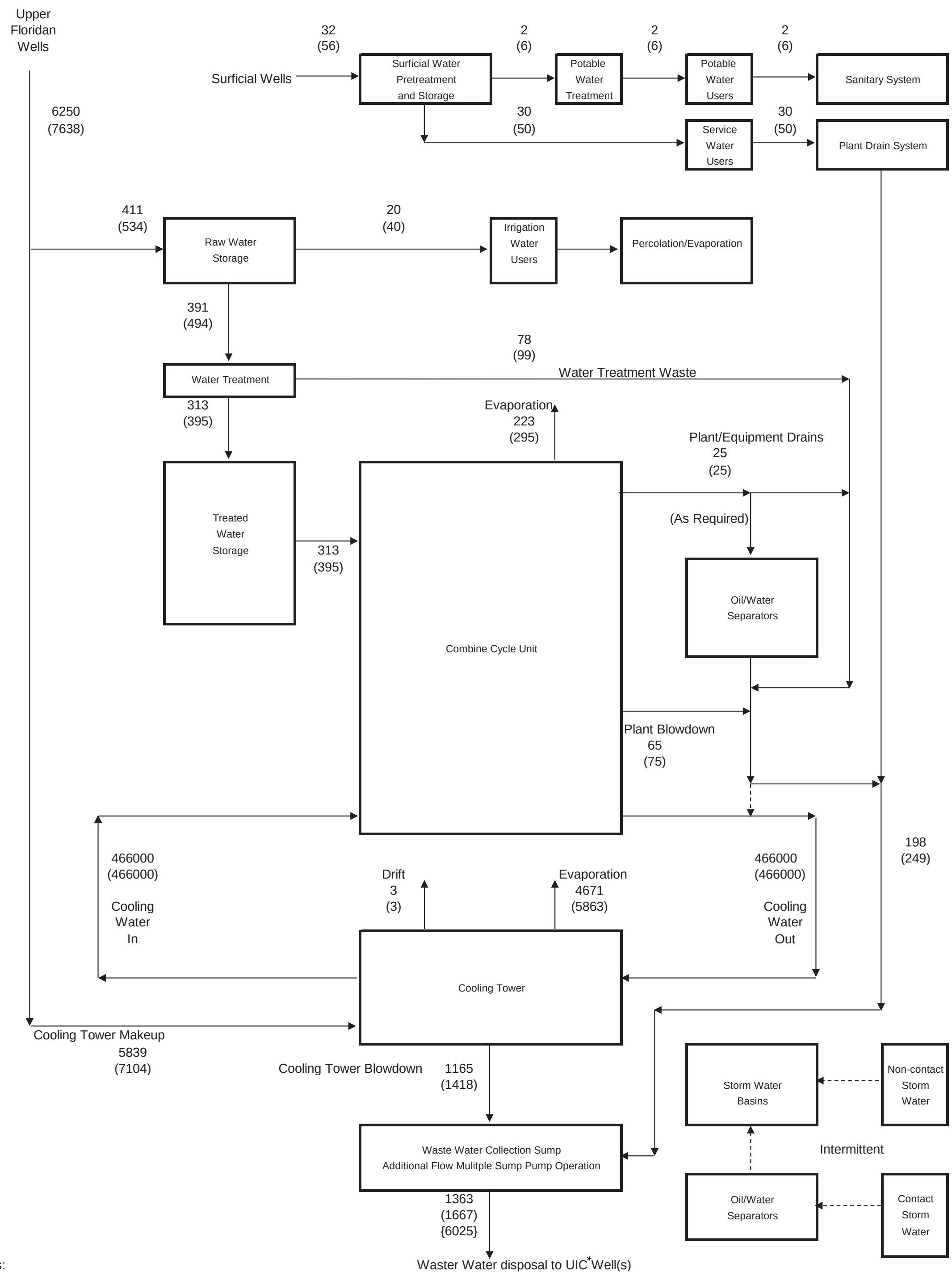
[1] Annual fixed O&M value includes capital replacement costs and fixed O&M presented as a levelized value to year 2019
[2] Variable O&M represents the value for year 2019
[3] Standard cubic feet per hour
[4] Parts per million volumetric dry

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 23
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Jacquelyn K. Kingston JKK-9

Docket No. 15__________-EI
OCEC Unit 1 Water Balance
Exhibit JKK-9, Page 1 of 1

Jun-15 OCEC



Notes:

1 Flows are in gallons per minute (GPM).
2 Flows shown with no parenthesis [{ } or ()] are estimated annual average daily values - annual average basis.
3 Flows shown in () are hot weather daily values - monthly maximum basis.
4 Flows shown in { } are peak intermittent short duration values.
5 - - - - - Dashed lines indicate intermittent or alternate flow paths.
* Underground Injection Control

FRCC
Florida Reliability Coordinating Council, Inc.

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.
3000 BAYPORT DRIVE, SUITE 600
TAMPA, FLORIDA 33607-8410
PHONE 813.289.5644 • FAX 813.289.5646
WWW.FRCC.COM

August 10, 2015

Mr. Pedro Modia
Director, Services and Planning
Florida Power and Light
4200 W. Flagler Street
Miami, FL 33134

Re: FRCC review of Florida Power and Light's Okeechobee County Energy Center Interconnection and Integration Request

Dear Pedro:

The Florida Reliability Coordinating Council's (FRCC) Transmission Working Group (TWG), and Stability Working Group (SWG) have evaluated and reviewed the Florida Power and Light (FPL) proposed Okeechobee Combined Cycle Unit Generation Interconnection Service Request (GISR) to serve FPL native load. The analyses conducted by the TWG, SWG and FPL for the interconnection and integration plan for FPL's Okeechobee County Energy Center (OCEC) are based on the 2014 FRCC databank, modified for planned facilities that resulted from the 2014 Long Range Study.

The OCEC, located in Okeechobee County, Florida, is comprised of three (3) natural gas fired Combustion Turbine (CT) generators and one (1) Steam Turbine (ST) generator with a total net output of 1652 MW for summer and 1625 MW for winter. The OCEC will be interconnected to the FPL transmission system by looping FPL's existing Martin-Poinsett 500kV line into a new 500 kV Okeechobee substation at the plant site. The project has a proposed in-service date of June 1, 2019.

The TWG evaluation found that FPL's steady state contingency analysis was comprehensive and complete. The analyses evaluated facilities 69 kV and above. Under normal operating conditions all facilities remained within applicable ratings. Both the FPL and the TWG contingency analyses identified potential 3rd party impacts of OCEC on the transmission system within the FRCC Region which have been addressed with appropriate remedies provided by the members of the TWG. A review of the short circuit analysis has also shown that there are no short circuit concerns from the OCEC.

In addition to the steady state and short circuit analyses, the SWG reviewed FPL's stability analyses. The dynamic simulations showed a stable response at both Peak and 50% load levels for planning events required to be analyzed by NERC Reliability Planning Standards.

FRCC
Florida Reliability Coordinating Council, Inc.

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.
3000 BAYPORT DRIVE, SUITE 600
TAMPA, FLORIDA 33607-8410
PHONE 813.289.5644 • FAX 813.289.5646
WWW.FRCC.COM

A Power transfer-Voltage (PV) sensitivity analysis was also performed to determine potential impacts on the Florida-Southern interface resulting from the loss of the entire combined cycle unit, and the results showed no impact on the future ability to import 3200 MW across the Florida-Southern interface with the addition of OCEC.

Based on the above review and analysis conducted by the TWG and SWG, the FRCC Planning Committee has determined that the proposed interconnection and integration plan for OCEC will be reliable, adequate and will not adversely impact the reliability of the FRCC transmission system.

Sincerely,

Vicente Ordax

VICENTE ORDAX
DIRECTOR OF PLANNING

OCEC Unit 1 Expected Construction Schedule

Milestone	Begin	End
Initiate sequence of HRSG orders (NTP[1] x 3)	Dec, 2015	-
Initiate NTP[1] for steam turbine	Dec, 2015	-
Initiate sequence of CT orders (NTP[1] x 3)	Jan, 2016	-
Receive approvals necessary to begin construction	-	Dec, 2016
Site preparation and install foundations	Mar, 2017	Dec, 2017
Balance of Plant	Mar, 2017	Sep, 2018
Erect HRSGs	Sep, 2017	Sep, 2018
Erect CTs	Sep, 2017	Sep, 2018
Erect steam turbine	Dec, 2017	Sep, 2018
Startup	Oct, 2018	Jun, 2019
Commercial Operation	-	Jun, 2019

[1] Notice to Proceed

OCEC Unit 1 Plant Construction Cost Components

Component	**Cost in millions (2019$)**
Power Block and Generator Transformers	$1,031.5
Land	$0
Transmission Interconnection and Integration	$52.0
Third Party Gas Infrastructure[1]	$0
Allowance for Funds Used During Construction (AFUDC)	$112.5
Total Plant Cost	**$1,196.0**

[1]Does not include cost to build gas pipeline or fuel charges

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company)	DOCKET NO. 150196-EI FILED: November 25, 2015

SECOND ERRATA SHEET OF HEATHER C. STUBBLEFIELD

September 3, 2015 Exhibits (as Corrected November 13, 2015)

EXHIBIT #	PAGE #	COLUMN #	LINE #	CORRECTION
Exhibit-HCS-1	1	D	9	Change \$4.11 to \$4.12 (consistent with FPL's Corrected Response to Staff's First Request For Production of Documents, Request No. 6, filed November 10, 2015)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 27
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (DIRECT)
DESCRIPTION: Heather C. Stubblefield

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company	DOCKET NO. 150196-EI FILED: November 13, 2015

ERRATA SHEET OF HEATHER C. STUBBLEFIELD

September 3, 2015 Direct Testimony

PAGE #	LINE #	CORRECTION
7	6	Delete "all of those"
7	21	Insert ", in addition to FPL's existing gas transportation capacity," after "capacity"

September 3, 2015 Exhibits

EXHIBIT #	PAGE #	COLUMN #	LINE #	CORRECTION
Exhibit-HCS-1	2	D	7-41	Delete original Column D to remove Sabal Trail from exhibit.

FPL'S NOVEMBER 3, 2014 FUEL PRICE FORECAST

	A	B	C	D	E	F	G	H	I	J	K
1											
2											
3		NATURAL GAS			OIL			COAL			
4		FLORIDA GAS TRANSMISSION	GULFSTREAM	FLORIDA SOUTHEAST CONNECTION / SABAL TRAIL	MARTIN PLANT RESIDUAL 0.7%	MANATEE / TURKEY POINT PLANTS RESIDUAL 0.7%	ALL PLANTS DISTILLATE	SCHERER 4	INDIANTOWN COGEN	CEDAR BAY	ST. JOHNS
5	YEAR	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
6											
7	2015	$4.02	$3.99		$12.79	$12.43	$19.76	$2.53	$5.12	$3.21	$3.25
8	2016	$4.11	$4.06		$13.29	$12.92	$19.92	$2.87	$5.25	$3.39	$3.45
9	2017	$4.10	$4.06	$4.12	$13.37	$13.01	$20.18	$3.00	$5.38	$3.59	$3.59
10	2018	$4.36	$4.31	$4.36	$13.58	$13.22	$20.80	$3.11	$5.52	$3.74	$3.74
11	2019	$4.70	$4.65	$4.69	$14.91	$14.55	$22.62	$3.14	$5.66	$3.86	$3.86
12	2020	$5.16	$5.11	$5.14	$16.16	$15.79	$24.19	$3.20	$5.80	$3.73	$3.73
13	2021	$5.56	$5.51	$5.53	$17.47	$17.11	$25.76	$3.27	$5.95	$3.77	$3.77
14	2022	$5.87	$5.81	$5.83	$17.81	$17.45	$26.60	$3.34	$6.10	$3.94	$3.94
15	2023	$6.11	$6.05	$6.06	$18.39	$18.03	$27.37	$3.41	$6.25	$4.07	$4.07
16	2024	$6.30	$6.23	$6.24	$19.32	$18.96	$28.37	$3.49	$6.41	$4.16	$4.16
17	2025	$6.49	$6.42	$6.43	$20.62	$20.26	$29.41	$3.57	$6.57	$4.24	$4.24
18	2026	$6.69	$6.62	$6.62	$21.43	$21.07	$30.41	$3.65	$6.74	$4.34	$4.34
19	2027	$6.89	$6.82	$6.82	$22.29	$21.92	$31.44	$3.73	$6.91	$4.44	$4.44
20	2028	$7.10	$7.02	$7.02	$23.14	$22.77	$32.46	$3.82	$7.08	$4.55	$4.55
21	2029	$7.32	$7.24	$7.23	$24.07	$23.71	$33.47	$3.91	$7.26	$4.66	$4.66
22	2030	$7.53	$7.45	$7.44	$25.05	$24.68	$34.53	$4.00	$7.44	$4.77	$4.77
23	2031	$7.76	$7.68	$7.66	$25.80	$25.43	$35.35	$4.09	$7.63	$4.92	$4.92
24	2032	$7.99	$7.90	$7.88	$26.56	$26.20	$36.18	$4.20	$7.83	$5.07	$5.07
25	2033	$8.22	$8.13	$8.11	$27.33	$26.97	$37.00	$4.31	$8.02	$5.22	$5.22
26	2034	$8.39	$8.30	$8.27	$28.10	$27.73	$37.82	$4.43	$8.23	$5.38	$5.38
27	2035	$8.55	$8.46	$8.43	$28.86	$28.50	$38.67	$4.55	$8.43	$5.55	$5.55
28	2036	$8.76	$8.66	$8.63	$29.31	$28.94	$39.32	$4.67	$8.65	$5.71	$5.71
29	2037	$8.97	$8.87	$8.83	$29.76	$29.39	$39.98	$4.80	$8.87	$5.87	$5.87
30	2038	$9.18	$9.08	$9.04	$30.21	$29.85	$40.66	$4.92	$9.09	$6.02	$6.02
31	2039	$9.40	$9.30	$9.26	$30.67	$30.31	$41.34	$5.05	$9.32	$6.17	$6.17
32	2040	$9.63	$9.52	$9.48	$31.14	$30.78	$42.04	$5.19	$9.56	$6.32	$6.32
33	2041	$9.86	$9.75	$9.70	$31.62	$31.26	$42.75	$5.32	$9.80	$6.48	$6.48
34	2042	$10.10	$9.99	$9.93	$32.11	$31.74	$43.47	$5.46	$10.05	$6.64	$6.64
35	2043	$10.34	$10.23	$10.17	$32.60	$32.24	$44.21	$5.61	$10.30	$6.80	$6.80
36	2044	$10.59	$10.47	$10.41	$33.10	$32.74	$44.96	$5.76	$10.56	$6.96	$6.96
37	2045	$10.84	$10.72	$10.65	$33.61	$33.24	$45.72	$5.91	$10.83	$7.13	$7.13
38	2046	$11.10	$10.98	$10.91	$34.12	$33.76	$46.49	$6.06	$11.10	$7.31	$7.31
39	2047	$11.37	$11.24	$11.16	$34.65	$34.29	$47.28	$6.22	$11.38	$7.49	$7.49
40	2048	$11.64	$11.51	$11.43	$35.18	$34.82	$48.08	$6.39	$11.67	$7.67	$7.67
41	2049	$11.92	$11.79	$11.70	$35.72	$35.36	$48.90	$6.56	$11.96	$7.86	$7.86

Docket No. 15________-EI
FPL's Nov. 3, 2014 and
Oct. 7, 2013 Fuel Price Forecasts
Exhibit HCS-1, Page 1 of 2

FPL'S OCTOBER 7, 2013 FUEL PRICE FORECAST

	A	B	C	D	E	F	G	H	I	J	K	L	M
3		NATURAL GAS		OIL						COAL			
4		FLORIDA GAS TRANSMISSION	GULFSTREAM	MARTIN PLANT RESIDUAL 0.7%	MANATEE / TURKEY POINT PLANTS RESIDUAL 0.7%	TURKEY POINT DISTILLATE	FORT MYERS DISTILLATE	PORT EVERGLADES / LAUDERDALE DISTILLATE	WCEC / PUTNAM / MARTIN / CANAVERAL / RIVIERA DISTILLATE	SCHERER 4	INDIANTOWN COGEN	CEDAR BAY	ST. JOHNS
5	YEAR	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
7	2015	$4.26	$4.25	$14.61	$14.45	$22.70	$22.41	$22.13	$22.27	$2.48	$5.90	$3.80	$3.58
8	2016	$4.51	$4.50	$15.28	$15.12	$23.28	$22.98	$22.71	$22.84	$3.28	$6.05	$3.93	$3.69
9	2017	$4.93	$4.92	$15.23	$15.08	$23.72	$23.42	$23.15	$23.28	$3.31	$6.20	$3.88	$3.88
10	2018	$6.00	$5.98	$17.23	$17.08	$25.07	$24.77	$24.50	$24.64	$3.40	$6.35	$4.00	$4.00
11	2019	$6.15	$6.13	$17.65	$17.49	$25.60	$25.30	$25.03	$25.16	$3.22	$6.52	$4.09	$4.09
12	2020	$6.31	$6.29	$18.18	$18.03	$26.29	$26.00	$25.73	$25.86	$3.29	$6.68	$4.18	$4.18
13	2021	$6.41	$6.39	$19.08	$18.92	$27.51	$27.21	$26.94	$27.08	$3.37	$6.85	$4.28	$4.28
14	2022	$6.62	$6.59	$19.89	$19.74	$28.80	$28.51	$28.24	$28.37	$3.45	$7.02	$4.38	$4.38
15	2023	$6.93	$6.90	$20.88	$20.72	$30.05	$29.76	$29.49	$29.62	$3.54	$7.20	$4.49	$4.49
16	2024	$7.34	$7.31	$21.88	$21.73	$31.26	$30.96	$30.69	$30.83	$3.63	$7.38	$4.61	$4.61
17	2025	$7.65	$7.61	$22.89	$22.73	$32.43	$32.13	$31.86	$32.00	$3.72	$7.57	$4.73	$4.73
18	2026	$7.96	$7.92	$23.30	$23.14	$33.07	$32.77	$32.50	$32.64	$3.82	$7.76	$4.86	$4.86
19	2027	$8.26	$8.22	$23.76	$23.60	$33.68	$33.38	$33.11	$33.25	$3.92	$7.96	$4.99	$4.99
20	2028	$8.68	$8.63	$24.17	$24.01	$34.25	$33.95	$33.68	$33.81	$4.02	$8.16	$5.12	$5.12
21	2029	$8.99	$8.94	$24.65	$24.49	$34.84	$34.54	$34.27	$34.41	$4.12	$8.36	$5.25	$5.25
22	2030	$9.19	$9.14	$25.09	$24.93	$35.42	$35.13	$34.86	$34.99	$4.22	$8.58	$5.39	$5.39
23	2031	$9.54	$9.48	$25.49	$25.34	$36.02	$35.72	$35.45	$35.59	$4.32	$8.79	$5.52	$5.52
24	2032	$9.90	$9.84	$25.90	$25.74	$36.63	$36.33	$36.06	$36.20	$4.42	$9.01	$5.66	$5.66
25	2033	$10.27	$10.21	$26.31	$26.16	$37.25	$36.95	$36.68	$36.81	$4.53	$9.24	$5.81	$5.81
26	2034	$10.66	$10.60	$26.74	$26.58	$37.88	$37.58	$37.31	$37.44	$4.64	$9.48	$5.96	$5.96
27	2035	$11.06	$10.99	$27.16	$27.01	$38.52	$38.22	$37.95	$38.08	$4.75	$9.72	$6.23	$6.23
28	2036	$11.48	$11.41	$27.60	$27.44	$39.17	$38.87	$38.60	$38.74	$4.86	$9.96	$6.46	$6.46
29	2037	$11.92	$11.84	$28.04	$27.88	$39.83	$39.53	$39.26	$39.40	$4.96	$10.21	$6.52	$6.52
30	2038	$12.37	$12.28	$28.49	$28.33	$40.51	$40.21	$39.94	$40.08	$5.08	$10.47	$6.55	$6.55
31	2039	$12.83	$12.75	$28.95	$28.79	$41.20	$40.90	$40.63	$40.76	$5.19	$10.74	$6.58	$6.58
32	2040	$13.32	$13.23	$29.41	$29.26	$41.90	$41.60	$41.33	$41.46	$5.31	$11.01	$6.61	$6.61
33	2041	$13.82	$13.72	$29.88	$29.73	$42.61	$42.31	$42.04	$42.18	$5.43	$11.29	$6.64	$6.64
34	2042	$14.35	$14.24	$30.36	$30.21	$43.34	$43.04	$42.77	$42.90	$5.55	$11.57	$6.68	$6.68
35	2043	$14.89	$14.78	$30.85	$30.70	$44.07	$43.78	$43.51	$43.64	$5.68	$11.86	$6.72	$6.72
36	2044	$15.45	$15.34	$31.35	$31.19	$44.83	$44.53	$44.26	$44.39	$5.81	$12.16	$6.77	$6.77
37	2045	$16.04	$15.91	$31.85	$31.69	$45.59	$45.30	$45.02	$45.16	$5.94	$12.47	$6.84	$6.84
38	2046	$16.64	$16.51	$32.36	$32.21	$46.37	$46.07	$45.80	$45.94	$6.07	$12.79	$6.92	$6.92
39	2047	$17.27	$17.14	$32.88	$32.73	$47.17	$46.87	$46.60	$46.73	$6.21	$13.11	$7.03	$7.03
40	2048	$17.92	$17.78	$33.41	$33.26	$47.97	$47.68	$47.40	$47.54	$6.35	$13.44	$7.16	$7.16
41	2049	$18.60	$18.46	$33.95	$33.79	$48.80	$48.50	$48.23	$48.36	$6.50	$13.78	$7.30	$7.30

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EXPERIENCE

Southern Alliance for Clean Energy
Director of Research, Asheville, North Carolina and Washington, DC, 2007 – present
- Manage technical and regulatory advocacy
- Conduct supporting research and policy development across all program areas

Galveston-Houston Association for Smog Prevention
Executive Director, Houston, Texas, 2001 – 2006
- Member, Regional Air Quality Planning Committee
- Member, Transportation Policy Technical Advisory Committee
- Member, Steering Committee, TCEQ Interim Science Committee
- Awards & recognition from the City of Houston, *Houston Press*, and environmental groups

The Goodman Corporation
Senior Associate, Houston, Texas, 2000 – 2001
- Transportation and Urban Planning Consulting
- Project Manager, Houston Main Street Corridor
- Project Manager, Houston Downtown Circulation Study
- Project Manager, Austin Corridor Planning
- Project Manager, Ft. Worth Berry Street Corridor Initiative

Florida Legislature
Senior Legislative Analyst and Technology Projects Coordinator, Office of Program Policy Analysis and Government Accountability, Tallahassee, Florida, 1997- 1999
- Coordinator, Florida Government Accountability Report, 1999
- Coordinator, Project Management Software Implementation, 1999
- Creator and Editor, *Florida Monitor Weekly*, 1998 - 99
- Author or team member for reports on water supply policy, environmental permitting, community development corporations, school district financial management and other issues – most recommendations implemented by the 1998 and 1999 Florida Legislatures

Florida State University
Environmental Management Consultant, Tallahassee, Florida, 1997
- Project staff, *Florida Assessment of Coastal Trends*, 1997

Houston Advanced Research Center
Research Associate, Center for Global Studies, The Woodlands, Texas, 1992 - 96
- Coordinator, Houston Environmental Foresight, 1993 - 96
- Coordinator, Rio Grande/Rio Bravo Basin Initiative, 1992 - 94
- Secretary, Task Force on Climate Change in Texas, 1992 - 94
- Researcher, *Policy Options: Responding to Climate Change in Texas*, 1992 - 93

US Environmental Protection Agency
Student Assistant, Climate Change Division, Washington, DC, 1991 - 92
- Special Achievement Award, 1991

EDUCATION

Harvard University
Master in Public Policy, John F. Kennedy School of Government, 1992
- Concentration areas: Environment, negotiation, economic and analytic methods

Rice University
Bachelor of Arts, conferred *cum laude*, 1990
- Majors: Physics (with honors) and history

Additional Training and Experience
Spanish language; Advanced computer skills; Served and led political committees for the Sierra Club and Clean Water Action; Certified Master Wildlife Conservationist, Leon County Extension Service

PUBLICATIONS

Expert Witness Testimony

John D. Wilson, Direct Testimony on Behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy, *In the Matter of Petition of the Office of Regulatory Staff to Establish Generic Proceeding Pursuant to the Distributed Energy Resource Program Act, Act No. 236 of 2014, Ratification No. 241, Senate Bill No. 1189,* South Carolina Public Service Commission Docket No. 2014-246-E (December 23, 2014).

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Anderson, SC, South Carolina Public Service Commission Docket No. 2013-392-E (December 10, 2013).

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John D. Wilson, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever, in *South Carolina Electric & Gas Company's Integrated Resource Plan*, South Carolina Public Service Commission Docket NO. 2011-9-E (June 1, 2011).

John D. Wilson, Direct Testimony on Behalf of Southern Alliance for Clean Energy, *In the Matters of Georgia Power Company's Application for Certification of its Demand Side Management Program*, Georgia Public Service Commission Docket No. 31082 (May 7, 2010).

John D. Wilson, Direct Testimony on Behalf of Southern Alliance for Clean Energy, *In the Matters of Georgia Power Company's Application for Approval of its 2010 Integrated Resource Plan*, Georgia Public Service Commission Docket No. 31081 (May 7, 2010).

John D. Wilson, Direct Testimony on Behalf of Environmental Defense Fund, The Sierra Club, Southern Alliance for Clean Energy, and the Southern Environmental Law Center, *In the Matter of Investigation of Integrated Resource Planning in North Carolina – 2009*, North Carolina Utilities Commission Docket No. E-100, Sub 124 (February 19, 2010).

John D. Wilson, Direct Testimony on Behalf of Environmental Defense Fund, the Natural Resources Defense Council, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and the Southern Environmental Law Center, *Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase Its Electric Rate and Charges,* South Carolina Public Service Commission Docket No. 2009-226-E (November 6, 2009).

John D. Wilson, Direct Testimony & Exhibits on behalf of Southern Alliance for Clean Energy and the Natural Resources Defense Council in *RE: Commission Review of Numeric Conservation Goals Florida Power & Light Company*, Florida Public Service Commission Docket No. 080407-EG, also filed in Dockets 080408-EG through 080413-EG (July 6, 2009).

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(Lead author or significant contributor)

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Comments (June 23, 2015).

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Southern Alliance for Clean Energy and Sierra Club, comments filed in *2014 Biennial Integrated Resource Plans and Related REPS Compliance Plans*, North Carolina Utilities Commission Docket No. E-100, Sub 141 (March 2, 2015).

John D. Wilson and Natalie Mims, *Views on TVA EE Modeling Approach*, Presentation to TVA "Evaluating Energy Efficiency in Utility Resource Planning" Meeting (February 10, 2015).

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Southern Alliance for Clean Energy, Sierra Club, and South Carolina Coastal Conservation League, comments filed *In the Matter of Rulemaking Proceeding to Consider Revisions to Commission Rule R8-60 on Integrated Resource Planning*, North Carolina Utilities Commission, Docket No. E-100, Sub 111 (December 8, 2014).

South Carolina Coastal Conservation League and Southern Alliance for Clean Energy, comments filed *In the Matter of Duke Energy Progress, Inc.'s Integrated Resource Plan*, South Carolina Public Service Commission, Docket No. 2014-8-E (December 3, 2014).

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Southern Alliance for Clean Energy, *Comments on Allen Fossil Plant Emission Control Project Draft Environmental Assessment,* submitted to Tennessee Valley Authority (August 7, 2014).

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Southern Alliance for Clean Energy, *Tennessee Valley Utility-Scale Solar Assessment*, submitted to Tennessee Valley Renewable Information Exchange (May 13, 2014).

John D. Wilson, "Rates vs. Energy Efficiency," 2013 ACEEE National Conference on Energy Efficiency as a Resource (September 2013).

Sierra Club and Southern Alliance for Clean Energy, reply comments filed in *Investigation of Integrated Resource Planning in North Carolina – 2012*, North Carolina Utilities Commission Docket No. E-100, Sub 137 (March 6, 2013).

Sierra Club and Southern Alliance for Clean Energy, comments filed in *Investigation of Integrated Resource Planning in North Carolina – 2012*, North Carolina Utilities Commission Docket No. E-100, Sub 137 (February 5, 2013).

South Carolina Coastal Conservation League and Southern Alliance for Clean Energy, comments filed in *Progress Energy Carolinas, LLC's Integrated Resource Plan*, South Carolina Public Service Commission Docket NO. 2012-8-E (January 25, 2013).

South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Upstate Forever, comments filed in *Duke Energy Carolinas, LLC's Integrated Resource Plan*, South Carolina Public Service Commission Docket NO. 2012-10-E (December 6, 2012).

Southern Alliance for Clean Energy, comments filed in *Investigation of Integrated Resource*

Planning in North Carolina – 2010-2011, North Carolina Utilities Commission Docket No. E-100, Sub 128 (January 13, 2012).

Southern Alliance for Clean Energy, and South Carolina Coastal Conservation League, comments filed in *Progress Energy Carolinas, Incorporated's Integrated Resource Plan (IRP)*, South Carolina Public Service Commission Docket NO. 2011-8-E (October 31, 2011).

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Southern Alliance for Clean Energy, comments on *Tennessee Valley Authority's Renewable Standard Offer*, submitted to Tennessee Valley Authority (September 6, 2011).

Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever, comments filed in *South Carolina Electric & Gas Company's Integrated Resource Plan*, South Carolina Public Service Commission Docket NO. 2011-9-E (April 15, 2011).

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Southern Alliance for Clean Energy, *Comments in Response to Tennessee Valley Authority's November 16, 2010 Release of its Draft Integrated Resource Plan and Accompanying Environmental Impact Statement (No. 20100379) for Public Review and Comment* (November 15, 2010).

Environmental Defense Fund, Southern Alliance for Clean Energy, and Southern Environmental Law Center, comments in *Rulemaking Proceeding to Implement Session Law 2007-397*, North Carolina Utilities Commission Docket No. E-100, Sub 113 (October 15, 2010).

Environmental Defense Fund, Southern Alliance for Clean Energy, and Southern Environmental Law Center, comments in *Rulemaking Proceeding to Implement Session Law 2007-397*, North Carolina Utilities Commission Docket No. E-100, Sub 113 (October 4, 2010).

South Carolina Coastal Conservation League and Southern Alliance for Clean Energy, comments filed *In the Matter of Duke Energy Carolinas, LLC's Integrated Resource Plan*, South Carolina Public Service Commission, Docket No. 2014-10-E (November 3, 2014).

Southern Alliance for Clean Energy and Environmental Defense Fund, statement of position letter in *Application for Residential Retrofit* and *Home Energy Comparison Report Pilot Programs*, North Carolina Utilities Commission Dockets Nos. E-7 Sub 952 and Sub 954 (September 17, 2010).

John D. Wilson, "Energy Efficiency: The Southeast Considers its Options," NAESCO Southeast Regional Workshop (September 2010).

Southern Alliance for Clean Energy, "SACE's Response to Progress Energy Florida's Response to SACE Comments," comments filed in *RE: Petition for Approval of Demand-Side Management Plan of Progress Energy Florida*, Florida Public Service Commission Docket No.

100160-EG (August 3, 2010).

Southern Alliance for Clean Energy, comments filed in *RE: Petition for Approval of Demand-Side Management Plan of Gulf Power Company*, Florida Public Service Commission Docket No. 100154-EG, also filed in Dockets 100155, 57, 59, 60 and 61-EG (July 14, 2010).

John D. Wilson, "Bringing Energy Efficiency to Southerners," Environmental and Energy Study Institute panel on "Energy Efficiency in the South" (April 10, 2010).

John D. Wilson, "The Changing Face of Energy Supply in Florida (and the Southeast)," 37th Annual PURC Conference (February 2010).

John D. Wilson, "Florida Energy Policy Discussion," testimony before Energy & Utilities Policy Committee, Florida House of Representatives (January 2010).

John D. Wilson, "Building the Energy Efficiency Resource for the TVA Region," presentation on behalf of Southern Alliance for Clean Energy to the Tennessee Valley Authority Integrated Resource Planning Stakeholder Review Group (December 10, 2009).

John D. Wilson, "An Advocates Perspective on the Duke Save-a-Watt Approach," ACEEE 5th National Conference on Energy Efficiency as a Resource (September 2009).

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Southern Alliance for Clean Energy, Comments in *RE: Establishment of Rule on Renewable Portfolio Standard*, Florida Public Service Commission Docket No. 080503-EI (September 5, 2008).

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John D. Wilson, "Clean Energy Solutions for Western North Carolina," presentation to Progress Energy Carolinas WNC Community Energy Advisory Council (February 7, 2008).

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Environmental Defense, Southern Alliance for Clean Energy, and Southern Environmental Law Center, comments in *Rulemaking Proceeding to Implement Session Law 2007-397*, North

Carolina Utilities Commission Docket No. E-100, Sub 113 (November 12, 2007).

Environmental Defense, Southern Alliance for Clean Energy, and Southern Environmental Law Center, comments in *Rulemaking Proceeding to Implement Session Law 2007-397*, North Carolina Utilities Commission Docket No. E-100, Sub 113 (September 21, 2007).

Southern Alliance for Clean Energy and the Natural Resources Defense Council, *Comments and Suggestions of the Southern Alliance for Clean Energy, and of the Natural Resources Defense Council, Pertaining to Rulemaking on a Renewable Portfolio Standard*, Florida Public Service Commission Undocketed Comments (September 2007).

Published Papers, Reports and Books

Southern Alliance for Clean Energy, *Cleaner Energy for Southern Company: Finding a Low Cost Path to Clean Power Plan Compliance* (July 2015).

Southern Alliance for Clean Energy, *Increased Levels of Renewable Energy Will Be Compatible with Reliable Electric Service in the Southeast* (November 2014).

Southern Alliance for Clean Energy, *Renewable Energy Standard Offer: A Tennessee Valley Authority Case Study* (November 2012).

Southern Alliance for Clean Energy, *Recommendations For Feed-In-Tariff Program Implementation In The Southeast Region To Accelerate Renewable Energy Development* (March 2011).

John D. Wilson, Tom Franks and J. Richard Hornby, "Seeking Consistency in Performance Incentives for Utility Energy Efficiency Programs," *2010 American Council for an Energy-Efficient Economy Summer Study on Energy Efficiency in Buildings* (August 2010).

John D. Wilson, "Energy Efficiency Program Impacts and Policies in the Southeast," Southern Alliance for Clean Energy (May 2009).

Dennis Creech, Eliot Metzger, Samantha Putt Del Pino, John D. Wilson, *Local Clean Power*, World Resources Institute Issue Briefs (April 2009).

Dennis Creech, Eliot Metzger, Samantha Putt Del Pino, John D. Wilson, *Green in the Grid: Renewable Electricity Opportunities in the Southeast United States*, World Resources Institute Issue Briefs (April 2009).

Southern Alliance for Clean Energy, *Yes We Can: Southern Solutions for a National Renewable Energy Standard* (February 2009).

Southern Alliance for Clean Energy, *Cornerstones: Building a Secure Foundation for North Carolina's Energy Future* (May 2008).

Southern Alliance for Clean Energy, *Bringing Clean Energy to the Southeastern United States: Achieving the Federal Renewable Energy Standard* (February 2008).

Galveston Houston Association for Smog Prevention, *Whiners Matter! Citizen Complaints Lead to Improved Regional Air Quality Control* (June 2006).

Galveston Houston Association for Smog Prevention, *Exceeding the Limit: Industry Violations of New Rule Almost Slid Under State's Radar* (January 2006).

Galveston Houston Association for Smog Prevention, *Mercury in Galveston and Houston Fish: Contamination by Neurotoxin Places Children at Risk* (October 2004).

Environmental Integrity Project and Galveston Houston Association for Smog Prevention, *Who's Counting: The Systematic Underreporting of Toxic Air Emissions* (June 2004).

Galveston Houston Association for Smog Prevention, *Reducing Air Pollution From Houston-Area School Buses* (March 2004).

Galveston Houston Association for Smog Prevention, *Smoke in the Water: Air Pollution Hidden in the Water Vapor from Cooling Towers – Agencies Fail to Enforce Against Polluters* (February 2004).

Office of Program Policy Analysis and Government Accountability, *Florida Water Policy: Discouraging Competing Applications for Water Permits; Encouraging Cost-Effective Water Development,* Report No. 99-06 (August 1999).

John D. Wilson, Janet E. Kohlhase, and Sabrina Strawn, "Quality of Life and Comparative Risk

in Houston," *Urban Ecosystems*, Vol. 3, Issue 2 (July 1999).

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Houston Advanced Research Center, *Policy Options: Responding to Climate Change in Texas*, US EPA and Texas Water Commission (October 1993).

2012

Duke Energy Carolinas 2012 Generation Reserve Margin Study

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Executive Summary

The reserve margin study performed by Astrape Consulting was requested by Duke Energy Carolinas in response to North Carolina Utilities Commission Order dated October 26, 2011 in Docket No. E -100, Sub 128. The Order requires DEC to perform a comprehensive reserve margin study and include it as part of its 2012 biennial IRP report.

The optimal planning reserve margin for Duke Energy is based on providing an acceptable level of physical reliability and minimizing economic costs to customers. Customers generally expect power to be available 24 hours a day, 365 days a year, but it is economically unreasonable for a load serving entity to maintain enough reserves to meet this expectation. From a physical reliability perspective, Loss of Load Expectation (LOLE) decreases as reserve margin increases. The most common physical metric used in the industry is to target a system reserve margin that meets the one day in 10 year standard which is interpreted as one firm load shed event every 10 years (LOLE = 0.1). A firm load shed event occurs when load plus spinning reserves is greater than available capacity and all options including market purchases and demand response have been exhausted. This results in unserved energy for a firm customer. From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. The economic optimum is defined as the point where the cost of additional reserves plus the cost of reliability events on customers is minimized. For this study, reserve margin is defined as the following:

- Reserve Margin = (Resources – Demand) / Demand
  - Demand is the Average Summer System Peak Load and has not been reduced by Demand Response
  - Resources are defined based on summer ratings and include Demand Response
  - The solar capacity within the study was given a 50% capacity credit while wind was given a 15% capacity credit (consistent with the 2011 IRP)

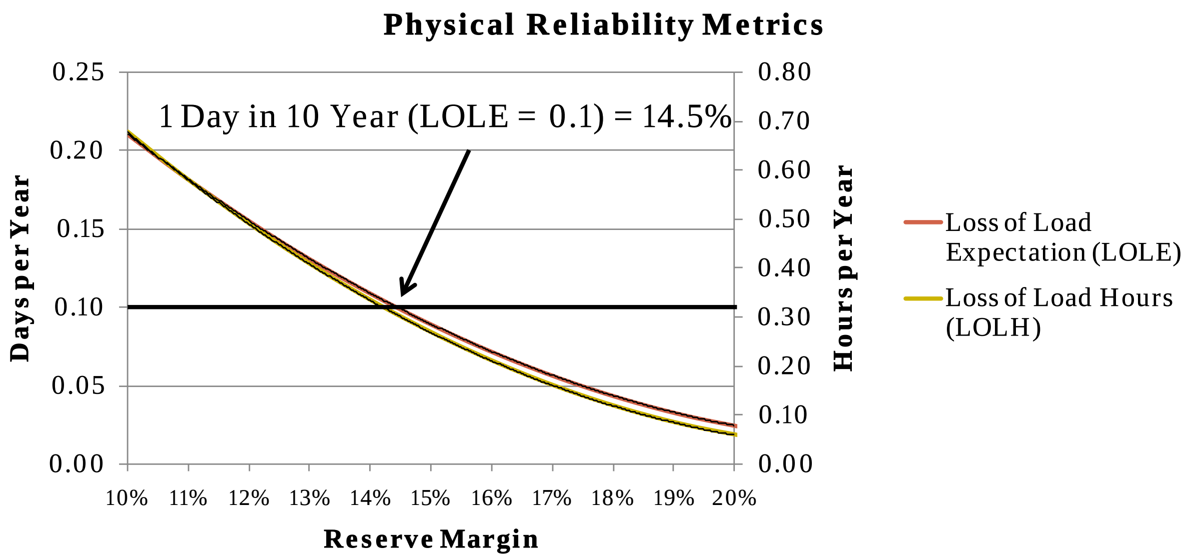
Astrape Consulting has taken a stochastic approach in modeling the uncertainty of weather, economic load growth, unit availability, hydro availability, and transmission availability for emergency tie assistance. Utilizing a multi-area reliability model called SERVM (Strategic Energy and Risk Valuation Model), over 1 million yearly simulations were performed at various reserve margins to calculate the physical reliability metrics and corresponding expected reliability costs. The physical metrics and reliability costs were used to determine an optimal planning reserve margin.

From an economic perspective, the study defines the capacity costs as the annual carrying costs associated with the marginal resource which for this study is a new natural gas combustion turbine. The study defines reliability energy costs as any energy costs the system experiences above the dispatch cost of the marginal resource. These costs include the dispatch of expensive peaking resources such as oil CTs, net imports of expensive market purchases during capacity shortages, and the societal cost of unserved energy.

Summary of Results and Key Insights

The reserve margin that results in 1 day in 10 year LOLE (0.1 days per year) is 14.5% as shown in Figure ES1. Loss of load hours (LOLH) approaches 0.30 hours per year at the 14.5% reserve margin.

Figure ES1. Physical Reliability Metrics



In resource adequacy simulations, firm load shed events are sensitive to inputs due to their infrequent nature. Weather diversity, transmission availability, neighbor reserve levels, and emergency hydro assumptions can shift the 0.1 LOLE reserve margin by several percentage points as shown in the sensitivity section of the report. As an example, emergency hydro assumptions impacted Duke's system LOLE substantially. If the portion of the 1,100 MW hydro capacity that is designated as emergency capacity is available to be used a few hours a month, then the target LOLE reserve margin shifts from 14.50% to 11.25%. This emergency designated block varies by year and month, but during drought conditions, it represents 700-750 MW of unavailable capacity as seen in 2007 and 2008. From a planning perspective, it is difficult to assess the availability of this capacity during drought conditions, and given experience in recent drought years such as 2007 and 2008, it is not prudent to expect this capacity to be available during peak conditions. However, by approaching resource adequacy planning from a more holistic perspective, the target reserve margin is not as sensitive to individual inputs. For this reason, we recommend assessing the economics in addition to the physical reliability metrics. This allows planners to not only assess the comprehensive benefits of incremental capacity, it also allows for better calibration of physical reliability metrics.

The economic reliability assessment which balances the costs and benefits of incremental capacity is seen in Figure ES2 which demonstrates that the long-term minimum cost reserve margin is 14%. As reserve margin increases, the CT carrying costs rise and the reliability energy costs made up of production costs above a CT, net imports above a CT, and expected unserved energy decrease. Between 14% and 16%, the flatness of the curve indicates that there is not a significant cost impact to being slightly above the minimum cost point. Since resource additions are too large to perfectly target a reserve margin, some years will inevitably result in reserve margins that are higher than the average economic optimum. The expected financial impact of these additions is not substantial, since the capacity above the weighted average target also brings some financial benefit. For example, the annual expected difference in cost between the 14% reserve margin and 16% reserve margin is only $9 million and can provide substantial risk benefit.

Figure ES2. Minimum Weighted Average Cost Reserve Margin

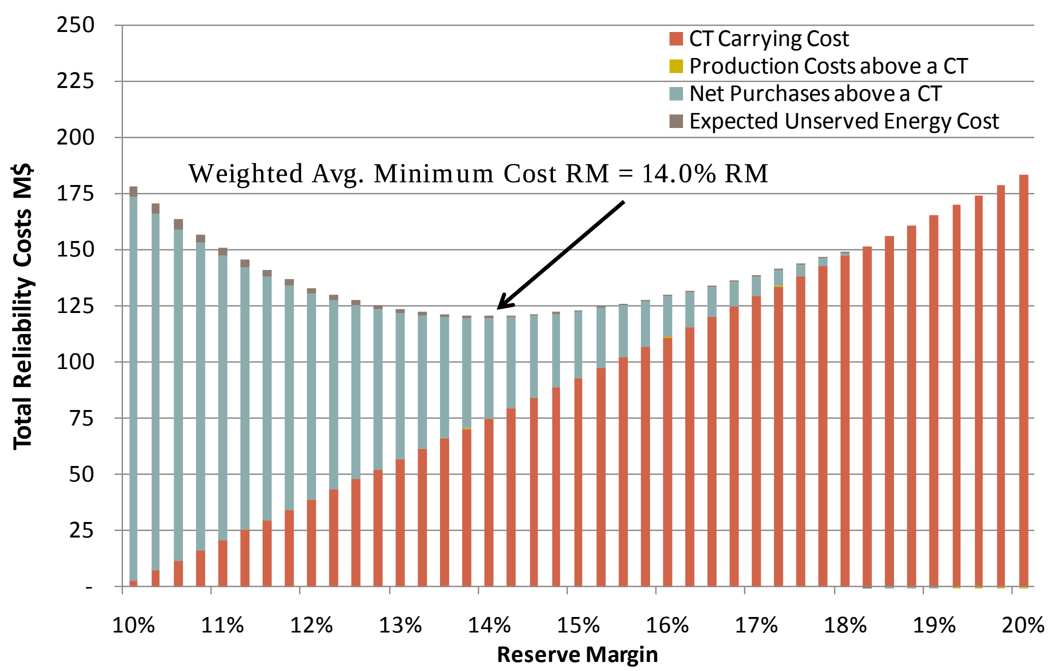
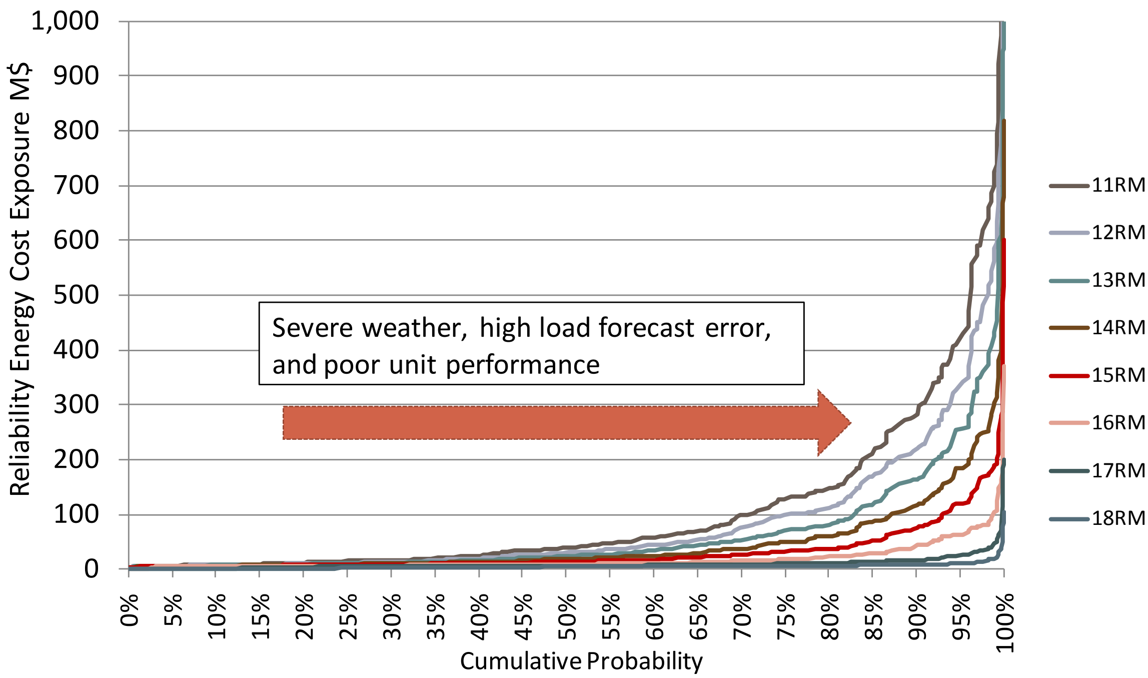


Figure ES3 demonstrates the distribution of reliability energy costs seen in Figure ES2 at each reserve margin level. It should be noted that even at the economic optimum reserve margin of 14% there is still potential for high reliability cost years due to abnormal weather, economic growth, or poor unit performance in the region as shown in the following figure. At a 14% reserve margin, there is a 5% chance that reliability energy costs could exceed $185 million in any given year and a 1% chance that it could exceed $303 million.

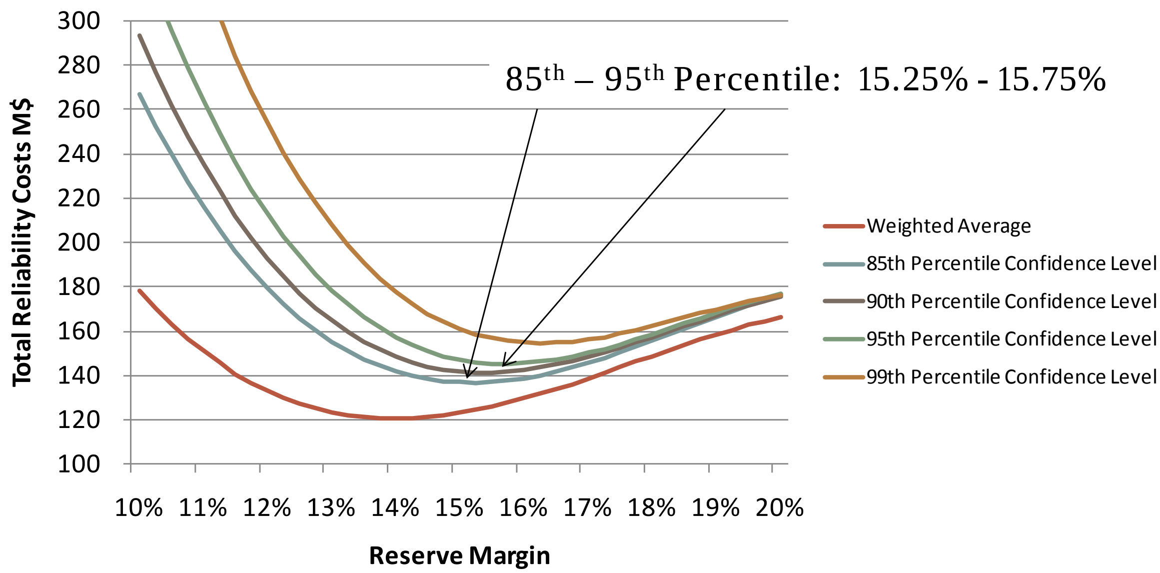
Figure ES3. Distribution of Reliability Energy Costs



Next we examined the optimal economic reserve margin recognizing the different risk profile of energy costs and capacity costs. By comparing capacity costs to reliability energy costs during years with extreme weather or poor unit performance as seen in Figure ES3, we assessed the tail benefit of additional capacity. The reliability energy costs seen in Figure ES3 were taken at different confidence levels (85%, 90%, 95%, and 99% probabilities) and added to the fixed capacity costs at each reserve margin to form the confidence level curves in Figure ES4. This assessment showed that in 10% of all scenarios, Duke

Energy would receive an economic benefit by adding efficient natural gas turbines up to a reserve margin of 15.50%. This is shown by the 90% confidence level curve in Figure ES4. As stated previously, when we review the weighted average curve in the same figure we can see that by adding capacity to achieve a 16% reserve margin versus a 14% reserve margin, average annual costs only increase by $9 million, but the additional capacity acts as an insurance product to customers. In fact, 10% of the time customers would see their cost exposure decrease by at least $70 million in any given year as seen in Figure ES3.

Figure ES4. Optimal Reserve Margins over a Range of Confidence Intervals



Recommendation

Astrape recommends that Duke set its absolute minimum reserve margin at the 14.5% LOLE target (LOLE = 0.1) and recommends a target of 15.50% based on the 90% confidence level economic target. Since capacity is added in large blocks to take advantage of economies of scale, the actual reserve margin will often be somewhat higher than the target threshold of 15.5%. As shown in the charts and data above, a reserve margin target in the range of 14.5% to 16% produces similar total customer costs whether at the low end or high end of the range. To accommodate large resource additions such as nuclear, coal, or even larger combined cycle resources, the reserve margin would likely rise above the top end of the reserve margin range. However, the additional production cost and economy of scale benefits provided by such resources would likely justify their addition. Therefore, the recommended target reserve margin of 15.50% with a range of 14.5% to 16% should not be considered absolute as all resource decisions should be made on a case-by-case basis.

I. List of figures

II. List of tables

III. Input Assumptions

A. Study Year

The selected study year is 2016. The year 2016 was chosen because it is three to four years into the future which is indicative of the amount of time needed to permit and construct a new generating facility. By looking three to four years out, this study reflects a longer term optimal reserve margin. Lower economic load forecast error as well as surrounding market conditions could potentially allow the company to carry slightly lower reserves in the short term.

Although 2016 was selected for the base case simulations, the SERVM simulation results should apply for the 3 to 5 year period following 2016 assuming that resource mixes and market structures do not change drastically over that term. To that end, several sensitivities were run to reflect changes in the market that could occur in this time period as well as a look at a 2023 Study Year.

B. Load Modeling

Table 1. 2016 Load Forecast

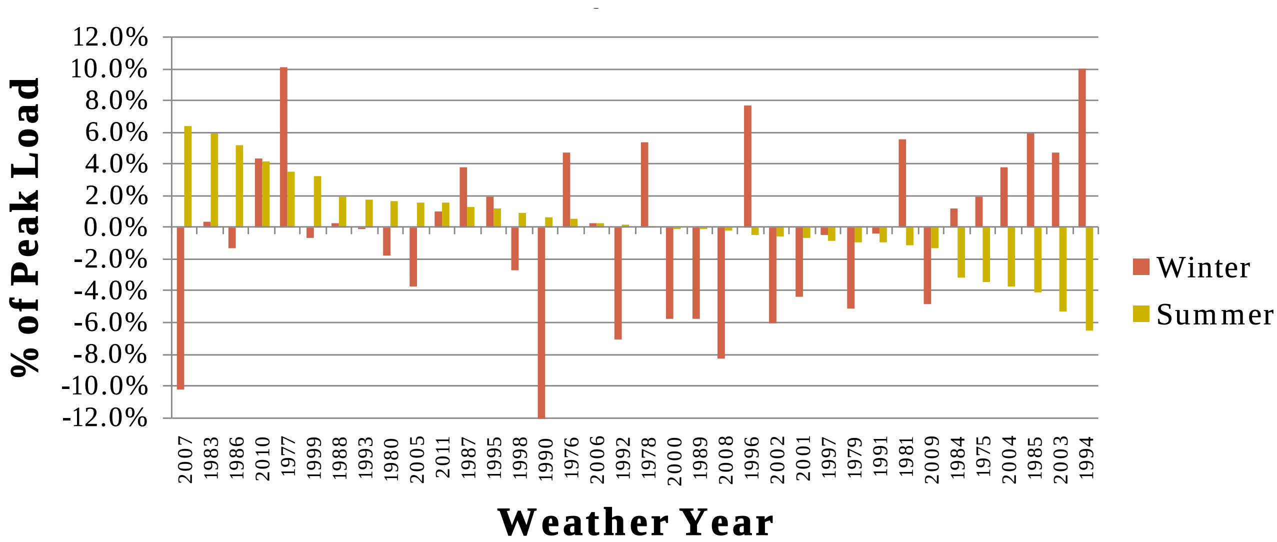
Month	Energy (MWh)	Peak Load (MW)
January	9,163,558	18,891
February	8,191,438	18,033
March	7,845,982	16,797
April	7,311,837	14,012
May	7,885,201	16,407
June	9,015,082	18,675
July	9,509,029	19,476
August	9,595,229	19,075
September	8,256,070	17,595
October	7,486,890	14,687
November	7,541,890	16,048
December	8,669,874	17,756

Table 1 displays the peak and energy forecasts for 2016 under normal weather conditions. The company is expected to have a winter peak of 18,891 MW and a summer peak of 19,476 MW. All values include the reduction for energy efficiency but exclude any other DSM reductions.

To model the effects of weather uncertainty, 37 historical weather years were developed to reflect the impact of weather on load. A neural network program was used to develop relationships between weather observations and load based on the last five years of historical weather and load. Different relationships were built for each month of the year using hourly temperature, time of day, day of week, 8 hour prior temperature, 24 hour prior temperature, 48 hour prior temperature, and heating and cooling degree hours.

These relationships were then applied to the last 37 years of weather to develop 37 load shapes for 2016. Equal probabilities were given to each of the 37 load shapes in the simulation. Figure 1 ranks all weather years by peak summer load for the system. In the most severe weather conditions, the summer peak can be approximately 6% higher than the peak under normal weather conditions and 10% for the winter. The reason for the larger variation in winter loads is the larger variation of temperature versus normal weather of 10 to 13 degrees whereas in the summer maximum variation versus normal weather is only 6 degrees.

Figure 1. Peak Load Variability Vs. Normal Weather



The difference in frequency of high load periods during winter versus summer can be seen in Figure 2. The duration of high load is far less in the winter causing the summer to have higher reliability risk. So despite higher variation in winter peak loads, sustained high loads in the summer cause the majority of reliability events.

Figure 2. Frequency of High Load Hours for Winter and Summer

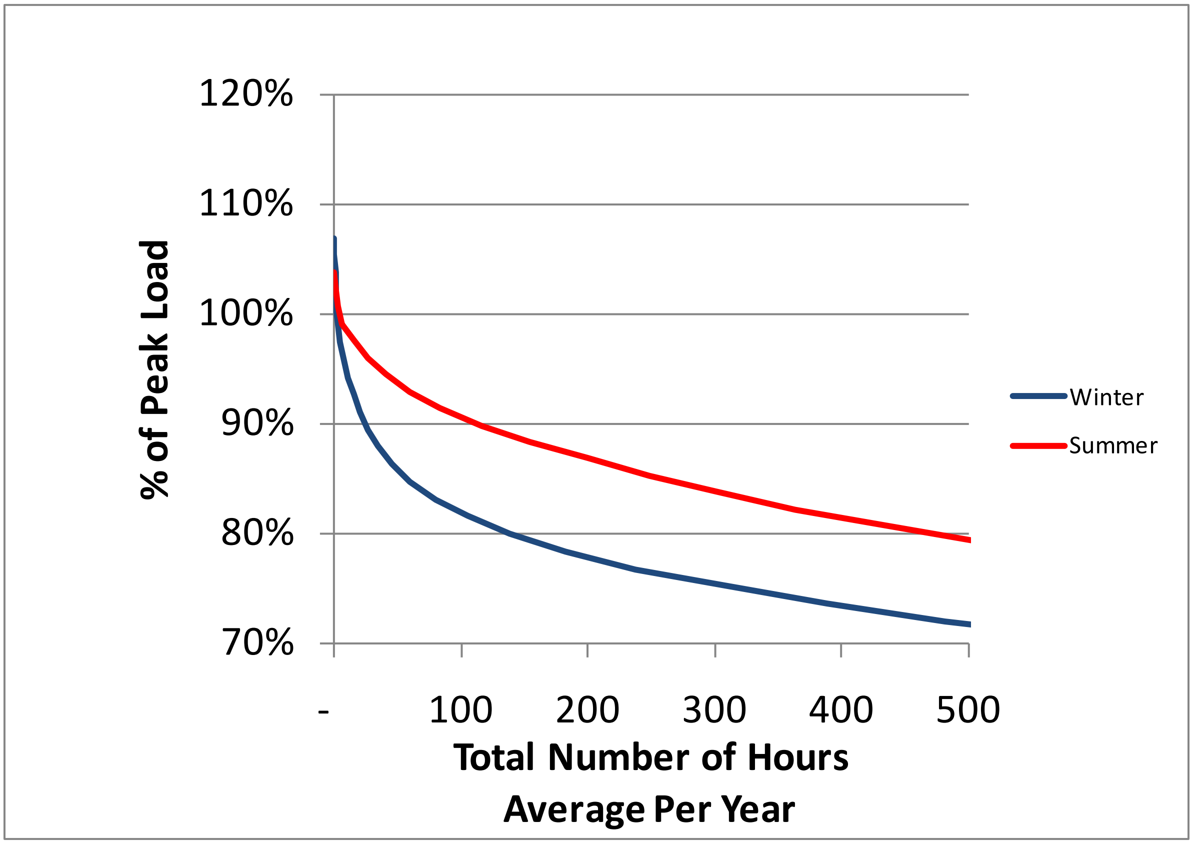


Table 2 summarizes the combined summer and winter peaks by weather year. The table shows that recent years including 2007 and 2010 were among the most severe summers.

Table 2. 2016 Peak Load Rankings for All Weather Years

Summer Peaks

Max	20,721	6.40%
Forecast	19,476	

Winter Peaks

Max	20,798	10.1%
Forecast	18,891	

Rank	Year	Peak	Versus Forecast (%)	Rank	Year	Peak	Versus Forecast (%)
1	2007	20,721	6.4%	1	1977	20,798	10.1%
2	1983	20,634	5.9%	2	1982	20,798	10.1%
3	1986	20,485	5.2%	3	1994	20,778	10.0%
4	2010	20,289	4.2%	4	1996	20,347	7.7%
5	1977	20,156	3.5%	5	1985	20,015	5.9%
6	1999	20,106	3.2%	6	1981	19,944	5.6%
7	1988	19,856	2.0%	7	1978	19,902	5.4%
8	1993	19,808	1.7%	8	2003	19,790	4.8%
9	1980	19,789	1.6%	9	1976	19,777	4.7%
10	2005	19,777	1.5%	10	2010	19,713	4.3%
11	2011	19,772	1.5%	11	1987	19,614	3.8%
12	1987	19,729	1.3%	12	2004	19,605	3.8%
13	1995	19,702	1.2%	13	1995	19,259	1.9%
14	1998	19,645	0.9%	14	1975	19,254	1.9%
15	1990	19,600	0.6%	15	1984	19,121.20	1.2%
16	1976	19,583	0.6%	16	2011	19,082	1.0%
17	2006	19,533	0.3%	17	1983	18,950	0.3%
18	1992	19,517	0.2%	18	2006	18,947	0.3%
19	1978	19,492	0.1%	19	1988	18,934	0.2%
20	2000	19,462	-0.1%	20	1993	18,884	0.0%
21	1989	19,461	-0.1%	21	1991	18,823	-0.4%
22	2008	19,429	-0.2%	22	1997	18,801	-0.5%
23	1996	19,388	-0.4%	23	1999	18,761	-0.7%
24	2002	19,362	-0.6%	24	1986	18,650	-1.3%
25	2001	19,345	-0.7%	25	1980	18,561	-1.7%
26	1997	19,317	-0.8%	26	1998	18,383	-2.7%
27	1979	19,300	-0.9%	27	2005	18,192	-3.7%
28	1991	19,288	-1.0%	28	2001	18,068	-4.4%
29	1981	19,247	-1.2%	29	2009	17,969	-4.9%
30	2009	19,225	-1.3%	30	1979	17,929	-5.1%
31	1984	18,859	-3.2%	31	2000	17,809	-5.7%
32	1975	18,797	-3.5%	32	1989	17,807	-5.7%
33	2004	18,750	-3.7%	33	2002	17,745	-6.1%
34	1985	18,670	-4.1%	34	1992	17,551	-7.1%
35	2003	18,446	-5.3%	35	2008	17,325	-8.3%
36	1994	18,202	-6.5%	36	2007	16,953	-10.3%
37	1982	17,849	-8.4%	37	1990	16,130	-15%

From an annual energy perspective, the following table shows the top 10 highest weather years. Table 3 shows that 2010 had energy consumption 5% higher than normal as both winter and summer seasons were severe. The second highest weather year was only 2.5% higher than average energy.

Table 3. Weather Years Ranked by Total Energy

Annual Energy
Top 10

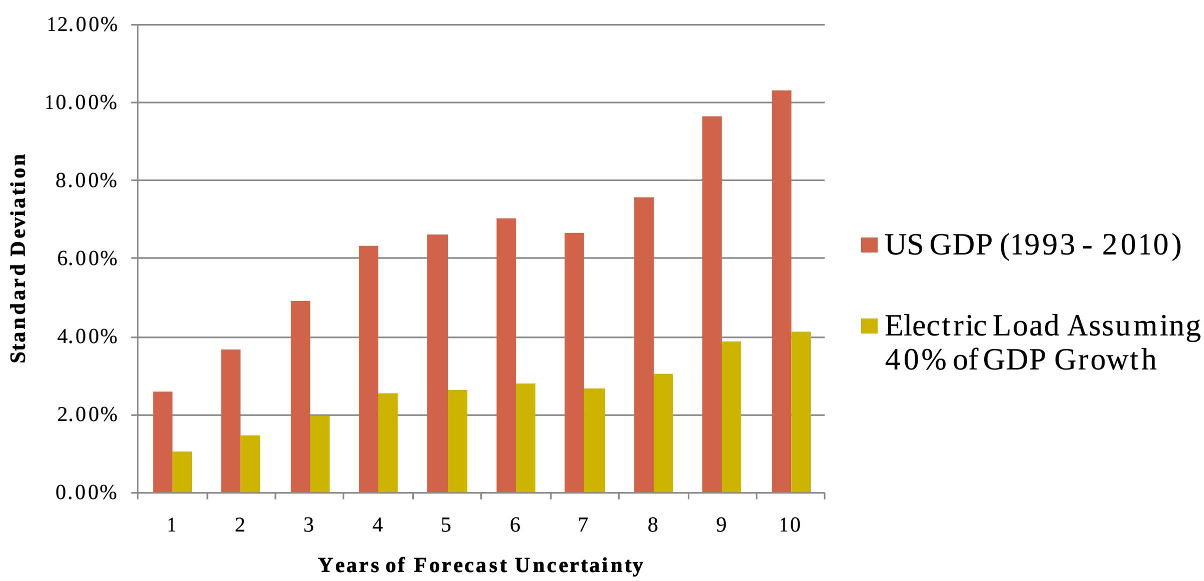
Max	106,073,456	5.0%
Forecast	101,065,715	

Rank	Year	Peak	Versus Forecast (%)
1	2010	106,073,456	5.0%
2	1977	103,627,852	2.5%
3	1993	103,014,691	1.9%
4	1980	102,568,028	1.5%
5	1987	102,319,099	1.2%
6	1978	102,300,173	1.2%
7	1986	102,249,879	1.2%
8	2007	102,241,193	1.2%
9	1981	102,065,451	1.0%
10	1988	101,879,158	0.8%

C. Load Forecast Error

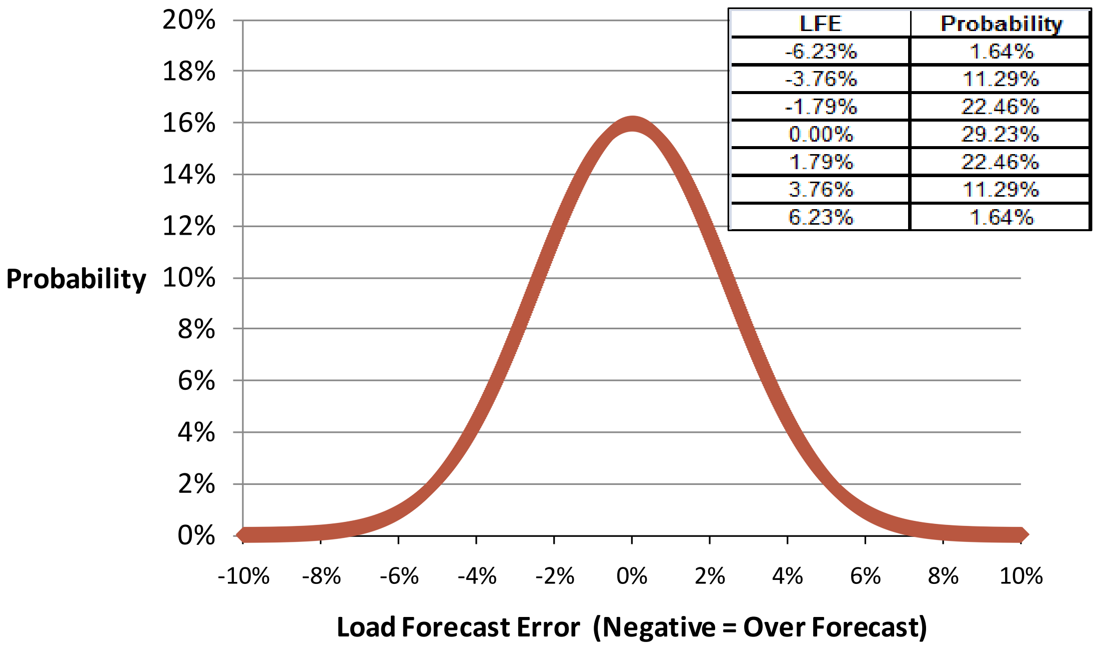
An analysis was performed using the historical Congressional Budget Office four year prior forecasts of GDP and comparing those forecasts to actual data from 1993 – 2010. Comparing how well GDP was predicted four years in advance provides insight into the economic uncertainty that should be applied to utility loads. The chart below shows the standard deviation of historical GDP forecast error for forecasting one to ten years in advance. As expected, the standard deviation of forecast error increases as the number of years increase. Based on discussions with Duke, electric load is assumed to grow at about 40% of GDP growth. Assuming four year forecast error, standard deviation for load forecast error uncertainty for utility load is 2.5% as shown in the following figure. If lead times for new generation changed substantially, then the standard deviation used to develop the economic load forecast error would need to be adjusted accordingly. However, it is unlikely that typical generation resources can be installed and brought in-service in less than three to four years given the time needed for environmental and regulatory approvals, construction, and startup testing.

Figure 3. Standard Deviation of GDP forecast error (1 to 10 Year Projections)



Astrape also performed a comparison of the company's historical four year prior forecasts to actual weather normalized load. Astrape observed that in recent years there was a tendency to over forecast given the economic downturns seen in the last decade. However, the standard deviation of load forecast error was 3.34%, which was in the range of the CBO study. The company and Astrape determined that using 2.5% was a reasonable value for the standard deviation and Astrape developed a normal distribution as shown in the following Figure 4. The continuous distribution was converted into a discrete distribution with the 7 points shown for use in determining discrete scenarios to be modeled. As an example of how to interpret the economic uncertainty data, there is a 1.64% chance that load will be 6.23% greater than forecasted.

Figure 4. Load Forecast Error



LFE	Probability
-6.23%	1.64%
-3.76%	11.29%
-1.79%	22.46%
0.00%	29.23%
1.79%	22.46%
3.76%	11.29%
6.23%	1.64%

SERVM utilized each of the 37 weather years and applied each of these seven load forecast error points to create 259 different load scenarios.

D. Resources

The resources and seasonal capacities for the 2016 study are shown in the following tables.

Table 4. Nuclear Resource Capacities (MW)

Unit Name	January	July
Catawba 1	891	857
Catawba 2	881	847
McGuire 1	900	844
McGuire 2	900	844
Oconee 1	875	856
Oconee 2	875	856
Oconee 3	875	856
Totals	6,196	6,196

Table 5. Baseload and Intermediate Resource Capacities (MW)

Unit Name	January	July
Allen 1	167	162
Allen 2	167	162
Allen 3	270	261
Allen 4	282	276
Allen 5	275	266
Belews Creek 1	1135	1110
Belews Creek 2	1135	1110
Cliffside 5	562	556
Cliffside 6	825	825
Marshall 1	380	380
Marshall 2	380	380
Marshall 3	658	658
Marshall 4	660	660
Buck CC	508	500
Buck CC Duct	120	120
Dan River CC	508	500
Dan River CC Duct	120	120
CPL SOR A	2	2
CPL SOR D	3	3
CPL SOR E	2	2
NUG	26	26
Totals	8,185	8,079

Retired by 2016
Buck 3
Buck 4
Buck 5
Buck 6
Cliffside 1
Cliffside 2
Cliffside 3
Cliffside 4
Dan River 1
Dan River 2
Dan River 3
Riverbend 4
Riverbend 5
Riverbend 6
Riverbend 7

Table 6. Peaking Resource Capacities (MW)

Unit Name	January	July
Lee 1 NG	100	100
Lee 2 NG	100	102
Lee 3 NG	170	170
Lee CT1	41	41
Lee CT2	41	41
Lincoln CT1	93	79.2
Lincoln CT2	93	79.2
Lincoln CT3	93	79.2
Lincoln CT4	93	79.2
Lincoln CT5	93	79.2
Lincoln CT6	93	79.2
Lincoln CT7	93	79.2
Lincoln CT8	93	79.2
Lincoln CT9	93	79.2
Lincoln CT10	93	79.2
Lincoln CT11	93	79.2
Lincoln CT12	93	79.2
Lincoln CT13	93	79.2
Lincoln CT14	93	79.2
Lincoln CT15	93	79.2
Lincoln CT16	93	79.2

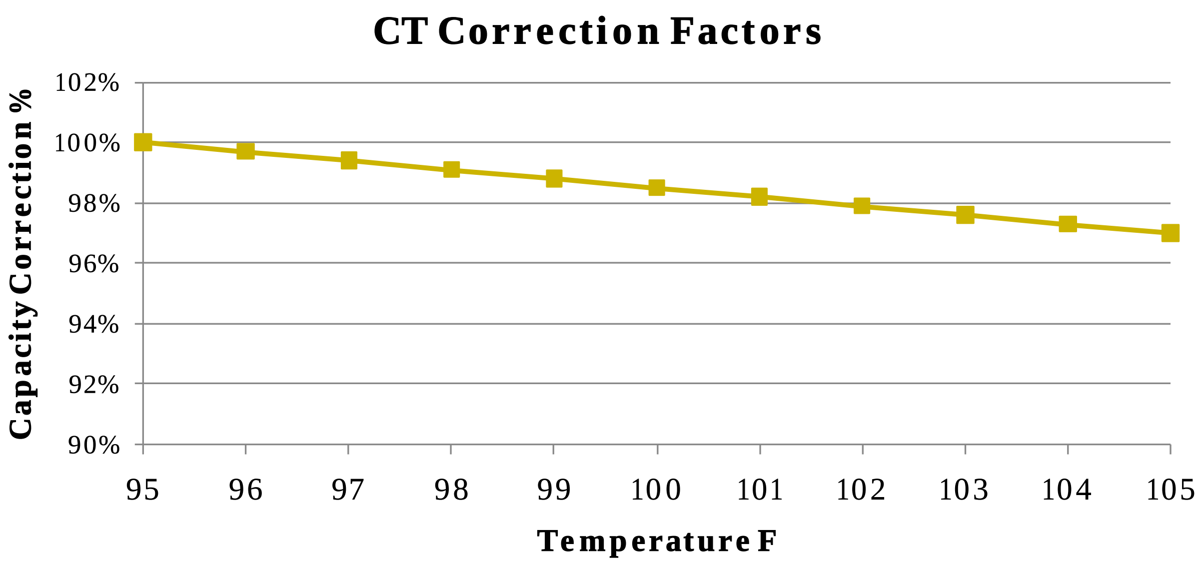
Unit Name	January	July
MillCreek CT1	92	74
MillCreek CT2	92	74
MillCreek CT3	92	74
MillCreek CT4	92	74
MillCreek CT5	92	74
MillCreek CT6	92	74
MillCreek CT7	92	74
MillCreek CT8	92	74
Rockingham CT1	165	165
Rockingham CT2	165	165
Rockingham CT3	165	165
Rockingham CT4	165	165
Rockingham CT5	165	165
Anson Hamlet CT	4	4
CPL Peaking CT	2	2
IRP CT 1	900	740
IRP CT 2*	0	740
Totals	4,410	4,628

Retired by 2016
Buck CT1
Buck CT2
Buck CT3
Buzzard Roost CT1
Buzzard Roost CT2
Buzzard Roost CT3
Buzzard Roost CT4
Buzzard Roost CT5
Buzzard Roost CT6
Buzzard Roost CT7
Buzzard Roost CT8
Buzzard Roost CT9
Buzzard Roost CT10
Dan River CT1
Dan River CT2
Riverbend CT1
Riverbend CT2
Riverbend CT3
Riverbend CT4

*IRP CT 2 is in service in June, 2016

All summer ratings in the previous tables are based on 95 degree F. On an hourly basis, SERVM can adjust the capacity of each resource based on the historical hourly temperature for the weather year being modeled. Because the maximum output of peaking units degrades as temperatures increase, the derating multipliers in Figure 5 were utilized to derate the units above 95 F. The multipliers were developed based on the Duke CT fleet which assumes a degradation of 0.3% of capacity per degree. This ensures correlation of capacity output with load since both are highly dependent on the hourly temperature.

Figure 5. Summer Rating Capacity Multipliers



The hydro portfolio is modeled in segments that include Run of River (ROR), Scheduled (Peak Shaving), and Emergency Capacity. The Run of River segment is dispatched as base load capacity providing its designated capacity every hour of the year. The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. If included, the emergency capacity is used only to prevent firm load shed and the model allows the emergency mode to "borrow" energy from the future dispatch of the scheduled hydro portion with the constraint that the energy amount is enough for only a few hours. Typically hydro resources are not able to be dispatched at their nameplate capacity during peak hours due to water constraints or river flow requirements as seen in 2008. By modeling the hydro resources in these three segments, the model captures the appropriate amount of capacity dispatched during peak periods. See the confidential Appendix for the details regarding hydro capacities.

Figure 6 shows the total breakdown of scheduled versus emergency hydro based on the last 37 years of weather. Out of the total 1,100 MW of capacity owned by the company, only 442 MW on average is dispatched during peak periods. During drought years, less than 390 MWs are dispatched on peak in specific months. For this reason, the use of emergency hydro was not included in the base case results due to recent experience, but a sensitivity was performed that included the additional emergency hydro capacity which could be utilized for a few hours per month.

Figure 6. Scheduled Capacity versus Emergency Capacity

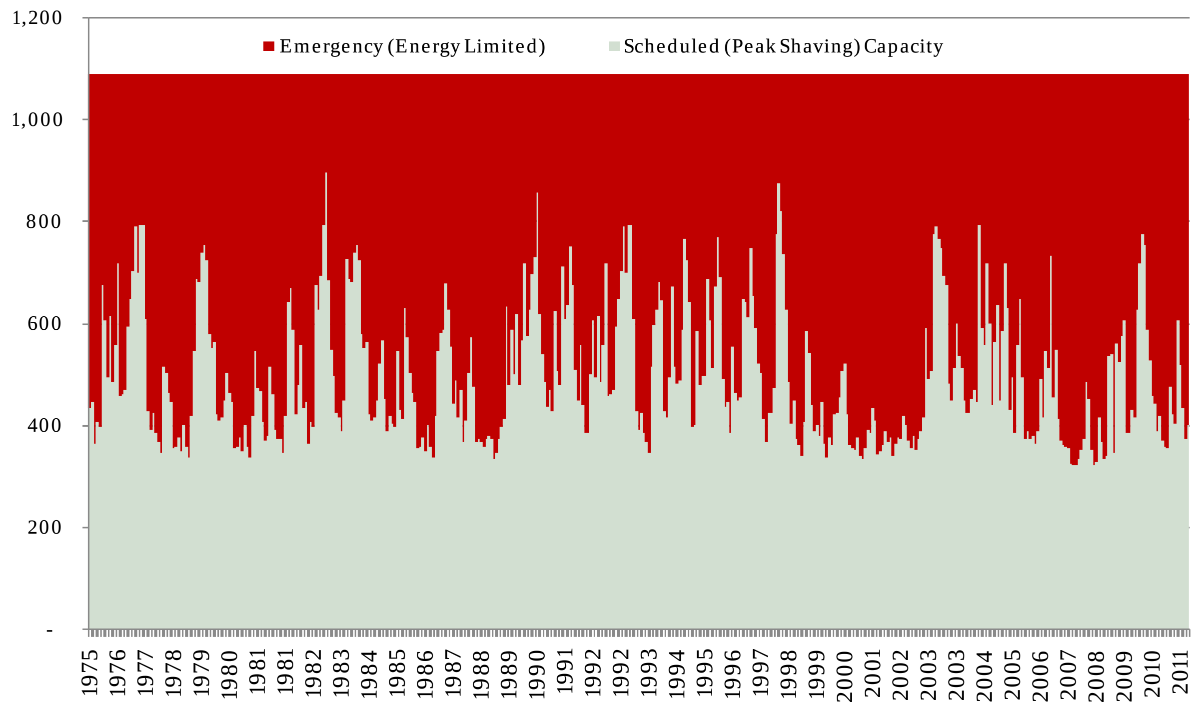


Figure 7 demonstrates the variation of hydro energy by weather year which is input into the model. The drought shown in 2001, 2007, and 2008 is captured in the reliability model.

Figure 7. Hydro Energy by Weather Year

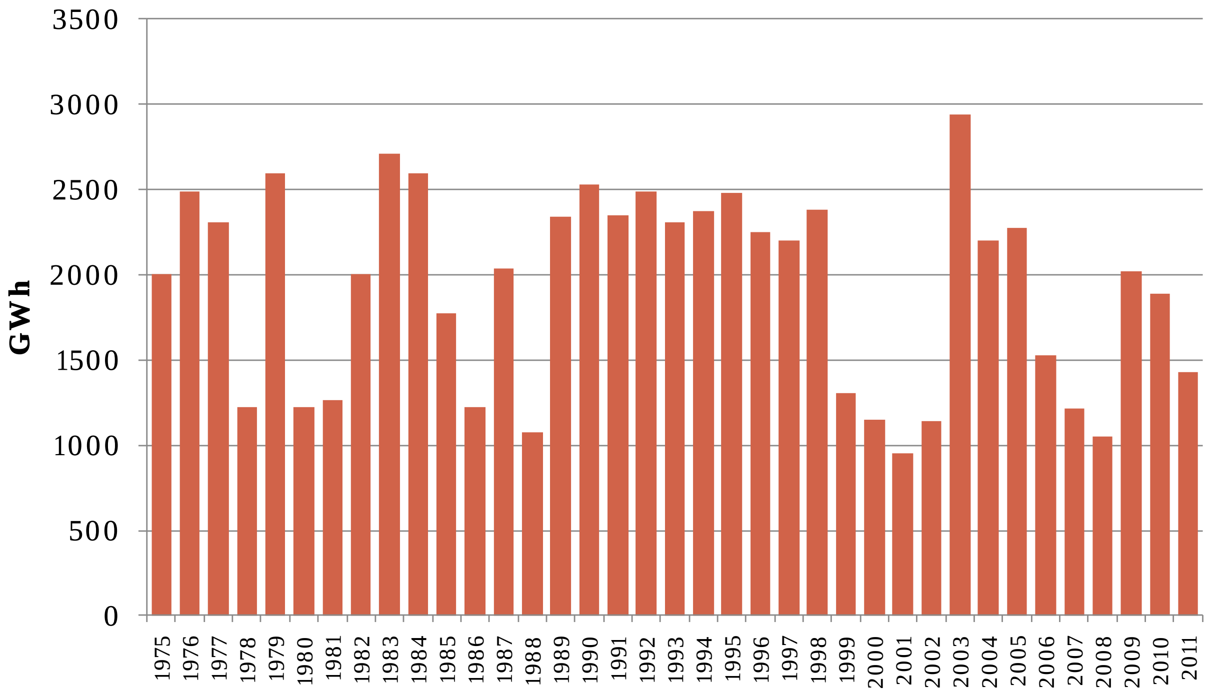


Figure 8 compares actual history of the dispatch level of the hydro resources for a 2008 and 2009 as a percentage of time versus how the model dispatches the resources. The figure demonstrates the drought conditions that were seen in 2008 and also shows that the model is capturing a realistic dispatch of the hydro resources.

Figure 8. Hydo Dispatch Calibration: Percent of Time above Capacity Threshold

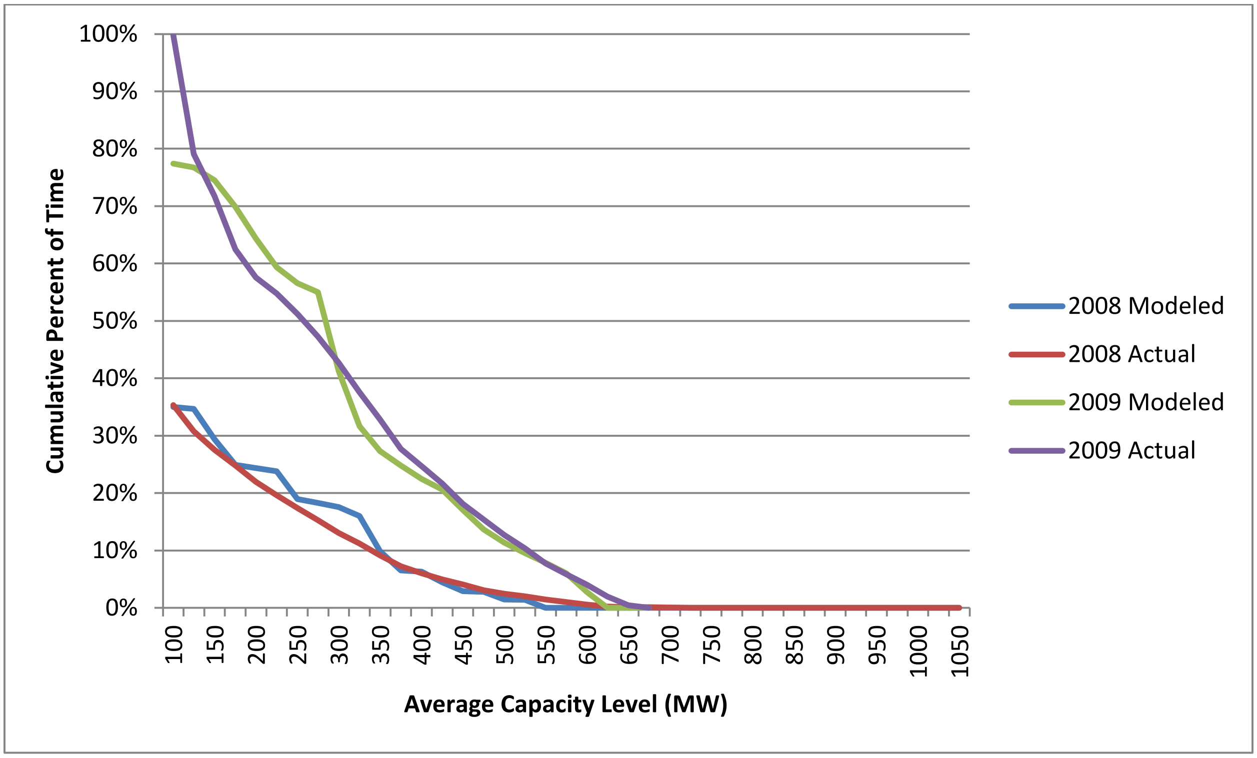


Table 7. Pump Storage Resources

Unit Name	January	July	Reservoir Capacity (MWh)	Reservoir Generating Hours
Bad Creek	1360	1360	33,030	24
Jocasse	780	780	57,540	74

Total	2140	2140

Pumping for pumped storage occurs anytime energy is available. During constrained periods, pumped storage resources are given dispatch priority to maintain a maximum level in the storage ponds. During less constrained periods, the dispatch order is switched so that the energy is used before CT's are dispatched. SERVM uses any excess capacity to fill up the ponds including economic purchases from the market. In actual practice, this process may be performed slightly differently to minimize production cost during off-peak periods. However, the model architecture is appropriate for reliability modeling, because it is always economic to build up the reservoirs of storage units with any generating asset available if that is what is required to have the units available to operate to avoid unserved energy.

Table 8. Renewable Resources

Unit Name	January	July
Solar – Nameplate Capacity	49	49
Wind – Nameplate Capacity	318	318
Landfill Gas	32	32
Poultry_PPA	14	14
Biomass_PPA	134	134
Totals	547	547

For reserve margin calculations, Solar capacity is given a 50% capacity credit and wind capacity is assumed to have a 15% capacity credit. For these resources, an 8760 hourly generation shape was used. The average summer and winter shapes are shown in Figure 9 and Figure 10. For each day, SERVM draws a daily shape from all the days in the month. Because historical data is unavailable, this random draw is used for all weather years.

Figure 9. Solar Profile

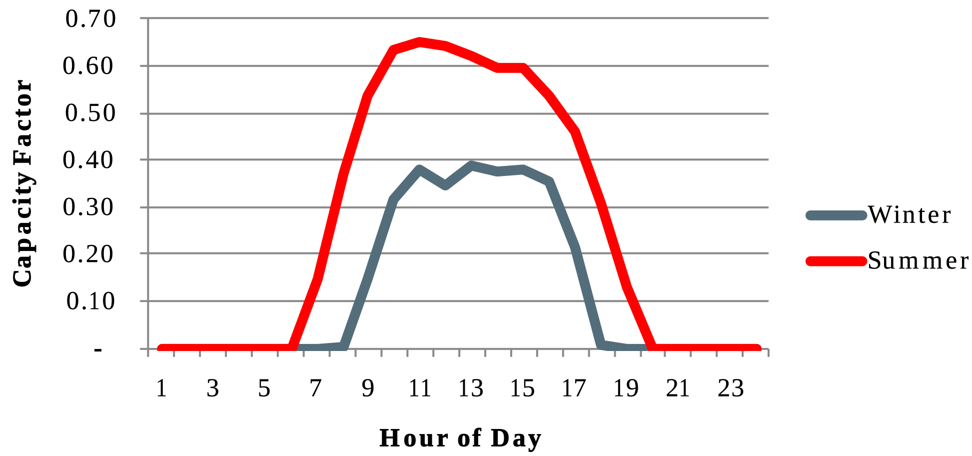
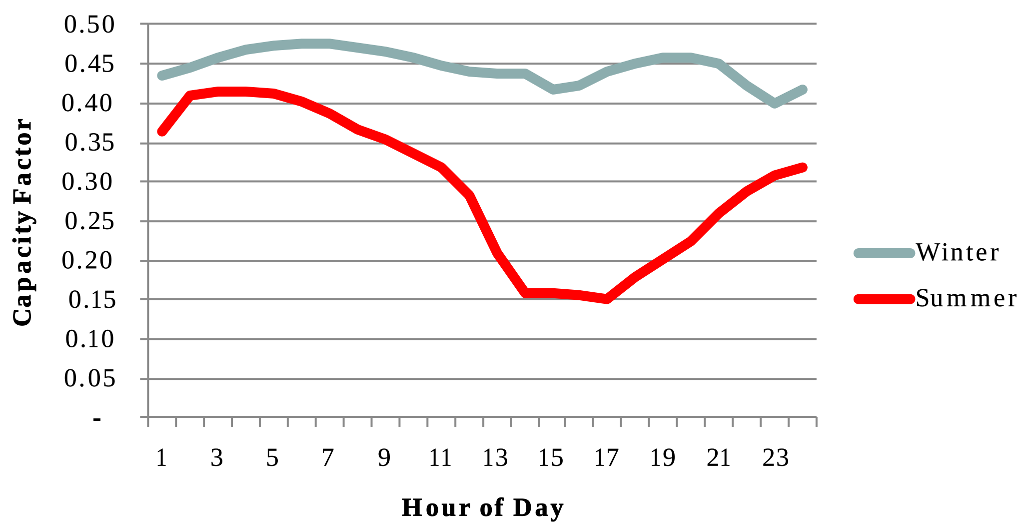


Figure 10. Wind Profile



E. Unit Outage Data

Unlike typical production cost models, SERVM does not use an EFOR for each unit as an input. Instead, historical GADS data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. For this RM Study, 2007-2011 GADS events were entered into SERVM. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Percentage - % of full outages that are maintenance outages. SERVM uses this percentage and allows units to remain online until the following weekend if they are needed in the short term.

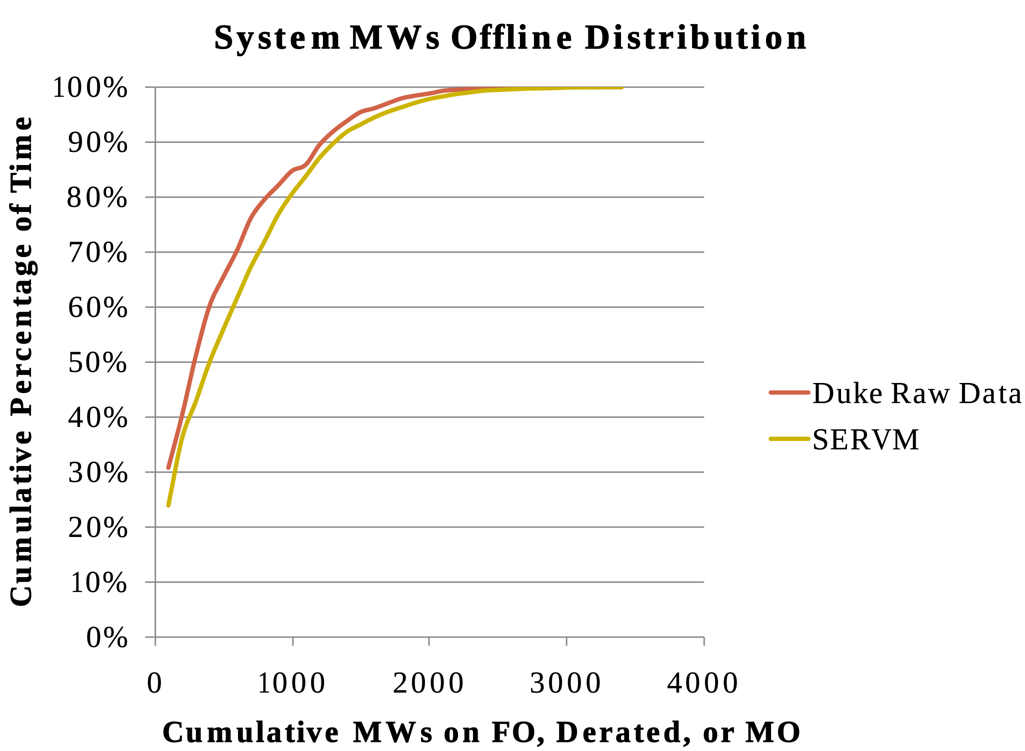
For example purposes, assume that from 2007 – 2011, Allen 1 had 15 full outage events and 30 partial outage events reported in the GADs data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data along with the other variables listed above. These multiple Time-to-Repair and Time-to-Fail distributions are used by SERVM. Because typically there is an improvement in EFOR across the summer, the data is typically broken up into seasons resulting in a set of Time-to-Repair and Time-to-Fail inputs for summer, off peak, and winter based on history. Assume Allen 1 is online in hour 1 of the simulation. SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new

Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture.

Unit Outage Calibration

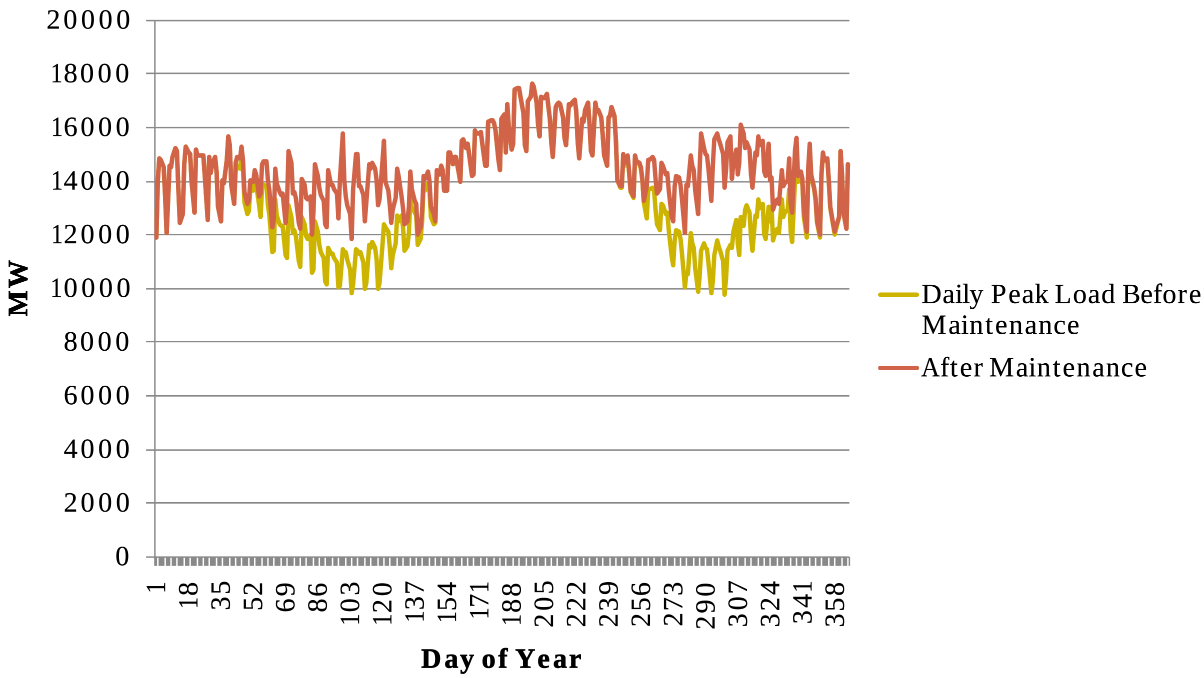
The critical aspect of unit performance modeling for a reliability study is the cumulative MW offline distribution. Most reliability problems are due to significant coincident outages. Figure 11 shows the distribution of outages for Duke Energy. The model has been calibrated to ensure this distribution is captured. Based on the data in the figure 10, the company may have 1,000 MW of capacity offline in 15% of all the hours. This equates to approximately 5% in reserve margin unavailable. System and individual outage rates are located in the confidential Appendix of this report. System and individual outage rates are located in the confidential Appendix of this report.

Figure 11. System Capacity Offline as a Percentage of Time



To capture the impact of planned maintenance, the 2016 maintenance schedule was modeled which removes capacity during the shoulder months of the year. Figure 12 shows that when planned maintenance is assumed in the shoulder months that the resulting load level between winter and shoulder periods is relatively flat.

Figure 12. Daily Peak Load Plus Planned Maintenance Requirement



F. Demand Response

A total of 987 MWs of demand response were modeled in the simulation. Energy efficiency (EE) was directly removed from load in the simulation while the resources in Table 9 were modeled as resources to be called upon given a reliability event. SERVM takes into account the constraints on demand response and dispatches accordingly. These constraints include a maximum number of hours per year, hours per day, days per week, and shadow dispatch price for the resources to be called.

Table 9. Demand Response Summary

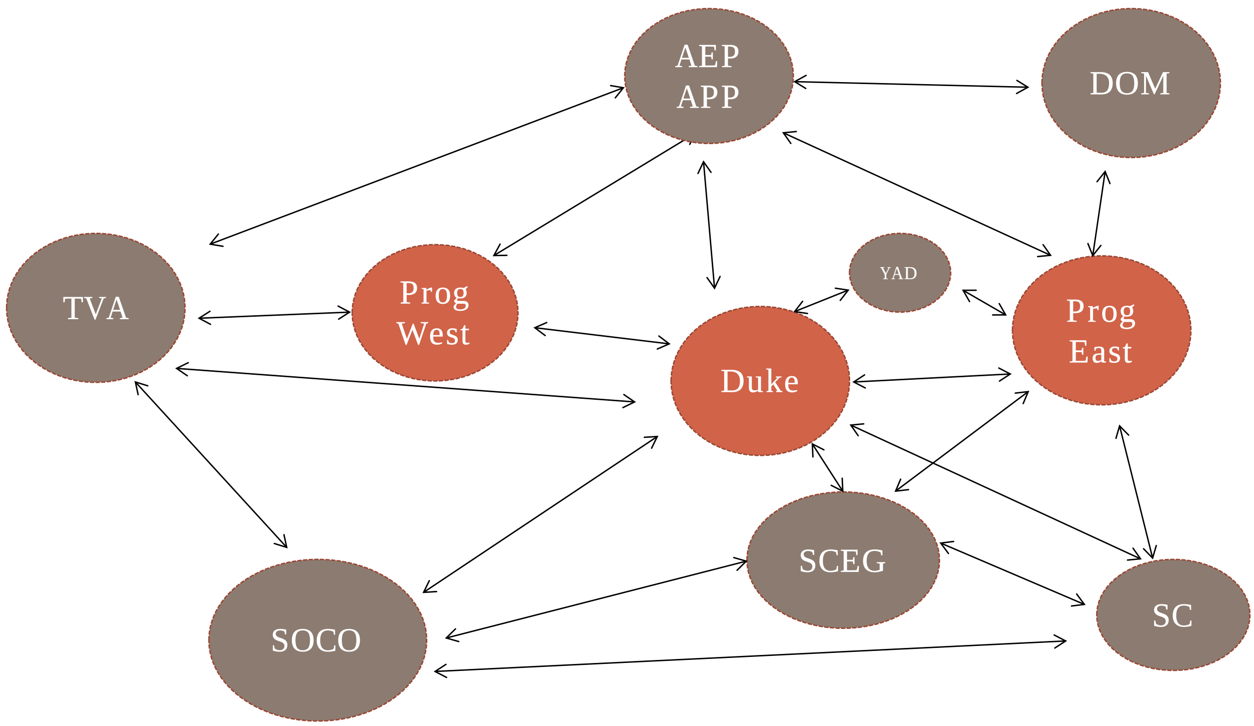
Unit Name	January Capacity	July Capacity	Hours Per Year Limit	Hours Per Day Limit	Days Per Week Limit
PowerManager	0	432	100	10	7
PowerShare0/5	8	9	40	8	7
PowerShare5/5	8	9	40	8	3
PowerShare10/5	8	9	40	8	3
PowerShare15/5	8	9	40	8	3
PowerShare_Mand	381	381	100	10	7
PowerShare_Generator	14	14	100	10	7
PowerShare_IS	111	110	150	10	7
PowerShare_SG	16	16	8760	24	7
Total	552	987			

G. Multi Area Modeling

The surrounding market must play a significant role in resource adequacy even for a utility the size of Duke Energy Carolinas. If several large generators are offline due to outage during peak season, it is likely that the company would depend on market purchases from surrounding regions.

The market representation used in SERVM was developed through consultation with Duke Energy Staff, EIA forms, Company Integrated Resource Plans (IRP), and reviews of NERC resource adequacy assessments. The base case level of reserves for neighbors is based on target reserve margins for surrounding neighbors. Using this methodology ensures that the company is not leaning on an external market more than is reasonable. Figure 13 shows the topology used for the region.

Figure 13. Regional Topology



Each neighbor's hourly loadshape was modeled based on historical hourly temperature data similarly to the Duke load. By using hourly weather, load diversity was captured for each neighboring area. Diversity of peak load is important to understand especially when examining physical reliability metric results. Table 10 shows the average diversity for summer months across all 37 years for each area. These values represent the percentage reduction from peak load that the neighbor is on average experiencing when Duke is experiencing its peak load. To ensure that Duke was not overstating the expectation of weather diversity and therefore available capacity from neighbors, Astrape believed it was prudent to cap the weather diversity in any given peak hour at 3%. A sensitivity assuming no weather diversity was simulated to understand the impact that weather diversity has on lowering the target reserve margin.

Table 10. Neighbor Diversity Factors

	Summer Diversity
SOCO	1.5%
AEP	1.7%
Dominion	1.9%
TVA	1.5%
SCEG	1.3%
Santee Cooper	1.3%
Progress East	1.2%
Progress West	3.3%

Table 11 displays a capacity and load summary of each of the neighbors including its current target reserve margin. The reserve margin calculations in this table assume that the interruptible capacity is included as a resource. While it is recognized that the region currently contains more capacity than these targets, it is not prudent to expect these additional reserves to be available long term. Outage rates for neighboring units were developed using existing Progress and Duke resources sorted by unit type and capacity size. Hydro resources reflect similar dispatch to the Progress and Duke hydro portfolios.

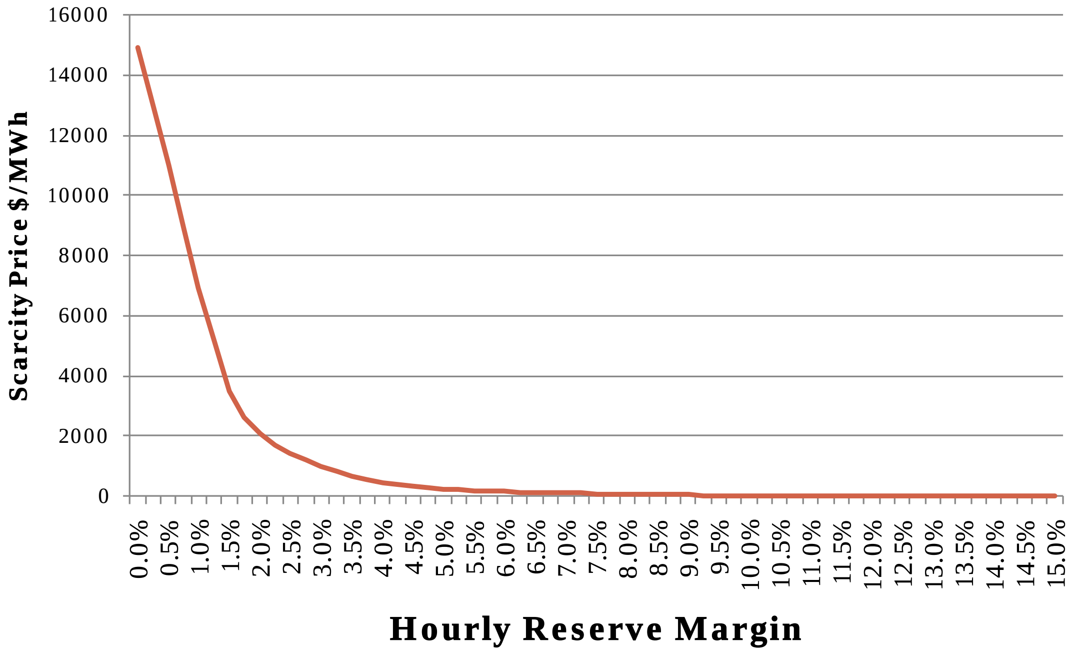
Table 11. Neighbor Capacity, Load, and Target Reserve Margin

	Progress	Southern Company	Santee Cooper	SCE&G	TVA	AEP_APP	DOM	Yadkin
Nuclear	3,563	6,895	318	2,066	7,832	0	3,501	
Coal and CC*	6,899	37,247	3,974	2,547	19,618	6,155	10,347	
Peaking	4,243	8,943	780	322	5,450	450	4,135	
Hydro	335	2,379	457	240	4,254	554	318	215
Pump Storage	0	1,186	0	576	1,739	238	3,003	
Interruptible	932	2,600	424	225	1,500	0	230	
Total Summer Capacity	15,972	59,249	5,953	5,976	40,393	7,397	21,534	215
Summer Peak Load	13,835	51,101	5,155	5,138	35,000	6,372	18,686	
Summer Reserve Margin	15.4%	15.9%	15.5%	16.3%	15.4%	16.1%	15.2%	

*includes renewable capacity

The costs of market purchases were calibrated using Duke Energy historical purchases and other market pricing data from the southeast region. As shown in Figure 14, scarcity pricing is based on the shortage in the specific region. As the excess capacity approaches zero, the price of capacity approaches the cost of unserved energy. Such an event is rare but can occur as a function of severe weather, poor unit performance, and significant load forecast error.

Figure 14. Scarcity Pricing Model



Available Transmission Capacity and TRM

The import capability is made up of Available Transmission Capability (ATC) and Transmission Reliability Margin (TRM). ATC is the non firm hourly transmission expected to be available in the market place while TRM is the portion of the transmission system that is held back for reliability needs. TRM is a fixed number while ATC is highly volatile. Due to its highly volatile nature, ATC is represented as a distribution to capture hours when there is little capacity to hours when there is abundance. The distributions used in SERVM are based on historical hours in 2011 during peak periods. It should be noted that these limits do not represent the amount of generation available from neighbors but only serve as the import constraint. Given these constraints, it is expected that the limiting factor will be generation availability from neighbors rather than transmission. However, transmission capability will be a critical sensitivity in the final analysis. See the appendix for details regarding the values used for ATC and TRM.

H. Carrying Cost of Capacity

The cost of carrying incremental reserves was based on the capital cost, fixed O&M, and estimated transmission upgrades of four Advanced CTs with a total summer rating of 740 MW. The cost assumptions were based on estimates provided by Duke Energy. The appendix displays the characteristics and costs of the four CT site used to develop the capacity costs and the avoided and levelized costs by year.

I. Operating Reserve Requirements

Duke provides 500 MW of spinning reserves and 600 MWs of total operating reserves which was implemented into the model.

J. Cost of Unserved Energy

Unserved energy costs were derived based on information from national studies completed for the Department of Energy in 2003 and 2009. The national studies were compilations of other surveys performed by utilities over the last two decades. The national study split the customer classes into residential, small commercial and industrial, and large commercial and industrial. The 2009 study shows higher costs for commercial and industrial consumers compared to 2003. We expect that the costs of outages have risen rapidly in recent history for commercial and industrial customers due to the impact of technology; however both Duke and Astrape questioned the $92.16/kWh values shown in the 2009 Study for Small C&I. Given the magnitude of the values seen in both studies, Astrape and Duke determined that $15,000/MWh was a reasonable base case assumption Due to the infrequent nature of unserved energy; the sensitivity results demonstrate that this assumption is not the main driver of the results.

Table 12. Unserved Energy Costs

	Class Breakdown %	2003 DOE Study 2003$/kWh	2009 DOE Study 2008$/kWh	2003 DOE Study 2016$/kWh	2009 DOE Study 2016$/kWh
Residential	35%	1.15	1.10	1.45	1.27
Small C&I	37%	26.00	79.90	32.79	92.16
Large C&I	28%	15.00	23.80	18.92	27.45
Weighted Average $/kWh				17.93	42.23
Average of Studies $/kWh				30.08	

V. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered. Deterministic selection of extreme events will not give an accurate representation of the operation of any system during such an event, nor would it be possible to estimate a distribution of when such events could occur. For Duke Energy, SERVM utilized 37 years of historical weather and load shapes, 7 points of economic load growth forecast error, and 400 iterations of unit outage draws to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 37 weather years * 7 load forecast errors * 10 reserve margin levels = 2590 total cases. For each of these cases, 400 iterations of unit outage draws are performed which means over one million yearly simulations were completed for the analysis. From this analysis, expected reliability costs can be calculated and compared to the cost of adding additional reserves.

A. Case Probabilities

An example of probabilities given for each case is shown in Table 13. It is assumed that each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the case probability.

Table 13. Case Probability Example

Weather Year	Weather Year Probabilitiy	Load Forecast Error	Load Forecast Error Probability	Total Case Probability (Weather Yr Prob x LFE Prob)
1975	2.70%	-6.23%	1.64%	0.0443%
1975	2.70%	-3.76%	11.29%	0.3051%
1975	2.70%	-1.79%	22.46%	0.6070%
1975	2.70%	0.00%	29.23%	0.7900%
1975	2.70%	1.79%	22.46%	0.6070%
1975	2.70%	3.76%	11.29%	0.3051%
1975	2.70%	6.23%	1.64%	0.0443%
1976	2.70%	-6.23%	1.64%	0.0443%
1976	2.70%	-3.76%	11.29%	0.3051%
1976	2.70%	-1.79%	22.46%	0.6070%
1976	2.70%	0.00%	29.23%	0.7900%
1976	2.70%	1.79%	22.46%	0.6070%
1976	2.70%	3.76%	11.29%	0.3051%
1976	2.70%	6.23%	1.64%	0.0443%

For this study, reliability costs are defined as the following:

1) Carrying Cost of Reserves + Production costs above that of a CT + Imports above the cost of a CT + Expected Unserved Energy Costs - Sales above that of a CT

These components are calculated for each of the above cases and weighted based on probability to calculate an expected reliability cost for the year.

B. Reserve Margin and Capacity Margin Definition

For this study, reserve margin is defined as the following:

- Reserve Margin = (Resources – Demand) / Demand
    - Demand is the Average Summer System Peak Load and has not been reduced by Demand Response
    - Resources are defined based on summer ratings and include Demand Response
    - The solar capacity within the study was given a 50% capacity credit while wind was given a 15% capacity credit (consistent with the 2011 IRP)

VI. Base Case Results

A. Physical Reliability Results

From a physical reliability standpoint, Figure 15 shows LOLE in events per year and LOLH in hours per year for the base case. The one day in 10 year standard (LOLE = 0.1 events per year) falls at a 14.5% summer reserve margin and the LOLH is approximately 0.30 hours per year for that level of reserves. Figure 16 displays expected unserved energy (EUE) at varying levels of reserves. At the 14.5% reserve margin level, EUE is 170 MWh. As demonstrated in the additional sensitivities, physical reliability metrics are sensitive to input assumptions such as weather diversity, transmission availability, neighbor reserve levels, and emergency hydro assumptions.

Figure 15. Base Case LOLE and LOLH

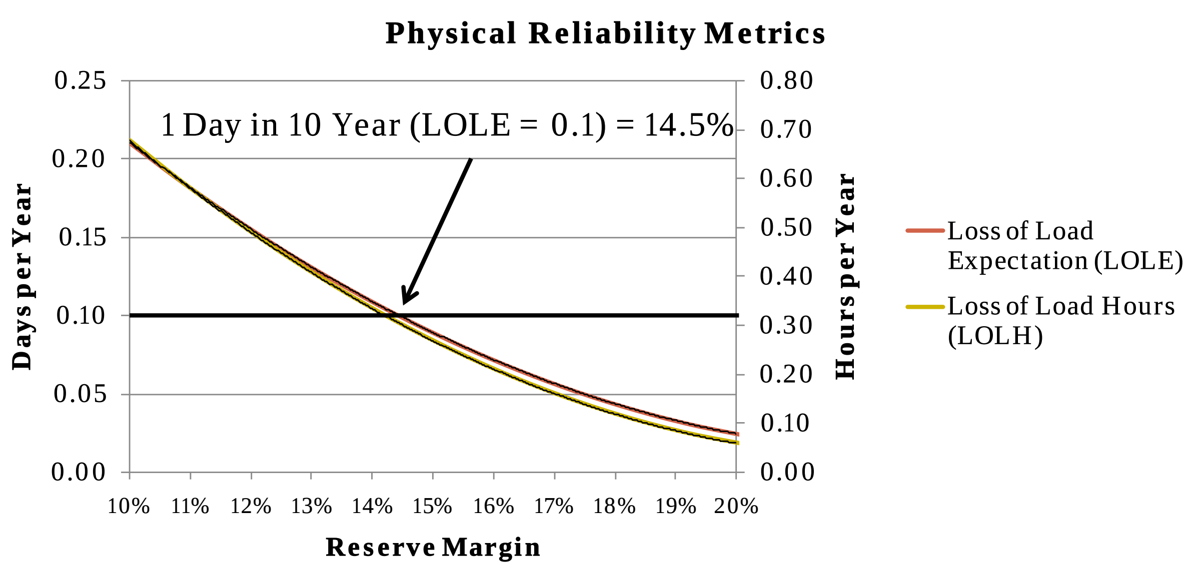
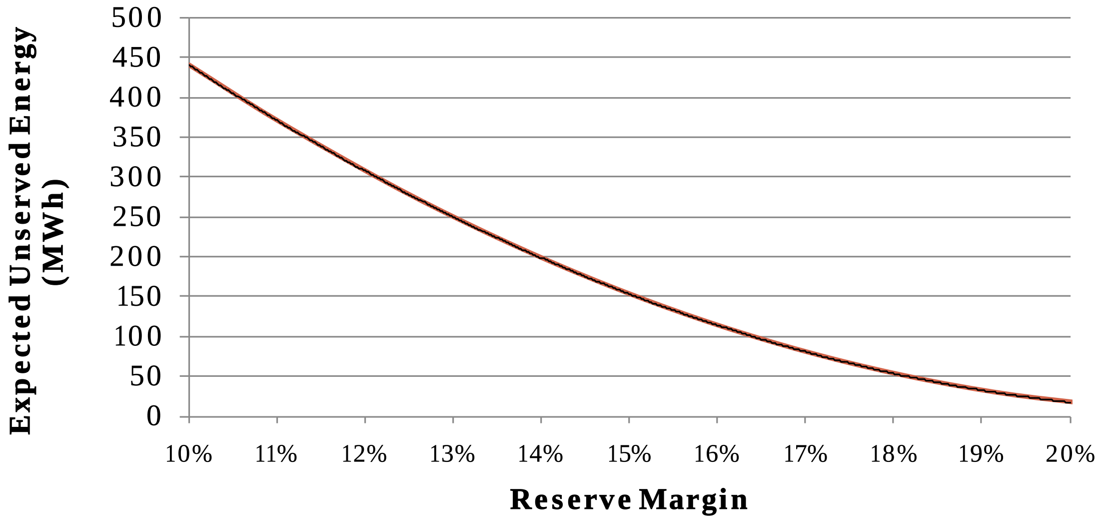


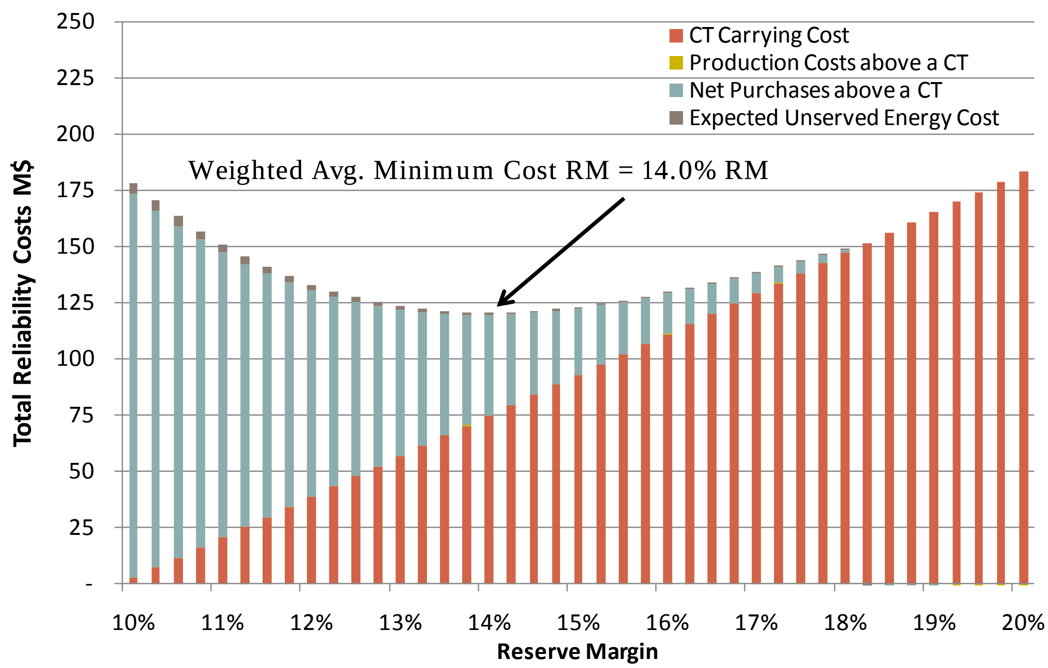
Figure 16. EUE



B. Economic Results

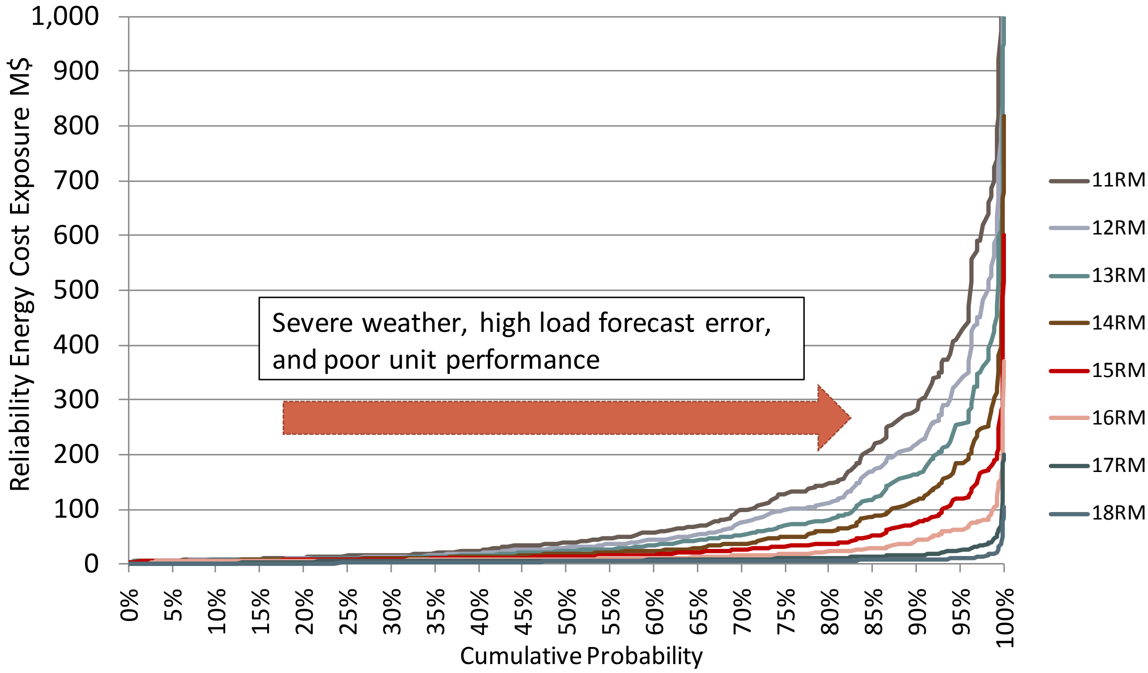
As previously discussed, physical reliability metrics only provide guidance for meeting a few peak load hours over a multi-year study period, and are therefore difficult to calibrate. To supplement the information provided by the base case LOLE analysis, economic reliability metrics were taken into consideration. Economic reliability costs include all costs from the next highest cost resource after a marginal CT all the way to the economic impact of shedding firm load. Since additional capacity will have some benefits in every year, this type of analysis is easily calibrated to actual practice and then allows accurate extrapolation to extreme scenarios. The base case economic results are shown in Figure 17. Based on these results, the long-term minimum cost reserve margin based on the weighted average of all results is 14%. As reserve margin increases, reliability energy costs (Production cost above a CT, net reliability imports above a CT, and cost of unserved energy) decrease while CT carrying cost increases. The flatness of the curve between 14% and 16% should be noted. Since resource additions are too large to perfectly target a reserve margin, some years will inevitably result in reserve margins that are higher than the average economic optimum. The expected financial impact of these additions to the total system cost is not substantial, since the capacity above the weighted average target also brings some financial benefit. For example, the annual expected difference in cost between the 14% reserve margin and 16% reserve margin is only $9 million and the higher level of reserves may provide risk benefits.

Figure 17. Base Case Weighted Average Economic Reserve Margin



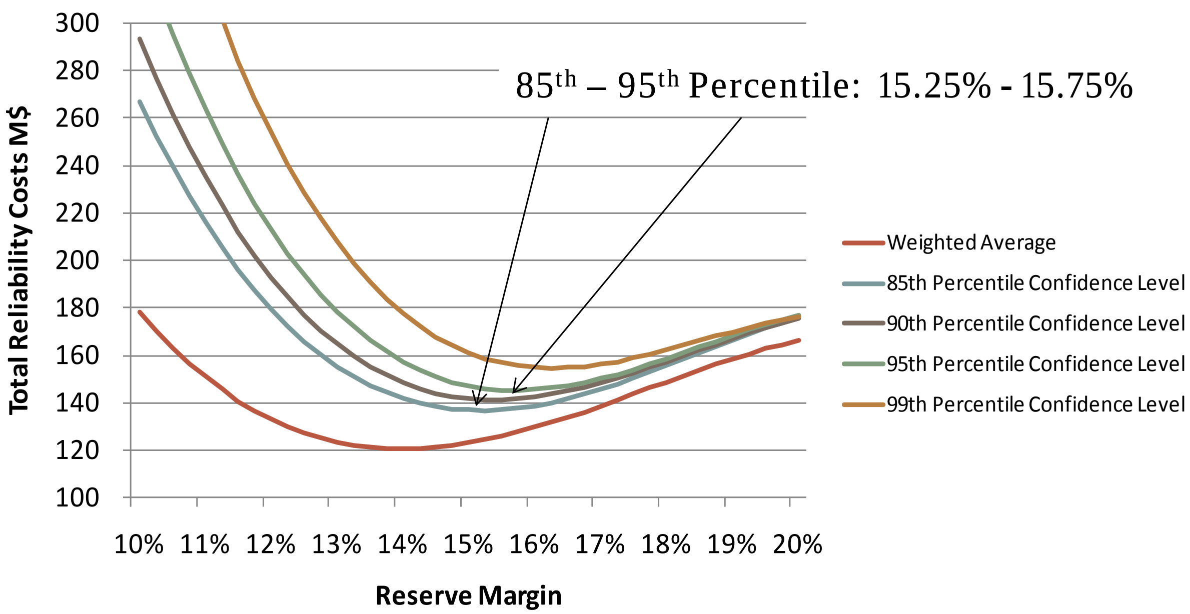
The previous figure represents the weighted average cost exposure and does not illustrate the high cost outcomes that can occur at each reserve margin level. While CT costs are mostly fixed, reliability energy costs are volatile dependent on the weather, load forecast error, or unit performance in a given year, so other confidence levels should be reviewed. While over a 30 year period this may be the optimal reserve margin, any single year can have significant risk at a 14% reserve margin level. Figure 18 shows the reliability energy costs on a probability weighted basis. At a 14% reserve margin, there is a 5% chance that reliability energy costs could exceed $185 million in any given year and a 1% chance that it could exceed $303 million.

Figure 18. Base Case Reliability Cost Exposure Distribution



Next we examined the optimal economic reserve margin recognizing the different risk profile of energy costs and capacity costs. By comparing capacity costs to reliability energy costs during years with extreme weather or poor unit performance as seen in Figure 18, we assessed the tail benefit of additional capacity. The reliability energy costs seen in Figure 18 were taken at different confidence levels (85%, 90%, 95%, and 99% probabilities) and added to the fixed capacity costs at each reserve margin to form the confidence level curves in Figure 19. This assessment showed that in 10% of all scenarios, Duke Energy would receive an economic benefit by adding efficient natural gas turbines up to a reserve margin of 15.50%. This is shown by the 90% confidence level (probability) curve in Figure 19. As we review the weighted average curve in the same figure we can see that by adding capacity to achieve a 16% reserve margin versus a 14% reserve margin, average annual costs only increase by $9 million, but the additional capacity acts as an insurance product to customers. In fact, 10% of the time customers would see their cost exposure decrease by at least $70 million as seen in Figure 18.

Figure 19. Risk Adjusted Reserve Margins



VII. Sensitivity Analysis

The following sensitivities were performed on the base case to only understand the movement in target reserve margins for both physical and economic metrics.

- Include Emergency Hydro: Allows the full nameplate capacity of the hydro fleet to be dispatched during peak periods.
- No Weather Diversity: All neighbors were given the same load shape as Duke to force all neighbors to peak at the same time.
- 50% ATC: The distributions of ATC were reduced by 50% to understand how transmission was impacting the base case results.
- Island Case: Duke is modeled as an island with no outside assistance.
- +2% Neighbor RM Level: The capacity of all neighbors was increased by a 2% reserve margin.
- +50% System EFOR: The EFOR for all Duke resources was increased by 50%.

- Marginal Resource Cost: +/- 25%: The capacity costs for the marginal resource was varied by +/-25%.
- EUE Cost: The cost of unserved energy was varied from $5,000/MWh to $25,000/MWh.
- 2023 Study Year: The study year was moved from 2016 to 2023. Load growth and generation expansion were included for each region and escalation in all economic factors such as the cost of EUE, scarcity pricing, and fuel prices was included for this sensitivity.

Table 14 shows the results of each sensitivity simulated. It is seen that the 0.1 LOLE reserve margin is more sensitive to key assumptions than the weighted average economic case. As discussed previously, this occurs because LOLE is impacted by only a few hours while economics looks at the broader economic impact of all costs above the costs of a CT.

The results show that LOLE is very sensitive to emergency hydro assumptions, weather diversity, and neighbor assistance while the economic results were more stable. Allowing the emergency hydro to be available during all peak periods decreases the LOLE target RM by 3.25% to 11.25% while the economic results were unchanged. Excluding weather diversity shifted the LOLE target up by 3.75 percentage points and the economic target up by 1 percentage point. Dividing the ATC distributions in half had a 1 percentage point impact on the LOLE target and a 2.5 percentage impact on economic results. The ATC sensitivity impacted transmission availability for every hour and so impacted the economic results more than LOLE. However, this sensitivity still indicates that even if substantial changes were to occur to the transmission system (loss of 50% of hourly available transmission capacity), target reserve margins would not need to shift dramatically. Increasing neighbor reserve levels by 2% shifted the LOLE target down by 3.75 percentage points and the economic target down by 0.75 of a percentage point. The island sensitivity should be seen purely as an academic exercise demonstrating the level of reserves the company would carry if it had no outside assistance. If Duke was a stand- alone utility, then it would need to carry reserves of 23.25%. In studying the year 2023, the target only changed slightly. It is expected that a long term reserve margin study should evaluate an optimal target three to five years in the future and therefore 2023 would need to be reviewed again in the 2018 to 2020 time frame.

Regarding the Economic Sensitivities, the cost of unserved energy had little impact on the overall results since firm load shed events are so rare, however, the cost assumed for the marginal CT resource moved the economic reserve margin by approximately +/- .75 of a percentage point. As the marginal resource cost increases, the economic target decreases.

Table 14. Sensitivities

	Physical	Economics	
	LOLE: 1 in 10 Standard Target RM	Weighted Average Target RM	90% Target RM
Base Case	14.50%	14.00%	15.50%
Include Emergency Hydro	11.25%	14.00%	15.50%
No Weather Diversity	18.25%	15.00%	16.75%
50% ATC	15.50%	16.50%	17.50%
Island Case	23.25%		
+2% Neighbor RM	10.75%	13.25%	15.25%
+50% System EFOR	16.75%	16.25%	17.50%
2023 Study Year	14.25%	14.00%	15.75%
EUE Cost: $25,000/MWh		14.00%	15.75%
EUE Cost: $5,000/MWh		13.75%	15.25%
Marginal Resource Cost: +25%		13.25%	14.75%
Marginal Resource Cost: -25%		14.75%	16.00%

VIII. Conclusions/Recommendations

Astrape recommends that Duke set its absolute minimum reserve margin at the 14.5% LOLE target (LOLE = 0.1) and recommends a target of 15.50% based on the 90% confidence level economic target. Since capacity is added in large blocks to take advantage of economies of scale, the actual reserve margin will often be somewhat higher than the target of 15.5%. As shown in the charts and data above, a reserve margin target in the range of 14.5% to 16% produces similar total customer costs whether at the low end or high end of the range. To accommodate large resource additions such as nuclear, coal, or even larger combined cycle resources, the reserve margin would likely rise above the top end of the reserve margin range. However, the additional production cost and economy of scale benefits provided by such resources would likely justify their addition. Therefore, the recommended target reserve margin of 15.50% with a range of 14.5% to 16% should not be considered absolute as all resource decisions should be made on a case-by-case basis.

The results should be reviewed periodically as there are shifts in generation mix, DSM, intermittent resource penetration, or load shape that could impact results. Provided that the results are greatly impacted by regional reserve margins, it is also recommended that Duke keep a close eye on the surrounding market. Short term capacity decisions should also be reviewed on a case-by-case basis. Since physical capacity changes can rarely be implemented inside a 3-year window, the cost of any procurement should be weighed against the distribution of reliability events and the distribution of reliability costs associated with not purchasing the capacity. Even in cases when Duke is below its minimum target reserve margin, economic and physical reliability metrics may suggest not procuring additional capacity. Or an analysis may suggest purchasing more capacity than is needed to achieve the minimum target.

VIX. Confidential Appendix

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FPL

The Need for a 3rd Reliability Criterion for FPL: a Generation-Only Reserve Margin (GRM) Criterion

Bob Barrett
VP Finance
February 28, 2014

A Note Regarding this New Presentation

- **This presentation first addresses 4 "carry over" topics from the Dec. 6th meeting:**
  1. What does a projected LOLP value really mean?
  2. LM customer "fatigue" benchmarking results.
  3. Benefits of generation reserves during pre-hurricane periods.
  4. Emergency declarations and regulatory scrutiny.

- **The presentation then discusses FPL's need for a new reliability criterion from 3 perspectives:**
  1. A "looking back" analysis of the Winter peak day of 2010 and what might have occurred if FPL had entered that January having a Summer GRM of 10% or 5%*
  2. A "looking forward" analysis using the year 2021
  3. Why 10% is a reasonable value for the new GRM criterion

- **The presentation concludes with a summary of "next steps"**

* Unless otherwise noted, all GRM values are Summer GRM values (because the Summer GRM values will have the most impact on resource planning)

FPL.

Executive Summary

- A generation-only reserve margin (GRM) reliability criterion is desirable from an operational perspective for several reasons:
  - If two resource plans have an identical total reserve margin value, but one plan has a 10% GRM and the other a 5% GRM, the 10% GRM plan can provide operators with hundreds of additional MW of reserves (generating and/or load management) during severe peaks
  - A higher GRM plan can also provide operators with significant additional reserves when hurricanes force early shut downs of nuclear units
- A GRM reliability criterion is also desirable from a resource planning perspective because it can lower LOLP projections
- A GRM criterion of a minimum of 10% matches well with Operation's projected need for 2,650 MW of "operational generation reserves" (i.e., generation above forecasted load)

FPL

The 1st topic, "what does an LOLP value mean?", is addressed both by looking at the calculatioı and providing an interpretation

How is an LOLP Value Calculated?

- LOLP calculations project the probability that a utility will not be able to serve 100% of its firm load (i.e., at least 1 MW of firm load cannot be served) during the time period analyzed after all available generation and LM have been used
- LOLP calculations do not provide information regarding: (1) the MW amount that cannot be served; and (2) the duration of the event
- The probability of not being able to serve all firm load is calculated for the peak hour for each day in the year
- These daily probabilities are then summed to derive a monthly probability of not being able to meet firm load on a peak hour during the month
- Then the monthly probabilities are summed to derive an annual probability of not being able to meet firm load on a peak hour during the year
- Thus an LOLP value is a sum of daily probabilities (which can exceed 1.00) and the LOLP value is commonly expressed in terms of "days per year"

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A monthly breakdown of previously provided annual LOLP projections is provided below

Monthly Breakdown of Previous LOLP Values

- In the 12/06/2013 presentation, two LOLP values were presented for the year 2021: 0.0358 days/year for a 5% GRM plan and 0.0257 days/year for a 10% GRM plan
- The following table shows a monthly breakdown of these values:

Month	w/ 5% GRM: Projected Days per Individual Month	w/ 5% GRM: Projected Cumulative Days per Year	w/ 10% GRM: Projected Days per Individual Month	w/ 10% GRM: Projected Cumulative Days per Year
January	0.000018	0.0000	0.000003	0.0000
February	0.000000	0.0000	0.000000	0.0000
March	0.000030	0.0000	0.000004	0.0000
April	0.000002	0.0001	0.000001	0.0000
May	0.000065	0.0001	0.000022	0.0000
June	0.001522	0.0016	0.000819	0.0008
July	0.000436	0.0021	0.000351	0.0012
August	0.001456	0.0035	0.001203	0.0024
September	0.031795	0.0353	0.023089	0.0255
October	0.000506	0.0358	0.000210	0.0257
November	0.000000	0.0358	0.000000	0.0257
December	0.000000	0.0358	0.000000	0.0257
Annual Days per Year =		0.0358		0.0257

FPL

LOLP discussion may be "flipped" from "days per year" to "years per day" terms to provide an easier-to-use interpretation

A Useful Interpretation of LOLP Values

- If one assumes that a projected LOLP value for a given year remains constant for each year in an LOLP analysis, one can project how many years will pass before the utility will not be able to meet firm load (i.e., before the sum of the annual LOLP values = 1.0) by dividing the annual LOLP into 1.0

- Some utilities, such as Hawaiian Electric Company, use this "years per day" format when reporting results of LOLP analyses

- The 5% GRM plan had an annual LOLP value of 0.0358 which converts to 27.9 years, and the 10% GRM plan had an annual LOLP value of 0.0257 or 38.9 years, before LOLP sums to 1.0

In this analysis, the 10% GRM plan is projected to allow FPL to meet firm load for 11 more years without an interruption than with the 5% GRM plan

FPL

Regarding the 2nd topic of LM "fatigue", benchmarking data was sought from multiple sources

Benchmarking Results

- **The DSM group contracted with Esource to canvas various industry leaders (utilities / consultants)**
- **No empirical data exists on customer fatigue due to over use of LM, but opinions received are in-line with FPL's view regarding avoiding LM fatigue:**
  - No greater than 10 events/year
  - Events should be spread out throughout the year (e.g., not all in summer or extreme winter events)
  - Events should not be prolonged (e.g., greater than 2-3 hours)
- **Ahmad Faruqui, Ph.D., an industry expert, stated this is a question "for which I have not been able to find any good data"**
  - He implied a range for which fatigue may occur: "Survey results indicate that the maximum realistic call duration for ERCOT is 4 hrs. and frequency should be no greater than 10 events/year."

LM benchmarking on customer fatigue is inconclusive

FPL

The 3rd topic is the relevance of generation reserves to address generation needed prior to hurricane landfall

Generation Margins Needed Pre-Hurricane

- Prior to land fall, loads are high due to customers cooling their homes and lowering refrigerator temperatures
- High loads prior to land fall occur while FPL is shutting down specific units
  - For example, a hurricane impacting the St. Lucie units (almost 2,000 MW of generation/gross output), must go to 60% output as early as 24 hours prior to land fall, and complete shut down at 18 hours prior to hurricane winds at the site.
- Activation of LM due to a capacity shortfall prior to landfall would have an impact on our customers' preparations including efforts to pre-cool their homes
- A generation reserve of approximately 2,650 MW (as discussed on slide 20 – Operational generation reserves) provides additional reliability, allowing service for our customers prior to hurricane impact

Operations prior to hurricane landfall must consider the unavailability of specific generation and impact to customers

FPL

If a hurricane impacts both PTN and PSL, there is high potential to shut down both units

PTN and PSL Impact and Generation Reserves

- Over the past 100 years, multiple hurricanes have impacted the PTN and PSL areas
- In 1960, Hurricane Cleo (Category 2) may have resulted in sustained hurricane force winds at both PTN and PSL (no anemometers in area)
- Both plants, with output of approx. 3,600 MW, would need to shut down if affected

- The operational generation reserves provide additional reliability to mitigate the unavailability of generation prior to hurricane impact

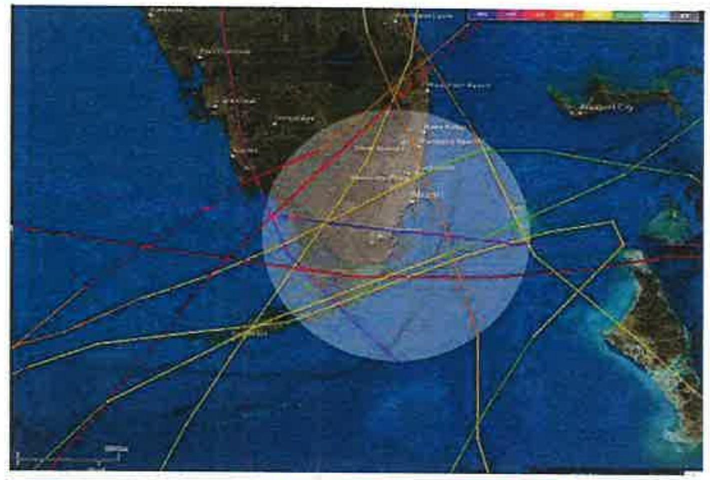
The impact of a hurricane affecting PTN and PSL would require the use of large amounts of LM. Shedding of firm customers is not expected.

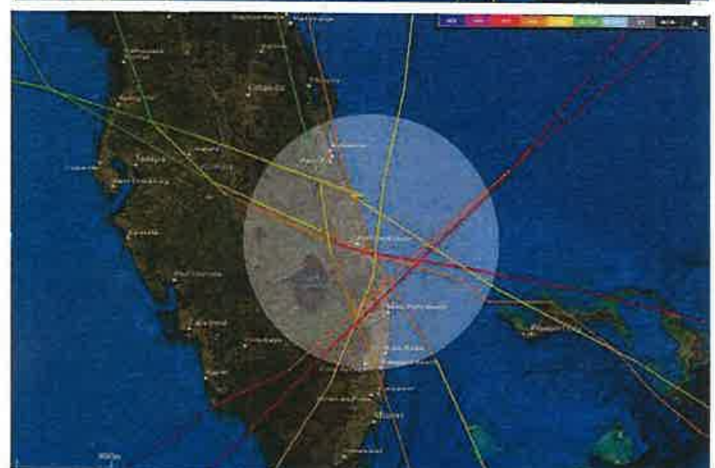
FPL

Generation reserves are needed to account for generation during periods prior to hurricane landfall

Generation Reserves Needed Pre-Hurricane

- **From the period of 1960-2013 eleven hurricanes tracked within 65 nautical miles of Turkey Point and another 8 hurricanes tracked within 65 nautical miles of St. Lucie**
  - Turkey Point hurricanes would reduce the total reserve margin from 21.0% (year 2021) to 13.9%
  - St. Lucie hurricanes would reduce the total reserve margin from 21.0% (year 2021) to 12.2%





The impact from a hurricane to one of the nuclear sites is significant, resulting in the loss of most of the generation reserves and likely needing to use LM

FPL

The 4th topic is that the potential for regulatory implications due to emergency operations declarations

North American Electric Reliability Corporation (NERC) Standards

- **EOP-002 NERC Reliability Standard: Declaration of Energy Emergency Alert (EEA)**
  - FPL's plan based on its interpretation of EOP-002 which is to declare an EEA-2 when LC capability is less (or close to less) than the required reserves necessary to cover the loss of largest FPL unit (FM2 at 1,515 MW by 2021)
    - -- Note: EEA-3 is when load shedding is eminent or underway
  - FPL plan will not result in a declaration for limited (e.g., less than 400 MW) use of LC
    - -- FPL has not declared an EEA under EOP-002
  - From discussions with peers in the Southeast and limited information on NERC website, FPL's practice appears to be consistent with historical declarations in other regions

FPL.

The 4th topic is that the potential for regulatory implications also influences FPL's operating philosophy (Cont'd)

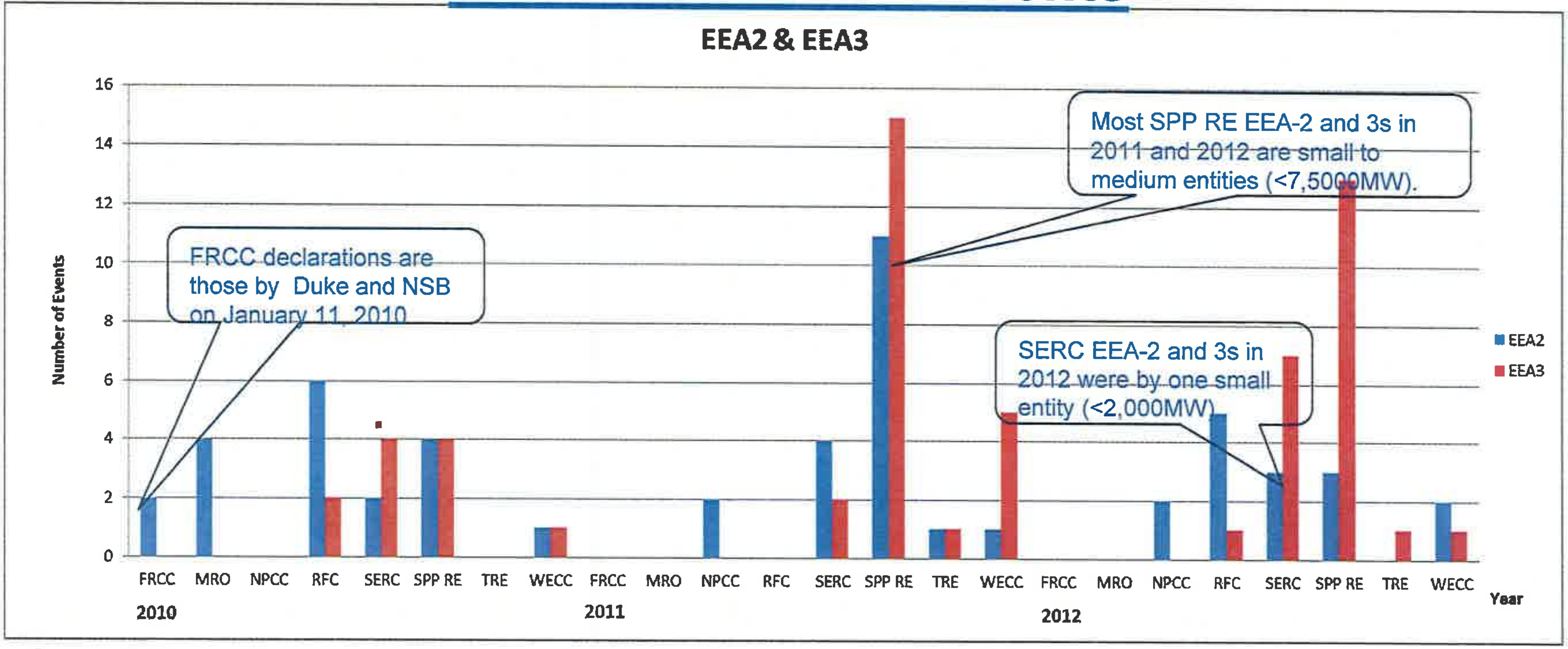
North American Electric Reliability Corporation (NERC) Standards

- **EOP-002 triggers for EEA-2s is not clear, and recognized as such industry-wide**
  - Standard implies that a declaration of an EEA-2 is linked to LC deployment
  - FRCC procedure linking the FRCC Emergency Capacity Plan with EOP-002 does clarify triggers for EEA-2
- **NERC tracks EEA-2s and EEA-3s under EOP-002 to measure the number of events declared during peak load periods, this may serve as leading indicator of capacity shortfall**

FPL

NERC historical tracking of alert declarations varies by region

EEA-2 and EEA-3 Events



- **Legitimate emergencies will be tracked by NERC**
  - NERC states that EEA-2 events calling solely for activation of DSM or interruption of non-firm load will be excluded from the metric in the future as demand response is a legitimate resource and are not of direct concern regarding reliability.

The potential, form, and results of regulatory scrutiny based on what NERC considers too many legitimate emergencies is unclear

FPL.

The need for a new GRM reliability criterion can be supported by 3 points

FPL's Need for a New Reliability Criterion

- **These 3 points (presented in decreasing order of importance) are:**
  1. "All resource plans with identical total reserve margins are not created equal" from an operational perspective (a higher GRM plan will result in significantly more total resources - generation and load management - available for system operators than a lower GRM plan in severe peak conditions)
  2. A resource plan with a higher GRM value is projected to be more reliable from an LOLP perspective (slides 3 through 5)
  3. A resource plan with a higher GRM value is projected to have to use its LM resources less frequently (from 12/06/13 presentation)
- **In regard to point 1 above:**
  - This point can be demonstrated by a "look backwards" analysis of Winter 2010 (slides 15 – 17 and Appendix slides 24 - 27)
  - This point can also be demonstrated by a "looking forward" analysis for Summer and Winter for the year 2021 (slides 18 & 19 and Appendix slides 28 -33)

FPL.

In the "look backwards" analysis, several perspectives were taken of the Winter peak day in 2010

Regarding the January 2010 Peak Day

- The first perspective was of what actually happened on that day (the 2009 Site Plan's projections for the year 2010 were used as the starting point for this analysis)
- The second perspective was to see how FPL's system would have fared if the resource plan had been different with a GRM of 10% in 2010 (but an identical Summer total RM of 20.4%)
- The third perspective was to see how FPL's system would have fared if the resource plan had been different with a GRM of 5% in 2010 (but an identical Summer total RM of 20.4%)

FPL

Sufficient generation reserves are needed for peak load periods

January 11, 2010 (7- 8 AM) – All Time FPL Peak Load

- **Relative to the 2009 Ten Year Site Plan (TYSP), the total reserves for the Winter were 58.2% with a Generation Reserve Margin (GRM) of 42.9%. The Summer reserve margin was 20.4% with an 8.4% GRM**
  - FPL's load was 24,872 MW, 6,196 MW higher than forecasted
  - FPL entered day with 7.4% reserves, all in load management (LM)
  - 24,872 MW of generation was available
  - FPL implemented C/I LM and voltage reduction (561 MW)
  - FPL sold 526 MW of emergency power
  - 1,144 MW of LM remained available during the peak hour
  - No firm load was curtailed by FPL or any other Florida utility
  - Several hours after the peak hour Turkey Point 4 (PTN4) tripped with 750 MW of generation

In Winter 2010, the generation reserves were just sufficient to provide reliable operations with no curtailment of firm load in Florida

Analyses of Winter 2010, using different GRM values, provide a couple of key "takeaways"*

Takeaways from the January 2010 Peak Day Analyses

	Firm Load is Shed?		
Scenario	**W/ TP4**	**W/O TP4**	**Comments**
Actual: 8.4% GRM	No	No	If PTN4 would have tripped prior to the peak, FPL would have implemented additional LM
w/ 10% GRM	No	No	A 10% GRM (as compared to a 5%) would have resulted in a 659 MW increase in LM reserves, and no utilities would have had to shed firm load Similar to the 8.4% GRM scenario, if PTN4 would have tripped prior to the peak, FPL would have implemented additional LM
w/ 5% GRM	No	Yes	W/O TP4 either FPL or another utility in Florida would have had to shed 52 MW of firm load impacting over 30,000 customers

Compared to 8.4%:
+213 w/10%
−446 w/5%
Δ = 659

* The actual analyses are presented in Appendix slides 24 - 27

On 1/11/10, a 5% GRM would have resulted in 30,000 firm load customers being shed, but a 10% GRM would have provided 659 MW of additional reserves

FPL.

A "looking forward" analysis of 2021 addressed both Summer and Winter with 5% and 10% GRM-based resource plans

How the Analyses of 2021 Were Conducted

- The 2013 Site Plan's resource plan for the year 2021 was the starting point: 6.9% GRM, 21.0% Summer total RM, and 34.5% Winter total RM
- Then two alternate resource plans with the same 21.0% Summer total RM, but either 5% or 10% Summer GRM were "constructed" for Summer (comparable alternate resource plans for Winter 2021 were also constructed)
- To simplify the analysis, the alternate plans differed in regard to EE and generation only (similar results would occur if LM instead of EE had been varied in the plans)
- Identical changes of 9% were made to forecasted load, EE, and available generation (the percentage change chosen is arbitrary, but reasonable and consistent)
- The resulting available generation and total resources remaining after these changes were made are compared (note that EE's impact has already "happened" at the peak)

FPL

The "looking forward" analyses of resource plans for 2021 provides additional support for a 10% GRM-based resource plan compared to a 5% GRM-based plan

Key Points from the "Looking Forward" Analyses

- Only the 10% GRM-based resource plan is projected to allow FPL to meet firm load in both Summer and Winter of 2021
- Furthermore, when comparing the two GRM-based resource plans, the 10% GRM-based plan provides significantly more MW of resources for both Summer and Winter

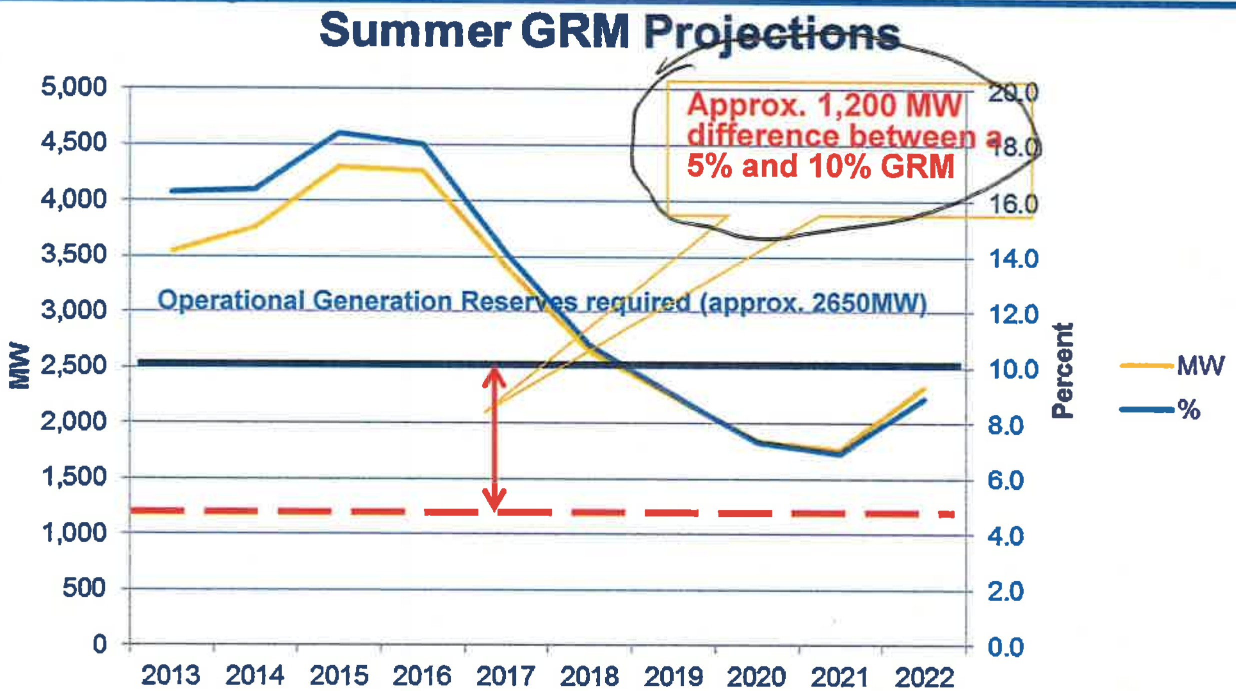
	Summer of 2021			Winter of 2021		
	w/ 10% GRM	w/ 5% GRM	Increased Total Reserves w/ 10% GRM	w/ 10% GRM	w/ 5% GRM	Increased Total Reserves w/ 10% GRM
Total Reserves Remaining after Load, EE, and Generation Adjustments	34	(169)	202	2,921	2,193	728

This "looking forward" analysis again shows system operators will have more resources for their use with a 10% GRM, rather than a 5% GRM, resource plan

FPL

A 10% GRM criterion is a reasonable, easy-to-articulate proxy for FPL's operational generation reserves need

GRM Projections from FPL's 2013 Site Plan



- **FPL's goal is to maintain ~ 2,650 MW of Operational Generation Reserves to cover the following operational situations:**
  - ≈ 700 - Expected unavailable generation (687 MW)
  - ≈ 1,500 - The generation loss of the largest the largest unit (1,515 MW)
  - 450 - Real time operating reserves deployable within 15 minutes as part of the Florida Reserve Sharing Group (450 MW by 2021)

2,650

A 10% GRM is consistent with FPL's required operational reserves

FPL.

FPL has begun using the new GRM criterion in its resource planning process and in 2014 analyses to be filed w/ the FPSC

Next Steps regarding the GRM Criterion

- Text explaining why FPL is using the new criterion will be included in the 2014 TYSP filing and as part of the DSM Goals testimony
- The explanation focuses on analyses comparing resource plans with 10% GRM vs. 5% GRM and include these key points :
  - A 10% GRM results in hundreds of MW of additional operational reserves on severe peak days
  - A 10% GRM results in lower LOLP projections
  - A 10% GRM criterion matches well with the approximately 2,650 MW of generation reserves necessary for operations
- Analyses supporting the 2014 TYSP and DSM Goals filings in April, and the 2014 NCRC filing in early May, all are using the 10% GRM criterion
- These analyses all assume that the 10% GRM criterion must be met beginning in the Summer of 2019

FPL

FPL is not making a separate filing seeking official FPSC approval for FPL's GRM criterion

Next Steps regarding the GRM Criterion (Continued)

- No separate filing/request seeking official FPSC approval for the new GRM criterion will be made
- The only time the FPSC has officially approved a reliability criterion is in the late 1990s when it approved the voluntary stipulation by FPL, TECO, and DEF to move from a 15% to a 20% total reserve margin criterion to close an FPSC docket examining Florida reserves
- TECO did not request approval for its similar supply side reserve margin which it has been using for approximately 10 years
- It is anticipated that discovery requests focused on the new GRM criterion will be received in regard to both the TYSP and DSM Goals filings

FPL

Appendix

FPL and others utilities in Florida were marginally able to serve their entire firm load and FPL met its operational reserve requirements with an 8.4% GRM

January 11, 2010 (7-8 AM) – All Time FPL Peak Load

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (7) - (5) - (3)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
2009 TYSP resource plan projection for Summer 2010	22,916	21,147	220	20,927	1,899	19,028	3,888	20.4%	1,769	8.4%	---
2009 TYSP resource plan projection for Winter 2010	26,852	18,790	114	18,676	1,705	16,971	9,881	58.2%	8,062	42.9%	---
Note that all subsequent rows present adjustments to show how Jan 2010 peak day actual conditions differed from planned conditions shown on row (2)											
Load Adjustments on Jan 2010 peak day---											
Increase in FPL load served after EE (w/o DSM)				6,196							---
Resulting operating conditions on 2010 Winter peak hour	26,852			24,872	1,705	23,167	3,685	15.9%	1,980	8.0%	**Yes**

FPL

FPL and other utilities in Florida were marginally able to serve entire firm load and meet operational reserve requirements with 8.4% GRM (additional adjustments)

January 11, 2010 (7-8AM) – All Time FPL Peak Load

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (7) - (5) - (3)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
Generation / Load Management (CILC and Voltage reduction) Adjustments of on Jan 2010 peak day											
	(1,980)			(561)	(561)						---
Operating conditions on 2010 Winter peak hour	24,872			24,311	1,144	23,167	1,705	7.4%	561	2.3%	Yes
Emergency Sales adjustments on Jan 2010 peak day resulted in 24,346MW of FPL load and 526MW of emergency sales. Total load (FPL and 3rd parties) served is 24,872MW											
Emergency sales (recallable)				526							---
Operating conditions on 2010 Winter peak hour	24,872			24,872	1,144	23,728	1,144	4.8%	0	0.0%	Yes
TP Unit 4 Nuclear Trip on Jan 2010 prior to peak day											
TP Nuclear Adjustment	(750)			(750)	(750)						---
Operating conditions on 2010 Winter peak hour	24,122			24,122	394	23,728	394	1.7%	0	0.0%	Yes

FPL

Two "what if" analyses examined how FPL would have fared if it had entered Winter 2010 with a higher (10%) or lower (5%) GRM

"What If"for January 2010 Peak Day w/ 10% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
Creation of Revised 10% GRM Summer Plan and Corresponding Winter Plan											
Modify the 2009 TYSP resource plan for Summer 2010 to achieve a 10% GRM	23,262	21,147	(72)	21,219	1,899	19,320	3,941	20.4%	2,115	10.0%	---
Using Winter vs Summer differentials, and the modified Summer resource plan, create a comparable resource plan for Winter 2010	27,216	18,790	(37)	18,827	1,705	17,122	10,094	59.0%	8,426	44.8%	Yes
Load Adjustments on Jan 2010 peak day											
Increase in FPL load served after EE but prior to LM utilization				6,231							
Resulting operating conditions on 2010 Winter peak hour due to load	27,216		(37)	25,058	1,705	23,353	3,863	16.5%	2,158	8.6%	Yes
Generation / Load Management / Further FPL Load Adjustments of on Jan 2010 peak day											
	(1,980)			(561)	(561)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments	25,236			24,497	1,144	23,353	1,883	8.1%	739	3.0%	Yes
Emergency Sales Adjustments on Jan 2010 peak day											
Emergency sales				526							
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments+Em. Sales	25,236			25,023	1,144	23,879	1,357	5.7%	213	0.9%	Yes
TP Unit 4 Nuclear Trip on Jan 2010 prior to peak day											
TP Nuclear Adjustment	(750)			(750)	(750)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, generation & TP adjustments	24,486			24,273	394	23,879	607	2.5%	213	0.9%	Yes

* The 2010 Tony letter showed FPL unit capability as 23,333 MW for Winter 2010 & 22,142 MW for Summer. The Winter/Summer ratio is 1.054.

FPL's generation and LM resources would have been greater with a 10% GRM than with 8.4% GRM

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FPL

The second "what if" analysis examined how FPL would have fared if it had entered Winter 2010 with a lower (5%) GRM

"What If"for January 2010 Peak Day w/ 5% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	—
Creation of Revised 5% GRM Summer Plan and Corresponding Winter Plan											
Modify the 2009 TYSP resource plan for Summer 2010 to achieve a 5% GRM	22,204	21,147	806	20,341	1,899	18,442	3,762	20.4%	1,057	5.0%	—
Using Winter vs Summer differentials, and the modified Summer resource plan, create a comparable resource plan for Winter 2010	26,102	18,790	418	18,372	1,705	16,667	9,435	56.6%	7,312	38.9%	Yes
Load Adjustments on Jan 2010 peak day											
Increase in FPL load served after EE but prior to LM utilization				6,231							
Resulting operating conditions on 2010 Winter peak hour due to load	26,102		418	24,603	1,705	22,898	3,204	14.0%	1,499	6.1%	Yes
Generation / Load Management / Further FPL Load Adjustments of on Jan 2010 peak day											
	(1,980)			(561)	(561)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments	24,122			24,042	1,144	22,898	1,224	5.3%	60	0.3%	Yes
Emergency Sales Adjustments on Jan 2010 peak day											
Emergency sales				526							
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments+Em. Sales	24,122			24,568	1,144	23,424	698	3.0%	[illegible]	-1.8%	No
TP Unit 4 Nuclear Trip on Jan 2010 prior to peak day											
TP Nuclear Adjustment	(750)			(750)	(750)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, generation & TP adjustments	23,372			23,818	394	23,424	[illegible]	-0.2%	[illegible]	-1.9%	No

* The 2010 Tony letter showed FPL unit capability as 23,333 MW for Winter 2010 & 22,142 MW for Summer. The Winter/Summer ratio is 1.054.

Even after exhausting FPL's generation and LM resources, FPL would not have been able to meet its firm load with a 5% GRM

FPL

Regarding a "look forward" to 2021, the 5% Summer GRM-based resource plan was examined first in regard to Summer peak

"What If" Summer 2021 Peak Day w/ 5% GRM

Summer	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
5% GRM resource plan	26,838	25,560	1,230	24,330	2,150	22,180	4,658	21.0%	1,278	5.0%
Higher-than-Projected Peak Load *		2,300								
Lower-than-projected EE Reduction *			(111)							
Resulting actual operating conditions on 2021 peak hour	26,838	27,860	1,119	26,741	2,150	24,591	2,247	9.1%	97	0.3%
Unavailable Generation *	(2,415)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	24,423	27,860	1,119	26,741	2,150	24,591	(169)	-0.7%	(2,319)	-8.3%

* A 9% adjustment was made to the starting point value in the first row.

With the 5% GRM plan, FPL would not be able to meet Summer firm load (as seen by the negative 169 MW) of Total Reserves in Col. 7)

FPL

The 10% Summer GRM-based resource plan was examined next in regard to Summer peak

"What If" Summer 2021 Peak Day w/ 10% GRM

Summer	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
10% GRM resource plan	28,116	25,560	174	25,386	2,150	23,236	4,880	21.0%	2,556	10.0%
Higher-than-Projected Peak Load *		2,300								
Lower-than-projected EE Reduction *			(16)							
Resulting actual operating conditions on 2021 peak hour	28,116	27,860	158	27,702	2,150	25,552	2,564	10.0%	414	1.5%
Unavailable Generation *	(2,530)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	25,586	27,860	158	27,702	2,150	25,552	34	0.1%	(2,117)	-7.6%

* A 9% adjustment was made to the starting point value in the first row.

With the 10% GRM plan, FPL would be able to meet Summer firm load (as seen by the positive 34 MW of Total Reserves)

FPL

The 5% Summer GRM-based resource plan was examined next in regard to Winter peak

"What If" Winter 2021 Peak Day w/ 5% GRM

Winter	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
Winter resource plan corresponding to the Summer plan w/ 5% GRM	28,287	23,601	637	22,964	1,597	21,367	6,920	32.4%	4,686	19.9%
Higher-than-Projected Peak Load *		2,124								
Lower-than-projected EE Reduction *			(57)							
Resulting actual operating conditions on 2021 peak hour	28,287	25,725	580	25,145	1,597	23,548	4,739	20.1%	3,142	12.2%
Unavailable Generation *	(2,546)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	25,741	25,725	580	25,145	1,597	23,548	2,193	9.3%	596	2.3%

* A 9% adjustment was made to the starting point value in the first row.

With the 5% GRM resource plan, FPL would be able to meet Winter firm load with 2,193 MW of Total Reserves to spare

FPL

The 10% Summer GRM-based resource plan was then examined in regard to Winter peak

"What If" Winter 2021 Peak Day w/ 10% GRM

Winter	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or	(10) = (9) / (2)
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
Winter resource plan corresponding to the Summer plan w/ 10% GRM	29,634	23,601	90	23,511	1,597	21,914	7,720	35.2%	6,033	25.6%
Higher-than-Projected Peak Load *		2,124								
Lower-than-projected EE Reduction *			(8)							
Resulting actual operating conditions on 2021 peak hour	29,634	25,725	82	25,643	1,597	24,046	5,588	23.2%	3,991	15.5%
Unavailable Generation *	(2,667)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	26,967	25,725	82	25,643	1,597	24,046	2,921	12.1%	1,324	5.1%

* A 9% adjustment was made to the starting point value in the first row.

With the 10% GRM resource plan, FPL would be able to meet Winter firm load with 2,921 MW of Total Reserves to spare

FPL

Another "look forward to 2021" case was analyzed in which LM, not EE, was allowed to vary

"What If" Summer 2021 Peak Day w/ 5% GRM & LM Varying

Summer	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
5% GRM resource plan	26,838	25,560	830	24,730	2,550	22,180	4,658	21.0%	1,278	5.0%
Higher-than-Projected Peak Load *		2,300								
Lower-than-projected EE and LM Reduction *					(230)					
Resulting actual operating conditions on 2021 peak hour	26,838	27,860	830	27,030	2,321	24,710	2,128	8.6%	-192	-0.7%
Unavailable Generation *	(2,415)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	24,423	27,860	830	27,030	2,321	24,710	(287)	-1.2%	(2,608)	-9.4%

* A 9% adjustment was made to the starting point value in the first row.

With the 5% GRM plan, FPL would not be able to meet Summer firm load (as seen by the negative 287 MW of Total Reserves in Col. 7)

 DRAFT Attorney-Client Work Product, Privileged & Confidential

FPL

Another "look forward to 2021" case was analyzed in which LM, not EE, was allowed to vary - continued

"What If" Summer 2021 Peak Day w/ 10% GRM & LM Varying

Summer	Total Projected Capacity (MW)	Forecasted Peak Load (MW)	Forecasted Utility EE (MW)	Peak Load After EE (MW)	Forecasted LC (MW)	Forecasted Firm Load After EE and LC (MW)	Total Reserves (MW)	Total Reserve Margin as % of Firm Load (%)	Generation Reserves (MW)	GRM (%)
10% GRM resource plan	28,116	25,560	830	24,730	1,494	23,236	4,880	21.0%	2,556	10.0%
Lower-than-projected EE and LM Reduction *		2,300								
Lower-than-projected EE Reduction *					(134)					
Resulting actual operating conditions on 2021 peak hour	28,116	27,860	830	27,030	1,360	25,671	2,445	9.5%	1,086	3.9%
Unavailable Generation *	(2,530)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	25,586	27,860	830	27,030	1,360	25,671	(85)	-0.3%	(1,445)	-5.2%

* A 9% adjustment was made to the starting point value in the first row.

With the 10% GRM plan, FPL comes closer to meeting Summer firm load (as seen by the negative 85 MW of Total Reserves in Col. 7)

FPL

DRAFT Attorney-Client Work Product

Calculation of "Generation - Only" Reserve Margins

FPL 2012 TYSP

	(1)	(2)	(3)	(4)	(5)	(6)	(7) = (5)+(6)	(8) = (4)-(7)	(9) = (8) [(3)-(8)] /	(10) = [(3) - (4)] / (4)	[(3)- (11) = [(4)-(6)] ((4)-(6))] /
August of the Year	Total Capacity (MW)	Planned Outage (MW)	Total Available Capacity (MW)	Load Forecast (MW)	Existing & Incremental Load Control (MW)	Incremental Conservation (MW)	Total DSM (MW)	Firm Peak (MW)	Standard Reserve Margin (%)	(FPL Method) Gen-Only Reserve Margin (%) 16.2%	(FPSC Staff Method) Gen-Only Reserve Margin (%)
2012	25,870	745	25,125	21,623	1,901	90	1,991	19,632	28.0%	15.5%	16.7%
2013	26,146	826	25,320	21,931	1,932	183	2,115	19,816	27.8%	14.4%	16.4%
2014	27,420	826	26,594	23,243	1,997	280	2,277	20,966	26.8%	15.6%	15.8%
2015	27,491	0	27,491	23,786	2,028	380	2,408	21,378	28.6%	13.2%	17.5%
2016	27,514	0	27,514	24,315	2,060	479	2,539	21,776	26.4%	10.6%	15.4%
2017	27,139	0	27,139	24,529	2,092	579	2,671	21,858	24.2%	10.0%	13.3%
2018	27,139	0	27,139	24,674	2,123	679	2,802	21,872	24.1%	8.4%	13.1%
2019	27,139	0	27,139	25,041	2,155	779	2,934	22,107	22.8%	6.4%	11.9%
2020	27,139	0	27,139	25,499	2,184	859	3,043	22,456	20.9%	5.5%	19.4%
2021	27,389	0				929					

PEF 2012 TYSP

	(1)	(2)	(3)	(4)	(5)	(6)	(7) = (5)+(6)	(8) = (4)-(7)	(9) = [(3)-(8)] / (8)	(10) = [(3) - (4)] / (4)	(11) = [(4)-(6)] [(3)- ((4)-(6))] /
August of the Year	Total Capacity (MW)	Planned Outage (MW)	Total Available Capacity (MW)	Load Forecast (MW)	Existing & Incremental Load Control (MW)	Incremental Conservation (MW)	Total DSM (MW)	Firm Peak (MW)	Standard Reserve Margin (%)	(FPL Method) Gen-Only Reserve Margin (%)	(FPSC Staff Method) Reserve Margin w/out LC/Intr. (%)
2012	12,003	789	11,214	9,810	842	46	888	8,922	25.7%	14.3%	14.9%
2013	11,903	789	11,114	9,693	889	87	976	8,717	27.5%	14.7%	15.7%
2014	11,782	789	10,993	9,779	882	124	1,006	8,773	25.3%	12.4%	13.9%
2015	11,936	0	11,936	10,024	904	156	1,060	8,964	33.2%	19.1%	21.0%
2016	11,209	0	11,209	10,076	914	184	1,098	8,978	24.8%	11.2%	13.3%
2017	11,209	0	11,209	10,385	967	208	1,175	9,210	21.7%	7.9%	10.1%
2018	11,209	0	11,209	10,580	980	230	1,210	9,370	19.6%	5.9%	8.3%
2019	11,976	0	11,976	11,037	1,005	251	1,256	9,781	22.4%	8.5%	11.0%
2020	11,976	0	11,976	11,242	1,030	273	1,303	9,939	20.5%	6.5%	9.2%
2021	13,068	0	13,068	11,339	1,047	292	1,339	10,000	30.7%	15.2%	18.3%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 31
PARTY: SOUTHERN ALLIANCE FOR CLEAN ENERGY (SACE) – (DIRECT) Exhibit
DESCRIPTION: John D. Wilson JDW-4

NATALIE A. MIMS

1035 Santa Barbara St, Suite 8 808-987-0389
Santa Barbara, CA 93101 mimsconsultllc@gmail.com

RELEVANT WORK EXPERIENCE

MIMS CONSULTING, LLC
Principal, April 2015 - current

SOUTHERN ALLIANCE FOR CLEAN ENERGY
Energy Efficiency Director, January 2013 - current
Earlier position: Energy Policy Manager, October 2010– December 2012

- Testifies as expert witness before the Public Service Commissions on energy efficiency cost recovery, program plans and financial incentive mechanisms in Georgia, North Carolina and South Carolina
- Responsible for ongoing energy efficiency portfolio and program level quantitative and qualitative research and analysis of major utilities in the Southeast
- Track and participate in energy efficiency regulatory proceedings. Current regulatory proceedings include IRP, cost-recovery filings, energy efficiency program pilots and existing program modifications
- Responsible for reviewing and writing comments and/or testimony for all major energy efficiency regulatory proceedings for utilities in Tennessee, North and South Carolina, Georgia and Florida
- Responsible for managing energy efficiency staff and establishing and implementing efficiency strategy for the SACE
- Assists in development/fundraising to ensure energy efficiency work funded in upcoming years
- Lead participant for SACE at TVA, Duke Energy and Georgia Power energy efficiency working groups

ROCKY MOUNTAIN INSTITUTE
Senior Consultant, July 2009 – October 2010
Earlier positions: Intern, Fellow, Analyst, and Consultant October 2004- July 2009

- Project manager for nine-person team creating energy efficiency component of national analysis to eliminate US fossil fuel consumption by 2050
- Project manager for company-wide energy efficiency strategy and development
- Lead on energy efficiency analysis for major southeastern IOU low-carbon strategy
- Lead author on published national analysis on electric productivity
- Member of senior leadership of Energy and Resources Team at the organization. Contributed to team strategy, resource planning and staffing for 12-20 person team and hiring as well as organizational professional development strategy
- Contributed to writing Hawaii Energy Strategy 2007 and planning Hawaii Biofuels Summit Contributed to RMI filings in Energy Efficiency docket before Hawaii Public Utility Commission
- Participated in Hawaii Energy Policy Forum Energy Efficiency working group
- Significant contributor to consulting and research projects including: national and state energy policies, utility revenue adjustment mechanisms, utility regulatory structures, private sector investment in energy efficiency, corporate carbon management strategy, renewable energy market assessments, large and small scale sustainable development projects, Hawaii agricultural sustainability barriers and solutions

PUBLICATIONS

- Legislative Options to Improve Transportation Efficiency. November 2005, RMI.
- Feebates: A Legislative Option to Encourage Continuous Improvements to Automobile Efficiency. February 2008, RMI.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 32
PARTY: SOUTHERN ALLIANCE FOR CLEAN ENERGY (SACE) – (DIRECT)
DESCRIPTION: Natalie Mims (NAM-1)

- Plug-In Hybrid Electric Vehicles and Environmentally Beneficial Load Building: Implications on California's Revenue Adjustment Mechanism, Presented at Association of Energy Service Professionals Conference, January 2008.
- Industrial Electric Productivity: Myths, Barriers, & Solutions. Presented at ACEEE Industrial Summer Study, July 2008.
- Assessing the Electric Productivity Gap and the U.S. Efficiency Opportunity. Presented at IEPEC, August 2009.

EDUCATION

MASTER OF ENVIRONMENTAL LAW & POLICY
Vermont Law School, South Royalton, Vermont
August 2004

- Relevant coursework includes: Environmental Justice, Environmental Law, Land Use, Water Law, Federal Natural Resource Law, Comparative Methods of Dispute Resolution, Environmental Law Principles, Extinction: The Endangered Species Act, Legal Research & Writing, Ecology
- Activities: Solutions Conference 2004

B.A. ENGLISH & B.A POLITICAL SCIENCE
The Pennsylvania State University, State College, Pennsylvania
May 2002

- Honors: Blue & White Scholarship; Dean's List five semesters; National Collegiate Honor Scholar
- Relevant coursework includes: Economics, Social & Developmental Psychology
- Activities: Shaver's Creek Outdoor School Camp Counselor, May 2001

Karl R. Rábago

Executive Director, Pace Energy and Climate Center
Pace University School of Law
t: +1.914.42.4082 c: +1.512.968.7543 e: krabago@law.pace.edu

Summary

Nationally recognized leader and innovator in electricity and energy law, policy, and regulation. Experienced as a public utility regulatory commissioner, educator, research and development program manager, utility executive, business builder, federal executive, corporate sustainability leader, consultant, and advocate. Thought leader and practice expert in organizational transformation. Highly proficient in advising, managing, and interacting with government agencies and committees, the media, citizen groups, and business associations. Successful track record of working with US Congress, state legislatures, governors, regulators, city councils, business leaders, researchers, academia, and community groups. National and international contacts through experience with Austin Energy, AES Corporation, US Department of Energy, Texas Public Utility Commission, Jicarilla Apache Tribal Utility Authority, Cargill Dow LLC (now NatureWorks, LLC), Rocky Mountain Institute, CH2M HILL, Houston Advanced Research Center, Environmental Defense Fund, and others. Skilled attorney, negotiator, and advisor with more than twenty years experience working with diverse stakeholder communities in electricity policy and regulation, emerging energy markets development, clean energy technology development, electric utility restructuring, smart grid development, and the implementation of sustainability principles. Extensive regulatory practice experience. Nationally recognized speaker on energy, environment and sustainable development matters. Managed staff as large as 250; responsible for operations of research facilities with staff in excess of 600. Developed and managed budgets in excess of $300 million. Law teaching experience at University of Houston Law Center and U.S. Military Academy at West Point. Trial experience as a Judge Advocate. Post doctorate degrees in environmental and military law. Military veteran.

Employment

PACE ENERGY AND CLIMATE CENTER, PACE UNIVERSITY SCHOOL OF LAW

Executive Director: May 2014—Present.

Leader of a team of professional and technical experts in energy and climate law, policy, and regulation. Secure funding for and manage execution of research, market development support, and advisory services for a wide range of funders, clients, and stakeholders with the overall goal of advancing clean energy deployment, climate responsibility, and market efficiency. Supervise a team of employees, consultants, and adjunct researchers. Provide learning and development opportunities for law students. Coordinate efforts of the Center with and support the environmental law faculty. Additional activities:

- Co-Director and Principal Investigator, Northeast Solar Energy Market Coalition (2015-present). The NESEMC is a US Department of Energy's SunShot Initiative Solar Market Pathways project. Funded under a cooperative agreement between the US DOE and Pace University, the NESEMC seeks to harmonize solar market policy and advance best policy and regulatory practices in the northeast United States.
- Chairman of the Board, Center for Resource Solutions (1997-present). CRS is a not-for-profit organization based at the Presidio in California. CRS developed and manages the Green-e Renewable Electricity Brand, a nationally and internationally recognized branding program for green power and green pricing products and programs. Past chair of the Green-e Governance Board (formerly the Green Power Board).

- Director, Interstate Renewable Energy Council (IREC) (2012-present). IREC focuses on issues impacting expanded renewable energy use such as rules that support renewable energy and distributed resources in a restructured market, connecting small-scale renewables to the utility grid, developing quality credentials that indicate a level of knowledge and skills competency for renewable energy professionals.

RÁBAGO ENERGY LLC

Principal: July 2012—Present. Consulting practice dedicated to providing expert witness and policy formulation advice and services to organizations in the clean and advanced energy sectors. Recognized national leader in development and implementation of award-winning "Value of Solar" alternative to traditional net metering. Additional information at www.rabagoenergy.com.

AUSTIN ENERGY – THE CITY OF AUSTIN, TEXAS

Vice President, Distributed Energy Services: April 2009—June 2012. Executive in 8th largest public power electric utility serving more than one million people in central Texas. Responsible for management and oversight of energy efficiency, demand response, and conservation programs; low-income weatherization; distributed solar and other renewable energy technologies; green buildings program; key accounts relationships; electric vehicle infrastructure; and market research and product development. Executive sponsor of Austin Energy's participation in an innovative federally-funded smart grid demonstration project led by the Pecan Street Project. Led teams that successfully secured over $39 million in federal stimulus funds for energy efficiency, smart grid, and advanced electric transportation initiatives. Additional activities included:

- Director, Renewable Energy Markets Association. REMA is a trade association dedicated to maintaining and strengthening renewable energy markets in the United States.
- Membership on Pedernales Electric Cooperative Member Advisory Board. Invited by the Board of Directors to sit on first-ever board to provide formal input and guidance on energy efficiency and renewable energy issues for the nation's largest electric cooperative.

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008. Government and regulatory affairs manager for AES Wind Generation, one of the largest wind companies in the country. Manage a portfolio of regulatory and legislative initiatives to support wind energy market development in Texas, across the United States, and in many international markets. Active in national policy and the wind industry through work with the American Wind Energy Association as a participant on the organization's leadership council. Also served as Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC, a GE and AES venture committed to generating and marketing greenhouse gas credits to the U.S. voluntary market. Authored and implemented a standard of practice based on ISO 14064 and industry best practices. Commissioned the development of a suite of methodologies and tools for various greenhouse gas credit-producing technologies. Also served as Director, Global Regulatory Affairs, providing regulatory support and group management to AES's international electric utility operations on five continents. Additional activities:

- Director and past Chair, Jicarilla Apache Nation Utility Authority (1998 to 2008). Located in New Mexico, the JAUA is an independent utility developing profitable and autonomous utility services that provides natural gas, water utility services, low income housing, and energy planning for the Nation. Authored "First Steps" renewable energy and energy efficiency strategic plan.

Karl R. Rábago

HOUSTON ADVANCED RESEARCH CENTER

Group Director, Energy and Buildings Solutions: December 2003—May 2006. Leader of energy and building science staff at a mission-driven not-for-profit contract research organization based in The Woodlands, Texas. Responsible for developing, maintaining and expanding upon technology development, application, and commercialization support programmatic activities, including the Center for Fuel Cell Research and Applications, an industry-driven testing and evaluation center for near-commercial fuel cell generators; the Gulf Coast Combined Heat and Power Application Center, a state and federally funded initiative; and the High Performance Green Buildings Practice, a consulting and outreach initiative. Secured funding for major new initiative in carbon nanotechnology applications in the energy sector. Developed and launched new and integrated program activities relating to hydrogen energy technologies, combined heat and power, distributed energy resources, renewable energy, energy efficiency, green buildings, and regional clean energy development. Active participant in policy development and regulatory implementation in Texas, the Southwest, and national venues. Frequently engaged with policy, regulatory, and market leaders in the region and internationally. Additional activities:

- President, Texas Renewable Energy Industries Association. As elected president of the statewide business association, leader and manager of successful efforts to secure and implement significant expansion of the state's renewable portfolio standard as well as other policy, regulatory, and market development activities.
- Director, Southwest Biofuels Initiative. Established the Initiative acts as an umbrella structure for a number of biofuels related projects, including emissions evaluation for a stationary biodiesel pilot project, feedstock development, and others.
- Member, Committee to Study the Environmental Impacts of Windpower, National Academies of Science National Research Council. The Committee was chartered by Congress and the Council on Environmental Quality to assess the impacts of wind power on the environment.
- Advisory Board Member, Environmental & Energy Law & Policy Journal, University of Houston Law Center.

CARGILL DOW LLC (NOW NATUREWORKS, LLC)

Sustainability Alliances Leader: April 2002—December 2003. Founded in 1997, NatureWorks, LLC is based in Minnetonka, Minnesota. Integrated sustainability principles into all aspects of a ground-breaking biobased polymer manufacturing venture. Responsible for maintaining, enhancing and building relationships with stakeholders in the worldwide sustainability community, as well as managing corporate and external sustainability initiatives. NatureWorks is the first company to offer its customers a family of polymers (polylactide – "PLA") derived entirely from annually renewable resources with the cost and performance necessary to compete with packaging materials and traditional fibers; now marketed under the brand name "Ingeo."

- Successfully completed Minnesota Management Institute at University of Minnesota Carlson School of Management, an alternative to an executive MBA program that surveyed fundamentals and new developments in finance, accounting, operations management, strategic planning, and human resource management.

ROCKY MOUNTAIN INSTITUTE

Managing Director/Principal: October 1999–April 2002. In two years, co-led the team and grew annual revenues from approximately $300,000 to more than $2 million in annual grant and consulting income. Co-authored "Small Is Profitable," a comprehensive analysis of the benefits of distributed energy resources. Worked to increase market opportunities for clean and distributed energy resources through consulting, research, and publication activities. Provided consulting and advisory services to help business and government clients achieve sustainability through application and incorporation of Natural Capitalism principles. Frequent appearance in media at international, national, regional and local levels.

- President of the Board, Texas Ratepayers Organization to Save Energy. Texas R.O.S.E. is a non-profit organization advocating low-income consumer issues and energy efficiency programs.
- Co-Founder and Chair of the Advisory Board, Renewable Energy Policy Project-Center for Renewable Energy and Sustainable Technology. REPP-CREST was a national non-profit research and internet services organization.

CH2M HILL

Vice President, Energy, Environment and Systems Group: July 1998–August 1999. Responsible for providing consulting services to a wide range of energy-related businesses and organizations, and for creating new business opportunities in the energy industry for an established engineering and consulting firm. Completed comprehensive electric utility restructuring studies for the states of Colorado and Alaska.

PLANERGY

Vice President, New Energy Markets: January 1998–July 1998. Responsible for developing and managing new business opportunities for the energy services market. Provided consulting and advisory services to utility and energy service companies.

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998. Managed renewable energy, energy efficiency, and electric utility restructuring programs for a not-for-profit environmental group with a staff of 160 and over 300,000 members. Led regulatory intervention activities in Texas and California. In Texas, played a key role in crafting Deliberative Polling processes. Initiated and managed nationwide collaborative activities aimed at increasing use of renewable energy and energy efficiency technologies in the electric utility industry, including the Green-e Certification Program, Power Scorecard, and others. Participated in national environmental and energy advocacy networks, including the Energy Advocates Network, the National Wind Coordinating Committee, the NCSL Advisory Committee on Energy, and the PV-COMPACT Coordinating Council. Frequently appeared before the Texas Legislature, Austin City Council, and regulatory commissions on electric restructuring issues.

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996. Manager of the Department's programs in renewable energy technologies and systems, electric energy systems, energy efficiency, and integrated resource planning. Supervised technology research, development and deployment activities in photovoltaics, wind energy, geothermal energy, solar thermal energy, biomass energy, high-temperature superconductivity, transmission and distribution, hydrogen, and electric and magnetic fields. Developed, coordinated, and advised on legislation, policy, and renewable energy technology development within the Department, among other agencies, and with Congress. Managed, coordinated, and developed international agreements for cooperative activities in renewable energy and utility sector policy, regulation, and market development between the Department and counterpart foreign national entities. Established and enhanced partnerships with stakeholder groups, including technology firms, electric utility companies, state and local governments, and associations. Supervised development and deployment support activities at national laboratories. Developed, advocated and managed a Congressional budget appropriation of approximately $300 million.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994. Appointed by Governor Ann W. Richards. Regulated electric and telephone utilities in Texas. Laid the groundwork for legislative and regulatory adoption of integrated resource planning, electric utility restructuring, and significantly increased use of renewable energy and energy efficiency resources. Appointed by Governor Richards to co-chair and organize the Texas Sustainable Energy Development Council. Served as Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation. Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT), a nationwide program to develop domestic markets for photovoltaics. Member, Southern States Energy Board Integrated Resource Planning Task Force. Member of the University of Houston Environmental Institute Board of Advisors.

LAW TEACHING

Professor for a Designated Service: Pace University Law School, 2014-present. Non-tenured member of faculty. Courses taught: Energy Law. Supervise a student clinical effort that engages in a wide range of advocacy, analysis, and research activities in support of the mission of the Pace Energy and Climate Center.

Associate Professor of Law: University of Houston Law Center, 1990–1992. Full time, tenure track member of faculty. Courses taught: Criminal Law, Environmental Law, Criminal Procedure, Environmental Crimes Seminar, Wildlife Protection Law. Provided *pro bono* legal services in administrative proceedings and filings at the Texas Public Utility Commission. Launched a student clinical effort that reviewed and made recommendations on utility energy efficiency program plans.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990. Member of the faculty in the Department of Law. Honorably discharged in August 1990, as Major in the Regular Army. Courses taught: Constitutional Law, Military Law, and Environmental Law Seminar. Greatly expanded the environmental law curriculum and laid foundation for the concentration program in law. While carrying a full time teaching load, earned a Master of Laws degree in Environmental Law. Established a program for subsequent environmental law professors to obtain an LL.M. prior to joining the faculty.

LITIGATION

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987. Assigned to Trial Defense Service and Office of the Staff Judge Advocate. Prosecuted and defended more than 150 felony-level courts-martial. As prosecutor, served as legal officer for two brigade-sized units (approximately 5,000 soldiers), advising commanders on appropriate judicial, non-judicial, separation, and other actions. Pioneered use of some forms of psychiatric and scientific testimony in administrative and judicial proceedings.

NON-LEGAL MILITARY SERVICE

Armored Cavalry Officer, 2d Squadron 9th Armored Cavalry, Fort Stewart, Georgia, May 1978–August 1981. Served as Logistics Staff Officer (S-4). Managed budget, supplies, fuel, ammunition, and other support for an Armored Cavalry Squadron. Served as Support Platoon Leader for the Squadron (logistical support), and as line Platoon Leader in an Armored Cavalry

Troop. Graduate of Airborne and Ranger Schools. Special training in Air Mobilization Planning and Nuclear, Biological and Chemical Warfare.

Karl R. Rábago

Formal Education

LL.M., Environmental Law, Pace University School of Law, 1990: Curriculum designed to provide breadth and depth in study of theoretical and practical aspects of environmental law. Courses included: International and Comparative Environmental Law, Conservation Law, Land Use Law, Seminar in Electric Utility Regulation, Scientific and Technical Issues Affecting Environmental Law, Environmental Regulation of Real Estate, Hazardous Wastes Law. Individual research with Hudson Riverkeeper Fund, Garrison, New York.

LL.M., Military Law, U.S. Army Judge Advocate General's School, 1988: Curriculum designed to prepare Judge Advocates for senior level staff service. Courses included: Administrative Law, Defensive Federal Litigation, Government Information Practices, Advanced Federal Litigation, Federal Tort Claims Act Seminar, Legal Writing and Communications, Comparative International Law.

J.D. with Honors, University of Texas School of Law, 1984: Attended law school under the U.S. Army Funded Legal Education Program, a fully funded scholarship awarded to 25 or fewer officers each year. Served as Editor-in-Chief (1983–84); Articles Editor (1982–83); Member (1982) of the Review of Litigation. Moot Court, Mock Trial, Board of Advocates. Summer internship at Staff Judge Advocate's offices. Prosecuted first cases prior to entering law school.

B.B.A., Business Management, Texas A&M University, 1977: ROTC Scholarship (3–yr). Member: Corps of Cadets, Parson's Mounted Cavalry, Wings & Sabers Scholarship Society, Rudder's Rangers, Town Hall Society, Freshman Honor Society, Alpha Phi Omega service fraternity.

Selected Publications

"The Value of Solar Tariff: Net Metering 2.0," The ICER Chronicle, Ed. 1, p. 46 [International Confederation of Energy Regulators] (December 2013)

"A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," co-author, Interstate Renewable Energy Council (October 2013)

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Table of Testimony Submitted by Karl R. Rábago, Rábago Energy LLC

(as of 28 August 2015)

Date	Proceeding	Case/Docket #	On Behalf Of:
Dec. 21, 2012	VA Electric & Power Special Solar Power Tariff	Case # PUE-202-0064	Southern Environmental Law Center
May 10, 2013	Georgia Power Company 2013 IRP	Docket # 36498	Georgia Solar Energy Industries Association
Jun. 23, 1203	Louisiana Public Service Commission Re-examination of Net Metering Rules	Docket # R-31417	Gulf States Solar Energy Industries Association
Aug. 29, 2013	DTE (Detroit Edison) 2013 Renewable Energy Plan Review (Michigan)	Case # U-17302	Environmental Law and Policy Center
Sep. 5, 2013	CE (Consumers Energy) 2013 Renewable Energy Plan Review (Michigan)	Case # U-17301	Environmental Law and Policy Center
Sep. 27, 2013	North Carolina Utilities Commission 2012 Avoided Cost Case	Docket # E-100, Sub. 136	North Carolina Sustainable Energy Association
Oct. 18, 2013	Georgia Power Company 2013 Rate Case	Docket # 36989	Georgia Solar Energy Industries Association
Nov. 4, 2013	PEPCO Rate Case (District of Columbia)	Formal Case # 1103	Grid 2.0 Working Group & Sierra Club of Washington, D.C.
Apr. 24, 2014	Dominion Virginia Electric Power 2013 IRP	VA SCC Case # PUE-2013-00088	Environmental Respondents
May 7, 2014	Arizona Corporation Commission Investigation on the Value and Cost of Distributed Generation	Docket No. E-00000J-14-0023	Rábago Energy LLC (invited presentation and workshop participation)
Jul. 10, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case	Docket # E-100, Sub. 140	Southern Alliance for Clean Energy
Jul. 23, 2014	Florida Energy Efficiency and Conservation Act, Goal Setting – FPL, Duke, TECO, Gulf	Florida PSC Docket Nos. 130199-EI, 130200-EI, 130201-EI, 130202-EI	Southern Alliance for Clean Energy

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 35
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-2

Sep. 19, 2014	Ameren Missouri's Application for Authorization to Suspend Payment of Solar Rebates	Missouri PSC File No. ET-2014-0350, Tariff No. YE-2014-0494	Missouri Solar Energy Industries Association
Aug. 6, 2014	Appalachian Power Company 2014 Biennial Rate Review	Virginia SCC Case No. PUE-2014-00026	Southern Environmental Law Center (Environmental Respondents)
Aug. 13, 2014	Wisconsin Public Service Corp. 2014 Rate Application	Wisconsin PSC Docket No. 6690-UR-123	RENEW Wisconsin and Environmental Law & Policy Center
Aug. 28, 2014	WE Energies 2014 Rate Application	Wisconsin PSC Docket No. 05-UR-107	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 18, 2014	Madison Gas & Electric Company 2014 Rate Application	Wisconsin PSC Docket No. 3720-UR-120	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 29, 2014	SOLAR, LLC v. Missouri Public Service Commission	Missouri District Court Case No. 14AC-CC00316	SOLAR, LLC
Ongoing	Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs, etc.	California PUC Rulemaking 14-07-002	The Utility Reform Network (TURN)
Mar. 20, 2015	Orange and Rockland Utilities 2015 Rate Application	New York PSC Case 14-E-0493	Pace Energy and Climate Center
May 22, 2015	DTE Electric Company Rate Application	Michigan PSC Case No. U-17767	Michigan Environmental Council, NRDC, Sierra Club, and ELPC
Jul. 20, 2015	Hawaiian Electric Company and NextEra Application for Change of Control	Hawai'i PUC Docket # 2015-0022	Hawai'i Department of Business, Economic Development, and Tourism
Sep. 2, 2015	Wisc PSCo Rate Application	Wisconsin PSC Case No. 6690-UR-124	ELPC
Sep. 15, 2015	Dominion Virginia Electric Power 2013 IRP	VA SCC Case # PUE-2015-00035	Environmental Respondents
Sep. 16, 2015	NYSEG & RGE Rate Cases	New York PSC Cases 15-E-0283, -0285	Pace Energy and Climate Center

ORIGINAL

FPL

Florida Power & Light Company, P.O. Box 029100, Miami, FL 33102

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01 APR -2 PM 4:12
RECORDS AND REPORTING

April 2, 2001

Ms. Blanca S. Bayo
Florida Public Service Commission
Director, Division of Records and Reporting
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

undocketed

VIA HAND DELIVERY

Dear Ms. Bayo:

In accordance with Chapter 186, Section 186.801 (Ten Year Power Plant Site Plans) of the Florida Statutes, enclosed for filing are twenty-five (25) copies of Florida Power & Light Company's Ten-Year Power Plant Site Plan.

If you have any questions, please do not hesitate to contact me at (305) 552-4332 or Richard Rump at (305) 552-4159.

Sincerely,

Anne Grealy/dc

Anne Grealy, Director
Regulatory Affairs Department

AG/rcr

Enclosures

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 36
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-A

DOCUMENT NUMBER-DATE
04079 APR-2 01
FPSC-RECORDS/REPORTING

Ten Year Power Plant Site Plan

2001 - 2010

FPL

FPL

Ten Year Power Plant Site Plan

2001-2010

Submitted To:

Florida Public
Service Commission

Miami, Florida
April, 2001

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Table of Contents

Table of Contents

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Overview of The Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten - Year Power Plant Site Plan. This plan includes an estimate of the utility's electric power generating needs, a projection of how those needs will be met, and a disclosure of information pertaining to the utility's preferred and potential power plant sites. This information is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (FAC).

This Ten - Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) 2000 planning analyses and the forecasted information presented in this plan addresses the 2001 – 2010 time frame.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information, especially for the latter years of the ten - year time horizon, and is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is data on other FPL resources, including its transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, are presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, as determined in FPL's 2000 IRP work.

Chapter IV – Environmental and Land Use Information

This chapter discusses various environmental information as well as preferred and potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional specific information which is to be included in a Site Plan filing.

Chapter VI – Summary of Required Schedules

This chapter is a contains of Schedules 1 thru 10. It also contains FPL's Ten Year Site Plan Fact Summary.

FPL
List of Abbreviations
Used in FPL Forms

Reference	*Abbreviation*	*Definition*
Unit Type	IC	Internal Combustion
	NP	Nuclear Power
	ST	Steam Unit
	GT	Gas Turbine
	CT	Combustion Turbine
	CC	Combined Cycle
	BIT	Bituminous Coal
Fuel Type	UR	Uranium
	NG	Natural Gas
	FO6	#4,#5,#6 Oil (Heavy)
	FO2	#1, #2 or Kerosene Oil (Distillate)
	BIT	Bituminous Coal
	No	None
Fuel Transportation	TK	Truck
	RR	Railroad
	PL	Pipeline
	WA	Water
	No	None
Air Pollution Control	LNB	Low No_x Burners
Cooling Method Type	OTS	Once Through - Saline
	CP	Cooling Pond
Unit/Site Status	P	Planned Unit
	A	Generation Unit Capability Increased (Rerated or Relicensed)

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Executive Summary

Florida Power & Light Company's (FPL) 2001 Ten - Year Power Plant Site Plan (Site Plan) primarily addresses FPL's plans to increase its electric generation capability as part of its efforts to meet its projected incremental resource needs for the 2001 – 2010 time period.

FPL's total generation capability will significantly increase during the 2001 – 2010 time period as is shown in Table ES.1. This table also shows the resulting Summer and Winter reserve margins for FPL over the ten-year time horizon.

Table ES 1 reflects FPL's efforts to repower existing units at its Fort Myers and Sanford sites, its approved DSM goals, planned changes to existing generation units (due to unit overhauls, etc.); and scheduled changes in the delivered amounts of purchased power. The table also reflects the planned additions of new generating units.

The number of these new generating units that will be added is driven in part by the outcome of the Florida Public Service Commission docket No. 981890-EU. This docket ended with a stipulated agreement that primarily resulted in FPL, along with Tampa Electric Company and Florida Power Corporation, switching from a minimum reserve margin planning criterion of 15% to one of 20% beginning with the Summer of 2004. As a consequence, FPL is now planning to add significantly more new generation capacity than was shown in its Site Plans filed prior to this agreement.

As shown in Table ES.1, FPL plans to add four new combustion turbines (CT's) in the 2001 – 2003 time period. Two new CT's will be installed at FPL's existing Martin plant site in 2001. Another two new CT's will be installed at FPL's existing Fort Myers plant site in 2003. All four CT's are projected to be converted into combined cycle (CC) units in 2005 As a result, the pair of new CT's at Martin and the pair of new CT's at Fort Myers will each be converted into one new CC unit. The resulting new CC unit at Martin, and the new CC unit at Fort Myers, will begin operation in 2005.

Also during the 2001 – 2003 time period, FPL will be repowering its two existing steam units at its Fort Myers site and will be repowering two (unit Nos. 4 & 5) of its existing three steam units at its Sanford site.

FPL is also securing capacity for the time period from mid-2001 to mid-2005 through a number of new firm capacity, short-term purchases from utilities and other entities. (Please see Chapter III for a further discussion of these new purchases.)

In addition, eight combined cycle (CC) units will be added during the 2005 – 2010 time period. [1] Two CC units will be added at FPL's Martin plant site, one in 2005 and one in 2006. Another CC unit is projected to be added at FPL's Midway site in 2005. In addition, one new CC unit will be added in 2007 and another in 2009. Finally, three new CC units will be added in 2010 as FPL's UPS contract with Southern Company ends. [2] Sites for the last five CC units for the 2007 – 2010 time frame have not yet been selected.

These planned increases in electric generation capability will allow FPL to continue to maintain system reliability and integrity at a reasonable cost.

[1] FPL's current planning studies have identified new combined cycle units as the generally preferred option to meet future load growth. However, repowering of existing FPL sites remains an alternative to new construction, and FPL will continue to examine this option.

[2] FPL has not yet determined whether it would extend or replace these purchases, or build new capacity to meet its needs. For purposes of this Site Plan it was assumed that the 2010 needs would be met through the addition of unsited CC units. A final decision regarding the 2010 needs is not needed for at least several years.

Projected Capacity Changes and Reserve Margins for FPL [1]					
		Net Capacity Changes (MW)		FPL Reserve Margin (%)	
		Winter [2]	Summer [3]	Winter	Summer
2001	Changes to existing plants	8	(56)	18%	20%
	Fort Myers Repowering:Initial Phase [4]	543	894		
	Combustion Turbines (2) at Martin [5]	---	298		
	New purchases [6]	---	196		
2002	Fort Myers Repowering:Second Phase	(1)	35	15%	22%
	Combustion Turbines (2) at Martin [5]	362	---		
	Sanford Repowering # 5: Initial Phase [7]	(394)	---		
	Sanford Repowering # 5: Second Phase [7]	---	567		
	Sanford Repowering # 4: Initial Phase [7]	---	(390)		
	New purchases [6]	50	779		
	Changes to existing QF's	---	(9)		
2003	Fort Myers Repowering:Second Phase	531	---	29%	25%
	Sanford Repowering # 5: Second Phase	1065	---		
	Sanford Repowering # 4: Second Phase	671	957		
	Combustion Turbines (2) Fort Myers [8]	---	298		
	Changes to existing QF's	(9)	---		
	New purchases [6]	1025	---		
2004	Combustion Turbines (2) Fort Myers	362	---	28%	22%
2005	Changes to existing QF's	(10)	(10)	25%	23%
	New purchases [6]	(50)	(975)		
	Martin Combined Cycle No. 5 [9]	---	547		
	Conversion of MR CT's to CC	---	249		
	Conversion of FM CT's to CC	---	249		
	Midway Combined Cycle [9]	---	547		
2006	Changes to existing QF's	(133)	(133)	25%	22%
	New purchases	(1025)	---		
	Martin Combined Cycle No. 5 [9]	596	---		
	Conversion of MR CT's to CC	234	---		
	Conversion of FM CT's to CC	234	---		
	Midway Combined Cycle [9]	596	---		
	Martin Combined Cycle No. 6 [9]	---	547		
2007	Martin Combined Cycle No. 6 [9]	596	---	26%	23%
	Unsited Combined Cycle #1 [9]		547		
2008	Unsited Combined Cycle #1 [9]	596	---	27%	21%
2009	Unsited Combined Cycle #2 [9]	---	547	25%	21%
	Changes to existing QF's	(51)	(51)		
2010	Changes to existing purchases [10]	---	(975)	25%	21%
	Unsited Combined Cycle #2 [9]	596	---		
	Unsited Combined Cycle #3 [9]	---	547		
	Unsited Combined Cycle #4 [9]	---	547		
	Unsited Combined Cycle #5 [9]	---	547		
	TOTALS =	***6,392***	***6,299***		

Table E.S. 1

Projected Capacity Changes and Reserve Margins for FPL

Note:

(1) Additional information about these capacity changes and resulting reserve margins is found in Chapter III of this document.

(2) Winter values are values for January of year shown.

(3) Summer values are values for August of year shown.

(4) The initial phase of the Fort Myers repowering project consists of the introduction of operational combustion turbines followed by taking existing steam units out-of-service. The second phase of repowering consists of completing the integration of the combustion turbines, heat recovery steam generators, and steam turbines.

(5) The two CT's at Martin are scheduled to be in-service in the Summer of 2001. Therefore, the CT's are included in the 2001 Summer reserve margin calculation and are included in the 2002 - on reserve margin calculations for Summer and Winter.

(6) These are firm capacity, short - term purchases. See Section I.D. and III.A. for more details.

(7) The initial phase of the Sanford repowering project consists solely of taking existing steam units out-of-service; combustion turbine operation is not introduced at this time. The second phase of the repowering consists of integrating the combustion turbines, heat recovery steam generators, and steam turbines.

(8) The two CT's at Fort Myers are scheduled to be in-service in the Spring of 2003. Therefore, the CT's are included in the 2003 Summer reserve margin calculation and are included in the 2004 - on reserve margin calculations for Summer and Winter.

(9) All combined cycle units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

10) FPL will be determining at a later date whether to extend or replace these UPS purchases from Southern Company. However, for purposes of this Site Plan, FPL has assumed that the 2010 needs would be met through the addition of unsited combined cyles.

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 7.3 million people. FPL served an average of 3,848,401 customer accounts in thirty-five counties during 2000. These customers were served from a variety of resources including: FPL-owned fossil and nuclear generating units, non-utility-owned generation, demand side management, and interchange/purchased power.

I.A. FPL-Owned Resources

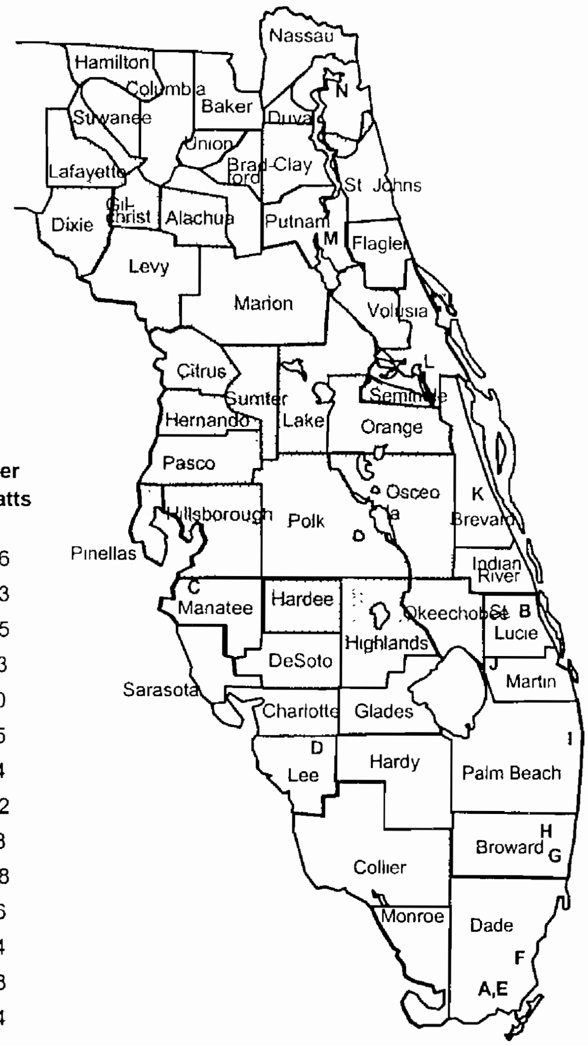
The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory and also include partial ownership of one unit located in Georgia and two units located in Jacksonville. The current generating facilities consist of four nuclear steam units, three coal units, six combined cycle units, twenty-one fossil steam units, forty-eight gas turbines, and five diesel units. The location of these units is shown on Figure I.A.1.

The bulk transmission system is composed of 1,107 circuit miles of 500 Kilovolt (KV) lines (including 75 miles of 500 KV lines [two 37-1/2 mile lines] between Duval Substation and the Florida-Georgia state line, which are jointly owned with Jacksonville Electric Authority) and 2,572 circuit miles of 230 KV lines. The underlying network is composed of 1,614 circuit miles of 138 KV lines, 717 circuit miles of 115 KV lines, and 180 circuit miles of 69 KV transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 497 substations.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3. shows FPL's interconnection ties with other utilities.

Capacity Resources
(as of December 31, 2000)

☐ Non-FPL Territory



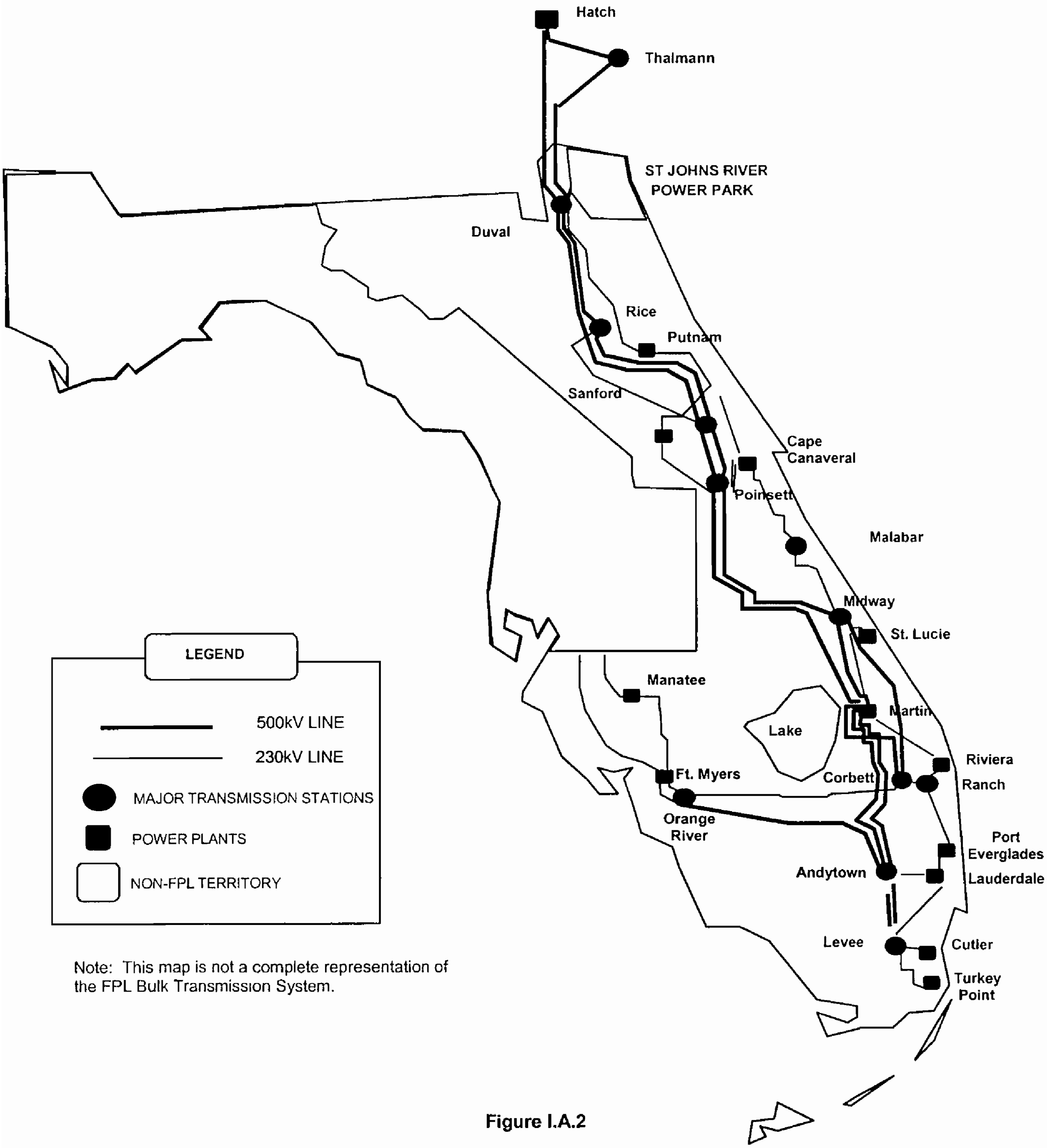
	Unit Name	No. of Units	Fuel Type	Summer Megawatts
A	Turkey Point	2	Nuclear	1,386
B.	St. Lucie *	2	Nuclear	1,553
C.	Manatee	2	Oil	1,625
D.	Ft. Myers	2	Oil	543
E.	Turkey Point	2	Oil/Gas	810
F.	Cutler	2	Gas	215
G.	Lauderdale	2	Oil/Gas	854
H.	Port Everglades	4	Oil/Gas	1,242
I.	Riviera	2	Oil/Gas	563
J.	Martin	4	Gas/Oil	2,588
K.	Cape Canaveral	2	Oil/Gas	806
L.	Sanford	3	Oil/Gas	914
M.	Putnam	2	Oil/Gas	498
N.	St. Johns River *	2	Coal	254
Scherer **		1	Coal	658
Peaking Units				2,355
FPL Generation				**16,864**

** Represents FPL's ownership share St. Lucie nuclear: 100% unit 1, 85% unit 2; St. Johns River: 20% of two units.*

*** The Scherer unit is located in Georgia and is not shown on this map.*

Figure I.A.1

FPL Substation and Transmission System Configuration



Note: This map is not a complete representation of the FPL Bulk Transmission System.

Figure I.A.2

FPL Interconnection Diagram

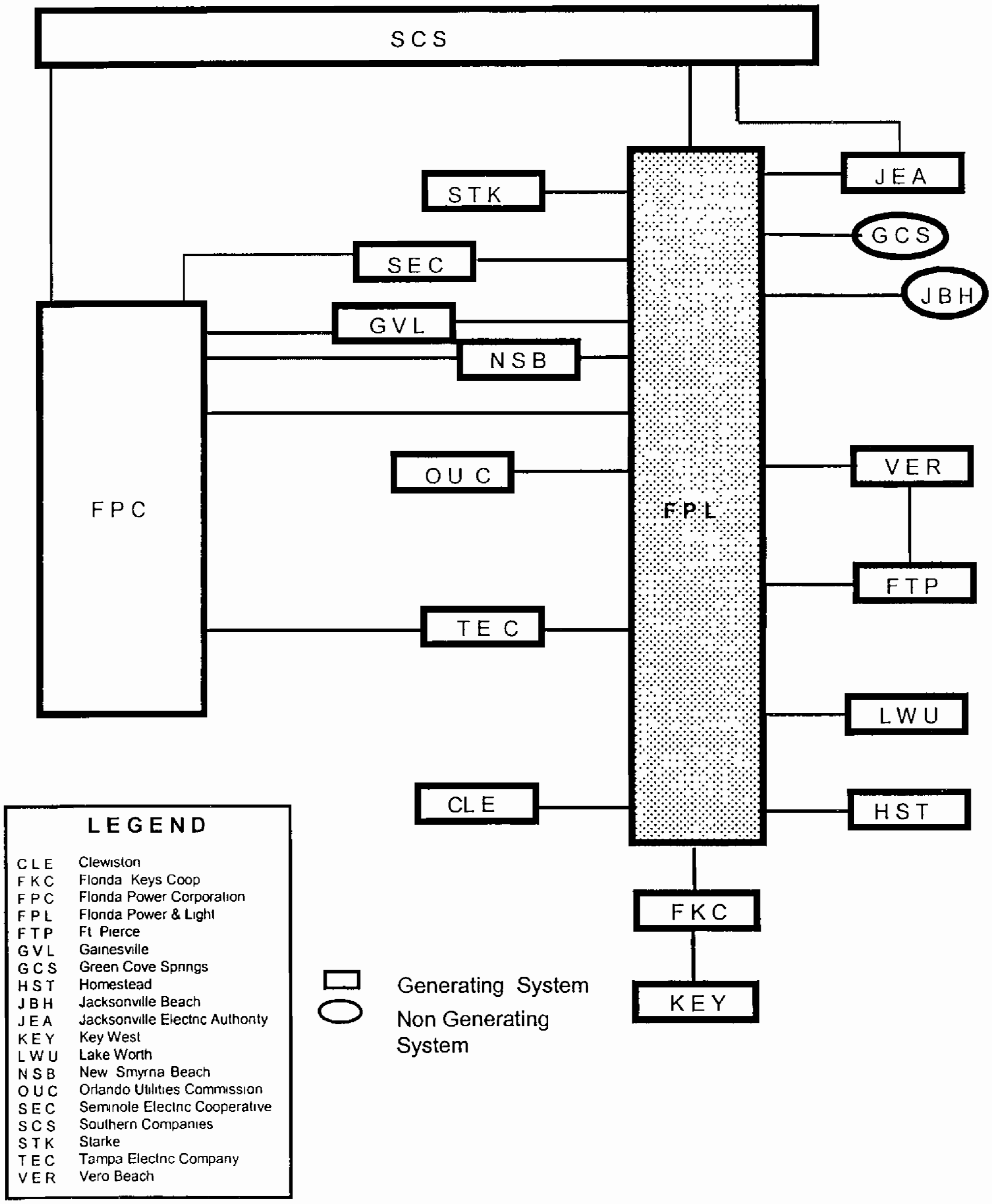


Figure I.A.3

I.B Non-Utility Generation

Non-utility generation is an important part of FPL's resource mix. FPL currently has contracts with eight cogeneration/small power production facilities to purchase firm capacity and energy. A listing of these facilities appears in Table I.B.1. In addition, FPL purchases as-available (non-firm) energy from several cogeneration facilities and small power production facilities as shown in Table I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

Florida Power & Light Company Firm Capacity and Energy Contracts with Cogeneration/Small Power Production Facilities					
Project	***County***	***Fuel***	***MW Capacity***	***In-Service Date***	***End Date***
Bio-Energy	Broward	Landfill Gas	10.0	5/1/98	1/1/05
Broward South	Broward	Solid Waste	50.6	4/1/91	8/1/09
			1.4	1/1/93	12/31/26
			1.5	1/1/95	12/31/26
			0.6	1/1/97	12/31/26
Broward North	Broward	Solid Waste	45.0	4/1/92	12/31/10
			7.0	1/1/93	12/31/26
			1.5	1/1/95	12/31/26
			2.5	1/1/97	12/31/26
Royster Mulberry	Polk	Waste Heat	8.0	4/1/92	3/31/02
			1.0	12/1/95	3/31/02
Cedar Bay Generating Co.	Duval	Coal (CFB)	250.0	1/25/94	12/31/24
Indiantown Cogen., LP	Martin	Coal (PC)	330.0	12/22/95	12/1/25
Palm Beach SWA	Palm Beach	Solid Waste	43.5	4/1/92	3/31/10
Florida Crushed Stone	Hernando	Coal (PC)	110.0	4/1/92	10/31/05
			11.0	1/1/94	10/31/05
			12.0	1/1/95	10/31/05

Table I.B.1

As-Available Energy Purchases From Non-Utility Generators in 2000				
Project	***County***	***Fuel***	***In-Service Date***	***Energy (MWH) Delivered to FPL in 2000***
US Sugar-Bryant	Palm Beach	Bagasse	2/80	5,101
Tropicana	Manatee	Natural Gas	2/90	10,886
Okeelanta	Palm Beach	Bagasse/Wood	11/95	296,140
Tomoka Farms	Volusia	Landfill Gas	7/98	19,868
Georgia Pacific	Putnam	Paper By- Product	2/94	8,925

Table I.B.2

I.C. Demand Side Management (DSM)

FPL's DSM activities continue what has been FPL's practice since 1978 of encouraging cost-effective conservation and load management. FPL's DSM efforts through 2000 have resulted in a cumulative Summer peak reduction of approximately 2,680 MW at the meter and an estimated cumulative annual energy saving of 4,830 GWH at the meter.

FPL's current DSM Plan was approved by the Florida Public Service Commission in late 1999 and reflects FPL's new DSM Goals for the 2000 – 2009 time frame. FPL's 2000 resource plan, and the schedule for new generation additions presented in this document, are based on these approved DSM levels.

I.D. Purchased Power

Purchased power remains an important part of FPL's resource mix. FPL has a unit power sales (UPS) contract to purchase up to 931 MW, with a minimum of 380 MW, of coal-fired generation from the Southern Company. In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 382 MW (Summer) and 388 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Unit Nos. 1 and 2 (FPL also has an ownership interest in these units; that ownership amount is reflected in FPL's installed capacity shown on Schedule 1).

Finally, FPL is projecting new firm capacity purchases for the mid - 2001 to mid - 2005 time period. These firm capacity purchases are projected to come from a variety of suppliers. Table I.D.1 presents the Summer and Winter MW resulting from these purchased power contracts through the year 2010.

	FPL's Purchased Power MW (1)							
	UPS		***SJRPP***		***New Firm Capacity Purchases (3)***		***Total***	
Year	***Winter***	***Summer***	***Winter***	***Summer***	***Winter***	***Summer***	***Winter***	***Summer***
2000 (2)	931	931	388	388	0	0	1319	1319
2001	931	931	388	382	0	196	1319	1509
2002	931	931	388	382	50	975	1369	2288
2003	931	931	388	382	1075	975	2394	2288
2004	931	931	388	382	1075	975	2394	2288
2005	931	931	388	382	1025	0	2344	1313
2006	931	931	388	382	0	0	1319	1313
2007	931	931	388	382	0	0	1319	1313
2008	931	931	388	382	0	0	1319	1313
2009	931	931	388	382	0	0	1319	1313
2010	931	0	388	382	0	0	1319	382

Note:

(1) Total reflects total resource entitlements resulting from existing agreements between FPL, Southern Companies, JEA, and from new firm purchase agreements

(2) Values for 2000 are actual

(3) A discussion of these new firm capacity purchases can also be found in Section III.A.

Table I.D.1

Schedule 1

Existing Generating Facilities
As of December 31, 2000

(1) Plant Name	(2) Unit No	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen Max Nameplate KW	(13) Net Capability 1/ Summer MW	(14) Net Capability 1/ Winter MW
Turkey Point		Dade County 27/57S/40E									2,338,100	2,208	2,260
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	410	411
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	400	403
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	760,000	693	717
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	760,000	693	717
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	14,000	12	12
Cutler		Dade County 27/55S/40E									236,500	215	217
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	74,500	71	72
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	162,000	144	145
Lauderdale		Broward County 30/50S/42E									1,863,972	1,694	1,952
	4		CC	NG	FO2	PL	PL	Unknown	Oct-57	Unknown	521,250	427	467
	5		CC	NG	FO2	PL	PL	Unknown	Apr-58	Unknown	521,250	427	467
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,736	420	509
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,736	420	509
Port Everglades		City of Hollywood 23/50S/42E									1,665,086	1,662	1,757
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	225,250	221	222
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	225,000	221	222
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	390	392
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	410	412
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,736	420	509

1/ These ratings are peak capability

Schedule 1

Existing Generating Facilities
As of December 31, 2000

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen Max Nameplate KW	(13) Net Capability 1/ Summer MW	(14) Net Capability 1/ Winter MW
Riviera		City of Riviera Beach 33/42S/43E									620,840	563	565
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	283	283
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	280	282
Martin		Martin County 29/29S/38E									2,950,000	2,588	2,674
	1		ST	NG	FO6	PL	PL	Unknown	Dec-80	Unknown	863,000	824	843
	2		ST	NG	FO6	PL	PL	Unknown	Jun-81	Unknown	863,000	816	831
	3		CC	NG	FO2	PL	PL	Unknown	Feb-94	Unknown	612,000	474	500
	4		CC	NG	FO2	PL	PL	Unknown	Apr-94	Unknown	612,000	474	500
St Lucie		St Lucie County 16/36S/41E									1,553,000	1,553	1,579
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	839,000	839	853
	2	2/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	714,000	714	726
Cape Canaveral		Brevard County 19/24S/36F									804,100	806	812
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	403	406
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	403	406
Sanford		Volusia County 16/19S/30E									1,022,450	914	919
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	150,250	142	144
	4		ST	FO6	NG	WA	PL	Unknown	Jul-72	Unknown	436,100	381	384
	5		ST	FO6	No	WA	No	Unknown	Jul-73	Unknown	436,100	391	391

1/ These ratings are peak capability

2/ Total capability is 839/853 MW Capabilities shown represent the company's share of the unit and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of 14.89551%

Schedule 1

Existing Generating Facilities
As of December 31, 2000

(1) Plant Name	(2) Unit No	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max Nameplate KW	(13) Net Capability 1/ Summer MW	(14) Net Capability 1/ Winter MW
Putnam		Putnam County 16/10S/27E									580,000	498	594
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,000	249	297
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,000	249	297
Fort Myers		Lee County 35/43S/25E									1,302,250	1,626	1,856
	1		ST	FO6	No	WA	No	Unknown	Nov-58	Unknown	156,250	141	142
	2		ST	FO6	No	WA	No	Unknown	Jul-69	Unknown	402,000	402	402
	1-12		GT	FO2	No	WA	No	Unknown	May-74	Unknown	744,000	636	769
	Repowering CT's (3)		GT	NG	FO2	PL	PL	Unknown	Dec-00	Unknown	543,000	447	543
Manatee		Manatee County 18/33S/20E									1,726,600	1,625	1,639
	1		ST	FO6	No	WA	No	Unknown	Oct-76	Unknown	863,300	815	822
	2		ST	FO6	No	WA	No	Unknown	Dec-77	Unknown	863,300	810	817
St Johns River Power Park 2/		Duval County 12/15/28E									250,000	254	260
	1		BIT	BIT	No	RR	No	Unknown	Mar-87	Unknown	125,000	127	130
	2		BIT	BIT	No	RR	No	Unknown	May-88	Unknown	125,000	127	130
Scherer 3/		Monroe, GA									891,000	658	666
	4		BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	891,000	658	666
									Total System as of December 31, 2000 =			16,864	17,750

1/ These ratings are peak capability.
2/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80% , SJRPP receives coal by water (WA) in addition to rail
3/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses

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CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are developed on an annual basis for resource planning work at FPL. These forecasts are a key input to the models used to develop the Integrated Resource Plan. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

The primary drivers to develop these forecasts are demographic trends, weather and economic conditions, and prices of electricity and other energy sources. In addition to these drivers, the resulting forecasts are an integration of economic evaluations, inputs of local economic development boards, weather assessments from NOAA, and inputs from FPL's own customer service planning areas. In the area of demographics, population trends by county, plus housing characteristics such as housing starts, housing size, and vintage of homes, are assessed.

Forecasts for electric usage in the residential and commercial classes include end-use information such as appliance saturation studies, efficiencies, and intensity of energy use. In addition to these inputs, residential forecasts also make use of household characteristics such as ages of members in household, number of members in households, and income distributions.

Several economic forecasting services are contracted to obtain their economic outlook for FPL's service territory. These include Wharton Economic Forecasting Associates (WEFA), Data Resources Incorporated (DRI), and the Bureau of Economic and Business Research (BEBR) of the University of Florida. In addition, FPL actively participates with local development councils and universities to obtain their assessments of the local economy, specifically in the area of expansion of new businesses and retention of the current business base. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

In recent years, the rise of the Tele-communications industry and its potential impact on electric demand has added a new dimension to the forecasting process. Since the needs of the customers in this industry are very project - specific, the customer representatives servicing this class of customers provide insight as to the magnitude and timing of each future project and this information is used in developing the forecast. For example, FPL's 2000 forecast includes an estimate that in 3 years the new load attributed to Tele-communications facilities could reach as much as 570 MW. This additional load in its entirety was treated as a line item adjustment and was added to FPL's 2000 energy and peak forecasts.

II.A. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for each revenue class for the forecasting period of 2000 – 2019. The results of these sales forecasts are presented in Schedules 2.1 – 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical tool Metrix ND. The methodologies used to develop sales forecasts for each jurisdictional revenue class are outlined below.

1. Residential Sales

Residential energy sales are forecast by multiplying the residential use per customer forecast by the residential customer forecast. Residential electric usage per customer is estimated by using a regression model which contains the real residential price of electricity, Florida per capita income, and Cooling and Heating Degree Days as explanatory variables. The price of electricity plays a role in explaining electric usage since electricity, like all other goods and services, will be purchased in greater or lesser quantities depending upon its price. The Cooling & Heating Degree Days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric heaters. A composite temperature is derived using hourly temperatures across FPL's service territory (Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained) weighted by regional energy sales. This composite temperature is used to derive Cooling and Heating Degree Days which are based on starting point temperatures of 72°F and 66°F, respectively. The Cooling Degree Days variable is multiplied by the level of air conditioning saturations and the Heating Degree Days variable is multiplied by the level of electric heating saturations. To capture economic conditions the model includes Florida per capita income. The degree of economic prosperity can, and does, affect residential electricity sales.

2. Commercial Sales

The commercial sales forecast is also developed using a regression model. Commercial sales are a function of the following variables: Florida non-agricultural employment, commercial real price of electricity, and Cooling Degree Days. Florida non-agricultural employment is used to capture the economic activity in FPL's service territory. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. Cooling Degree Days are used to capture weather-sensitive load in the commercial sector.

3. Industrial Sales

Industrial sales were forecasted through a linear multiple regression model using Florida manufacturing employment and the price of electricity as explanatory variables. Energy sales in this revenue class are primarily due to manufacturers; therefore, employment in this sector is a key variable in capturing the economic activity. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage.

4. Other Public Authority Sales

The sales for this class are developed using an econometric model. Florida manufacturing employment and the other public authority sales of the previous year are used as explanatory variables.

5. Street & Highway Sales and Railroad & Railways Sales

The forecast of Street & Highway sales was developed using a regression model with FPL's total customers and the street and highway sales of the previous period serving as inputs.

The forecasts for Railroads & Railways are held constant since there are no plans for expansion of this economic sector in FPL's service territory.

6. Resales Sales

Resale (Wholesale) customers are composed of municipalities and/or electric cooperatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers.

Contract Rate

Currently there are four customers in this class: the Florida Keys Electric Cooperative (Florida Keys), City Electric System of the Utility Board of the City of Key West, Florida (City of Key West), Metro-Dade County, and FMPA. Sales to the Florida Keys are forecasted using a regression model. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor. Metro-Dade County sells 60 MW to Florida Power Corporation. Line losses are billed to Metro-Dade under a wholesale contract. The forecast is calculated based on assumptions about the magnitude of line losses, the sales monthly capacity factor, and the number of hours in a particular month. FMPA has contracted for delivery of 75 MW for the period of June 2002 through October 2007.

Total Sales

Sales forecasts by revenue class are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, an expansion factor is applied to generate a forecast of annual Net Energy for Load (NEL).

II.B. Net Energy for Load

An annual econometric model is developed to produce a Net Energy for Load (NEL) forecast. The key inputs to the model are: the price of electricity, Heating & Cooling Degree Days, and Florida Non-Agricultural Employment. Once an annual NEL forecast is obtained using the above-mentioned model, the results are then compared for reasonability to the NEL forecast generated using the total sales forecast. The sales by class are then adjusted to match the NEL from the annual NEL model.

The monthly NEL forecast is also generated for the entire long-term forecasting period of 2000 – 2019. Historical data is used to develop month-to-annual ratios. The ratios are then used to produce the monthly NEL forecast.

The forecasted NEL values for 2001 – 2010 are presented in Schedule 3.3 which appears at the end of this chapter.

II.C. System Peak Forecasts

In recent years, the absolute growth in FPL system load has been associated with a larger customer base, varying weather conditions, continued economic growth, changing patterns of customer behavior (including an increasing stock of electricity-consuming appliances), and more efficient heating and cooling appliances. The Peak Forecast models were developed to capture these behavioral relationships.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2001 - 2010 are presented in Schedules 3.1 and 3.2, as well as in Schedules 7.1 and 7.2.

System Summer Peak

The Summer peak forecast is developed using an econometric model. Key variables used in the model include: the total number of FPL Summer customers, the price of electricity, a ratio of Gross Domestic Product (GDP) and Florida Non-Agricultural employment, a dummy variable, and a weather variable. The dummy variable is included to capture the structural change in the economy after the oil crisis in 1975. The weather variable is the product of saturation of air conditioning equipment and maximum Summer temperature.

System Winter Peak

Like the system Summer peak model, this model is also an econometric model. The Winter peak model is a per customer model which consists of three weather-related variables: the minimum temperature on the peak day, a weather term which is a product of heating saturation and minimum Winter day temperature, and Heating Degree Hours for the prior day as well as for the morning of the Winter peak day. In addition, the model also has an economic term which is a ratio of GDP and Florida non-agricultural employment, a dummy variable used to capture the effects of larger homes, and another dummy variable designed to provide additional emphasis for the more recent weather data.

Monthly Peak Forecasts

Monthly peaks for the 2000 - 2019 period are forecasted to provide information for the scheduling of maintenance for power plants and fuel budgeting. The forecasting process is basically the same as for the monthly NEL forecast:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to seasonal peak (Summer = April-October, Winter = November-March).

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.D The Hourly Load Forecast

Forecasted values for system hourly load for the period 2000 - 2019 are produced using a System Load Forecasting "shaper" program. This model uses sixteen years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. These daily load shapes are ranked and used with forecasted monthly peaks, NEL, and calendars in developing an hourly forecast. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential				Commercial	
Year	Population**	Members per Household	GWH	Average*** No. of Customers	Average KWH Consumption Per Customer	GWH	Average*** No of Customers	Average KWH Consumption Per Customer
1991	6,211,996	2 17	34,617	2,863,198	12,090	27,232	343,834	79,200
1992	6,314,005	2 17	34,198	2,911,807	11,745	26,991	350,269	77,058
1993	6,380,715	2 14	36,360	2,975,479	12,220	28,508	358,679	79,481
1994	6,516,879	2 15	38,716	3,037,629	12,745	29,946	366,409	81,729
1995	6,639,165	2 14	40,556	3,097,192	13,094	30,719	374,005	82,135
1996	6,754,084	2 14	41,302	3,152,625	13,101	31,211	380,860	81,949
1997	6,884,909	2 15	41,849	3,209,298	13,040	32,942	388,906	84,703
1998	7,014,152	2 15	45,482	3,266,011	13,926	34,618	396,749	87,255
1999	7,133,361	2 14	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,282,933	2 13	46,320	3,414,002	13,568	37,001	415,295	89,096
2001 *	7,406,700	2 13	46,949	3,471,810	13,523	39,840	426,053	93,508
2002 *	7,527,519	2 13	48,497	3,538,346	13,706	41,421	437,810	94,608
2003 *	7,645,392	2 12	49,807	3,603,435	13,822	43,654	448,835	97,262
2004 *	7,760,318	2 12	50,558	3,666,716	13,788	44,537	459,199	96,989
2005 *	7,872,296	2 11	51,302	3,727,940	13,762	45,404	469,038	96,803
2006 *	7,983,660	2 11	52,026	3,786,871	13,738	46,220	478,234	96,647
2007 *	8,095,024	2 11	52,730	3,843,274	13,720	47,004	487,101	96,498
2008 *	8,208,083	2 11	53,425	3,897,570	13,707	47,799	495,697	96,427
2009 *	8,322,839	2 11	54,141	3,950,803	13,704	48,619	504,107	96,446
2010 *	8,437,594	2 11	54,952	4,003,154	13,727	49,516	512,269	96,660

* Forecasted values for these years reflect the Most Likely economic scenario
** Population represents only the area served by FPL
*** Average No of Customers is the annual average of the twelve month values

Schedule 2.2
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)		(10)	(11)	(12)	(13)	(14)	(15)	(16)
		Industrial			Railroads	Street &	Other Sales to	Total*** Sales to
Year		GWH	Average** No of Customers	Average KWH Consumption Per Customer	& Railways GWH	Highway Lighting GWH	Public Authorities GWH	Ultimate Consumers GWH
1991		4,090	15,348	266,493	81	345	733	67,098
1992		4,054	14,788	274,135	77	353	721	66,393
1993		3,889	14,866	261,602	79	330	665	69,830
1994		3,845	15,588	246,658	85	353	664	73,608
1995		3,883	15,140	256,481	84	358	648	76,248
1996		3,792	14,783	256,515	83	368	577	77,334
1997		3,894	14,761	263,830	85	383	702	79,855
1998		3,951	15,126	261,233	81	373	625	85,131
1999		3,948	16,040	246,112	79	473	465	84,676
2000		3,768	16,410	229,592	81	408	381	87,959
2001	*	3,953	15,631	252,888	80	406	500	91,728
2002	*	3,987	15,637	255,005	81	404	523	94,913
2003	*	4,016	15,665	256,344	82	404	540	98,503
2004	*	4,047	15,743	257,072	83	405	553	100,183
2005	*	4,084	15,836	257,914	84	408	563	101,845
2006	*	4,111	15,901	258,540	83	411	571	103,421
2007	*	4,135	15,966	258,995	83	414	577	104,944
2008	*	4,158	16,029	259,397	84	419	582	106,466
2009	*	4,175	16,075	259,699	84	423	586	108,028
2010	*	4,199	16,280	257,919	83	428	589	109,767

* Forecasted values for these years reflect the Most Likely economic scenario
** Average No.of Customers is the annual average of the twelve month values
*** Total Sales GWH = Col 4 + Col 7 + Col 10 + Col 13 + Col 14 + Col 15

Schedule 2.3
History and Forecast of Energy Consumption And Number of Customers by Customer Class

(1)		(17)	(18)	(19)	(20)	(21)
Year		Sales for Resale GWH	Utility Use & Losses GWH	Net*** Energy For Load GWH	Average ** No of Other Customers	Total Average**** Number of Customers
1991		716	5,346	73,160	4,076	3,226,455
1992		702	6,002	73,097	4,374	3,281,238
1993		958	4,988	75,776	3,086	3,352,110
1994		1,400	5,367	80,376	2,560	3,422,187
1995		1,437	6,276	83,961	2,460	3,488,796
1996		1,353	5,984	84,671	2,480	3,550,748
1997		1,228	5,770	86,853	2,520	3,615,485
1998		1,326	6,205	92,662	2,584	3,680,470
1999		953	5,829	91,458	2,605	3,756,009
2000		970	7,059	95,989	2,694	3,848,401
2001	*	992	6,837	99,557	2,604	3,916,098
2002	*	1,215	7,087	103,215	2,601	3,994,394
2003	*	1,434	7,369	107,306	2,598	4,070,533
2004	*	1,455	7,493	109,131	2,595	4,144,253
2005	*	1,474	7,617	110,936	2,592	4,215,407
2006	*	1,474	7,733	112,628	2,589	4,283,595
2007	*	1,407	7,913	114,264	2,586	4,348,927
2008	*	1,073	8,360	115,899	2,583	4,411,879
2009	*	1,073	8,476	117,577	2,580	4,473,566
2010	*	1,073	8,607	119,447	2,577	4,534,280

* Forecasted values for these years reflect the Most Likely economic scenario
** Average Number of Customers is the annual average of the twelve month values
*** Net Energy for Load GWH = Col. 16 + Col 17 + Col 18
**** Average No of Customers Total = Col 5 + Col 8 + Col 11 + Col. 20

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1991	14,123	281	13,842	0	160	129	177	38	13,786
1992	14,661	223	14,438	0	234	151	248	51	14,179
1993	15,266	397	14,869	0	311	182	320	79	14,635
1994	15,179	409	14,770	0	392	220	354	125	14,433
1995	16,172	435	15,737	0	466	259	391	193	15,315
1996	16,064	364	15,700	0	531	339	414	296	15,119
1997	16,613	380	16,233	0	615	440	432	341	15,566
1998	17,897	426	17,471	0	656	480	441	359	16,800
1999	17,615	169	17,446	0	722	565	450	397	16,443
2000	17,808	161	17,647	0	767	626	456	432	16,585
2001	18,150	148	18,003	0	784	87	480	55	16,744
2002	18,801	225	18,576	0	793	128	490	74	17,316
2003	19,507	227	19,280	0	799	169	499	93	17,947
2004	19,964	229	19,735	0	805	211	510	113	18,325
2005	20,433	231	20,201	0	811	254	519	134	18,715
2006	20,918	231	20,687	0	817	298	527	154	19,122
2007	21,392	231	21,160	0	822	343	535	174	19,518
2008	21,788	156	21,632	0	827	389	543	193	19,836
2009	22,220	156	22,063	0	831	436	549	212	20,192
2010	22,722	156	22,565	0	832	451	550	219	20,670

Historical Values (1991 - 2000):

Cols (2) - (4) are actual values for historical summer peaks As such, they incorporate the effects of conservation (Cols. (7&9)), and MAY incorporate the effects of load control IF load control was operated on these peak days Therefore, Col. (2) represents the actual Net Firm Demand
Cols (5) - (9) represent actual DSM capabilities starting from January 1988
Note that the values for FPL's former Interruptible Rate are incorporated into Col (8), which also includes CILC and GS-LC
Col (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak Col (10) is derived by the formula Col (10) =Col. (2) - Col.(6) - Col (8)

Projected Values (2001 - 2010):

Cols (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control The effects of conservation implemented prior to 2000 are incorporated into the forecast
Cols (5) - (9) represent all incremental conservation and cumulative load control These values are projected August values and are based on projections with a 1/2000 starting point.
Col (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak Col (10) is derived by using the formula Col (10) =Col (2) - Col (5) - Col (6) - Col (7) - Col (8) - Col (9)

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
1991/92	13,319	105	13,214	0	174	170	193	38	12,952
1992/93	12,964	102	12,862	0	242	195	275	48	12,447
1993/94	12,594	278	12,316	0	317	231	342	67	11,935
1994/95	16,563	635	15,928	0	393	265	360	93	15,810
1995/96	18,096	698	17,398	0	459	310	406	143	17,231
1996/97	16,490	626	15,864	0	731	368	418	154	15,341
1997/98	13,060	239	12,821	0	823	403	429	168	11,807
1998/99	16,802	149	16,653	0	1,218	438	417	182	15,167
1999/00	17,057	142	16,915	0	1,296	469	441	193	15,320
2000/01	18,219	150	18,069	0	972	493	448	201	16,799
2001/02	19,333	130	19,203	0	1,403	81	459	26	17,364
2002/03	20,122	206	19,915	0	1,414	107	465	33	18,103
2003/04	20,555	208	20,347	0	1,425	132	471	41	18,486
2004/05	20,986	210	20,776	0	1,436	156	477	50	18,867
2005/06	21,413	210	21,203	0	1,446	181	483	59	19,244
2006/07	21,841	210	21,631	0	1,455	205	487	68	19,626
2007/08	22,186	135	22,051	0	1,464	228	492	77	19,925
2008/09	22,586	135	22,451	0	1,473	251	497	86	20,279
2009/10	22,978	135	22,843	0	1,480	272	500	93	20,633

Historical Values (1991/92 - 2000/01):

Cols. (2) - (4) are actual values for historical winter peaks As such, they incorporate the effects of conservation (Cols (7&9)), and MAY incorporate the effects of load control IF load control was operated on these peak days Therefore, Col. (2) represents the actual Net Firm Demand
Cols. (5) - (9) represent actual DSM capabilities starting from January 1988
Note that the values for FPL's former Interruptible Rate are incorporated into Col (8), which also includes CILC and GS - LC
Col (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak Col (10) is derived by the formula Col (10) = Col (2) - Col.(6) - Col.(8)

Projected Values (2001/02-2009/10):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control The effects of conservation implemented prior to 1997 are incorporated into the forecast
Cols. (5) - (9) represent all incremental conservation and cumulative load control These values in are projected August values and are based on projections with a 1/2000 starting point
Col (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col (10) is derived by using the formula Col (10) = Col (2) - Col.(5) - Col (6) - Col (7) - Col (8) - Col (9)
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col (10) is derived by using the formula Col (10) = Col (2) - Col (5) - Col.(6) - Col (7) - Col (8) - Col (9)

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	C/I Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy For Load	Load Factor(%)
1991	73,743	397	186	73,027	716	5,346	73,160	59 1%
1992	73,778	460	221	73,076	702	6,002	73,097	56 9%
1993	76,632	553	303	75,674	958	4,988	75,776	56.7%
1994	81,493	661	456	80,093	1,400	5,367	80,376	60.4%
1995	85,415	777	677	83,978	1,437	6,276	83,961	59 3%
1996	86,708	971	1,039	85,355	1,353	5,984	84,698	60 2%
1997	89,240	1,213	1,174	88,012	1,228	5,770	86,853	59 7%
1998	95,316	1,374	1,279	93,990	1,326	6,205	92,663	63.0%
1999	94,361	1,542	1,362	93,408	953	5,829	91,458	63.5%
2000	99,094	1,674	1,431	98,123	970	7,059	95,989	66 1%
2001	99,557	56	15	98,565	992	6,837	99,486	67.8%
2002	103,215	152	46	102,000	1,215	7,087	103,017	67.9%
2003	107,306	250	77	105,872	1,434	7,369	106,979	68 0%
2004	109,131	349	110	107,676	1,455	7,493	108,672	67 7%
2005	110,936	450	145	109,462	1,474	7,617	110,341	67 3%
2006	112,628	554	180	111,155	1,474	7,733	111,894	66.8%
2007	114,264	659	213	112,857	1,407	7,913	113,392	66.3%
2008	115,899	765	245	114,826	1,073	8,360	114,889	66 1%
2009	117,577	874	276	116,504	1,073	8,476	116,427	65 8%
2010	119,447	919	291	118,374	1,073	8,607	118,237	65 3%

Historical Values (1991 - 2000):

Col (2) represents derived "Total Net Energy For Load w/o DSM" The values are calculated using the formula: Col.(2) = Col.(8) + Col (3) + Col (4)
Cols. (3) & (4) are DSM values starting in January, 1988 through 1997 which contributed to the values in Cols (5) - (9)
Cols (5) & (6) are a breakdown of Net Energy For Load in Col (2) into Retail and Wholesale
Col. (9) is calculated using Col (8) from this page and Col (2), "Total", from Schedule 3 1

Projected Values (2001 - 2010):

Col. (2) represents Net Energy for Load w/o DSM values.
Cols (3) - (4) are forecasted values of the reduction on sales from incremental conservation
Cols (5) & (6) are a breakdown of Net Energy For Load in Col (2) , into Wholesale and Retail
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented the values for Col. (8) above and the values for Col. (10) on Schedule 3 1

Schedule 4
Previous Year Actual and Two-Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2000 ACTUAL		2001 * FORECAST		2002 * FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	17,057	6,947	18,840	7,427	19,333	7,700
FEB	12,755	6,377	16,776	6,783	17,259	7,033
MAR	13,411	7,099	14,529	7,282	14,948	7,550
APR	14,959	7,424	14,120	7,494	14,626	7,769
MAY	16,856	8,287	15,487	8,036	16,042	8,332
JUN	16,979	9,336	17,099	9,351	17,712	9,695
JUL	17,778	9,216	17,749	9,675	18,386	10,031
AUG	17,808	9,743	18,150	10,168	18,801	10,542
SEP	17,701	9,694	17,625	9,861	18,257	10,223
OCT	16,920	7,712	16,358	8,430	16,944	8,739
NOV	13,804	7,184	15,257	7,646	15,696	7,927
DEC	14,858	6,971	15,593	7,402	16,042	7,674
TOTALS		95,989		99,557		103,215

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation

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CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990's and has since utilized the process to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of potential new power plants, the primary subjects of this document, are determined as part of the IRP process work. This section discusses how FPL applied this process in its 2000 planning work.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental "steps" to FPL's resource planning These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs,

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans;

Step 3: Determine the economics for the total utility system with each of the competing options and resource plans; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process

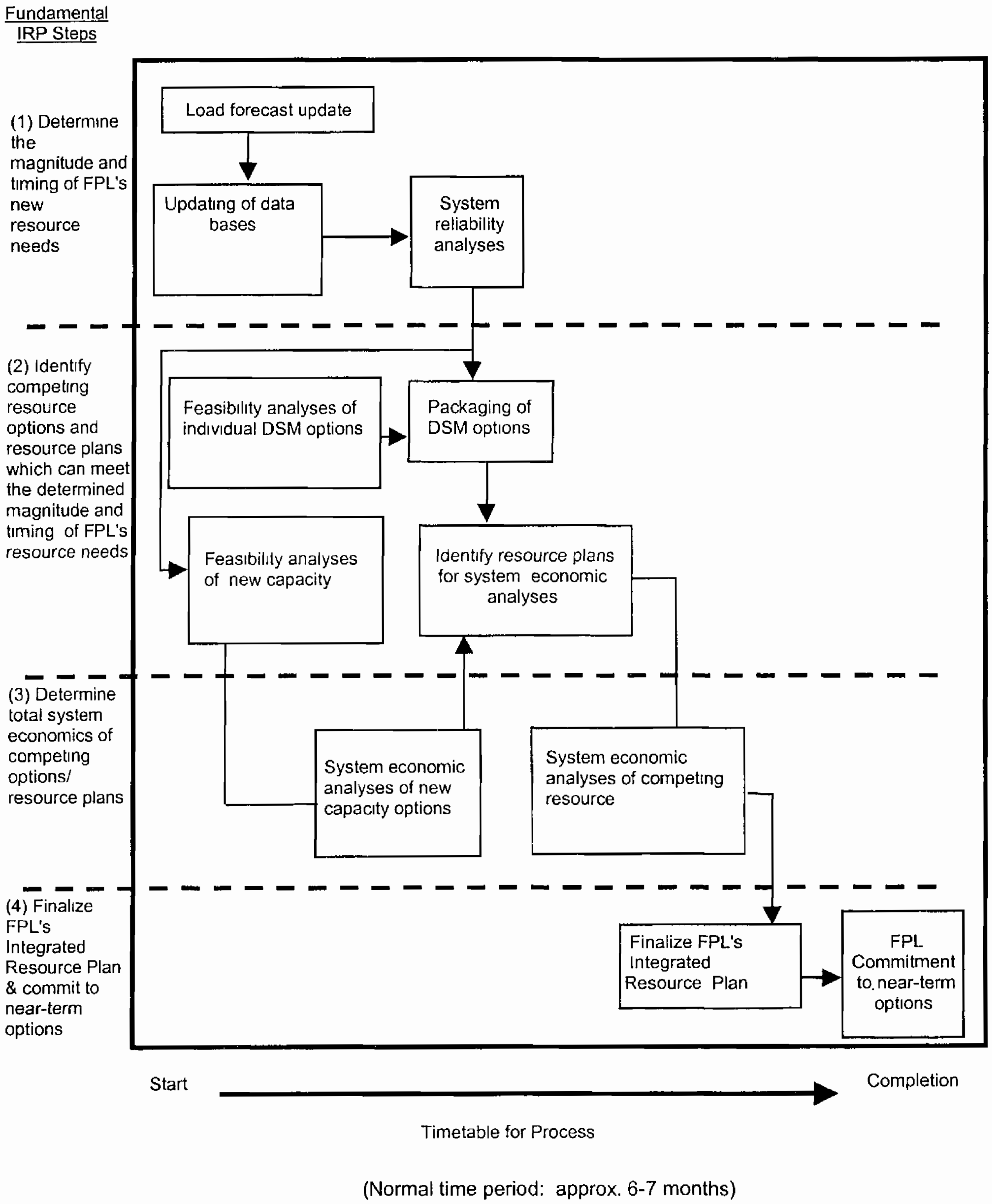


Figure III.A.1

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of these four resource planning steps – determining the magnitude and timing of FPL's resource needs – is essentially a determination of how many megawatts (MW) of load reduction, new capacity, or a combination of both load reduction and new capacity options are needed. Also determined in this step is when the MW are needed to meet FPL's planning criteria. This step is often referred to as a reliability analysis for the utility system.

Step 1 starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information which is used in many of the fundamental steps in resource planning. Examples of this new information include: delivered fuel price projections, current financial and economic assumptions, and power plant capability and reliability assumptions. Four assumptions made by FPL during its 2000 IRP work involved near-term construction capacity additions, near-term firm capacity purchase additions, conversion of some of the near-term construction capacity additions from combustion turbine (CT) units to combined cycle (CC) units, and long-term DSM implementation.

The first of these assumptions included FPL's announced plans to add near-term capacity through various construction projects. These construction projects include the repowering of several existing units and the addition of several new CT's. FPL committed in 1998 to repower both existing steam units at its Fort Myers plant site and two of the three existing steam units at its Sanford plant site. These two repowering efforts will add significant capacity to FPL's system and will greatly increase the efficiency of the capacity at those two sites. The repowered Fort Myers capacity is scheduled to come in-service by the Summer, 2002. CT's, which are components of the repowering effort, began coming in-service at Fort Myers in late 2000 and through their initial operation in a stand-alone mode have already increased FPL's system capacity. A somewhat different schedule is planned for the two Sanford units which will be repowered. Both of these units will be repowered without the combustion turbine components coming in-service during the process. Sanford Unit No. 5 will come out-of-service in the Fall, 2001, and return fully repowered by Summer, 2002. Sanford Unit No. 4 will come out-of-service in the Spring, 2002, and return fully repowered at the end of 2002. As a result of this commitment, FPL assumed that these capacity additions resulting from the Fort Myers and Sanford repowerings were a "given" in its 2000 resource planning work.

Another part of FPL's construction capacity addition assumption was its previously announced (in last year's Site Plan) decision to add four new CT's in the 2001 through 2003 time frame. The first two CT's are scheduled to be in-service at FPL's existing Martin site in 2001. The second pair of CT's is scheduled to be in-service in 2003 and will be placed at FPL's existing Fort Myers site. FPL's 2000 resource planning work assumed that these new CT construction capacity additions would also be a "given".

The second of the four assumptions made during the 2000 planning work was that the two CT's at Martin, and the two CT's at Fort Myers, would later be converted into one CC unit at each site. The resulting 2 - CT's – to – 1 - CC conversions at both Martin and Fort Myers are scheduled to be completed by mid-2005. These conversions were also assumed to be a "given" in FPL's 2000 resource planning work.

The third of these assumptions involved a decision which was made during FPL's 2000 resource planning work to secure an amount of capacity for the next few years through firm capacity, short-term purchases. These firm capacity purchases will be from a combination of utility and non-utility generators. These capacity purchases were not all finalized at the time of printing this document[3], but negotiations were sufficiently far along so that FPL projects that the purchases will total approximately 975 MW (Summer) and 1,075 MW (Winter) and will begin in mid-2001 and run to mid-2005. This purchase amount is also assumed as a "given" in FPL's 2000 resource planning work.

The fourth of these assumptions involved DSM. Since 1994, FPL's resource planning work has used the DSM MW called for in FPL's approved DSM goals as a "given" in its analyses. This was again the case in FPL's 2000 planning work as its recently approved new DSM goals through the year 2009 were taken as a given.

[3] Once all of the purchase negotiations are finalized, FPL will inform the Florida Public Service Commission of the details of the purchases including names of selling entities, sizes of purchases, lengths of purchases, etc.

The first place in which these assumptions and much of the other updated information and assumptions are used is the first fundamental step: the determination of the magnitude and the timing of FPL's resource needs. This determination is accomplished by system reliability analyses which are typically based on a dual planning criteria of a minimum peak period reserve margin of 15% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 days/year criteria. Both of these criteria are commonly used throughout the utility industry. FPL also used a "third" reliability criterion in its 2000 planning work: a minimum 20% Summer and Winter reserve margin which was applied in the analysis starting in mid-2004 due to a joint settlement reached among FPL, FPC, TECO, and the FPSC in the FPSC's Docket No. 981890-EU.

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analyses. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method and this relatively simple calculation can be performed on a spreadsheet. It provides an indication of how well a generating system can meet its native load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as: unit reliability; unit numbers and sizes (i.e., two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time); and the value of being part of an interconnected system.

Therefore, probabilistic methodologies have been used to provide additional information on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss-of-load probability or LOLP. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does reserve margin analysis.

The end result of the first fundamental step of resource planning is a projection of how many MW are needed to maintain system reliability and of when the MW are needed. This information is used in the second fundamental step: identifying resource options and resource plans which can meet the determined magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans Which Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, feasibility analyses of new capacity options are carried out to determine which new capacity options appear to be the most competitive on FPL's system. These analyses also establish capacity size (MW) values, projected construction / permitting schedules, and operating parameters and costs.

The individual new capacity options are then "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new resource needs are met. The creation of these competing resource plans is typically carried out using dynamic programming techniques.

Therefore, at the conclusion of the second fundamental resource planning step in 2000, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs were identified. These resource plans were then compared on an economic basis.

Step 3: Determining the Total System Economics:

At the completion of fundamental Steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for comparing the system economics of these resource plans. FPL combines the resource options into resource plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI) and Stone & Webster Management

Consultants, Inc. The EGEAS model is also used to perform the economic analyses of the resource plans.

The economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of the competing resource plans is the competing resource plans' impact on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e. a Rate Impact Measure or RIM methodology). However, in cases such as existed for FPL's 2000 planning work in which the DSM contribution was taken as a "given" and the only competing options were new generating units, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. Consequently, for FPL's 2000 resource planning work, the competing options and plans were evaluated on a present value system revenue requirement basis.

At the conclusion of the analyses carried out in Step 3, a determination of FPL's preferred resource plan was made.

Step 4: Finalizing FPL's 2000 Resource Plan

The results of the previous three fundamental steps' activities were evaluated by FPL management and a decision was made as to what FPL's 2000 resource plan would be. This plan is presented in the following section.

III.B Incremental Resource Additions

FPL's projected incremental generation capacity additions/changes for 2001 through 2010 are depicted in Table III.B.1. (The planned DSM additions are shown separately in Table III.C.1.) These capacity additions/changes will result from a variety of actions including: changes to existing units (which are typically achieved as a result of plant component replacements during major overhauls), changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, repowering of existing units, projected construction of new units, and conversion of CT's into CC's.

As shown in Table III.B.1, the bulk of the capacity additions are made up of the following items: the repowering of both existing steam units at FPL's Fort Myers site by Summer, 2002; a similar repowering of FPL's Sanford Unit Nos. 5 and 4 by the Summer, 2002, and the end of 2002, respectively; the construction of four new CT's during the 2001 through 2003 time period followed by their conversion into two CC's in 2005; new firm capacity, short-term purchases in the mid-2001 to mid-2005 time frame; and the construction of eight additional CC units in the 2005 through 2010 time frame.[4]

The increase in the number of CC units which are projected to be built in FPL's 2001 Site Plan, compared to the number of CC units shown in previous Site Plans, is due to three factors. Two of these factors are a higher load forecast and the change from a 15% to a 20% reserve margin criterion.

The third factor is that this year's Site Plan must show for the first time plans for the year 2010. Approximately 930 MW of firm capacity purchases from the Southern Company are scheduled to end in 2010. The end of these purchases requires FPL to replace this capacity, as well as to meet projected load growth for 2010, in a way which meets a minimum 20% reserve margin requirement. While FPL has not yet determined whether it would extend or replace these purchases, or build new capacity to meet its needs, for purposes of this Site Plan it was assumed that the 2010 needs would be met through the addition of unsited CC units. (Note that this is an assumption; FPL may look to extend the purchases or replace them. This decision is not needed for at least several years.)

[4] FPL's current planning studies have identified new combined cycle units as the generally preferred option to meet future load growth. However, repowering of existing FPL sites remains an alternative to new construction, and FPL will continue to examine this option.

Projected Capacity Changes for FPL [1]		Net Capacity Changes (MW)	
		Winter [2]	***Summer*** [3]
2001	Changes to existing plants	8	(56)
	Fort Myers Repowering:Initial Phase [4]	543	894
	Combustion Turbines (2) at Martin [5]	---	298
	New purchases [6]	---	196
2002	Fort Myers Repowering:Second Phase	(1)	35
	Combustion Turbines (2) at Martin [5]	362	---
	Sanford Repowering # 5: Initial Phase [7]	(394)	---
	Sanford Repowering # 5: Second Phase [7]	---	567
	Sanford Repowering # 4: Initial Phase [7]	---	(390)
	New purchases [6]	50	779
	Changes to existing QF's	---	(9)
2003	Fort Myers Repowering:Second Phase	531	---
	Sanford Repowering # 5: Second Phase	1065	---
	Sanford Repowering # 4: Second Phase	671	957
	Combustion Turbines (2) Fort Myers [8]	---	298
	Changes to existing QF's	(9)	---
	New purchases [6]	1025	---
2004	Combustion Turbines (2) Fort Myers	362	---
2005	Changes to existing QF's	(10)	(10)
	New purchases [6]	(50)	(975)
	Martin Combined Cycle No. 5 [9]	---	547
	Conversion of MR CT's to CC	---	249
	Conversion of FM CT's to CC	---	249
	Midway Combined Cycle [9]	---	547
2006	Changes to existing QF's	(133)	(133)
	New purchases	(1025)	---
	Martin Combined Cycle No. 5 [9]	596	---
	Conversion of MR CT's to CC	234	---
	Conversion of FM CT's to CC	234	---
	Midway Combined Cycle [9]	596	---
	Martin Combined Cycle No. 6 [9]	---	547
2007	Martin Combined Cycle No. 6 [9]	596	---
	Unsited Combined Cycle #1 [9]		547
2008	Unsited Combined Cycle #1 [9]	596	---
2009	Unsited Combined Cycle #2 [9]	---	547
	Changes to existing QF's	(51)	(51)
2010	Changes to existing purchases [10]	---	(975)
	Unsited Combined Cycle #2 [9]	596	---
	Unsited Combined Cycle #3 [9]	---	547
	Unsited Combined Cycle #4 [9]	---	547
	Unsited Combined Cycle #5 [9]	---	547
	TOTALS =	***6,392***	***6,299***

Table III.B.1

Projected Capacity Changes for FPL

Note:

(1) Additional information about these capacity changes and resulting reserve margins is found in Chapter III of this document.

(2) Winter values are values for January of year shown.

(3) Summer values are values for August of year shown.

(4) The initial phase of the Fort Myers repowering project consists of the introduction of operational combustion turbines followed by taking existing steam units out-of-service. The second phase of repowering consists of completing the integration of the combustion turbines, heat recovery steam generators, and steam turbines.

(5) The two CT's at Martin are scheduled to be in-service in the Summer of 2001. Therefore, the CT's are included in the 2001 Summer reserve margin calculation and are included in the 2002 - on reserve margin calculations for Summer and Winter.

(6) These are firm capacity, short - term purchases. See Section I.D and III.A. for more details.

(7) The initial phase of the Sanford repowering project consists solely of taking existing steam units out-of-service; combustion turbine operation is not introduced at this time. The second phase of the repowering consists of integrating the combustion turbines, heat recovery steam generators, and steam turbines.

(8) The two CT's at Fort Myers are scheduled to be in-service in the Spring of 2003. Therefore, the CT's are included in the 2003 Summer reserve margin calculation and are included in the 2004 - on reserve margin calculations for Summer and Winter.

(9) All combined cycle units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

10) FPL will be determining at a later date whether to extend or replace these UPS purchases from Southern Company. However, for purposes of this Site Plan, FPL has assumed that the 2010 needs would be met through the addition of unsited combined cyles.

III.C Demand Side Management (DSM)

1. FPL's Current DSM Programs

FPL's currently approved DSM programs are summarized as follows.

Residential Conservation Service: This is an energy audit program which is designed to assist residential customers in understanding how to make their homes more energy-efficient through the installation of conservation measures/practices.

Residential Building Envelope: This program is designed to encourage the installation of energy-efficient ceiling insulation in residential dwellings that utilize whole-house electric air-conditioning.

Duct System Testing and Repair: This program is designed to encourage demand and energy conservation through the identification of air leaks in whole-house air conditioning duct systems and by the repair of those leaks by qualified contractors.

Residential Air Conditioning: This is a program which is designed to encourage customers to purchase higher efficiency central cooling and heating equipment.

Residential Load Management (On Call): This program offers load control of major appliances/household equipment to residential customers in exchange for monthly electric bill credits.

New Construction (BuildSmart): This program encourages the design and construction of energy-efficient homes that cost-effectively reduce coincident peak demand and energy consumption.

Business Energy Evaluation: This program encourages energy efficiency in both new and existing commercial and industrial facilities by identifying DSM opportunities and providing recommendations to the customer.

Commercial/Industrial Heating, Ventilating, and Air Conditioning: This program is designed to encourage the use of high-efficiency heating, ventilating, and air conditioning (HVAC) systems in commercial/industrial facilities.

Commercial/Industrial Efficient Lighting: This program encourages the installation of energy-efficient lighting measures in commercial/industrial facilities.

Business Custom Incentive: This program encourages commercial/industrial customers to implement unique energy conservation measures or projects not covered by other FPL programs.

Commercial/Industrial Load Control: This program is designed to reduce peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits. (This program is closed to new participants in 2000).

Commercial/Industrial Demand Reduction: This program (which starts in 2001) is similar to the Commercial/Industrial Load Control mentioned above by continuing the objective to reduce peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits.

Commercial/Industrial Building Envelope: This program encourages the installation of energy-efficient building envelope measures such as window treatments and roof/ceiling insulation for commercial/industrial facilities.

Business On Call: This program offers load control of central air conditioning units to both small, non-demand-billed and medium, demand - billed commercial/industrial customers in exchange for monthly electric bill credits.

2. Research and Development

FPL's DSM Plan continues to support research and development activities. Historically, FPL has performed extensive DSM research and development. FPL will continue such activities not only through its Conservation Research and Development program, but also through individual research projects. These efforts will examine a wide variety of technologies which build on prior FPL research where applicable and will expand the research to new and promising technologies as they emerge.

Conservation Research and Development Program

FPL's Conservation Research and Development Program is designed to evaluate emerging conservation technologies to determine which are worthy of pursuing for program development and approval. FPL has researched a wide variety of technologies and from that research has been able to develop new programs such as Residential New Construction, Commercial/Industrial Building Envelope, and Business On Call.

Cool Communities Research Project

Cool Communities is a concept developed by American Forests to demonstrate the extent to which strategic tree planting and surface color lightening can cool ambient air temperature and impact energy consumption. This research project is designed to evaluate emerging conservation technologies and practices associated with residential structures to determine which are worthy of pursuing for program development and approval. The project, which consists of data gathering, statistical regression analysis, and economic evaluation, will quantify savings from lightened roof color and tree shading of homes.

Commercial/Industrial New Construction Research Project

The objective of this project is to identify cost-effective opportunities in the commercial/industrial new construction market. If cost-effective opportunities are identified, the results of this effort may be used to design a new construction program (and other market intervention strategies) with the ultimate goal being to reduce building demand and energy use beyond that required by the Florida Energy Efficiency Code.

Low Income Weatherization Retrofit Project

This R&D project is investigating cost-effective methods of increasing the energy efficiency of FPL's low - income customers. The research project addresses the needs of low - income housing retrofits by providing monetary incentives to various housing authorities including weatherization agency providers, (WAPS), and non-weatherization agency providers (non-WAPS). These incentives are used by the housing authorities to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting. FPL either conducts a home energy survey, trains housing authority employees to perform FPL home energy surveys, accept the National Energy AudiT (NEAT) (as supplemented to capture water heating recommendations not included in the NEAT audit), or approves similar FPL - approved audits conducted by weatherization providers to determine the need for energy efficient retrofit measures for each home. FPL has designed the project so as to minimize extra work for the retrofit housing authorities.

Photovoltaic Research, Development and Education Project

Photovoltaic (PV) roof-tile systems are a relatively new technology which directly replaces existing roofing materials such as shingles and standing-rib roofing with PV materials. These PV materials have the same water - proofing characteristics as conventional roofing materials. This project is consistent with the Federal Government's Million Solar Roofs initiative. However, based on FPL's research to - date, a primary hurdle to the physical installation of PV systems, whether roofing materials or flat plate collectors, is the lack of awareness, understanding, and acceptance by local building officials. For the most part, these officials are unclear about how these systems work and how to address these systems as part of the building, permitting, and inspection process. This creates barriers toward the use of this technology.

Green Energy Project

FPL has recently finished an R&D project addressing customer acceptance of green energy where donations were used as the funding mechanism for the purchase and installation of utility grid connected PV systems. This project raised in excess of $89,500 and a 10.1 kW (dc) PV system has been constructed at FPL's Martin power plant site.

FPL is now investigating potential customer acceptance of green pricing rates in its Green Energy Project. Under this project, FPL will purchase electric energy generated from new renewable resources including solar-powered technologies, biomass energy, landfill methane, wind energy, low impact hydroelectric energy, and/or other renewable resources. Participating customers will be charged higher "green" electric rates for utilizing electric energy derived from these sources.

Real-Time Pricing

Although not part of FPL's approved DSM Plan, FPL continues to research new conservation/efficiency options such as Real-Time Pricing. This option is an experimental service offering for large C/I customers designed to evaluate customer load response to hourly, marginal cost-based energy prices provided on a day-ahead basis.

3. FPL's DSM MW Goals

FPL's DSM implementation plan is designed to meet currently approved DSM Goals for 2000 – 2009 The combined total residential and commercial/industrial Summer MW reduction values from FPL's DSM Goals for 2000 – 2009 are presented in Table III C.1. FPL has already implemented approximately 2,680 MW at the meter of DSM through 2000.

FPL's Summer MW Reduction Goals for DSM (At the Meter)

Year	Cumulative Summer MW
2000	122
2001	200
2002	269
2003	339
2004	410
2005	484
2006	554
2007	625
2008	697
2009	795

Table III.C.1

III.D Non-Utility Generation Additions

As previously mentioned in Section III.A, FPL is entering into a number of new firm capacity, short-term purchases for the mid-2001 to the mid-2005 time frame. Negotiations for these purchases were not yet completed at the time this document went to print, but some of these purchases are expected to be from non-utility generating facilities. Once all of the purchase negotiations are finalized, FPL will inform the Florida Public Service Commission of the details of the purchases.

Tables I.B.1 and I.B.2 present the previously contracted cogeneration/small power production facilities which are addressed in FPL's resource planning.

III.E Transmission Plan

The 2001 - 2010 transmission plan will allow for the reliable delivery of the required capacity and energy for FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 KV and 500 KV bulk transmission lines.

List of Proposed Power Lines
2001 – 2010

OWNER	LINE TERMINAL (FROM)	LINE TERMINAL (TO)	NEW CIRCUIT MILES	COMMERCIAL IN-SERVICE DATE (Mo/YR)	NOMINAL OPERATING VOLTAGE (KV)
FPL	Flagami-Turkey Point	Galloway	1.80	Jan-01	230
FPL	Broward-Parkland	Ranch	9.50	Apr-01	230
FPL	Calusa	Fort Myers	1.60	Apr-01	230
FPL	Broward-Corbett	Rainberry	1.75	Jun-01	230
FPL	Greynolds	Laudania	6.70	Jun-01	230
FPL	Poinsett	Sanford	45.00	Jun-01	230
FPL	Poinsett	Sanford	45.00	Jun-01	230
FPL	Fort Myers	Orange River	1.80	Dec-01	230
FPL	Brevard	Malabar	27.00	Jun-02	230
FPL	Broward-Goolsby	Yamato	2.50	Jun-02	230
FPL	Andytwon	Pennsuco	2.00	Jun-03	230
FPL	Broward-Corbett	Yamato	12.50	Jun-03	230
FPL	Cortez	Johnson	11.00	Jun-03	230
FPL	Dade	Overtwon	11.00	Jun-03	230
FPL	Broward-Corbett	Marymount-Yamato	0.25	Jun-03	230
FPL	Yulee	Oneil	6.50	Jun-04	230
FPL	Indiantown	Martin	11.80	Jun-06	230
FPL	Conservation	Levee	36.00	Jun-08	500

Table III.E.1

In addition, there will be transmission facilities needed to connect FPL's projected capacity additions to the system transmission grid. These integrated transmission facilities for the projected capacity additions at FPL's existing Fort Myers, Sanford, Martin, and Midway sites are described below. Since the projected capacity additions for 2007 through 2010 are as-yet unsited, no "integrated" transmission facilities information is provided. This information may be provided in future Site Plan documents once a site is selected.

It should be noted that FPL currently proposes to transfer its transmission facilities to a for - profit transmission company (Grid Florida) which is being formed in response to FERC Order 2000. Once that transfer is completed, FPL will receive transmission service from Grid Florida which will be responsible for transmission planning in the future.

III.E.1 Intregrated Transmission Facilities at Martin

The work required to integrate the incremental capacity projected to be added at Martin from two new CT units with the FPL grid is as follows:

I. Substation:

1. Build one collector bus with 3 breakers each to connect the CT's and the start-up transformer.
2. Add two main step-up transformers (2-200 MVA), one for each CT unit.
3. Add the start-up transformer.
4. Add bus breaker in bay #4 to connect the collector bus in - between this new breaker and breaker 154.
5. Add relays and other protective equipment.

II. Transmission:

1. Construct one string bus to connect the collector and main switchyard.

MARTIN COMBUSTION TURBINES

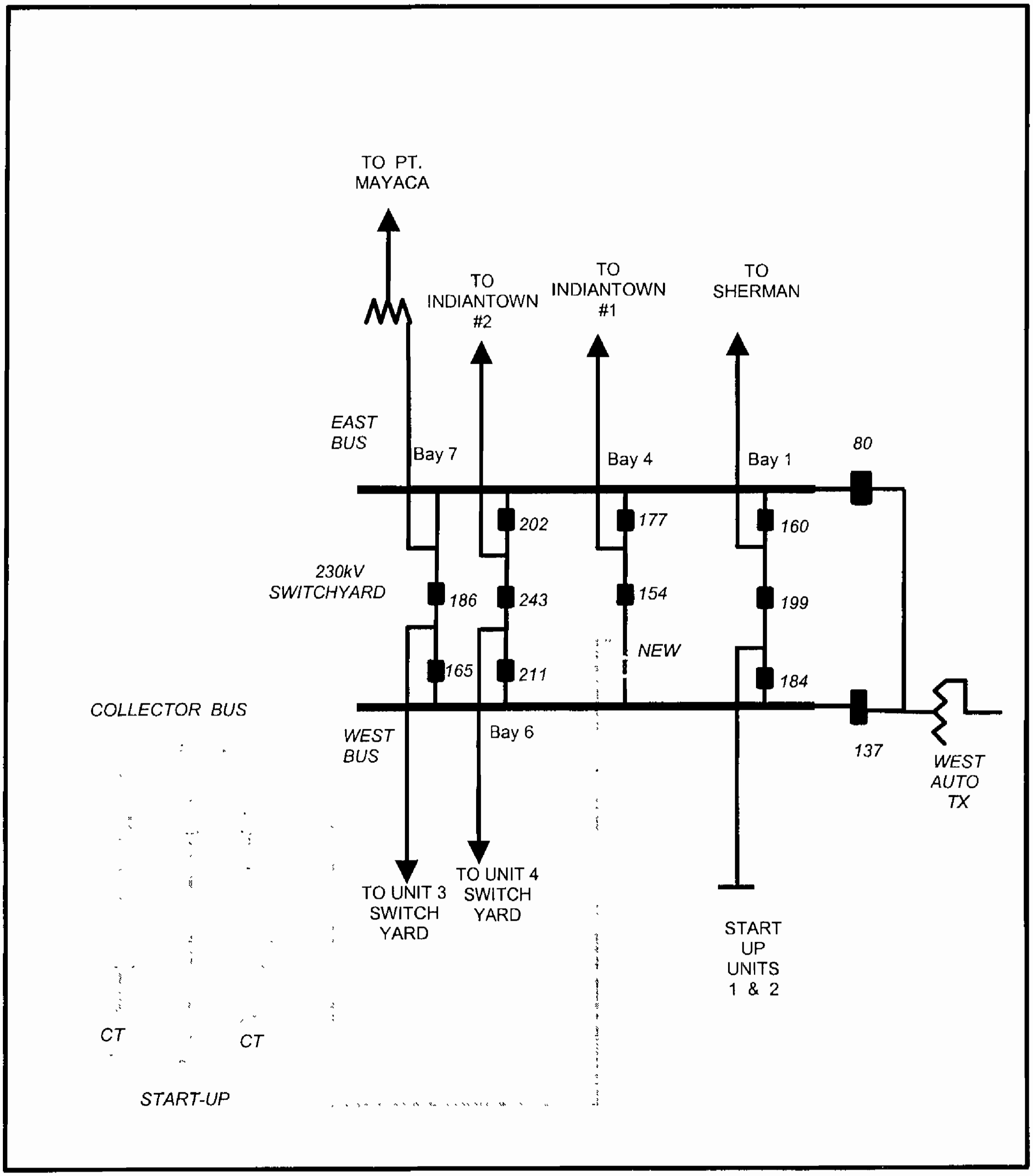


Figure III.E.1

III.E.2 Integrated Transmission Facilities at Fort Myers

The work required to integrate the repowering capacity addition at Fort Myers with the FPL grid is as follows:

I. Substation:

1. Build two collector busses with 3 breakers each to connect 3 CT's on each one. Add another breaker to one of those collector buses to connect the start-up transformer.
2. Add the six main step-up transformers (200MVA/each), one for each CT.
3. Add the start-up transformer.
4. Add a three - breaker bay in the 230 kV substation to connect one of the collector buses and a new transmission line to Calusa.
5. Add a three - breaker bay in the 230 kV substation to connect the other collector bus and a new transmission line to Orange River 230 kV.
6. Add a two - breaker bay at Orange River 230 kV substation to connect the new line from Fort Myers.
7. Add a two - breaker bay at Calusa 230 kV substation to connect the new line from Fort Myers.
8. Replace breakers 3 and 36 (rated 37.6 kA) on bay 9N with new ones rated 63 kA.
9. Add relay and other protective equipment at Fort Myers, Orange River, and Calusa substations.

II. Transmission:

1. Build a new 230 kV line from Fort Myers to Orange River (approximately 2.57 miles) similar to the existing circuits which are bundle 2-1431 ACSR 2580 Amps (1028 MVA) each.
2. Build a new 230 kV line from Fort Myers to Calusa (approximately 1.58 miles) using 1431 ACSR conductor rated 1600 Amps (637 MVA).
3. Add protection and control equipment for the new lines.

FORT MYERS REPOWERING PROJECT

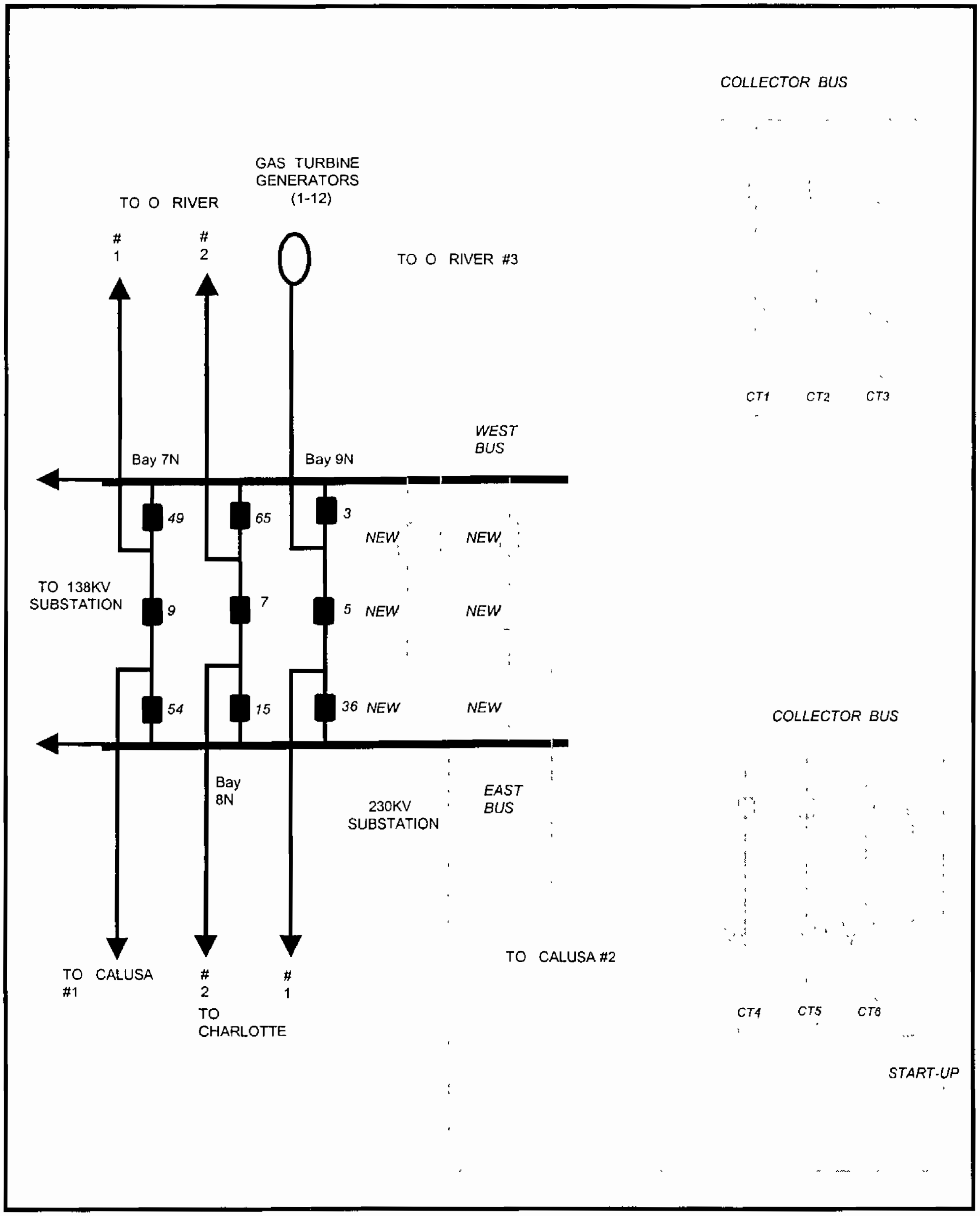


Figure III.E.2

III.E.3 Integrated Transmission Facilities at Sanford

The work required to integrate the repowering capacity additions at Sanford with the FPL grid is as follows:

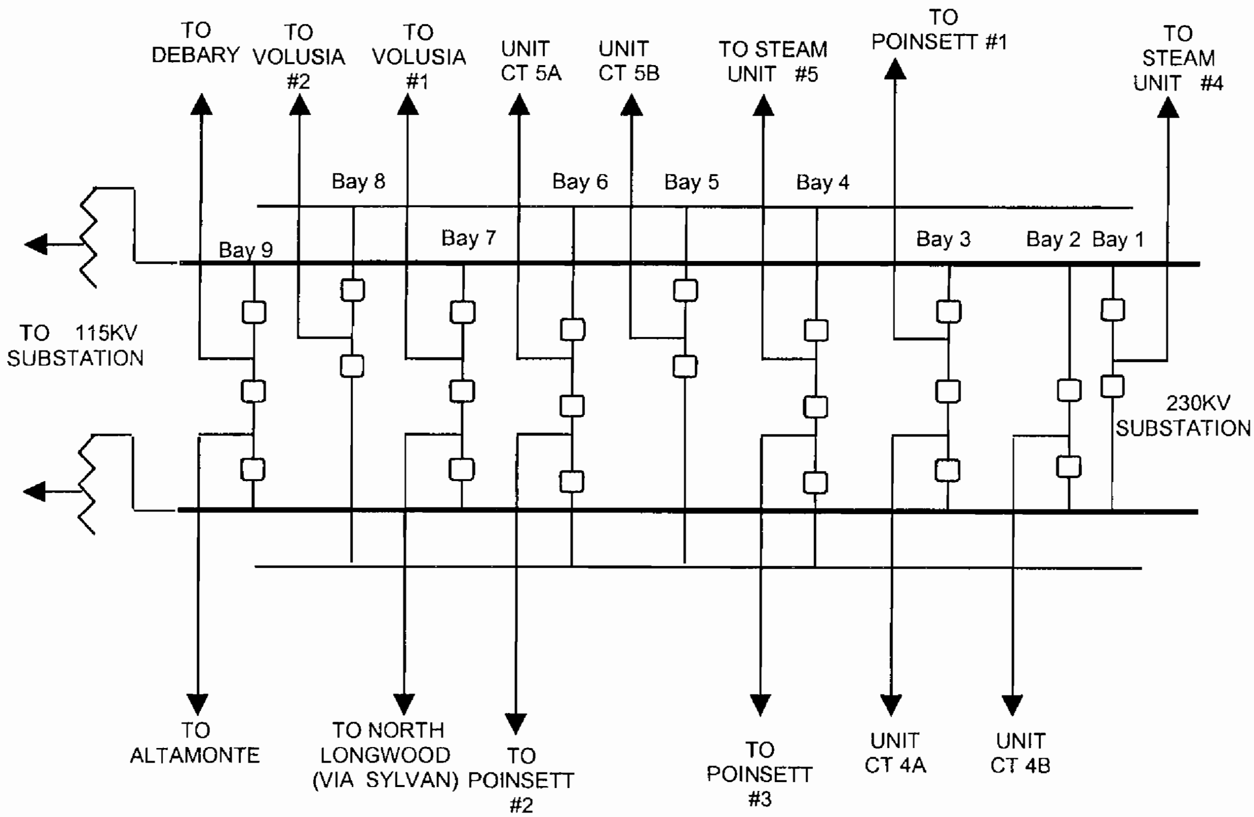
I. Substation:

1. Build four collector buses with 2 breakers each to connect 2 CT's on each one. Add another breaker to one of those collector buses to connect the start-up transformer.
2. Add the eight main step-up transformers (200MVA/each), one for each CT.
3. Add the start-up transformer.
4. Build a new substation with 1 new three - breaker bay, 1 new two - breaker bay, and using 2 existing three - breaker bays to connect 2 collector buses and the new transmission lines.
5. Build 2 new three - breaker bays and 1 new two - breaker bay at the existing substation to connect 2 collector buses.
6. Move the Volusia #2 line terminal from the existing yard to the new 230 KV yard.
7. Add a three - breaker bay at Poinsett 230 kV substation to connect the new lines from Sanford.
8. Add relay and other protective equipment at Sanford and at Poinsett substations.

II. Transmission:

1. Build two new 230 kV lines from the new Sanford to Poinsett (approximately 45 miles each) with conductor rated for 1600 Amps.
2. Add protection and control equipment for the new lines.
3. Upgrade the Volusia #2 transmission line to 1475 Amps.

SANFORD REPOWERING PROJECT



- *SANFORD #4 STEAM AND CT UNITS WILL BE CONNECTED TO THE INSIDE 230KV YARD*
- *SANFORD #5 STEAM AND CT UNITS WILL BE CONNECTED TO THE OUTSIDE 230KV YARD*

Figure III.E.3

III.E.4 Integrated Transmission Facilities at Fort Myers

The work required to integrate the Fort Myers capacity expansion from two new CT units with the FPL grid is as follows:

I. Substation:

1. Build one collector bus with 2 breakers each to connect 2 CT's on each one. Add another breaker to the collector bus to connect the start-up transformer.
2. Add the two main step-up transformers (200MVA/each), one for each CT.
3. Add the start-up transformer.
4. Disconnect the existing Fort Myers GT collector bus from the Fort Myers 230kV switchyard.
5. Add two breakers at Orange River 230 kV substation to connect the new line from the Fort Myers GT collector bus.
6. Connect the new Fort Myers collector bus to the Fort Myers 230kV switchyard.
7. Connect the Fort Myers collector bus to the Fort Myers 230kV switchyard.
8. Replace 4 breakers at the existing Fort Myers 230 kV switchyard.
9. Add relay and other protective equipment at Fort Myers and Orange River substations.

II. Transmission:

1. Build a new 230 kV line from the Fort Myers GT collector bus to Orange River (approximately 2.57 miles) similar to the existing circuits which are bundle 2-1431 ACSR 2580 Amps (1028 MVA) each.
2. Add protection and control equipment for the new line.

FORT MYERS COMBUSTION TURBINES

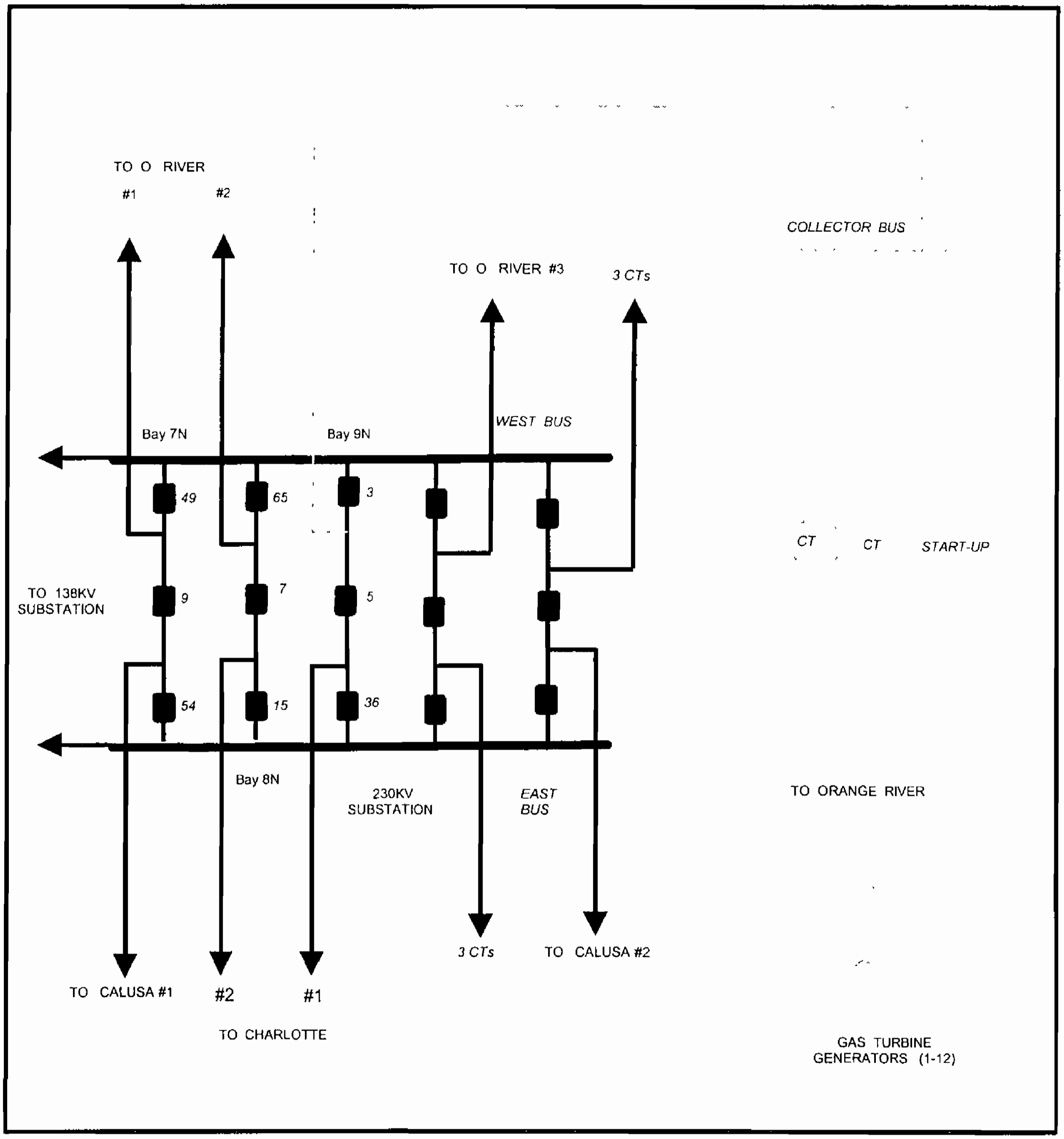


Figure III.E.4

III.E.5 Integrated Transmission Facilities at Martin

The work required to integrate the incremental capacity projected to be added at Martin from two new combined cycle units, Martin Nos. 5 and 6, with the FPL grid is as follows:

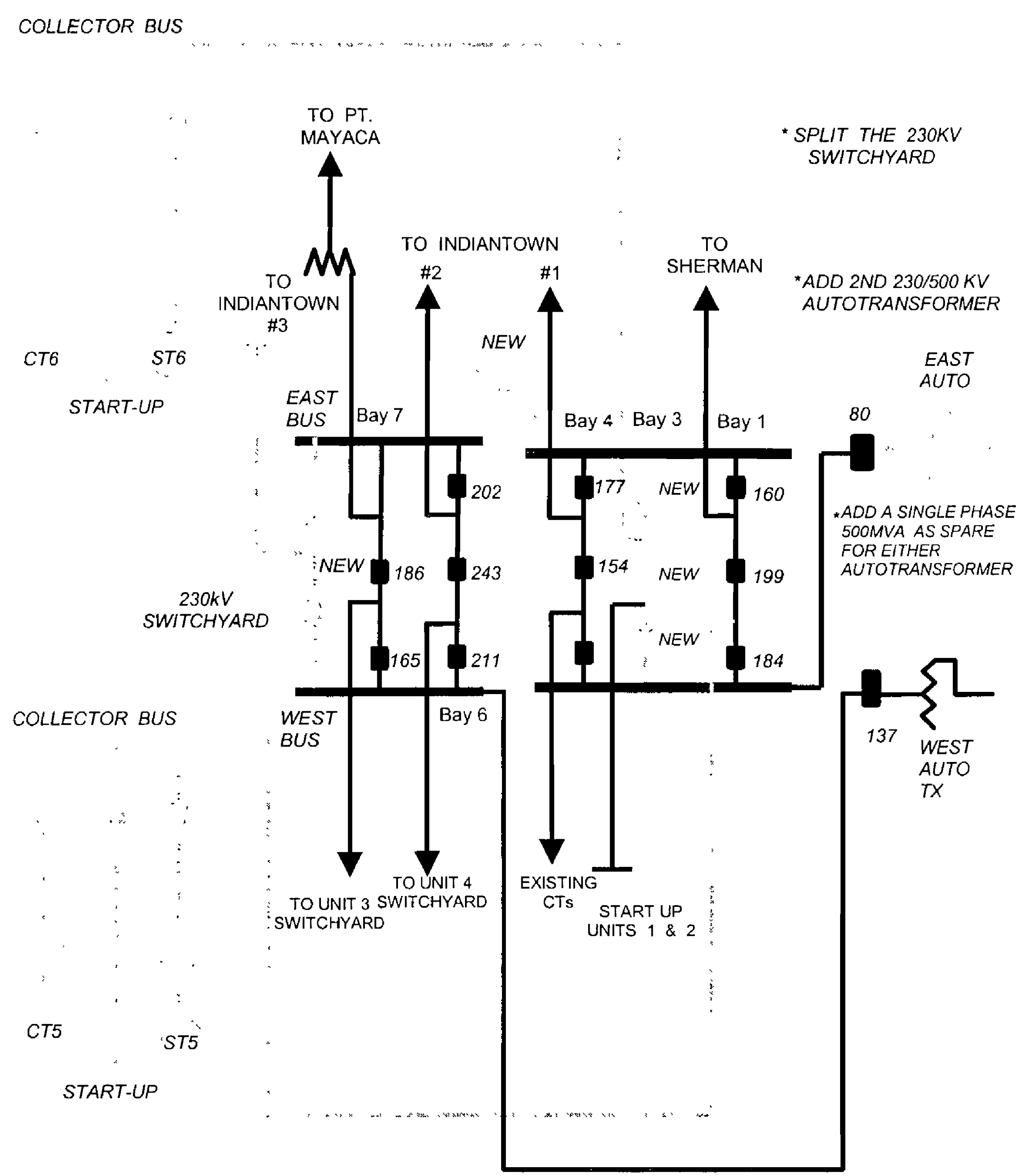
I. Substation:

1. Build two collector busses with 3 breakers each to connect the CT's, the ST units, and the start-up transformers.
2. Add the four main step-up transformers (2-400 MVA and 2-200 MVA), one for each CT and one for each ST unit.
3. Add the start-up transformers.
4. Add a new three-breaker bay (bay #3) to connect the Martin #6 collector bus and the existing start-up for units 1 &2.
5. Connect the Martin #5 collector bus to bay #1 between breakers 199 and 184.
6. Add relays and other protective equipment.
7. Split the 230 kV bus in order to reduce fault current levels in the switchyard. This will effectively separate units 3 and 4 from the new units 5 and 6. The 500/230 kV autotransformer #1 will remain connected to the units 3 and 4 switchyard and the new autotransformer #2 will connect the units 5 and 6 switchyard to the 500 kV bus.
8. Add the second 500/230 kV autotransformer and connect it to breaker 80 and the 230 kV side which is tied to the switchyard for units 5 and 6.
9. Add a single phase 230/500 kV, 500 MVA transformer to be used as a spare for either autotransformer.
10. Add a two-breaker bay (bay 8) to connect the new Martin-Indiantown 230kV line.
11. Add a breaker and line terminal at Indiantown to connect the new Martin-Indiantown 230kV line.
12. Add relays and other protective equipment.

II. Transmission:

1. Construct two string buses to connect the collector and main switchyards.
2. Uprate the Pratt & Whitney-Indiantown 230 kV circuit from 2020 Amps to 2520 Amps.
3. Uprate the Pratt & Whitney-Ranch 230 kV circuit from 2020 Amps to 2520 Amps.
4. Build a new 230kV line from Martin to Indiantown (approximately 11.8 miles) similar to existing circuit which is 2-795B ACSR 2290 Amps (912MVA).

MARTIN COMBINED CYCLE UNITS



* ALSO NEED TO UPRATE THE PRATT & WHITNEY - INDIANTOWN AND PRATT& WHITNEY - RANCH 230KV LINES FROM 2020 AMPS TO 2520 AMPS.

Note. Configuration is subject to modification based on final engineering analysis associated with the Martin area.

Figure III.E.5

III.E.6 Integrated Transmission Facilities at Martin

The work required to integrate the conversion of two existing CT's at Martin add a new steam unit into a combined cycle unit with the FPL grid is as follows:

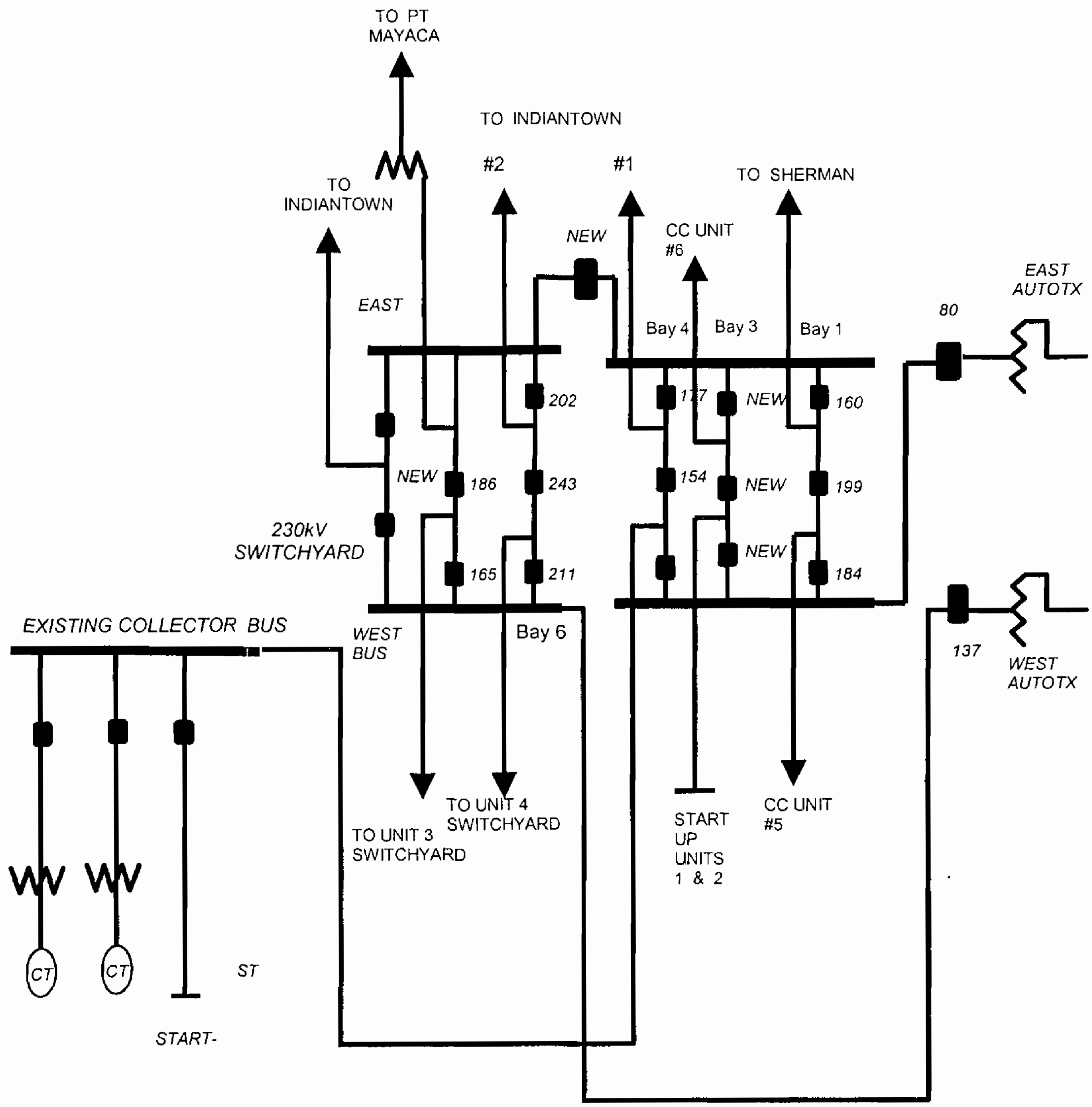
I. Substation:

1. Add one breaker to the collector bus to connect the steam unit step-up transformer (300MVA).
2. Add relay and other protective equipment at the Martin substation.

II. Transmission:

1. None.

MARTIN CONVERSION OF CT'S – TO - CC



Note: Configuration is subject to modification based on final engineering and reliability analysis associated with the Martin area.

Figure III.E.6

III.E.7 Integrated Transmission Facilities at Fort Myers

The work required to integrate the conversion of two existing CT's at Fort Myers into a combined cycle unit with the FPL grid is as follows:

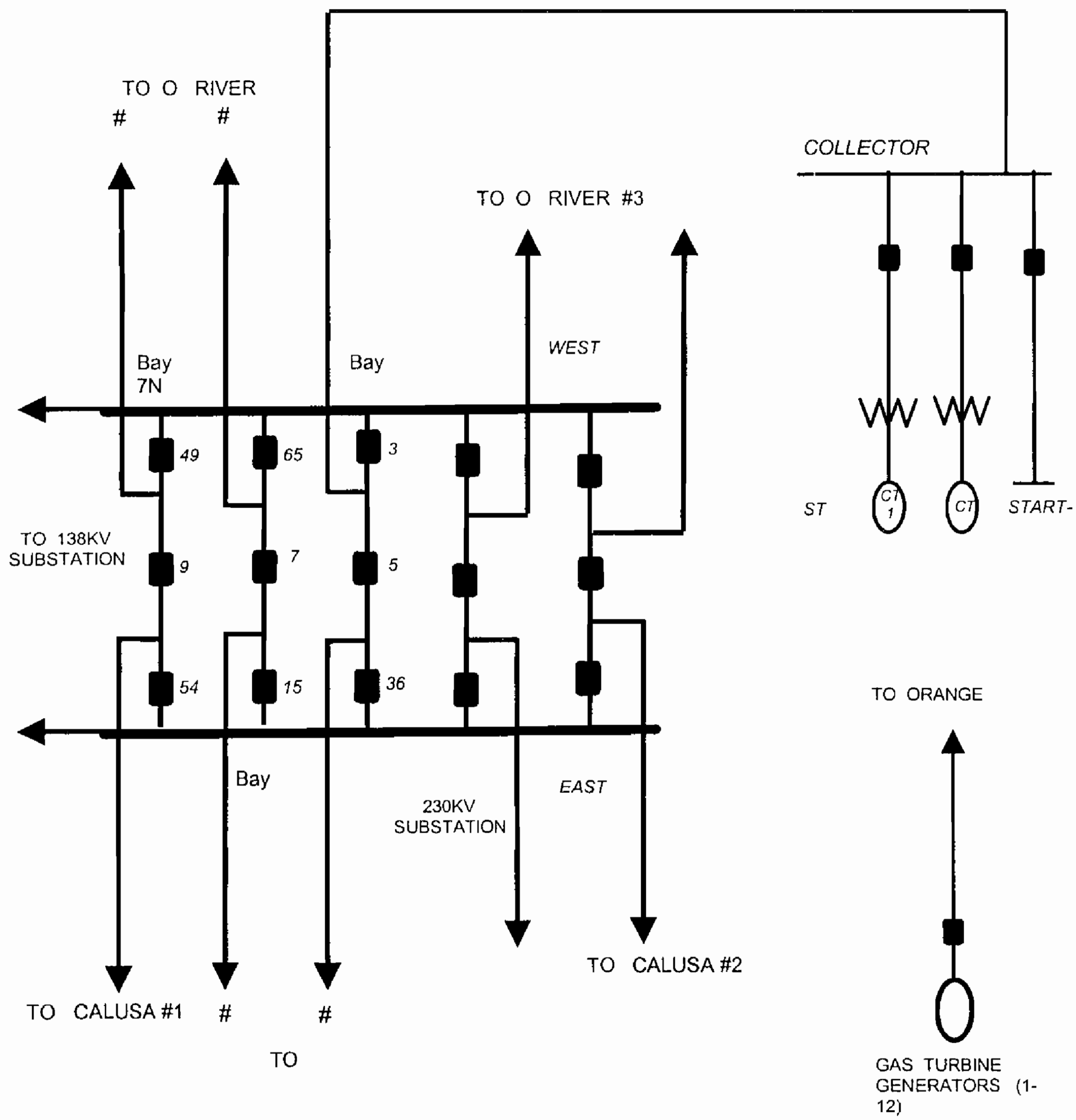
I. Substation:

1. Add one breaker to the collector bus to connect the steam unit step-up transformer (300MVA).
2. Add relay and other protective equipment at the Fort Myers substation.

II. Transmission:

1. None.

FORT MYERS CONVERSION OF CT'S - TO - CC



Note: Configuration is subject to modification based on final engineering and reliability analysis associated with the Ft. Myers area.

Figure III.E.7

II.E.8 Integrated Transmission Facilities at Midway

The work required to integrate the incremental capacity projected to be added at Midway from a new combined cycle unit with the FPL grid is as follows:

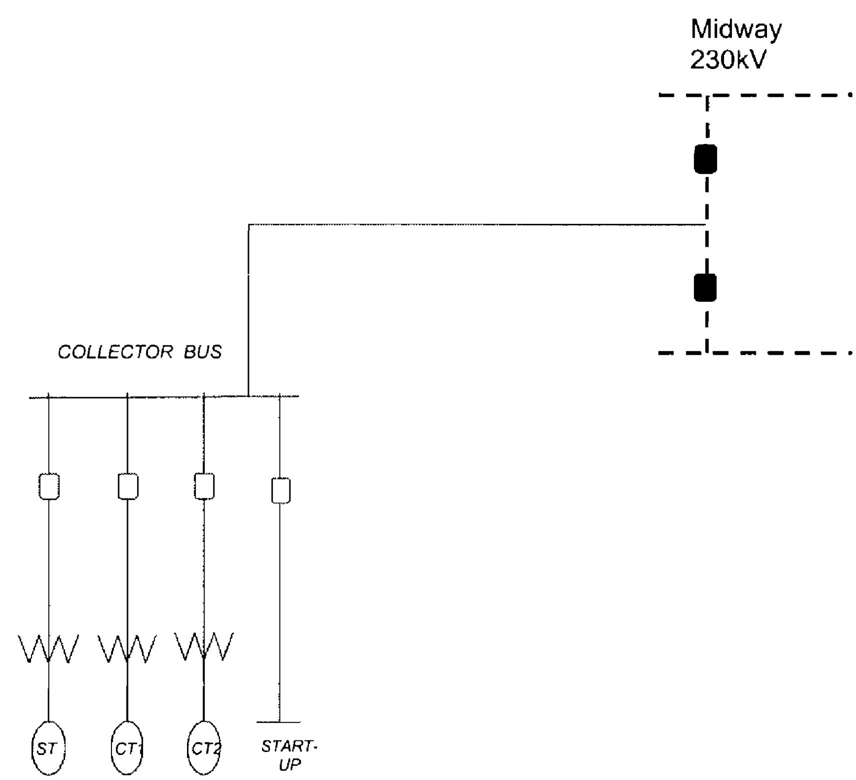
I. Substation:

1. Build one collector bus with 4 breakers to connect the CT's, the ST units, and the start-up transformers.
2. Add the three main step-up transformers (2-225 MVA, 1-300 MVA), one for each CT and one for the ST unit.
3. Add the start-up transformer.
4. Add a new two-breaker bay to connect the Midway collector bus.
5. Add relays and other protective equipment.

II. Transmission:

1. Construct one string bus to connect the collector and the Midway 230kV yard.

MIDWAY COMBINED CYCLE UNIT



Note: Configuration is subject to modification based on final engineering and reliability analysis associated with the Midway area.

Figure III.E.8

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to utilize renewable energy technologies to meet its customers' current and future needs. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various technologies.

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970's in demonstrating the first residential solar photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities on both a daily and annual basis in Florida. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10 kilowatt (KW) system was placed into operation in 1984. The testing of this PV installation was completed, and the system was removed, in 1990 to make room for substation expansion.

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant site. The FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's recent Green Pricing effort (which is discussed on the following page).

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first and only utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was not cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980's, FPL introduced another renewable energy program. FPL's Passive Home Program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. Complete designs and construction blueprints for 6 passive homes were created by 3 Florida architectural firms with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building code. This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the Florida Public Service Commission to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test may be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, as well as customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

More recently, FPL has analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach does not require all of its customers to bear PV's high cost, but allows customers who are interested in facilitating the use of renewable energy the means to do so. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund, which FPL used to make PV purchases in bulk quantities. PV modules were then installed and delivered PV-generated electricity directly into the FPL grid. Thus, when sunlight is available at this site(s), the PV-generated electricity displaces an equivalent amount of fossil fuel-generated electricity.

FPL's basic approach, which has been termed Green Pricing, was initially discussed with the FPSC in 1994. FPL's initial effort to implement this approach were then formally presented to the FPSC as part of FPL's DSM Plan in 1995 and FPL received approval from the FPSC in 1997 to proceed. FPL initiated the effort in 1998 and received approximately $89,000 in contributions which significantly exceeded the goal of $70,000. FPL has purchased the PV modules and installed them at FPL's Martin plant site.

As previously discussed, FPL initiated two new renewable efforts in 2000. FPL's first new initiative in 2000 was the Green Energy Project which is a second, different attempt to implement the basic Green Pricing approach. Under this project FPL will purchase electric energy generated from new renewable resources. The project offers to meet all, or part of, a customer's load with generation from new renewable resources, with the remaining portion of that load being served by the Company's conventional generating facilities.

Participants will be residential (and possibly commercial) customers who will pay higher ("green" rates) for electricity provided from these renewable sources.

The second effort initiated in 2000 is FPL's Photovoltaic Research, Development and Education Project. This demonstration project's objectives are to increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks as well as the energy capabilities of roof tile PV systems, and assess the homeowner's financial benefits and costs of PV roof tile systems.

Finally, FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy, and as-available energy, have been purchased by FPL from these developers. (Please refer to Tables I.B.1 and I.B.2).

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980's, FPL relied primarily on a combination of oil, natural gas, and nuclear energy to generate electricity. In 1986, coal was first added to the fuel mix, allowing FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources have been added with the acquisition (76%) of Scherer Unit # 4. In 1997, petroleum coke was added to the fuel mix as a blend stock with coal at the St. Johns River Power Park.

2. Fuel Price Forecasts

FPL's long-term oil price forecast assumes that worldwide demand for petroleum products will grow moderately throughout the planning horizon. Non-OPEC crude oil supply is projected to increase as new and improved drilling technology and seismic information will reduce the cost of producing crude oil and increase both recovery from existing fields and new discoveries. However, the rate of increase in non-OPEC supply is projected to be slower than that of petroleum demand, resulting in an increase in OPEC's market share throughout the planning horizon. As OPEC gains market share, prices for petroleum products are projected to increase.

FPL's natural gas price forecast assumes that domestic demand for natural gas will grow throughout the planning horizon, primarily due to increased requirements for electric generation. Domestic natural gas production will increase as new and improved drilling technology and seismic information will reduce the cost of finding, developing, and producing natural gas fields. The rate of increase in domestic natural gas production is assumed to be slower than that of demand, with the balance being supplied by increased Canadian and liquefied natural gas (LNG) imports. As demand for natural gas in Florida grows, it is anticipated that based on natural gas users' commitments, the Florida Gas Transmission pipeline system will be augmented/expanded and/or a new pipeline will be constructed to meet the growth in demand.

Schedule 5
Fuel Requirements 1/

			Actual 2/		Forecasted									
	Fuel Requirements	Units	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Nuclear	Trillion BTU	268	268	257	263	258	258	263	258	257	263	258	257
(2)	Coal	1,000 TON	3,107	4,170	3,788	3,552	3,705	3,556	3,629	4,019	3,795	3,817	4,073	3,821
(3)														
(4)	Residual(FO6)- Total	1,000 BBL	36,475	36,859	32,769	26,951	24,455	26,018	19,352	14,059	12,416	12,546	11,973	9,188
(5)	Steam	1,000 BBL	36,475	36,859	32,769	26,951	24,455	26,018	19,352	14,059	12,416	12,546	11,973	9,188
(6)	Distillate(FO2)- Total	1,000 BBL	488	461	505	315	2,350	2,642	449	381	212	316	181	46
(7)	CC	1,000 BBL	3	14	0	0	0	0	0	0	0	0	0	0
(8)	CT	1,000 BBL	405	1	0	74	1,959	2,118	406	356	195	289	160	33
(9)	Steam	1,000 BBL	80	446	505	241	391	524	42	25	17	27	21	13
(10)	Natural Gas -Total	1,000 MCF	193,723	203,234	248,439	299,368	319,720	321,203	378,635	423,640	446,604	452,639	468,918	519,426
(11)	Steam	1,000 MCF	73,309	80,967	100,772	76,589	9,521	9,519	7,046	5,361	4,919	4,795	4,736	3,888
(12)	CC	1,000 MCF	3,535	117,684	139,066	214,673	308,615	310,455	371,466	418,226	441,651	447,780	464,137	515,507
(13)	CT	1,000 MCF	116,879	4,583	8,601	8,106	1,584	1,229	124	54	34	63	45	32

1/ Reflects fuel requirements for FPL only
2/ Source A Schedules

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 1/ 1999	2000	Forecasted 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Annual Energy Interchange 2/	GWH	8,180	10,092	12,386	11,509	9,611	10,029	9,169	8,492	8,452	8,332	8,282	5,582
(2)	Nuclear	GWH	24,706	24,584	23,776	24,284	23,873	23,844	24,284	23,874	23,778	24,331	23,874	23,778
(3)	Coal	GWH	6,146	6,977	6,906	6,504	6,711	6,541	6,660	7,307	6,942	6,980	7,398	6,986
(4)	Residual(FO6) -Total	GWH	22,903	23,230	20,706	16,871	15,375	16,370	12,211	8,869	7,833	7,911	7,556	5,828
(5)	Steam	GWH	22,903	23,230	20,706	16,871	15,375	16,370	12,211	8,869	7,833	7,911	7,556	5,828
(6)	Distillate(FO2) -Total	GWH	167	193	213	159	1,674	1,865	331	282	156	232	131	31
(7)	CC	GWH	2	9	0	0	0	0	0	0	0	0	0	0
(8)	CT	GWH	165	1	0	58	1,461	1,581	312	271	149	220	123	26
(9)	Steam	GWH	0	183	213	101	212	284	19	11	7	11	9	5
(10)	Natural Gas -Total	GWH	23,098	24,217	28,259	37,053	43,976	44,209	52,388	58,883	62,148	63,034	65,297	72,491
(11)	Steam	GWH	7,038	7,840	9,398	7,226	851	849	626	474	435	423	418	346
(12)	CC	GWH	15,863	16,064	18,120	29,105	42,983	43,251	51,753	58,406	61,711	62,608	64,876	72,143
(13)	CT	GWH	197	313	741	723	143	110	9	3	2	4	3	2
(14)	Other 3/	GWH	6,349	6,696	7,240	6,636	5,759	5,814	5,298	4,187	4,082	4,069	3,888	3,540
	Net Energy For Load 4/	GWH	91,549	95,989	99,486	103,017	106,979	108,672	110,341	111,894	113,392	114,889	116,427	118,237

1/ Source A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies
3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc
4/ Net Energy For Load is Column 2 on Schedule 3 3 and Column 1 on EIA411 Form 11C

Schedule 6.2
Energy % by Fuel Type

	Energy Source	Units	Actual 1/		Forecasted									
			1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Annual Energy Interchange 2/	%	8 9	10 5	12 4	11 2	9 0	9 2	8 3	7.6	7 5	7 3	7 1	4 7
(2)	Nuclear	%	27 0	25 6	23 9	23 6	22 3	21 9	22 0	21 3	21 0	21 2	20 5	20 1
			0 0											
(3)	Coal	%	6 7	7 3	6 9	6 3	6 3	6 0	6 0	6 5	6 1	6 1	6 4	5 9
(4)	Residual(FO6) -Total	%	25 0	24.2	20 8	16 4	14 4	15 1	11 1	7 9	6 9	6 9	6 5	4 9
(5)	Steam	%	25 0	24.2	20 8	16 4	14 4	15 1	11 1	7 9	6 9	6 9	6 5	4 9
(6)	Distillate(FO2) -Total	%	0 2	0 2	0 2	0 2	1.6	1 7	0 3	0 3	0 1	0.2	0 1	0 0
(7)	CC	%	0 0	0 0	0 0	0 0	0.0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
(8)	CT	%	0 2	0 0	0.0	0 1	1 4	1 5	0 3	0 2	0 1	0 2	0 1	0 0
(9)	Steam	%	0 0	0 2	0 2	0 1	0 2	0 3	0 0	0 0	0 0	0 0	0 0	0.0
(10)	Natural Gas -Total	%	25 2	25 2	28 4	36 0	41 1	40 7	47 5	52 6	54 8	54 9	56 1	61.3
(11)	Steam	%	7 7	8 2	9 4	7.0	0 8	0 8	0.6	0 4	0 4	0 4	0 4	0.3
(12)	CC	%	17.3	16 7	18 2	28 3	40 2	39 8	46 9	52 2	54 4	54.5	55 7	61 0
(13)	CT	%	0 2	0 3	0 7	0 7	0 1	0 1	0.0	0 0	0.0	0 0	0 0	0 0
(14)	Other 3/	%	6 9	7 0	7 3	6 4	5 4	5 4	4 8	3 7	3 6	3.5	3.3	3 0
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source A Schedules

2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies

3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capacity MW	Firm Capacity Import 2/ MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 3/ MW	Total Peak 4/ Demand MW	DSM 5/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 6/ MW	Reserve Margin Before Maintenance 6/ % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 7/ MW	Reserve Margin After Maintenance 7/ % of Peak
2001	17,704	1,509	0	886	20,099	18,150	1,406	16,744	3,355	20 0	0	3,355	20 0
2002	17,915	2,288	0	877	21,080	18,801	1,485	17,316	3,764	21 7	0	3,764	21 7
2003	19,170	2,288	0	877	22,335	19,507	1,560	17,947	4,388	24 4	0	4,388	24 4
2004	19,170	2,288	0	877	22,335	19,964	1,639	18,325	4,010	21 9	0	4,010	21 9
2005	20,762	1,313	0	867	22,942	20,433	1,718	18,715	4,227	22 6	0	4,227	22 6
2006	21,309	1,313	0	734	23,356	20,918	1,796	19,122	4,234	22 1	0	4,234	22 1
2007	21,856	1,313	0	734	23,903	21,392	1,874	19,518	4,385	22 5	0	4,385	22 5
2008	21,856	1,313	0	734	23,903	21,788	1,952	19,836	4,067	20.5	0	4,067	20 5
2009	22,403	1,313	0	683	24,399	22,220	2,028	20,192	4,207	20 8	0	4,207	20.8
2010	24,044	382	0	640	25,066	22,722	2,052	20,670	4,396	21 3	0	4,396	21 3

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated All values are Summer net MW

2/ Firm Capacity Imports include all firm capacity purhcases whether from out - of - state or in - state

3/ Total Capacity Available=Col (2) + Col (3) - Col (4) + Col (5)

4/ These forecasted values reflect the Most Likely forecast without DSM

5/ The MW shown represent cumulative load management capability plus incremental conservation from 1/99 - on They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based

6/ Margin (%) Before Maintenance = Col (10)/Col (9)

7/ Margin (%) After Maintenance =Col (13) /Col (9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled
Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Total	Firm	Firm		Total	Total		Firm Winter	Reserve			Reserve	
	Installed 1/	Capacity	Capacity	Firm	Capacity	Peak 4/		Peak	Margin Before		Scheduled	Margin After	
	Capability	Import 2/	Export	QF	Available 3/	Demand	DSM 5/	Demand	Maintenance 6/		Maintenance	Maintenance 7/	
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2000/01	17,785 *	1,319	0	886	19,990	18,840 *	1,902	16,938	3,052	18 0	0	3,052	18 0
2001/02	17,752	1,369	0	886	20,007	19,333	1,969	17,364	2,643	15 2	0	2,643	15 2
2002/03	20,019	2,394	0	877	23,290	20,122	2,019	18,103	5,187	28 7	0	5,187	28 7
2003/04	20,381	2,394	0	877	23,652	20,555	2,069	18,486	5,166	27 9	0	5,166	27 9
2004/05	20,381	2,344	0	867	23,592	20,986	2,119	18,867	4,725	25 0	0	4,725	25 0
2005/06	22,041	1,319	0	734	24,094	21,413	2,169	19,244	4,850	25 2	0	4,850	25 2
2006/07	22,637	1,319	0	734	24,690	21,841	2,215	19,626	5,064	25 8	0	5,064	25 8
2007/08	23,233	1,319	0	734	25,286	22,186	2,261	19,925	5,361	26 9	0	5,361	26 9
2008/09	23,233	1,319	0	734	25,286	22,586	2,307	20,279	5,007	24 7	0	5,007	24 7
2009/10	23,829	1,319	0	683	25,831	22,978	2,345	20,633	5,198	25 2	0	5,198	25 2

* Denotes actual installed capability and total peak demand All other assumptions are projections

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecasted to occur during January of the "second" year indicated All values are Winter net MW

2/ Firm Capacity Imports include all firm capacity purhcases whether from out - of - state or in - state

3/ Total Capacity Available = Col (2) + Col (3) - Col (4) + Col (5)

4/ These forecasted values reflect the Most Likely forecast without DSM

5/ The MW shown represent cumulative load management capability plus incremental conservation They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based

6/ Margin (%) Before Maintenance = Col (10) /Col (9)

7/ Margin (%) After Maintenance = Col (13) /Col (9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm	Expected	Gen Max	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter	Summer	
Plant Name	No	Location	Type	Pri	Alt	Pri	Alt	Mo /Yr	Mo /Yr	Mo /Yr	KW	MW	MW	Status
ADDITIONS														
2001														
Martin Combustion Turbines	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-99	Jun-01	Unknown	190,000	—	149	P
Martin Combustion Turbines	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-99	Jun-01	Unknown	190,000	---	149	P
											2001 Total:	**0**	**298**	
2002														
Martin Combustion Turbines	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-99	Jun-01	Unknown	190,000	181	---	P
Martin Combustion Turbines	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-99	Jun-01	Unknown	190,000	181	—	P
											2002 Total:	**362**	**---**	
2003														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	Apr-03	Unknown	190,000	---	149	P
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	May-03	Unknown	190,000	---	149	P
											2003 Total:	**---**	**298**	
2004														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	Apr-03	Unknown	190,000	181	—	P
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	May-03	Unknown	190,000	181	---	P
											2004 Total:	**362**	**---**	
2005														
Martin Combined Cycle Unit	5	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	—	547	P
Midway Combined Cycle Unit	1	St Lucie County 2/36S/39E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	—	547	P
											2005 Total:	**---**	**1094**	

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm	Expected	Gen Max	Net Capability		
Plant Name	Unit No	Location	Unit Type	Pri	Alt	Pri	Alt	Start Mo /Yr	In-Service Mo /Yr	Retirement Mo /Yr	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS														
2006														
Martin Combined Cycle Unit	5	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	596	---	P
Midway Combined Cycle Unit	1	St Lucie County 2/36S/39E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	596	---	P
Martin Combined Cycle Unit	6	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	Jun-03	Jun-06	Unknown	470,000	---	547	P
											2006 Total:	**1192**	**547**	
2007														
Martin Combined Cycle Unit	6	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	Jun-03	Jun-06	Unknown	470,000	596	---	P
Unsited Combined Cycle Unit #1	1	Unknown	CC	NG	FO2	PL	PL	Jun-04	Jun-07	Unknown	470,000	---	547	P
											2007 Total:	**596**	**547**	
2008														
Unsited Combined Cycle Unit #1	1	Unknown	CC	NG	FO2	PL	PL	Jun-04	Jun-07	Unknown	470,000	596	---	P
											2008 Total:	**596**	**0**	
2009														
Unsited Combined Cycle Unit #2	2	Unknown	CC	NG	FO2	PL	PL	Jun-06	Jun-09	Unknown	470,000	---	547	P
											2009 Total:	**0**	**547**	
2010														
Unsited Combined Cycle Unit #2	2	Unknown	CC	NG	FO2	PL	PL	Jun-06	Jun-09	Unknown	470,000	596	---	P
Unsited Combined Cycle Unit #3	3	Unknown	CC	NG	FO2	PL	PL	Jun-07	Jun-10	Unknown	470,000	---	547	P
Unsited Combined Cycle Unit #4	4	Unknown	CC	NG	FO2	PL	PL	Jun-07	Jun-10	Unknown	470,000	---	547	P
Unsited Combined Cycle Unit #5	5	Unknown	CC	NG	FO2	PL	PL	Jun-07	Jun-10	Unknown	470,000	---	547	P
											2010 Total:	**596**	**1641**	

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (Cont.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm	Expected	Gen Max	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter [1) 2)]	Summer [1) 2)]	
Plant Name	No	Location	Type	Pri	Alt	Pri	Alt	Mo /Yr	Mo /Yr	Mo /Yr	KW	MW	MW	Status
CHANGES/UPGRADES														
2001														
Martin	1	Martin County 29/29S/38E	ST	NG	FO6	PL	PL	N/A	May-01	Unknown	863,000	0	(30)	OT
Martin	2	Martin County 29/29S/38E	ST	NG	FO6	PL	PL	N/A	May-01	Unknown	863,000	0	(20)	OT
Martin	3	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	N/A	May-01	Unknown	612,000	0	(7)	OT
Martin	4	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	N/A	May-01	Unknown	612,000	0	(7)	OT
Cape Canaveral	2	Brevard County 19/24S/36F	ST	FO6	NG	WA	PL	Nov-00	Nov-00	Unknown	402,050	8	8	OT
Ft Myers Repowering Initial Phase	1 & 2	Lee County 35/43S/25E	CC	NG	No	PL	No	Nov-00	Jan-01	Unknown	161,700	543	894	RP,U
											2001 Total:	**551**	**838**	
2002														
Sanford Repowering Initial Phase	4	Volusia County 16/19S/30E	ST	FO6	NG	WA	PL	Jan-00	N/A	Unknown	106,600	0	(390) [3)]	RP
Sanford Repowering Initial Phase	5	Volusia County 16/19S/30E	ST	FO6	NG	WA	PL	Jan-00	N/A	Unknown	106,600	(394) [3)]	0	RP
Sanford Repowering Second Phase	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	N/A	Jul-02	Unknown	106,600	0	567	RP
Fort Myers Repowering Second Phase	1 & 2	Lee County 35/43S/25E	CC	NG	No	PL	No	Sep-01	Jan-02	Unknown	161,700	(1)	35	RP,U
											2002 Total:	**(395)**	**212**	
2003														
Sanford Repowering Second Phase	4	Volusia County 16/19S/30E	CC	NG	No	PL	No	N/A	Dec-02	Unknown	106,600	671	957	RP
Sanford Repowering Second Phase	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	N/A	Jul-02	Unknown	106,600	1,065	0	RP
Fort Myers Repowering Second Phase	1 & 2	Lee County 35/43S/25E	CC	NG	No	PL	No	Sep-01	Jun-02	Unknown	161,700	531	0	RP,U
											2003 Total:	**2,267**	**957**	
2004														
—		—	—	—	—	—	—	—	—	—	—	—	—	—
											2004 Total:	**0**	**0**	
2005														
Martin Combustion Turbine Conversion	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	—	124.5	P
Martin Combustion Turbine Conversion	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	—	124.5	P
Fort Myers Combustion Turbine Conversion	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	—	124.5	P
Fort Myers Combustion Turbine Conversion	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	—	124.5	P
											2005 Total:	**0**	**498**	

1)The Winter Total MW value consists of all generation additions and changes achieved by January The Summer Total MW value consists of all generation additions and changes achieved by July All other MW will be picked up in the following year This is done for reserve margin calculation

2) All MW differences are calculated based on using IRP 2000 Submittal (for the year 2000) as the base for all other years

3) Negative values for Sanford and Ft Myers reflect the existing steam units being temporarily out of service during that seasonal period for repowering efforts

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (Cont.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm	Expected	Gen Max	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter [1]	Summer [1]	
Plant Name	No	Location	Type	Pri	Alt	Pri	Alt	Mo /Yr	Mo /Yr	Mo /Yr	KW	MW	MW	Status
CHANGES/UPGRADES														
2006														
Martin Combustion Turbine Conversion	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	117 0	---	P
Martin Combustion Turbine Conversion	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	117 0	---	P
Fort Myers Combustion Turbine Conversion	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	117 0	---	P
Fort Myers Combustion Turbine Conversion	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	117 0	---	P
											2006 Total:	**468**	**0**	
2007														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2007 Total:	**0**	**0**	
2008														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2008 Total:	**0**	**0**	
2009														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2009 Total:	**0**	**0**	
2010														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2010 Total:	**0**	**0**	

1)The Winter Total MW value consists of all generation additions and changes achieved by January The Summer Total MW value consists of all generation additions and changes achieved by July All other MW will be picked up in the following year This is done for reserve margin calculation

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Martin Combustion Turbines No. 8A and No. 8B *	
(2)	**Capacity**		
	a Summer	149	MW
	b. Winter	181	MW
(3)	**Technology Type:**	Combustion Turbine	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	1999	
	b. Commercial In-service date:	2001	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0 05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Air Coolers	
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	1%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	98%	
	Resulting Capacity Factor (%):	Approx. 10%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	10,430	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	477.98	
	Direct Construction Cost ($/kW):	449.20	
	AFUDC Amount ($/kW):	29.30	
	Escalation ($/kW):	-0.53	
	Fixed O&M ($/kW -Yr.):	0.68	
	Variable O&M ($/MWH):	0.86	
	K Factor:	1.5134	

* Values shown are per unit values for the two units being added.
** $/KW values are based on Summer capacity.
*** Fixed O&M includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Fort Myers Repowering	
(2)	**Capacity**		
	a. Summer	929	MW Incremental (1473 MW Total After Repowering)
	b. Winter	1,073	MW Incremental (1617 MW Total After Repowering)
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	None	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas	
(7)	**Cooling Method:**	Once-through Cooling	
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	6,830	Btu/kWh
(13)	**Projected Unit Financial Data, *,**,*** **		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	655.96	
	Direct Construction Cost ($/kW):	560.71	
	AFUDC Amount ($/kW):	94.59	
	Escalation ($/kW):	0.66	
	Fixed O&M ($/kW -Yr.):	13.30	
	Variable O&M ($/MWH):	0.37	
	K Factor:	1.5419	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Sanford Unit 4 Repowering	
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	671	MW Incremental (1065 MW Total After Repowering)
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	None	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors and Natural Gas	
(7)	**Cooling Method:**	Cooling Pond	
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	6,860	Btu/kWh
(13)	**Projected Unit Financial Data *,**,*** **		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	708.12	
	Direct Construction Cost ($/kW):	595.11	
	AFUDC Amount ($/kW):	112.45	
	Escalation ($/kW):	0.56	
	Fixed O&M ($/kW -Yr.):	14.25	
	Variable O&M ($/MWH):	0.37	
	K Factor:	1.4701	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:** Sanford Unit 5 Repowering		
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	671	MW Incremental (1065 MW Total After Repowering)
(3)	**Technology Type:** Combined Cycle		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Cooling Pond	
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	6,860	Btu/kWh
(13)	**Projected Unit Financial Data *,**,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	678.08	
	Direct Construction Cost ($/kW):	595.11	
	AFUDC Amount ($/kW):	82.41	
	Escalation ($/kW):	0.56	
	Fixed O&M ($/kW -Yr.):	14.25	
	Variable O&M ($/MWH):	0.37	
	K Factor:	1.5341	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Fort Myers Combustion Turbines No. 13 and No. 14 *	
(2)	**Capacity**		
	a. Summer	149 MW	
	b. Winter	181 MW	
(3)	**Technology Type:**	Combustion Turbine	
(4)	**Anticipated Construction Timing**		
	a Field construction start-date:	2002	
	b. Commercial In-service date:	2003	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Air Coolers	
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	1%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	98%	
	Resulting Capacity Factor (%):	Approx. 10%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	10,430	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	542.80	
	Direct Construction Cost ($/kW):	509.94	
	AFUDC Amount ($/kW):	31.30	
	Escalation ($/kW):	1.56	
	Fixed O&M ($/kW -Yr.):	0.68	
	Variable O&M ($/MWH):	0.86	
	K Factor:	1.5247	

* Values shown are per unit values for the two units being added.
** $/KW values are based on Summer capacity.
*** Fixed O&M includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:** Martin No. 5		
(2)	**Capacity**		
	a Summer	547 MW	
	b. Winter	596 MW	
(3)	**Technology Type:** Combined Cycle		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2002	
	b. Commercial In-service date.	2005	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Cooling Pond	
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	503.31	
	Direct Construction Cost ($/kW):	411.88	
	AFUDC Amount ($/kW):	82.95	
	Escalation ($/kW):	8.48	
	Fixed O&M ($/kW -Yr.):	9.30	
	Variable O&M ($/MWH):	0.74	
	K Factor:	1.5489	

* $/KW values are based on Summer capacity.
** Fixed O&M includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Martin Combustion Turbine Conversion	
(2)	**Capacity**		
	a. Summer	249	MW
	b Winter	234	MW
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2004	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Cooling Pond	
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data** *		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data** **,***		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	481.36	
	Direct Construction Cost ($/kW):	433.91	
	AFUDC Amount ($/kW):	31.29	
	Escalation ($/kW):	16.16	
	Fixed O&M ($/kW -Yr.):	9.30 *	
	Variable O&M ($/MWH):	0.74 *	
	K Factor:	1.5147	

* Values represent an operational combined cycle unit after the conversion is completed.
** $/KW values are based on Summer incremental capacity.
*** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Fort Myers Combustion Turbine Conversion	
(2)	**Capacity**		
	a Summer	249 MW	
	b. Winter	234 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2004	
	b Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0 05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Cooling Tower	
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data ***		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR).	7,150	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	481.36	
	Direct Construction Cost ($/kW):	433.91	
	AFUDC Amount ($/kW):	31.29	
	Escalation ($/kW):	16.16	
	Fixed O&M ($/kW -Yr.):	9.30 *	
	Variable O&M ($/MWH):	0.74 *	
	K Factor:	1.5147	

• Values represent an operational combined cycle unit after the conversion is completed.
** $/KW values are based on Summer incremental capacity.
*** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:** Midway Combined Cycle		
(2)	**Capacity**		
	a. Summer	547 MW	
	b. Winter	596 MW	
(3)	**Technology Type:** Combined Cycle		
(4)	**Anticipated Construction Timing**		
	a Field construction start-date:	2002	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Grey water or groundwater	
(8)	**Total Site Area:**	122	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	439.57	
	Direct Construction Cost ($/kW):	362.93	
	AFUDC Amount ($/kW):	68.27	
	Escalation ($/kW):	8.37	
	Fixed O&M ($/kW -Yr.):	9.30	
	Variable O&M ($/MWH):	0.74	
	K Factor:	1.5457	

* $/KW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Martin No 6	
(2)	**Capacity**		
	a. Summer	547	MW
	b. Winter	596	MW
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2006	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Cooling Pond	
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data *,***		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	454.41	
	Direct Construction Cost ($/kW):	367.96	
	AFUDC Amount ($/kW):	71.07	
	Escalation ($/kW):	15.38	
	Fixed O&M ($/kW -Yr.):	9.30	
	Variable O&M ($/MWH):	0.74	
	K Factor:	1.5460	

* $/KW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:** Unsited Combined Cycle No. 1		
(2)	**Capacity**		
	a. Summer	547	MW
	b. Winter	596	MW
(3)	**Technology Type:** Combined Cycle		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2004	
	b. Commercial In-service date:	2007	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	532.83	
	Direct Construction Cost ($/kW):	419.24	
	AFUDC Amount ($/kW):	85.38	
	Escalation ($/kW):	28.21	
	Fixed O&M ($/kW -Yr.):	12.10	
	Variable O&M ($/MWH):	0.74	
	K Factor:	1.5473	

* $/KW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 2	
(2)	**Capacity**		
	a. Summer	547 MW	
	b. Winter	596 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2006	
	b. Commercial In-service date:	2009	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	554.71	
	Direct Construction Cost ($/kW):	419.24	
	AFUDC Amount ($/kW):	88.86	
	Escalation ($/kW):	46.61	
	Fixed O&M ($/kW -Yr.):	12.10	
	Variable O&M ($/MWH):	0.74	
	K Factor:	1.5473	

* $/KW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 3, No. 4, and No 5 *	
(2)	**Capacity**		
	a. Summer	547 MW	
	b. Winter	596 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2007	
	b. Commercial In-service date	2010	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	566.41	
	Direct Construction Cost ($/kW):	419.24	
	AFUDC Amount ($/kW):	90.72	
	Escalation ($/kW):	56.45	
	Fixed O&M ($/kW -Yr.):	12.10	
	Variable O&M ($/MWH):	0.74	
	K Factor:	1.5473	

* Values shown are per unit values for the three units being added.
** $/KW values are based on Summer capacity.
*** Fixed O&M cost includes capital replacement.

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Martin: 2 CT's

(1)	Point of Origin and Termination:	Not Applicable
(2)	Number of Lines:	Not Applicable
(3)	Right-of-way	FPL Owned
(4)	Line Length:	Not Applicable
(5)	Voltage.	Not Applicable
(6)	Anticipated Construction Timing:	Start date: Not Applicable End date: Not Applicable
(7)	Anticipated Capital Investment:	Not Applicable
(8)	Substations:	Not Applicable
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Ft. Myers Repowering

(1)	Point of Origin and Termination:	From Ft. Myers – To Calusa
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	1.58 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: May 1, 2000 End date: April 1, 2001
(7)	Anticipated Capital Investment:	$354,000
(8)	Substations:	Ft. Myers and Calusa
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	From Ft. Myers – To Orange River
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	2.57 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: March 1, 2000 End date: October 1, 2000
(7)	Anticipated Capital Investment:	$706,750
(8)	Substations:	Ft. Myers and Orange River
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Sanford Repowering

(1)	Point of Origin and Termination:	From Sanford – To Poinsett
(2)	Number of Lines:	2
(3)	Right-of-way	FPL Owned
(4)	Line Length:	45 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: January 1, 2001 End date: June 1, 2001
(7)	Anticipated Capital Investment:	$20,360,000
(8)	Substations:	Sanford and Poinsett
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Ft. Myers: 2 CT's

(1)	Point of Origin and Termination:	From Ft. Myers GT Collector bus – To Orange River
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	2.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: January 1, 2003 End date: May 1, 2003
(7)	Anticipated Capital Investment:	$1,050,000
(8)	Substations:	Orange River and Ft. Myers GT collector bus
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Martin 5

(1)	Point of Origin and Termination:	a. From Pratt & Whitney – To Indiantown b. From Pratt & Whitney – To Ranch c. From Martin – To Indiantown
(2)	Number of Lines:	3
(3)	Right-of-way	FPL Owned
(4)	Line Length:	a. 8.45 miles b. 20.74 miles c. 11.8 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: June 1, 2004 End date: June 1, 2005
(7)	Anticipated Capital Investment:	$6,725,000
(8)	Substations:	Pratt & Whitney, Ranch, Martin, and Indiantown
(9)	Participation with Other Utilities:	None

Note: The existing lines (a & b) will be upgraded to a higher current rating. The line from Martin to Indiantown (c) will be a new circuit integrated with this project.

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Martin: Conversion of CT's into a Combined Cycle Unit

(1)	Point of Origin and Termination:	Not Available
(2)	Number of Lines:	Not Available
(3)	Right-of-way	FPL Owned
(4)	Line Length:	Not Available
(5)	Voltage:	Not Available
(6)	Anticipated Construction Timing:	Start date: Not Available End date: Not Available
(7)	Anticipated Capital Investment:	Not Available
(8)	Substations:	Not Available
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Ft. Myers: Conversion of CT's into a Combined Cycle Unit

(1)	Point of Origin and Termination:	Not Available
(2)	Number of Lines:	Not Available
(3)	Right-of-way	FPL Owned
(4)	Line Length:	Not Available
(5)	Voltage:	Not Available
(6)	Anticipated Construction Timing:	Start date: Not Available End date: Not Available
(7)	Anticipated Capital Investment:	Not Available
(8)	Substations:	Not Available
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Midway: Combined Cycle Unit

(1)	Point of Origin and Termination:	Not Available
(2)	Number of Lines:	Not Available
(3)	Right-of-way	FPL Owned
(4)	Line Length:	Not Available
(5)	Voltage:	Not Available
(6)	Anticipated Construction Timing:	Start date: Not Available End date: Not Available
(7)	Anticipated Capital Investment:	Not Available
(8)	Substations:	Not Available
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Martin 6

(1)	Point of Origin and Termination:	Not Applicable
(2)	Number of Lines:	Not Applicable
(3)	Right-of-way	FPL Owned
(4)	Line Length:	Not Applicable
(5)	Voltage:	Not Applicable
(6)	Anticipated Construction Timing:	Start date: Not Applicable End date: Not Applicable
(7)	Anticipated Capital Investment:	Not Applicable
(8)	Substations:	Not Applicable
(9)	Participation with Other Utilities:	None

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered plant and animal species. Population growth in our service area is continuing, which heightens competition for air, land, and water resources which are necessary to meet the increased demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

Over the years FPL has gained national recognition for its commitment to meeting its customers' energy needs in harmony with the environment. For example, in 1983, FPL won the U.S. Department of the Interior's Conservation Service Award and received the Florida Audubon Society's Corporate Service Award in 1986. In 1998, FPL won the U.S. Coast Guard's prestigious William M. Benkert Award for demonstrating "tremendous vision and dedication to excellence in marine environmental protection." FPL's environmental protection commitment is an integral part of how it conducts business and formal corporate policies have been established to protect the environment.

In March, 2000, Innovest, a company that evaluates environmental performance of Fortune 500 companies, ranked FPL number one of 30 electric utilities reviewed. The Innovest report relates environmental performance with overall management performance and suggests that good environmental performance is a predictor of good investment opportunity.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Statement in 1992 to clearly define the Company's position. This statement reflects how FPL incorporates environmental values into all aspects of the Company's activities and serves as a framework for new environmental initiatives throughout the Company. The FPL environmental statement further establishes a long-term direction of environmental responsibility for the Company. FPL's Environmental Statement is:

It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:

- Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
- Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
- Encourage the wise use of energy to minimize the impact on the environment.
- Communicate effectively on environmental issues.
- Conduct periodic self-evaluations, report performance, and take appropriate actions.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an environmental management system to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program which is discussed below. Other components include: written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident/emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to: evaluate environmental performance, verify compliance with Company policy as well as with legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to: 1) facilitates management control of environmental practices; and, 2) assess compliance with existing environmental regulatory requirements and Company policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and public education. Some of FPL's 2000 environmental outreach activities are noted in Table IV.E.1.

2000 FPL Environmental Outreach Activities

Site	Activity	# of Participants (approx.)
St. Lucie Plant	Turtle Beach Nature Trail Visitation	2,020
Riviera Plant & Fort Myers Plant	Manatee Awareness Activities	144,000
St. Lucie Plant	Turtle Walk Participation	725
St. Lucie Plant	FPL Energy Encounter	32,974
Not Applicable	Inquiries – 800 environmental information line and emails	4,500
Martin Plant	Barley Barber Swamp Visitation	3,400

Table IV.E.1

IV.F Preferred And Potential Sites

Based upon its projection of future resource needs, FPL has identified preferred and potential sites for future generation additions. These preferred and potential sites are discussed in separate sections below.

IV.F.1 Preferred Sites

FPL has identified four preferred sites: the existing Fort Myers plant site, the existing Sanford plant site, the existing Martin plant site and the existing Midway substation site, These four sites are currently the expected known locations for the capacity additions, which FPL projects to make during the 2001 – 2006 period. (Other capacity additions, in the form of new combined cycle units, will be made in the 2007 through 2010 time period. Selection of sites for these later capacity additions is not yet needed and has not been made. Please see Table III.B.1).

The four preferred sites are discussed below. FPL has committed to repower existing units at both its Fort Myers and Sanford sites, to first add new combustion turbine (CT), then later convert this CT capacity into combined cycle (CC) capacity at the Martin and Fort Myers sites, and to add new combined cycle (CC) capacity at the Martin and Midway sites.

Preferred Site #1: Fort Myers Plant, Lee County

The site is located on the 460-acre Fort Myers property. Current facilities on the site include two steam electric generating units (nominally 150 MW and 400 MW, respectively), three CT's (which will soon be joined by three more CT's) which, along with heat recovery steam generating (HRSG) units and the existing steam turbines will comprise the repowered facility (construction completion in 2002); and a bank of 12 simple-cycle combustion turbine peaking units. The site has direct access to a four-lane highway, State Road (SR) 80, and barge access is available. The nearest town is Tice, which is approximately 4 miles west of the site. The City of Fort Myers is approximately 8 miles west of the site. The Fort Myers site has been listed as a potential or preferred site in previous FPL Site Plans.

FPL is planning to add new capacity by first adding two CT's, then converting the two CT's into one CC unit. The CT's are expected to be in service in the Spring of 2003 and will add 298 MW (Summer) and 362 MW (Winter) to FPL's system. The conversion to CC configuration is planned to be completed and in - service by mid-2005. The CT – to – CC conversion will add approximately another 249 MW (Summer) and 234 MW (Winter) to FPL's system.

The repowering project currently underway at the site will add approximately 930 MW during Summer conditions and approximately 1,070 MW during Winter conditions. This project is expected to be completed in mid-2002.

The output capability of the existing bank of 12 CT's at the site will be unaffected by the repowering project and the addition of the two new CT's.

a. and b. U.S. geological Survey (USGS) May and Proposed Facilities Layout Map

A USGS map of the Fort Myers plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter. It is pertinent to note that several designations on the current South Florida Water Management District Florida Land Use, Cover, and Forms Classification System (FLUCCS) appear to be in error, or to require some clarification. For example, the freshwater marsh identified toward the western boundary of the site is actually FPL's 50-acre evaporation/percolation pond. Similarly, while there are scattered mangroves along the shore, the "Central Mangrove" area shown is not mangrove but is the FPL switchyard for that site. The "Improved Pasture" shown towards the east of the site is currently the location of a tree nursery.

d. Existing Land Uses of Site and Adjacent Areas

The land on the site is primarily dedicated to industrial use with surrounding grassy and landscaped areas. There is the previously mentioned 50-acre evaporation/percolation pond on the site. Much of the site is currently being used for either direct construction activities or in support of the repowering project.

FPL has recently donated an 18-acre island, located north of the plant in the Caloosahatchee River, to the United States Fish & Wildlife Service (USFWS) for the purpose of wildlife conservation. This island has been owned by FPL since the 1950's, but has never been developed. The USFWS plans to incorporate the island into the Caloosahatchee National Wildlife Refuge.

Lee County operates Manatee Park (approximately 5 acres) with a manatee viewing area on FPL property to the east side of the discharge canal where it adjoins the Orange River south of SR 80. This manatee viewing area provides public viewing and education about the species. FPL leases the property to the county for a nominal amount.

The adjacent land uses are light commercial and retail to the south of the property and some residential areas located toward the west. Mixed scrub with some hardwoods and wetlands, plus agriculture land, can be found to the east and further to the south. The Caloosahatchee National Wildlife Refuge is located across the Caloosahatchee River, northwest of the power plant.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

The site is adjacent to the south bank of the Caloosahatchee River near the confluence of the Orange River and the Caloosahatchee. Much of the site is no longer in its original natural condition. However, a scattering of mangroves can be found along the river shoreline. Some mixed scrub with some hardwoods and wetlands can be found to the east and further to the south. Other than the occasional congregation of manatees noted below, FPL is not aware of any significant environmental features on the site or in the vicinity.

2. Listed Species

Construction and operation of the repowered facility, plus the new CT's/CC at the site, are not expected to affect any rare, endangered, or threatened species. The only known listed species associated with the site are the West Indian Manatees (Trichechus manatus: Federal - and - State listed as Endangered) which are attracted to the warmed waters in the vicinity of the site discharge and can be found congregating in the area during cool weather.

The Florida Natural Areas Inventory (FNAI) reports the presence of the Eastern Indigo Snake (Drymarchons corais couperi: Federal - and - State listed as Threatened) and Tricolored Heron (Egretta tricolor: State - listed as a Species of Special Concern) within a two-mile radius of the site.

3. Natural Resources of Regional Significance Status

No Natural Resource of Regional Significance is identified on the plant site in the Southwest Florida Regional Strategic Policy Plan.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design options currently being pursued for the Fort Myers site are the repowering of the two existing oil-fired boilers with natural gas-fired CT's and HRSG's, plus the installation of two stand-alone CT's. As previously mentioned, these two CT's will later be converted into one CC unit. All of this new generation equipment will be installed on the existing facility property and will make effective use of existing transmission facilities and infrastructure although some transmission line upgrades will be required. Steam developed in the new HRSG's will be directed to the existing steam turbines. FPL has contracted with Florida Gas Transmission (FGT) for a firm natural gas supply to the plant.

Mitigation options being planned for the capacity additions at Fort Myers include: the capture and reuse of plant process water, the use of combustion technology that is inherently low in air pollutant emissions, the reduction or cessation of heavy oil barge traffic on the Caloosahatchee River, plumbing the sanition system to Lee County's system and closing the on-site septic tanks, and closing the on-site ash basins.

Six CT's are being installed at the site in support of the repowering project. Several of these CT's are now operational in simple-cycle mode. Conversion to combined-cycle mode to complete the repowering process will occur during mid-2002.

g. Local Government Future Land Use Designations

The Local Government Future Land Use Plan designates the major portion of the site as Public Facilities and a small area as Resource Protection. Since there are no significant environmental resources on the site, and the "Resource Protection" designated area appears to be the location of a current tree nursery, FPL believes that this designation is in error.

h. Site Selection Criteria and Process

For the past several years, many of FPL's existing power plant sites have been considered potentially suitable sites for new, expanded, or repowered generation. The Fort Myers plant has been selected as a preferred site due to a combination of electrical transmission and system load factors, plus economic considerations. Environmental issues were not a deciding factor in FPL's site evaluation since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All of these sites are considered permittable.

i. Water Resources

The available surface water source is the Caloosahatchee River and the available groundwater source is the shallow aquifer.

j. Geological Features of Site and Adjacent Areas

The geology underlying the Fort Myers Plant consists of Quaternary Holocene and Pleistocene undifferentiated materials. The upper part of these undifferentiated materials consists of fine-to-medium-grained quartz sand with varying percentages of shell and clay. Hardpan frequently occurs at the base of the quartz sands. The lower section consists of shell beds with interbedded limestones. Underlying the undifferentiated materials are the Pliocene Tamiami formations, the Miocene Hawthorn formation, Oligocene Suwanee Limestone, the Eocene Crystal River and Williston formations, the Avon Park Limestone, and the Lake City Limestone.

Several stratigraphic units can be differentiated based upon shallow borings drilled on the plant property. Sand with some heterogeneous fill material related to past site construction activity covers most of the surface. It is underlain by layers of clayey sand and clay to a depth of approximately 23 feet. These units mantle a thicker clay unit with numerous shell fragments that occurs from 15 feet to about 55 feet below the surface. A silty sand with a trace of clay was encountered at 55 feet near the termination depth of one deep boring on the site.

The water table at the site occurs at levels from just under the surface to about 5 feet below grade. Locally, the surficial aquifer and surface water will generally flow toward the Caloosahatchee River. However, at the site, the intake and discharge canal will affect groundwater near the power block area. A drainage canal that borders the plant property on the west will affect groundwater flow along the western portion of the waste treatment area.

k. Projected Water Quantities For Various Uses

It is estimated that 150 gallons per minute (gpm) will be needed for industrial processing water for uses such as boiler makeup and service water. For industrial cooling (once-through cooling water), no significant increase is projected in the current 451,000 gpm usage rate. Other facility water uses may include irrigation, potable use, etc. The total volume of these uses is estimated to be about 5 gpm.

l. Water Supply Sources By Type

For industrial processing, FPL anticipates that groundwater will be available. For cooling water, for the repowered unit, FPL plans to continue to use its existing allocation from the Caloosahatchee River in a once-through cooling mode. The new CT's will be air-cooled. After the conversion of these CT's into a CC unit, a cooling tower with blowdown (i.e., a closed system) is expected to be used.

m. Water Conservation Strategies Under Consideration

A plan to treat and recycle equipment wash water, boiler blowdown, and equipment area runoff for use as service water would reduce ground water consumption. FPL would anticipate this site being designed and classified as a wastewater zero-discharge site following the completion of the repowering work.

n. Water Discharges and Pollution Control

Heated water discharge will be dissipated using both the existing once-through cooling water system and a multi-cell cooling tower. Non-point source discharges are not anticipated to be an issue because surface water runoff will be collected and used to recharge the surficial aquifer. Treating and recycling equipment wash water, boiler blowdown, and equipment area runoff will minimize industrial discharges. Storm water runoff will be collected and used to recharge the surficial aquifer via a stormwater management system. Design elements will be included to capture suspended sediments. Various facility permits mandate various sampling and testing activities, which will provide indication of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

A combustion turbine-based repowering project, plus the addition of the new CT's/CC, at the Fort Myers site requires a natural gas pipeline to be installed. Florida Gas Transmission has initiated permitting to install and operate such a facility. Virtually no waste is associated with natural gas firing.

p. Air Emissions and Control Systems

A natural gas-fired facility would generally have air pollutant emissions, which are substantially lower than emissions from the current oil-fired boilers. While several technologies are available for nitrogen oxide (NOx) emissions control, FPL is using a dry-low-NOx combustion turbine design. In these devices, combustion is staged in order to reduce the formation of combustion-derived oxides of nitrogen. FPL has proposed NOx emission limits for this facility that will be among the lowest in the state once the facility is constructed. Sulfur dioxide and particulate emissions are intrinsically low due to the lack of sulfur and solids in natural gas fuel. Carbon monoxide and volatile organic compound emissions can each be controlled via the use of efficient combustion rather than through the use of add-on control devices. Carbon dioxide emission rates associated with burning natural gas are well below those of other liquid or solid fuels. While the Fort Myers plant site is located within 100 kilometers of a Class I area (Everglades National Park), the reduction in emissions associated with repowering is expected to improve the air quality in the area as compared to current levels. CC and CT facilities have been permitted at several locations throughout the state of Florida including near Class I areas. Dry-low-NOx combustor systems have been repeatedly demonstrated to be the Best Available Control Technology (BACT) for the control of NOx emissions for this technology pursuant to the requirements of the Clean Air Act.

q. Noise Emissions and Control systems

Lee County has a noise ordinance which limits noise at the receiving property line to 75 decibels. Noise emissions from the Fort Myers project s are not anticipated to approach this level based upon demonstrated noise control at similar natural gas-fired facilities (the Lauderdale plant in Broward County and the Martin plant in Martin County) and computer modeling of the anticipated noise emissions from the Fort Myers repowered plant. FPL will undertake studies to assure that noise level associated with the new CT's comply with Lee County noise standard.

r. Status of Applications

FPL has received all the permits necessary to construct and start up the repowered plant and the two new CT units. FPL will apply for permits for the CT's – to - CC conversion at the appropriate time.

Preferred Site #2: Sanford Plant, Volusia County

The site is located on the 1,718–acre FPL Sanford property just west of Lake Monroe on the north bank of St. Johns River in Volusia County. Current facilities on the site include three steam electric generating units (one with a nominal rating of 150 MW and two with nominal ratings of 400 MW). The site is within the city limits of Debary and the community of Debary is located approximately 2 miles to the northwest. The town of Deland is approximately 4 miles west of the site. The site has direct access to a four-lane highway, State Road (SR) 17-92, and barge access is available. The Sanford site has been listed as a potential or preferred site in previous FPL Site Plans.

FPL is currently in the process of adding new capacity at the Sanford site by replacing two existing oil-and gas-fired units (i.e., existing units #4 and #5) with advanced natural gas-fired combustion turbines (CT's) and heat recovery steam generators (HRSG's). This type of steam generation replacement is commonly called "repowering".

This repowering will enable FPL to produce significantly more electrical output with nearly the same environment impact. The repowering of units # 4 and # 5 will each produce approximately 570 additional MW during Summer conditions, and approximately 670 additional MW of generation during Winter conditions, beyond the current capabilities of these units. The two repowered units # 5 and # 4 are scheduled to be in-service by mid-2002 and late-2002, respectively. The existing 150 MW unit # 3 at Sanford will be unaffected by the repowering of units # 5 and # 4.

a. and b. U.S. Geological Survey (USGS) May and Proposed Facilities Layout Map

A USGS map of the Sanford plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A large part of the property is covered by the 1,100-acre closed-cycle-cooling pond which occupies almost all of the northern portion of the site. The remainder of the site is primarily rangeland and the power plant facilities.

The surrounding land use is largely crop land and pasture. To the east of the plant there is a small residential area and some commercial/industrial land use. There are some residential areas mixed in with the agricultural areas located between the site and the St. John's River to the west To the south is the St. Johns River and residential homes and commercial/industrial businesses are located along the south side of the river.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

   Small, scattered wooded areas can be found on the site. There are two small areas of wetland marsh on the site and a few acres of wetland forest along the riverbank. There are some wooded areas on the site, primarily upland coniferous forest. Forested and non-forested wetlands can be found to the west, adjacent to the river. Rover and wetland areas towards the northwest are designated as part of the Wekiwa River Aquatic Preserve and Wekiwa River State Preserve.

2. Listed Species

   One inactive bald eagle (Haliaeetus leucocephalus: Federal - and - State listed as Threatened) nest has been found on the site. Bald eagles have also nested in the Lake Monroe area. There are a number of other eagle nests in the vicinity of the site, primarily along the river. The Florida Natural Areas Inventory (FNAI) reports several Scrub Jay populations (Aphelocoma coerulescens: Federal – and - State listed as Threatened) located in scrub vegetation to the northwest of the site. West Indian Manatees (Trichechus manatus: Federal – and - State listed as Endangered) have also been found in this area.

3. Natural Resources of Regional Significance Status

The Wekiwa River Aquatic Preserve extends along the St. John's River in the vicinity of the plant.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option for the Sanford site is the repowering of two existing oil-and gas-fired boilers with natural gas-fired combustion turbines (CT's) and heat recovery steam generators (HRSG's) Advanced CT's can be installed on the existing facility property to make effective use of existing transmission facilities and infrastructure although some transmission line upgrades will be required. Steam produced in the new HRSG's will be directed to two of the existing steam turbines. Natural gas-fired facilities represent one of the cleanest, most efficient technologies currently available for capacity additions to FPL's system.

Mitigation options being considered in the repowering project at Sanford include the reduction in the use of ground water, the use of combustion technology that is inherently low in air pollutant emissions, reduction in the amount of solid waste generated, plumbing the sanitary waste system into the Volusia county system, and the significant reduction of oil barge traffic on the St. Johns River.

g. Local Governmental Future Land Use Designations

The site is designated as "Industrial Utilities" in the Local Government land use plan. The city is currently updating its Land Use Plan. It is expected that the name, but not the expected use designation, may change. Land use designation of the surrounding area is primarily Agricultural. There is an area of "Public Institution" around Lake Monroe to the southeast and a small area of "Mixed Use" to the west along Barwick Road.

h. Site Selection Criteria and Process

The Sanford plant has been selected as a preferred site due to a combination of system load and economic factors. Environmental issues were not a deciding factor in FPL's site evaluation since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All are considered permittable.

i. Water Resources

For surface water supply, the available water resource is the St. John's River and / or the on-site cooling pond, which is periodically refilled from the St. John's River. For groundwater supply, the available resources are the shallow aquifer or the Floridan Aquifer.

j. Geological Features of Site and Adjacent Areas

The near-surface geology of Volusia County, like that of most of north central Florida, is represented by late Tertiary and Quaternary geologic units. Soils in the vicinity of the plant include unconsolidated Pleistocene to Recent sands, with intervening beds of shells and clay. These deposits form the reservoir for the surficial aquifer in the county. Deposits of Pliocene or Miocene clay with some sand underlie the aquifer. These low-permeability units serve to confine groundwater under pressure in the underlying porous limestone formations of Eocene age. These formations are part of the principal hydrologic unit referred to as the Floridian Aquifer. This aquifer, the top of which generally occurs through the region at or below 100 feet, is the major source of potable groundwater in Volusia County. Two faults, one trending north-to-south, the other trending east-to west, intersect a number of miles north of the site. Downward displacement of the fault is hypothesized as being approximately 60 to 100 feet.

k. Projected Water Quantities for Various Uses

FPL has estimated that 150 gallons per minute (gpm) would be required for industrial processing purposes (boiler makeup, service water, etc.). Note that Units # 5 and # 4 both currently take their cooling water directly from an on-site FPL cooling pond and are expected to continue to do so once the units are repowered. The cooling water needs for the repowered facilities are expected to increase over what is currently used, due primarily to the increased heat loading to the cooling pond that will result from operating the larger repowered units more than they have been operated in the past, and corresponding evaporative losses. Therefore, greater quantities of water may be used.

Existing Unit # 3 will use water from the St. John's River in a once-through cooling mode.

FPL also evaluated alternative sources of water to meet the expected needs of the site. It is anticipated that the existing off-site wells and the existing once-through cooling water system and cooling pond would continue to be used after the repowering project is completed, albeit the use of groundwater is expected to decrease significantly from past usage.

l. Water Supply Sources by Type

The available surface water supply source is the St. Johns River. The Floridan Aquifer is an available groundwater source for service water and boiler water.

m. Water Conservation Strategies Under Consideration

A plan to treat and recycle equipment wash water, boiler blowdown, and equipment area runoff for use as service water would reduce groundwater consumption.

n. Water Discharges and Pollution Control

Heated water discharge will be dissipated using the existing once-through cooling water system. Non-point source discharges are not anticipated to be an issue because surface water runoff is planned to be collected and reused. Treating and recycling equipment wash water, boiler blowdown, and equipment area runoff will minimize industrial discharges. Storm water runoff will be collected and used to recharge the surficial aquifer via a stormwater management system. Design elements will be included to capture suspended sediments. Various facility permits mandate various sampling and testing activities, which will provide indication of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The repowered facilities at the Sanford site would require a larger natural gas pipeline to be installed. FPL has contracted with Florida Gas Transmission Company (FGT) to permit, install, and operate such a facility. Virtually no waste is associated with natural gas firing.

p. Air Emissions and Control Systems

A natural gas-fired facility would generally have air pollutant emissions which are substantially lower than emissions from the current oil-fired boilers. While several technologies are available for nitrogen oxide (NOx) emissions control, the most appropriate candidate for the Sanford site is a dry-low-NOx combustion turbine design type. In these types of devices, combustion is staged in order to reduce the formation of combustion-derived oxides of nitrogen. Sulfur dioxide and particulate emissions are intrinsically low, due to the lack of sulfur and solids in natural gas fuel. Carbon monoxide and volatile organic compound emissions can each be controlled via the use of efficient combustion, rather than through the use of add-on control devices. CC and CT facilities have been permitted at several locations throughout the state of Florida. Dry-low-NOx combustor systems have been repeatedly demonstrated to be the Best Available Control Technology (BACT) for the control of NOx emissions for this technology pursuant to the requirements of the Clean Air Act.

q. Noise Emissions and Control Systems

Noise emissions from the project are not anticipated to be significantly different from current levels at the existing plant. FPL will install appropriate sound attenuation devices such as insulation on high-energy piping systems in order to ensure that sound levels do not exceed allowable levels. Similar natural gas-fired facilities (the Lauderdale plant in Broward County and the Martin plant in Martin County) have been constructed and operated without exceeding allowable noise levels.

r. Status of Applications

FPL has now acquired all permits needed to commence construction. Modifications to operating permits will continue to be pursued as necessary through 2001.

Preferred Site #3: Martin Plant, Martin County

The Martin site is located approximately 40 miles northwest of West Palm Beach, 5 miles east of Lake Okeechobee, and 7 miles northwest of Indiantown in Martin County, Florida. The site is bounded on the west by the Florida East Coast Railway (FEC) and the adjacent South Florida Water Management District (SFWMD) L-65 Canal, on the south by the St. Lucie Canal (C-44 or Okeechobee Waterway), and on the northeast by SR 710 and the adjacent CSX Railroad.

The Martin site was identified in 1987 as a preferred location for development of coal gasification/combined cycle electric generation facilities and subsequent FPL Site Plans have continued to identify this site as a preferred site.

The existing 2,588 MW of Summer generating capacity at FPL's Martin plant occupies a portion of the approximately 11,300-acre Martin site which is wholly owned by FPL. The generating capacity is made up of two steam units (units # 1 and # 2), plus two combined cycle units (units # 3 and # 4). The site includes a 6,800-acre cooling pond (6,500 acres of water surface and 300 acres of dike area) and approximately 300 acres for the existing power plant units and related facilities.

Additional generating capacity will be added to the site in several stages. First, two combustion turbines (CT's) are being added to the site in 2001. These two CT's will then be converted into one combined cycle (CC) unit in 2005. An additional CC unit (Martin Unit # 5) will also be added in 2005. Finally, one more CC unit (Martin Unit # 6) will be added in 2006.[5]

The two new peaking CT's are currently under construction will add 298 MW (Summer) and 362 MW (Winter) of additional capacity to FPL's system. The later conversion of these two CT's to one CC unit will add approximately 249 MW (Summer) and 234 MW (Winter) of capacity. The addition of the Martin units # 5 and # 6 will each add approximately 547 MW (Summer) and 596 MW (Winter).

a) and b) U.S. Geological Survey (USGS) Map and Proposed Facilities Layout Map

A USGS map of the Martin plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c) Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d) Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a 6,800-acre cooling pond. The existing power plant facilities are located on approximately 300 acres. To the east of the power plant

[5] Ultimately, coal gasification facilities may be constructed and operated to supply coal-derived gas to existing Units #3 and #4 and/or these new CC units, if economically justified. FPL currently has no plans to introduce coal gasification at the site Coal gasification would not produce additional megawatts, so it is not discussed further in this document. Approx. 1,300 acres could potentially be used to accommodate the associated coal handling, coal storage, by-product handling, and storage facilities which would be constructed if coal gasification is implemented In such a case, natural gas and/or distillate fuel coil could serve as backup fuels.

there is an area of mixed pine flatwood with a scattering of small wetlands. To the north of the reservoir there is a 1,200-acre area which has been set aside as a mitigation area. There is peninsula of wetland forest on the west side of the reservoir which is named the Barley Barber Swamp. The Barley Barber Swamp encompasses 400 acres and is preserved as a natural area. There us also a 10 kilowatt (KW) photovoltaic energy facility at the south end of this site.

e) General Environment Features On and In The Site Vicinity

1) Natural Environment

As noted above, the Barley Barber Swamp is located on the site. There is also a 1,200-acre mitigation area in the northern area of the site where wetlands and uplands have been restored. Along the south and west sides of the cooling pond is an area where the vegetation has been allowed to return to its natural state in order to serve as a wildlife corridor. FPL has preserved a Florida Panther corridor along the west side of the cooling pond. There are pine flatwoods and small scattered wetlands to the east of the plant.

2) Listed Species

Construction and operation of new units at the site are not expected to affect any rare, endangered, or threatened species. There are two active Bald Eagle (Haliaeetus leucocephalus: Federal - and - State listed as Threatened) nests that have been on the site for many years. The Florida Natural Areas Inventory (FNAI) database notes a record of Eastern Indigo Snakes (Drymachon coralis coupert which are Federal - and - State listed as Threatened) in the Barley Barber Swamp. A number of other Bald Eagle nests and sightings of Eastern Indigo Snakes are reported by the FNAI database within a two-mile radius of the site. Infrequent sightings of Florida Panther have been made in the site area.

3) Natural Resources of Regional Significance Status

The Treasure Coast Regional Planning Council lists the "FPL Preserve", including the Barley Barber Swamp, as a Significant Regional Facility. Natural communities such as uplands and wetlands are also generically listed as Resources of Regional Significance.

4) Other significant features

FPL is not aware of any other significant features of the site.

f) Design Features and Mitigation Options

The design options are to add four additional CT's and two HRSG's which will comprise the Martin # 5 and #6 units, in 2005 and 2006, respectively. In addition, two new CT's will begin operation in mid – 2001. In 2005 they will be converted into one CC unit. Natural gas delivered via pipeline is envisioned as the fuel type for these units (with distillate serving as a backup fuel for the stand-alone CT's.). Natural gas-fired facilities are among the cleanest, most efficient technologies currently available.

Mitigation options being considered in the addition of this capacity at the existing Martin site include the capture and reuse of plant process water and rainwater. The facility already encompasses several preserved areas where wildlife is abundant.

g) Local Government Future Land Use Designations

Local government future land use designation for the site is "Public Utilities". Designations for the surrounding area are primarily "Agricultural". There are also limited areas of "Agricultural Ranchette", "Industrial", and a small "Commercial" area designation. To the southeast of the property, fronting on the St. Lucie Canal, there is an area designated for "Public Conservation".

h) Site Selection Criteria and Process

For the past several years, a number of FPL's existing power plant sites have been considered as potentially suitable sites for new or repowered generation. The Martin plant has been selected as a preferred site due to a combination of site, location, and economic factors. The Martin site has been selected as a preferred site due to a combination of electrical transmission and system load factors, plus economic considerations. Environmental issues were not a deciding factor in FPL's site evaluation since none of the existing preferred and potential site exhibit significant environmental sensitivity or other environmental issues. All of these sites are considered permittable.

i) Water Resources

Surface water resources currently used at the Martin facility include the cooling pond, which takes its water from the St. Lucie canal. The available groundwater resource is the shallow aquifer which is used as a source of potable water and for service water for Units # 1 and # 2. Both of these sources are available for use with the site expansion.

j) Geological Features of Site and Adjacent Areas

FPL's Martin site is underlain by approximately 13,000 feet of sedimentary rock strata The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine in origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, or clay. The deepest formation in Martin County on which significant published data are available is the Eocene Age Avon Park. Limited information is available from wells penetrating the underlying Lake City formation. The published information on the sediments comprising the formations below the Avon Park Limestone in western Martin County is based on projections from deep wells in Okeechobee, St. Lucie, and Palm Beach counties.

k) Projected Water Quantities for Various Uses

The estimated additional quantity of water required for industrial processing is 130 gallons per minute (gpm) for uses such as boiler water and service water. FPL operates on-site water treatment systems for each of these uses. Cooling water for new Units # 5 and # 6, as well as for the other new CC unit which will result from the conversion of the 2 new CT's into a CC unit, will be supplied from the on-site 6,800-acre cooling pond. The CT's will be air-cooled until they are converted into a CC unit. Makeup water for the pond is taken from the St. Lucie canal. The current makeup water quantity to the cooling pond (approximately 4,800 gpm) is expected to be adequate for the proposed expansion. Water quantities needed for other uses such as irrigation and potable water are estimated to be approximately 5 gpm.

l) Water Supply Sources by Type

All additional capacity at the site will utilize the existing on-site cooling pond as the source of cooling water and as a heat sink for the dissipation of cooling water heat. The cooling pond operates as a "closed cycle" system in which heated water from the generating units loses its heat as it is circulated within the pond and back around to the plant intake. Makeup water to the pond is withdrawn from the St. Lucie Canal as needed to replace net evaporation and seepage losses from the pond. Such needs will comply with the existing agreement between FPL and the South Florida Water Management District (SFWMD) regarding allocation of cooling water to the pond and with SFWMD's regulations for consumptive water use.

The existing water treatment system at the plant, which provides treated water for use in the Unit 1 and 2 boilers, as well as the HRSG's associated with Units 3 and 4, will be used to provide treated water for the two new, and expanded to provide treated water for New Unit # 5. To avoid impacts to the surficial aquifer, FPL and SFWMD have agreed that the process water for Units # 3 and # 4 can be obtained initially from the cooling pond, but upon completion of Units # 5 and # 6, process water for all four CC units will be obtained solely from the Floridan Aquifer via approximately 1,500-foot deep wells.

m) Water Conservation Strategies Under Consideration

Impacts on the surficial aquifer will be reduced by changing the source of plant process water to the Floridan aquifer, upon completion of Units #5 and #6. In addition, the facility captures and reuses process water whenever feasible, and manages stormwater in such a manner so as to recharge the surficial aquifer.

n) Water Discharges and Pollution Control

Heated water discharges will be dissipated in the cooling pond. Non-point source discharges are not an issue since there are none at this facility. Industrial discharges will be minimized by treating and recycling equipment wash water, boiler blowdown water, and equipment area runoff. Storm water runoff is collected and used to recharge the surficial aquifer via a stormwater management system. Design elements have been included to capture suspended sediments. Facility permits mandate various sampling and testing activities, which provide indication of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o) Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by multiple fuel delivery facilities. However, the addition of future natural gas-fired CC units would require an enlargement of the existing pipeline(s), the installation of a new pipeline, or the addition of another natural gas pipeline compressor station. There are currently two natural gas supply lines into the facility, as well as an oil pipeline, which serve the existing steam boilers and combined cycle generating units. The existing natural gas line will also serve the new CT's.

p) Air Emissions and Control Systems

FPL's plan for the two new CT's/CC and for new Units # 5 and # 6 are subject to "New Source Review" under Federal and State Prevention of Significant Deterioration (PSD) regulations. This review required these units to meet New Source Performance Standards (NSPS) and that Best Available Control Technology (BACT) be selected to control emissions of those pollutants emitted in excess of applicable PSD significant emission rates. The primary purpose of BACT analysis is to minimize the allowable increases in air pollutants and thereby increase the potential for future economic growth without significantly degrading air quality.

Air emission rates will be limited to levels far below NSPS requirements. In addition, BACT determination was established for the following pollutants: sulfur dioxide (SO_2) , sulfuric acid mist (H_2SO_4), nitrogen oxides (NO_x), particulates (PM_{10} and TSP), carbon monoxide (CO), volatile organic compounds (VOC), lead, beryllium, mercury, and inorganic arsenic. By stipulation, the Department of Environmental Protection (DEP) has determined final BACT for Units # 3 and # 4 firing natural gas and distillate oil. Emission limitations and conditions concerning development of subsequent units at the site (e.g. the two CT's/CC and Units # 5 and # 6) reflect a preliminary BACT determination for those phases to support certification of ultimate site capacity and shall be determined finally upon review of supplemental applications.

Emission limits for the new CT's currently under construction reflect BACT limits of 10 ppm for natural gas firing and 42 ppm for distillate oil firing. Different limits were also established for operation of the peaking units in power augmentation and peaking modes. FPL projects that lower emission levels to those listed above will be required for the conversion of the CT's to CC operation and for the operation of new Units # 5 and # 6.

q) Noise Emissions and Control Systems

A field survey and impact assessment of noise expected to be caused by unit construction at the site indicated that construction noise will be below current noise levels at the residents nearest the site. Noise from the operation of the new units will also be within allowable levels.

r) Status of Applications

A Site Certification application was filed in December, 1989, for the construction and operation of the Martin Coal Gasification/Combined Cycle project under the Florida Electrical Power Plant Siting Act.

On June 15, 1990, the Public Service Commission issued a Determination of Need Order for proposed Martin Units # 3 and # 4. This determination of need applies only to the first phase of the Project, or 832 MW of combined cycle generation. The Siting Board issued a Land Use Order on June 27, 1990. The Certification Hearing was held on November 5-7, 1990. As mentioned earlier, on February 12, 1991, the Governor and Cabinet, serving as the Siting Board, approved the construction and operation of natural gas-fired combined cycle Units # 3 and # 4 and determined that the Martin Site has capacity to accommodate additional combined cycle units fueled by natural gas, fuel oil, or coal-derived gas produced at the site which will encompass new Units # 5 and # 6.

Since the initial certification in 1991, the certification has been modified five times to provide authorization for items such as CT testing, increasing the cooling pond elevation, incorporating changes from other permits, and incorporating a custom fuel monitoring program. For the addition of the two CT's mentioned above, FPL obtained a sixth modification to the existing site certification in August 2000.

In order to convert these two CT's from simple cycle to CC configuration, a seventh modification to the Site Certification will be required. FPL will file an application for this modification at the appropriate time.

Preferred Site #4: Midway Substation Property, St. Lucie County

The site is located on the 122-acre Midway Substation property. Current facilities on the site include an electric substation. The site has direct access to a two-lane highway, State

Road (SR) 712. The nearest town is White City, which is approximately 5 miles east of the site. The City of Fort Pierce is approximately 9 miles northeast of the site. The Midway site has not previously been listed as a potential or preferred site in previous FPL Ten Year Power Plant Site Plans.

FPL is planning to add new capacity by constructing a combined cycle (CC) gas-fired facility on the property. The new plant would consist of two combustion turbines (CT's), two heat recovery steam generators (HRSG's) and one steam turbine-generator. This addition will add approximately 547 MW (Summer) and 596 MW (Winter) to FPL's system. The construction of the CC unit is planned to be completed and the plant in service by mid-2005.

a. and b. U.S. Geological Survey (USGS) May and Proposed Facilities Layout Map

A USGS map of the Midway Substation site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The land on the site is currently dedicated to industrial and agricultural use. Much of the site is currently not being used.

Developed portions of the adjacent properties are primarily agricultural (orange groves and cattle grazing). Undeveloped portions include mixed scrub with some hardwoods and wetlands.

e. General Environmental Features On and In the Site Vicinity

1) Natural Environment

The majority of the sixty-acre site is improved pasture, with active grazing by cattle occurring over the entire site. There is a strip of upland pine/palmetto community and small, isolated wetlands between the transmission corridor to the east and the improved pasture to the west. The isolated wetlands are of moderate ecological value and could be avoided by using the improved pasture to the west. There is an area of historic wetlands in the western improved pasture area of very low functional value over which the Florida Department of Environmental Protection will claim jurisdiction. Minimal mitigation ratios would be expected based on the condition of the historic wetlands.

2) Listed Species

One active gopher tortoise (*Gopherus polyphemus:* State species of special concern) nest was observed in the pine/palmetto upland area. No indication of any other listed species was observed.

3) Natural Resources of Regional Significance Status

The Savannas State Preserve lies approximately 7 miles to the east of the proposed site.

4) Other Significant Features

FPL is not aware of any other significant features of this site.

5) Natural Resources of Regional Significance Status

No Natural Resource of Regional Significance is identified on the plant site in the Southwest Florida Regional Strategic Policy Plan.

6) Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option currently being pursued for the Midway site is the construction of a 500 MW (nominal) CC unit, using natural gas-fired CT's and HRSG's. All of this new generation equipment will be installed on the existing facility property and make effective use of existing transmission facilities and infrastructure although some transmission line upgrades will be required. Steam developed in the new HRSG's will be directed to a new steam turbine.

Operation of the Midway unit is dependent upon securing a firm natural gas supply to the site which is both sufficient for fueling the electrical capacity involved and economically attractive. FPL is exploring a contract with Florida Gas Transmission (FGT) for this fuel supply.

Mitigation options being planned for the capacity additions at Midway include: the capture and reuse of plant process water, the use of combustion technology that is inherently low in air pollutant emissions, and the use of gray water if available,

g. Local Government Future Land Use Designations

A Comprehensive Plan Amendment, a rezoning and a Conditional Use permit will be required from St. Lucie County; followed by a Site Plan review & approval. The current zoning for the substation is "Utility", but is "MXD" (mixed use development) on the rest of the property. FPL will need to change that to "Utility" in order to develop the site.

Two public hearings would be required; one for the Comprehensive Plan, Rezoning and Conditional Use permit (if FPL is able to file all simultaneously), and a second for the Site Plan approval.

h. Site Selection Criteria and Process

For the past several years, many of FPL's existing facility sites have been considered potentially suitable sites for new, expanded, or repowered generation. The Midway facility has been selected as a preferred site due to a combination of electrical transmission and system load factors, plus economic considerations. Environmental issues were not a deciding factor in FPL's site evaluation since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All of these sites are considered permittable.

i. Water Resources

No surface water source is available at the site. The groundwater source would either be the shallow aquifer or a local source of gray water.

j. Geological Features of Site and Adjacent Areas

The site lies in the Atlantic Coastal Lowlands physiographic province. The Lowlands are characterized by monotonously flat, low elevations (less than 25 feet above mean sea level) that are swampy and poorly drained. These lowlands (or flatlands as they are also called) represent the shallow, flat bottoms of ancient seas.

Thick sequences of sedimentary rocks overlie the crystalline basement rocks. These sediments are over 12,000 feet thick in eastern St. Lucie county. Sediments within a few hundred feet of the surface generally consist of clastics, such as sands, silts and clays; and carbonates, such as limestones, dolomites or shell beds. Many of these lithologic units are interbedded or interfingered and are gradational from one to another. Sediments exposed at the surface range from Miocene age (26 to 12 million years ago) through Pleistocene age (3 to 2 million years ago) to Recent age. A veneer of Pleistocene sand covers almost all of St. Lucie county. Marine processes laid down the shell beds, clays, sands and limestone. During the last two million years of Pleistocene time, the sea level rose more than 100 feet and fell more than 200 feet below present sea levels. These sea level fluctuations occurred several times, alternately covering and exposing parts of the Floridan Plateau. Each significant change in sea level created a different environment of deposition for any given location across the relatively flat Plateau. The result of these sea level changes is a very complex interbedding and interfingering of heterogeneous lithologies in the subsurface stratigraphy.

k. Projected Water Quantities For Various Uses

It is estimated that 150 gallons per minute (gpm) will be needed for industrial processing water for uses such as inlet air-cooling, NOx control during distillate oil firing, and service water. Other facility water uses may include irrigation, potable use, etc. The total volume of these uses is estimated to be about 5 gpm.

l. Water Supply Sources By Type

For industrial processing and cooling water, FPL plans to use either gray water or groundwater.

m. Water Conservation Strategies Under Consideration

FPL plans to utilize an auxiliary equipment cooling system that will recirculate cooling water through the plant equipment, thus minimizing water losses.

n. Water Discharges and Pollution Control

Water discharges will be minimal. Storm water runoff will be collected and used to recharge the surficial aquifer via a stormwater management system. Design elements will be included to capture suspended sediments. It is anticipated that various facility permits will mandate various sampling and testing activities, which will provide indication of any pollutant discharges. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

A CC project at the Midway site requires a natural gas pipeline to be installed. FPL anticipates working with a local natural gas utility to permit, install, and operate such a facility. Virtually no waste is associated with natural gas firing.

p. Air Emissions and Control Systems

A natural gas-fired CC facility would generally have air pollutant emissions that are among the lowest currently available for electric power production. While several technologies are available for nitrogen oxide (NOx) emissions control, FPL plans to use a dry-low-NOx combustion turbine design. In these devices, combustion is staged in order to reduce the formation of combustion-derived oxides of nitrogen. FPL anticipates NOx emission limits for this facility that will be among the lowest in the State once the facility is constructed. Sulfur dioxide and particulate emissions would be intrinsically low due to the lack of sulfur and solids in natural gas fuel. Carbon monoxide and volatile organic compound emissions can each be controlled via the use of efficient combustion rather than through the use of add-on control devices. Carbon dioxide emission rates associated with burning natural gas are well below those of other liquid or solid fuels. CC and CT facilities have been permitted at several locations throughout the State of Florida. Dry-low-NOx combustor systems have been repeatedly demonstrated to be the Best Available Control Technology (BACT) for the control of NOx emissions for this technology pursuant to the requirements of the Clean Air Act.

q. Noise Emissions and Control systems

St. Lucie County has a noise ordinance which limits noise at the receiving property line to 55-75 decibels, depending upon the adjacent land use classification. Noise emissions from the Midway project are not anticipated to approach these levels based upon demonstrated noise control at similar natural gas-fired facilities (the Lauderdale plant in Broward County and the Martin plant in Martin County) and computer modeling of the anticipated noise emissions from the Midway facility. FPL will undertake studies to assure that noise level associated with the new CT's comply with St. Lucie County noise standard.

r. Status of Applications

FPL will apply for all the permits necessary to construct and start up the new CC unit at the appropriate time.

IV.F.2. Potential Sites

Three FPL-owned sites are identified as the next most likely potential sites for future generation after the four preferred sites just discussed. These three sites are considered the next most likely potential sites due to considerations of space, infrastructure, and accessibility to fuel and transmission facilities. These sites are located in Brevard, Palm Beach, and Broward Counties. These sites are suitable for different capacity levels and technologies, and they will remain as potential sites pending future decisions on how best to meet the timing and magnitude of FPL's future capacity needs.[6]

Each of these potential sites offers advantages and disadvatanges relative to engineering considerations and/or costs associated with the construction and operation of feasible technologies. In addition, each potential site has different characteristics, which could require further definition and attention. For purposes of estimating water usage amounts, it is assumed that a natural gas-fired CC unit would be the technology of choice for any capacity additions at the sites.

Permits are presently considered to be obtainable for all three sites, assuming measures can be taken to mitigate any particular site-specific environmental concerns. None of the sites exhibit any significant environmental constraints. The potential sites are briefly discussed below. (Note: The order in which the sites are discussed below does not reflect a relative ranking of these sites in regard to how likely it is for FPL to add capacity at the site.)

Potential Site #1: Cape Canaveral Plant, Brevard County

The site is located on the FPL Cape Canaveral property in unincorporated Brevard County. The city of Port St. Johns is located less than a mile away. The site has direct access to a four-lane highway, US 1, and barge access is available. A rail line is located near the plant. The existing facility consists of two 400 MW (nominal) steam boiler type generating units.

a) U.S. Geological Survey (USGS) Map

A USGS map of the Cape Canaveral plant site is found at the end of this chapter.

b) and c) Land Uses and Environmental Features

[6] As has been described in previous FPL Plant Site Plans, FPL also considers a number of other sites as possible sites for future generation additions These include the remainder of FPL's existing generation sites as well as non-FPL-owned sites located in Hardee, Highlands, Glades, and Hendry Counties.

This site is located on the Indian River. The land is primarily dedicated to industrial use with surrounding grassy areas and a few acres of remnant pine forest. The land adjacent to the site is dedicated to light commercial and residential use. There are no significant environmental features on the site.

d) and e) Water Quantities and Supply Sources

FPL projects that an increase of up to 260 gallons per minute (gpm) would be required for industrial processing use (boiler makeup, service water, etc.) It is expected that industrial cooling water needs could be met using the current 550,000 gpm once-through cooling water quantity. For industrial processing, FPL would use existing on-site wells. For industrial cooling, the Indian River would continue to be utilized.

Potential Site #2: Riviera Plant, Palm Beach County

This site is located on the FPL Riviera Plant property in Riviera Beach, Palm Beach County. The site has direct access to a four-lane highway, US 1, and barge access is available. A rail line is located near the plant. The facility currently houses two operational 300 MW (nominal) steam boiler generating units and one retired 50 MW generating unit.

a) U.S. Geological Survey (USGS) Map

A USGS map of the Riviera plant site is found at the end of this chapter.

b) and c) Land Uses and Environmental Features

The land on the site is primarily covered by the existing generation facilities with some open maintained grass areas. There is a small manatee viewing area on the site which is operated seasonally by FPL. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development. The site is located on the Intracoastal Waterway near the Lake Worth Inlet.

d) and e) Water Quantities and Supply Sources

Additional industrial processing water needs are estimated to be up to 40 gallons per minute (gpm). Industrial cooling water needs are estimated to be up to 54,000 gpm using the existing once-through cooling water system. The existing municipal water supply would be used for industrial processing water if additional generating capacity is placed at Riviera. For once-through cooling water, FPL would continue to use Lake Worth as a source of water.

Potential Site #3: Port Everglades Plant, Broward County

This site is located on the 94-acre FPL Port Everglades plant site in Port Everglades, Broward County. The site has convenient access to State Road (SR) 84 and Interstate 595. Currently, direct barge access is not available. A rail line is located near the plant. The existing plant consists of four steam boiler generating units: two 200 MW (nominal) and two 400 MW (nominal) sized units.

a) U.S. Geological Survey (USGS) Map

A USGS map of the Port Everglades plant site is found at the end of this chapter.

b) and c) Land Uses and Environmental Features

The land on the site is primarily industrial. The adjacent land uses are port facilities and associated industrial activities, oil storage, cruise ships, and light commercial.

d) and e) Water Quantities and Supply Sources

FPL estimates that up to 130 gallons per minute (gpm) of industrial processing water would be required for uses such as boiler makeup, fogger usage, and service water. FPL would expect to use the existing municipal water supply for industrial process water. For cooling water, FPL would anticipate that the existing 320,000 gpm once-through cooling seawater source would continue to be used.

Environmental and Land Use Information: Supplemental Information

Preferred Site: Fort Myers Plant

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Ft. Myers Plant

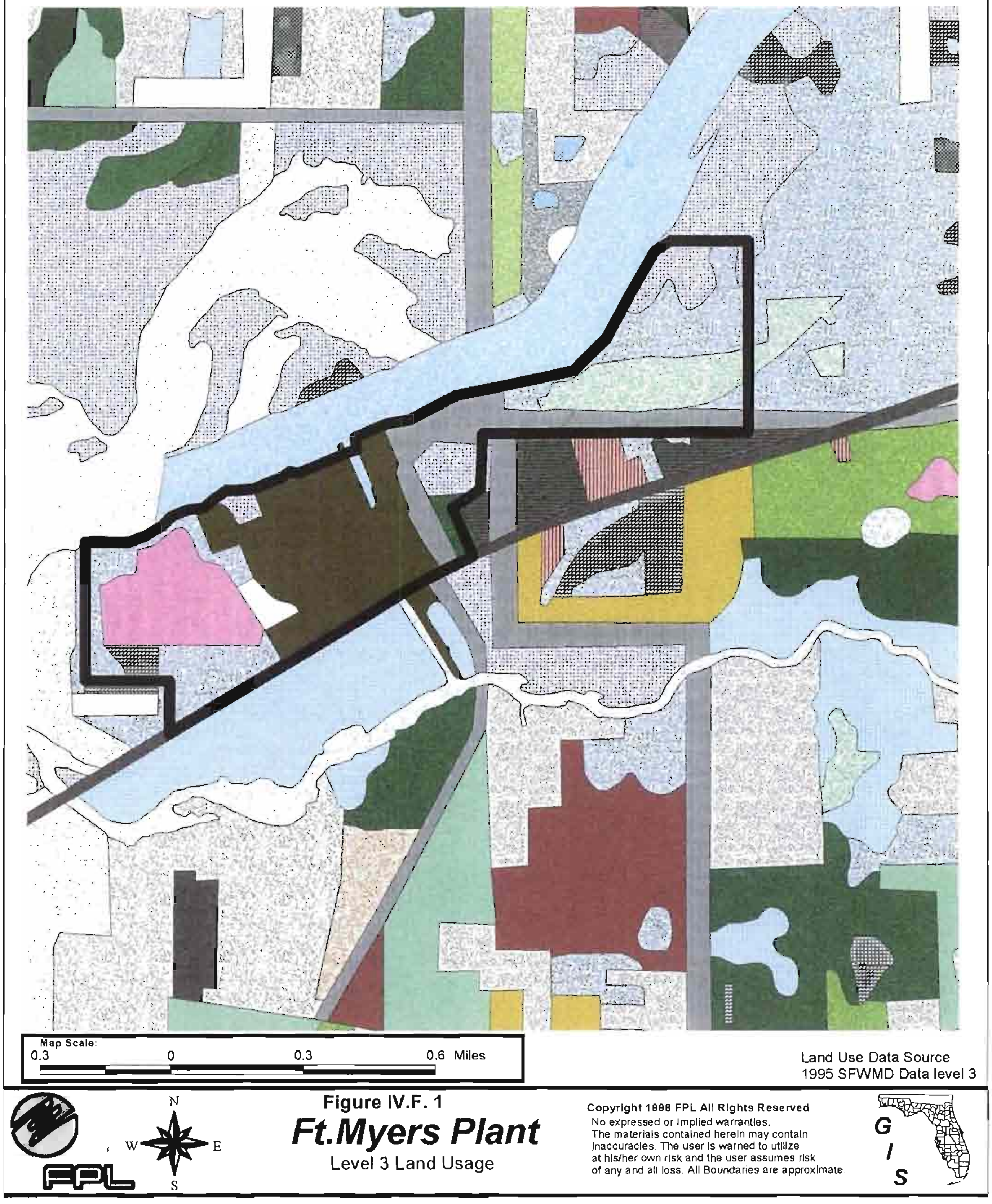
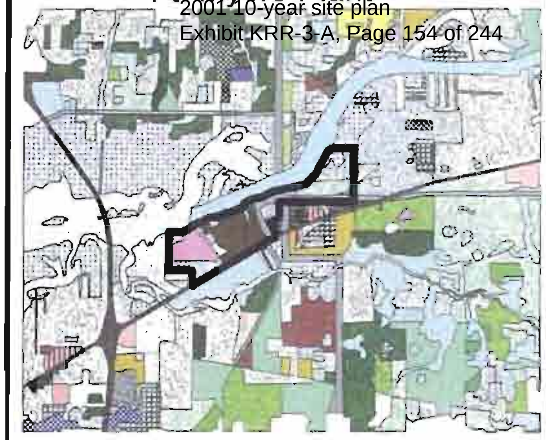


Figure IV.F. 1
Ft.Myers Plant
Level 3 Land Usage

Ft. Myers Plant



Land Usage Legend
Level 3

Ft Myers Plant Boundary

Surrounding Land Usage

- Mobile Homes
- Fixed Single Family Units
- Fixed Single Family Units 2-5 du/ac
- Fixed & Mobile Units
- Fixed Single Family Units
- Multiple Dwelling Units Low Rise
- Multiple Dwelling Units High Rise
- Retail Sales & Service
- Shopping Centers
- Wholesale Sales & Service
- Junkyards
- Professional Services
- Tourists Services
- Oil & Gas Storage
- Mixed Commercial & Services
- Cemeteries
- Food Processing
- Other Light Industrial
- Other Heavy Industrial
- Strip Mines
- Sand & Gravel Pits
- Rock Quarries
- Educational Facilities
- Religious
- Medical & Health Care
- Governmental
- Correctional
- Other Institutional
- Commercial Child Care
- Swimming Beach
- Golf Courses
- Marinas & Fish Camps
- Parks & Zoos
- Community Recreatioal Facilities
- Historical Sites
- Other Recreational
- Undeveloped Land Within Urban Areas
- Inactive Land W/Street Pattern
- Urban Land In Transaction
- Other Open Land
- Improved Pastures
- Unimproved Pastures
- Woodland Pastures
- Row Crops
- Field Crops
- Sugar Cane Fields
- Citrus Groves
- Tree Nurseries
- Sod Farms
- Ornamentals
- Floriculture
- Horse Farms
- Dairies
- Aquaculture
- Fallow Crop Land
- Herbaceous Rangeland
- Palametto Praries
- Coastal Scrub
- Other Scrubs & Brush
- Mixed Rangeland
- Pine Flatwoods
- Melaleuca Infested
- Longleaf Pine - Xeric Oak
- Sand Pine
- Pine - Mesic Oak

Continued Legend

- Xeric Oak
- Brazilian Pepper
- Melaleuca
- Temperate Hardwood
- Tropical Hardwoodw
- Live Oak
- Cabbage Palm
- Sand Live Oak
- Hardwood Conifer Mixed
- Austrailian Pine
- Mixed Hardwoods
- Streams & Waterways
- Lakes > or = to 500 Acres
- Lakes > or = to 10 Acres - < or = to 500 Acres
- Lakes < or = to 10 Acres
- Reservoirs > or = to 500 Acres
- Reservoirs > or = to 100 Acres - < or = to 500 Acres
- Reservoirs > or = to 10 Acres - < or = to 100 Acres
- Reservoirs < or = to 10 Acres
- Embayments Opening
- Bay Swamps
- Mangrove Swamps
- Stream & Lake Swamps
- Inland Ponds & Sloughs
- Mixed Wetland Hardwoods
- Willows
- Mixed Shrubs
- Cypress
- Cypress - w/Wet Praries
- Cypress - Pine - Cabbage - Pine
- Wetland Forested Mixed
- Freshwater Marshes
- Freshwater Sawgrass Marshes
- Freshwater Cattail Marshes
- Saltwater Marshes
- Wet Praries
- Wet Praries - with Pine
- Emergent Aquatic Vegetation
- Submergent Aquatic Vegetation
- Sand Other Than Beaches
- Rural Land In Transition
- Borrow Areas
- Spoil Areas
- Fill Areas Highways & Railways
- Airports
- Roads & Highways
- Canals & Locks
- Auto Parking Facilities
- Transmission Towers
- Communication faciiities
- Electrical Power Facilities
- Electrical Power Transmission
- Water Supply Plants
- Sewage Treatment

Land Use Data Source
1995 SFWMD Data Level 3

Figure IV.F.2
Ft. Myers Plant
Land Usage Legend

FPL

G I S

Fort Myers Plant Site Plan Showing Location of New Facility

Figure IV.F.3

Ft Myers Plant Site

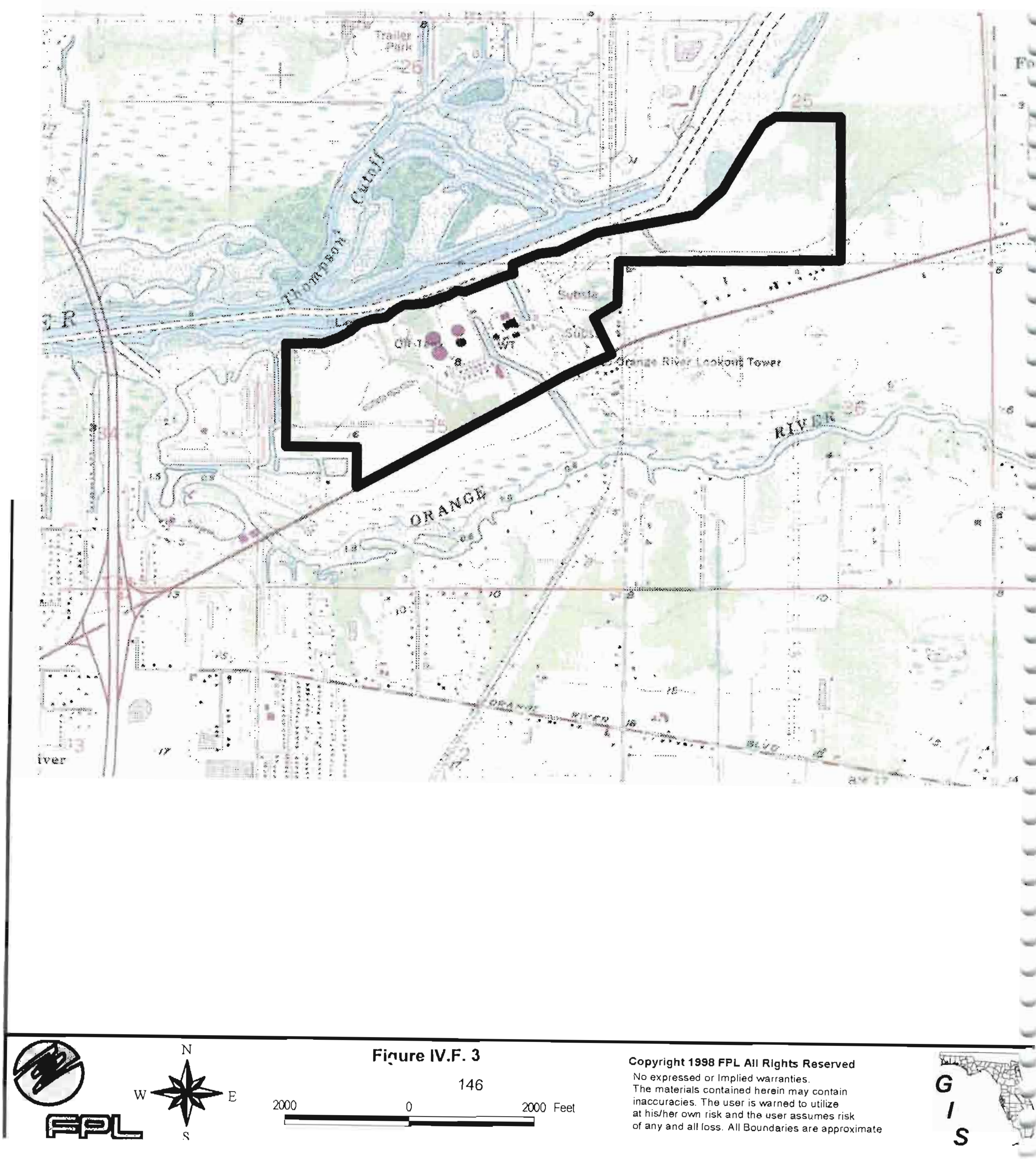


Figure IV.F. 3

Environmental and Land Use Information: Supplemental Information

Preferred Site: Sanford Plant

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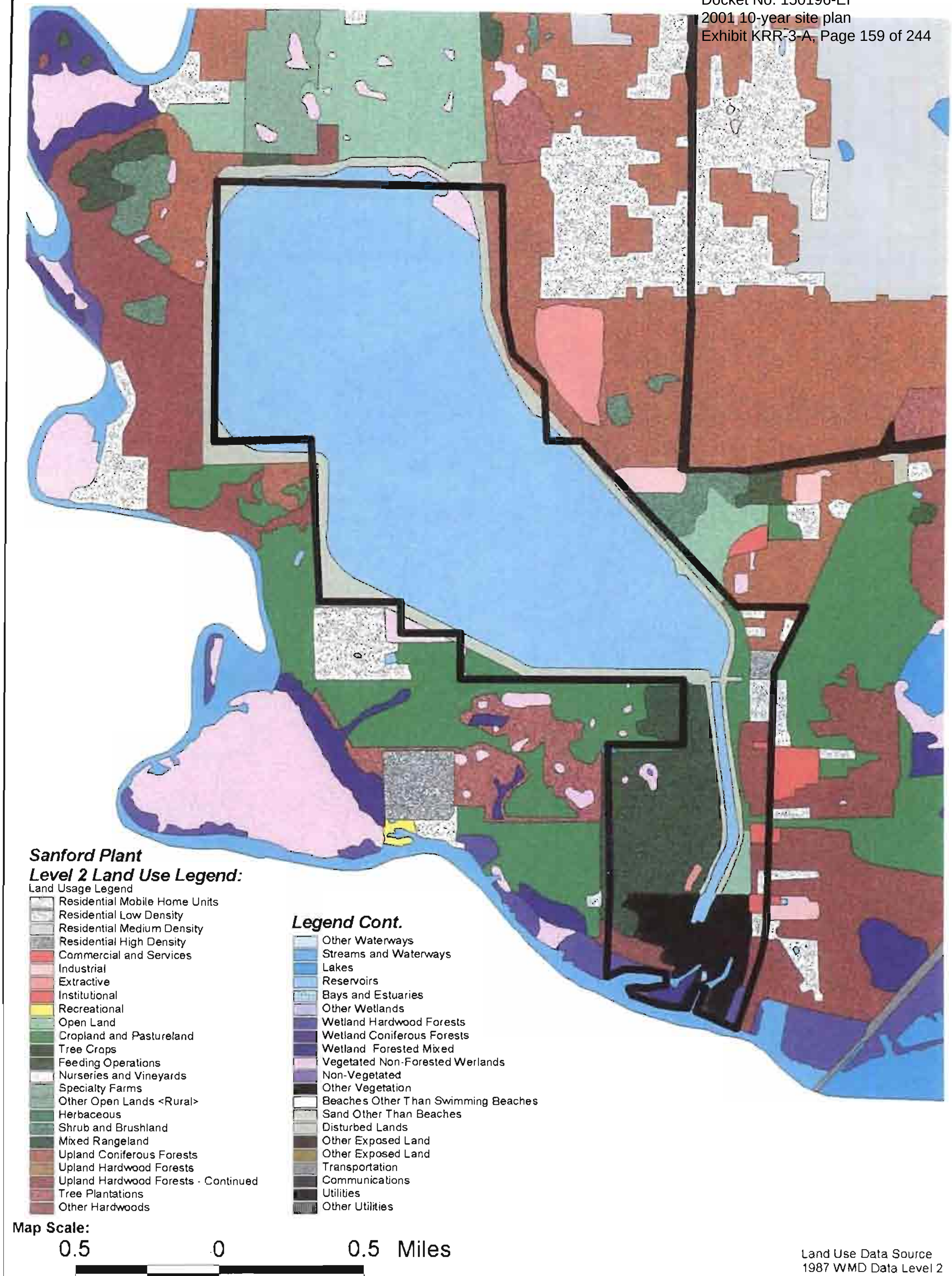

N
W E
S

Figure IV.F.5

Sanford Plant Land Use

Level 2 Land Use

Last Revised 2/4/98

G I S

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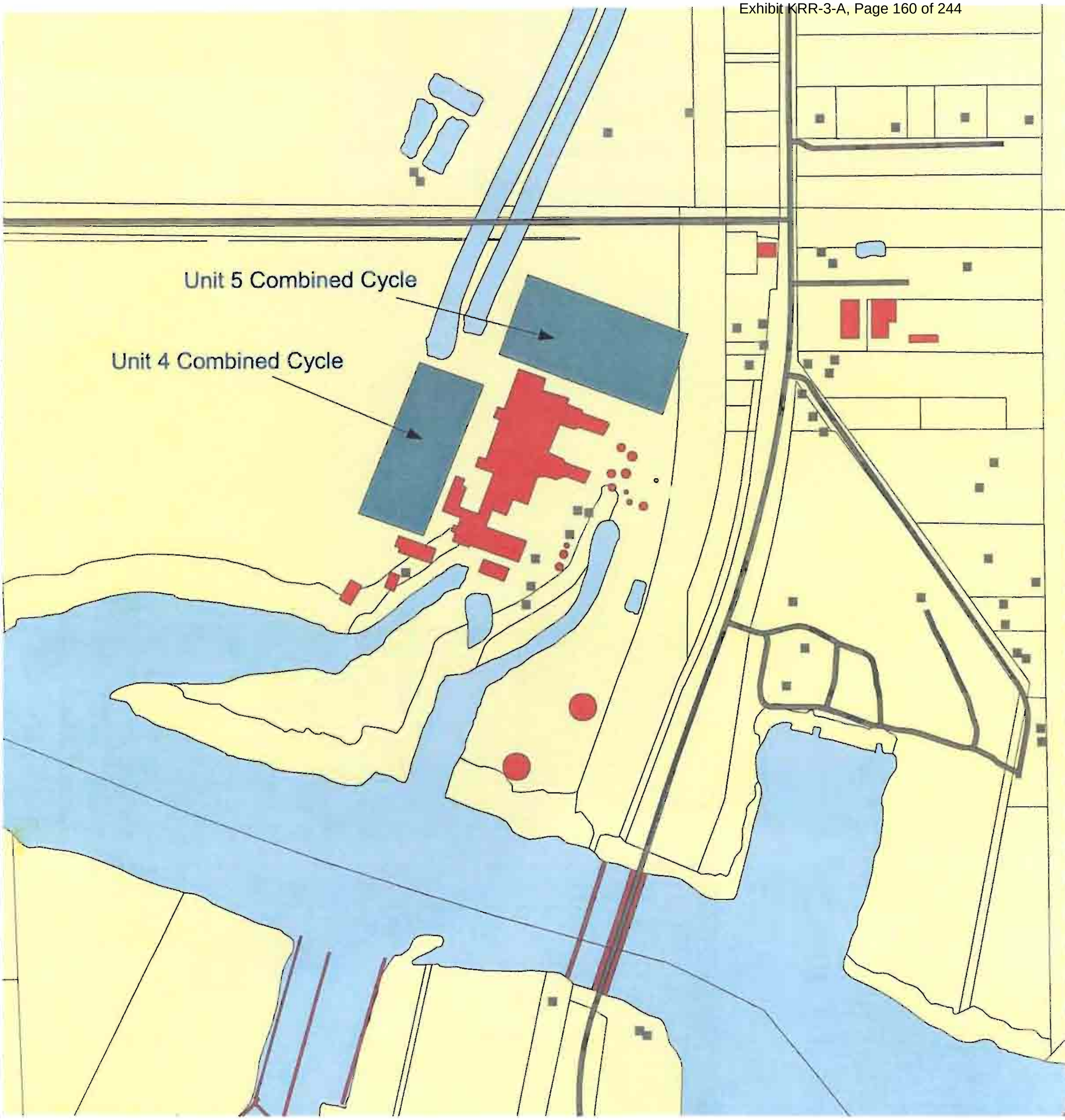

Figure IV.F.6

Sanford Plant Site Plan Showing Location of New Facility

FPL

0.1 0 0.1 0.2 Miles

N
W
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S

FPL Sanford Plant Site

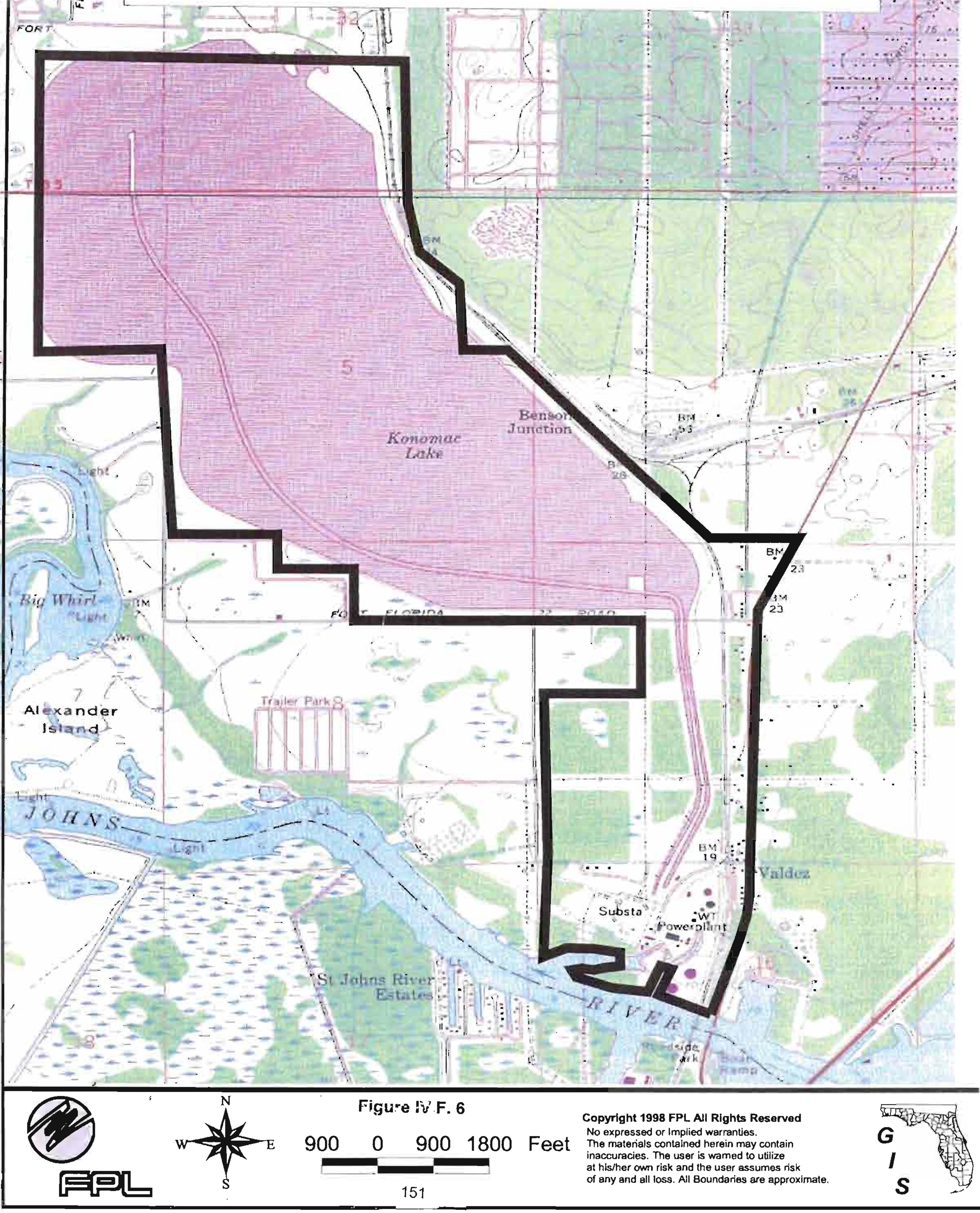

Figure IV.F. 6

900 0 900 1800 Feet

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IV. Environmental and Land Use Information: Supplemental Information

Preferred Site: Martin Plant

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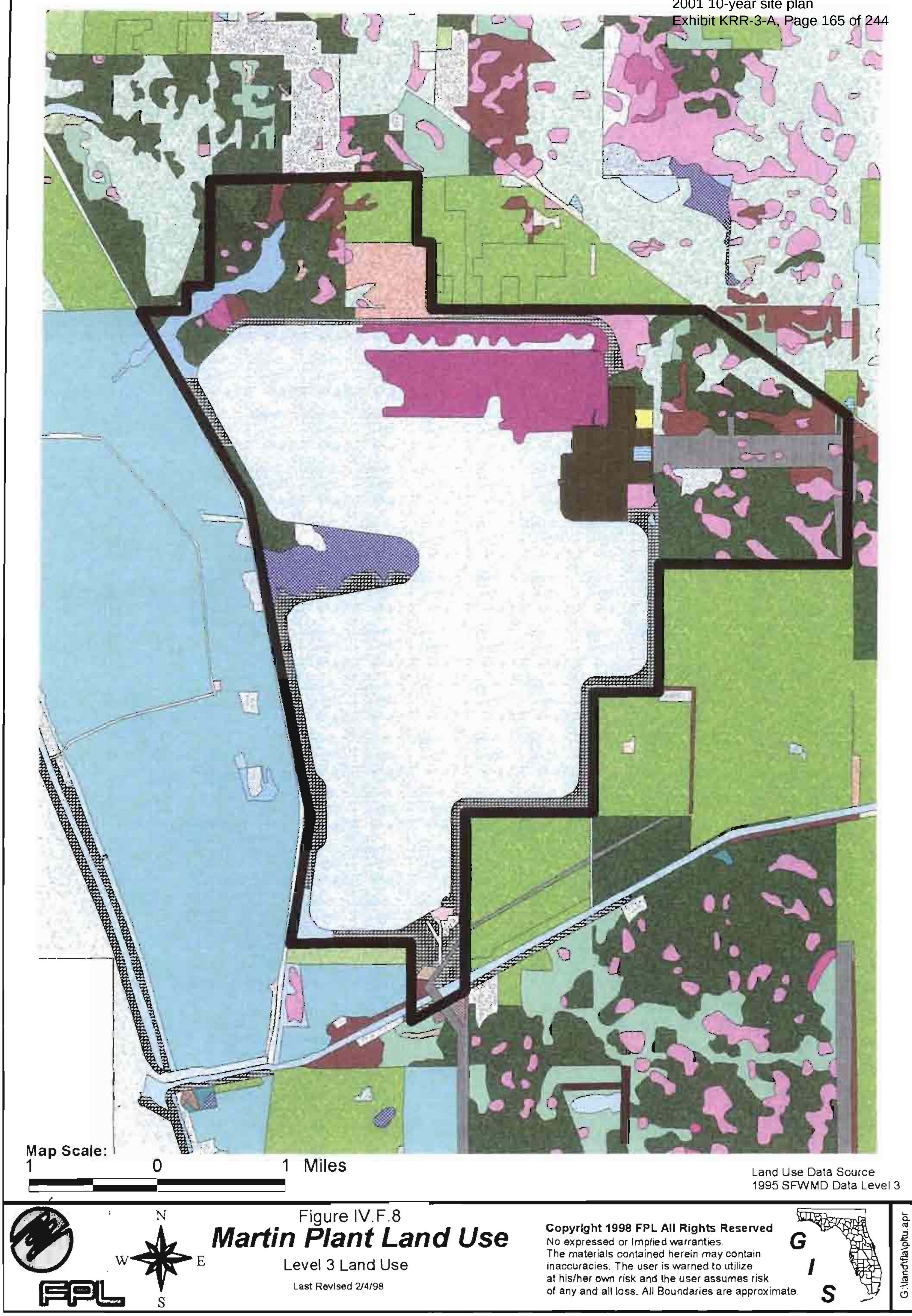
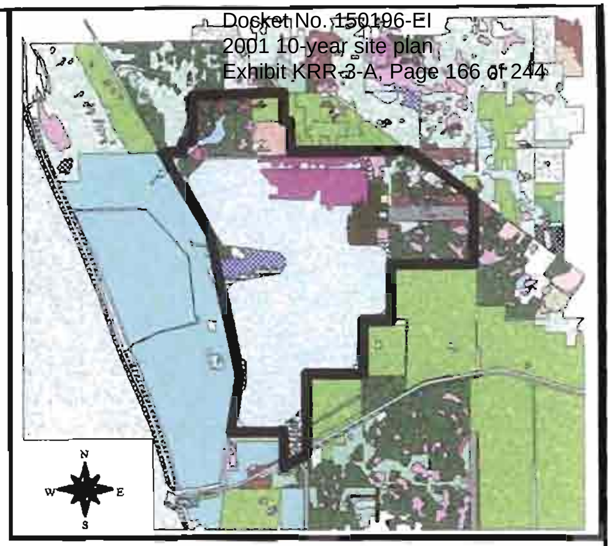


Figure IV.F.8
Martin Plant Land Use
Level 3 Land Use
Last Revised 2/4/98



Martin Plant
Level 3 Land Use Legend:

Land Usage Legend

- Mobile Homes
- Fixed Single Family Units
- Fixed Single Family Units 2-5 du/ac
- Fixed & Mobile Units
- Fixed Single Family Units
- Multiple Dwelling Units Low Rise
- Multiple Dwelling Units High Rise
- Retail Sales & Service
- Shopping Centers
- Wholesale Sales & Service
- Junkyards
- Professional Services
- Tourists Services
- Oil & Gas Storage
- Mixed Commercial & Services
- Cemeteries
- Food Processing
- Other Light Industrial
- Other Heavy Industrial
- Strip Mines
- Sand & Gravel Pits
- Rock Quarries
- Educational Facilities
- Religious
- Medical & Health Care
- Governmental
- Correctional
- Other Institutional
- Commercial Child Care
- Swimming Beach
- Golf Courses
- Marinas & Fish Camps
- Parks & Zoos
- Community Recreational Facilities
- Historical Sites
- Other Recreational
- Undeveloped Land Within Urban Areas
- Inactive Land with Street Pattern
- Urban Land In Transaction
- Other Open Land
- Improved Pastures
- Unimproved Pastures
- Woodland Pastures
- Row Crops
- Field Crops
- Sugar Cane Fields
- Citrus Groves
- Tree Nurseries
- Sod Farms
- Ornamentals
- Floriculture
- Horse Farms
- Dairies
- Aquaculture
- Fallow Crop Land
- Herbaceous Rangeland
- Palmetto Prairies
- Coastal Scrub
- Other Scrubs & Brush
- Mixed Rangeland
- Pine Flatwoods
- Melaleuca Infested
- Longleaf Pine - Xeric Oak
- Sand Pine
- Pine - Mesic Oak
- Xeric Oak
- Brazilian Pepper
- Melaleuca
- Temperate Hardwood

Legend Cont.

- Tropical Hardwood
- Live Oak
- Cabbage Palm
- Sand Live Oak
- Hardwood Conifer Mixed
- Austrailian Pine
- Mixed Hardwoods
- Streams & Waterways
- Lakes > or = to 500 Acres
- Lakes > or = to 10 Acres - < or = to 500 Acres
- Lakes < or = to 10 Acres
- Reservoirs > or = to 500 Acres
- Reservoirs > or = to 100 Acres - < or = to 500 Acres
- Reservoirs > or = to 10 Acres - < or = to 100 Acres
- Reservoirs < or = to 10 Acres
- Embayments Opening
- Bay Swamps
- Mangrove Swamps
- Stream & Lake Swamps
- Inland Ponds & Sloughs
- Mixed Wetland Hardwoods
- Willows
- Mixed Shrubs
- Cypress
- Cypress - with Wet Prairies
- Cypress - Pine - Cabbage - Pine
- Wetland Forested Mixed
- Freshwater Marshes
- Freshwater Sawgrass Marshes
- Freshwater Cattail Marshes
- Saltwater Marshes
- Wet Prairies
- Wet Prairies - with Pine
- Emergent Aquatic Vegetation
- Submergent Aquatic Vegetation
- Sand Other Than Beaches
- Rural Land In Transition
- Borrow Areas
- Spoil Areas
- Fill Areas Highways & Railways
- Airports
- Roads & Highways
- Canals & Locks
- Auto Parking Facilities
- Transmission Towers
- Communication Facilities
- Electrical Power Facilities
- Electrical Power Transmission
- Water Supply Plants
- Sewage Treatment

Land Use Data Source
1995 SFWMD Data Level 3

Figure IV.F.9
Martin Plant Land Use
Level 3 Land Use Legend
Last Revised 2/4/98

G I S

G:\en\fl\gis\pltlu.apr

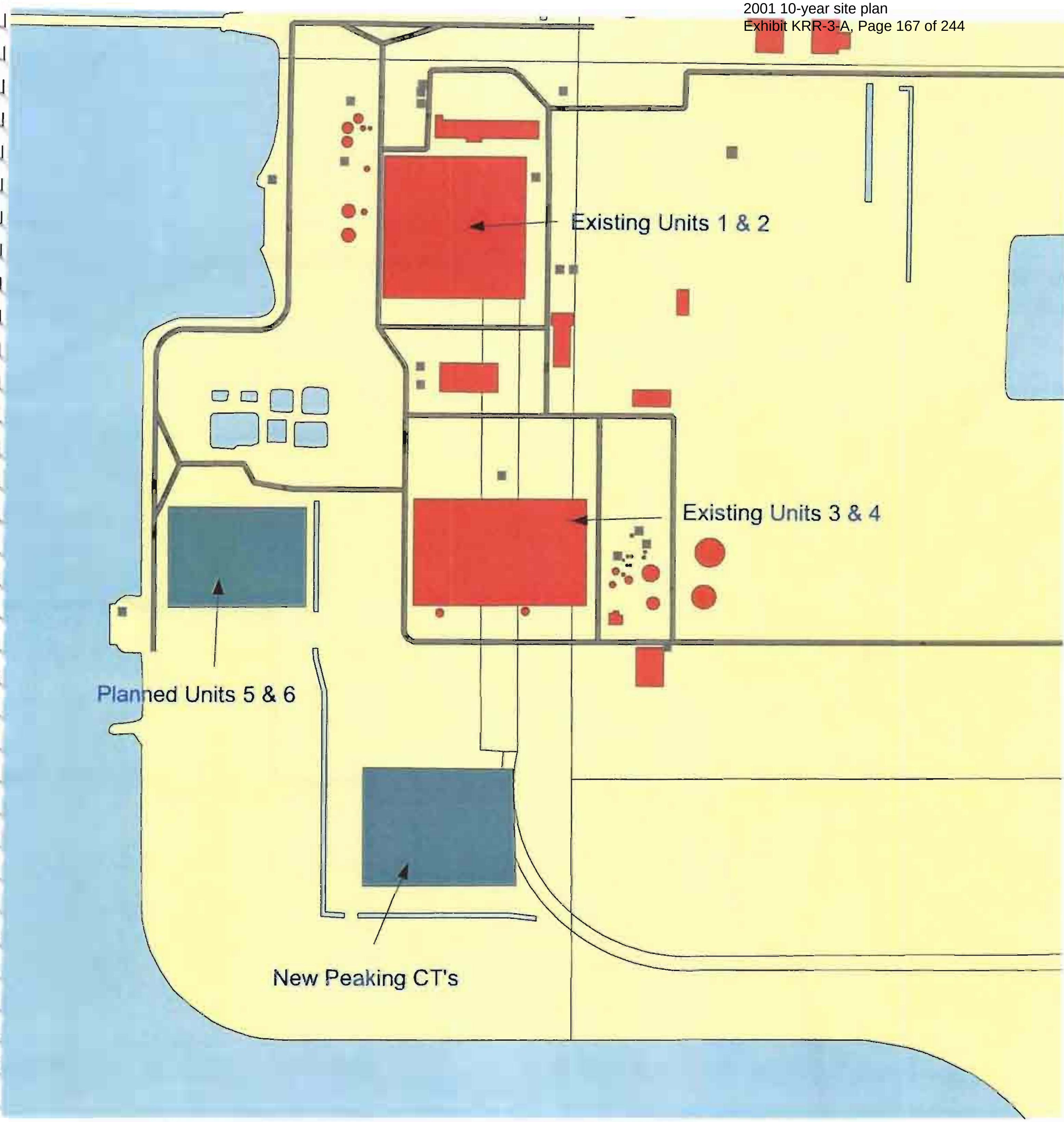
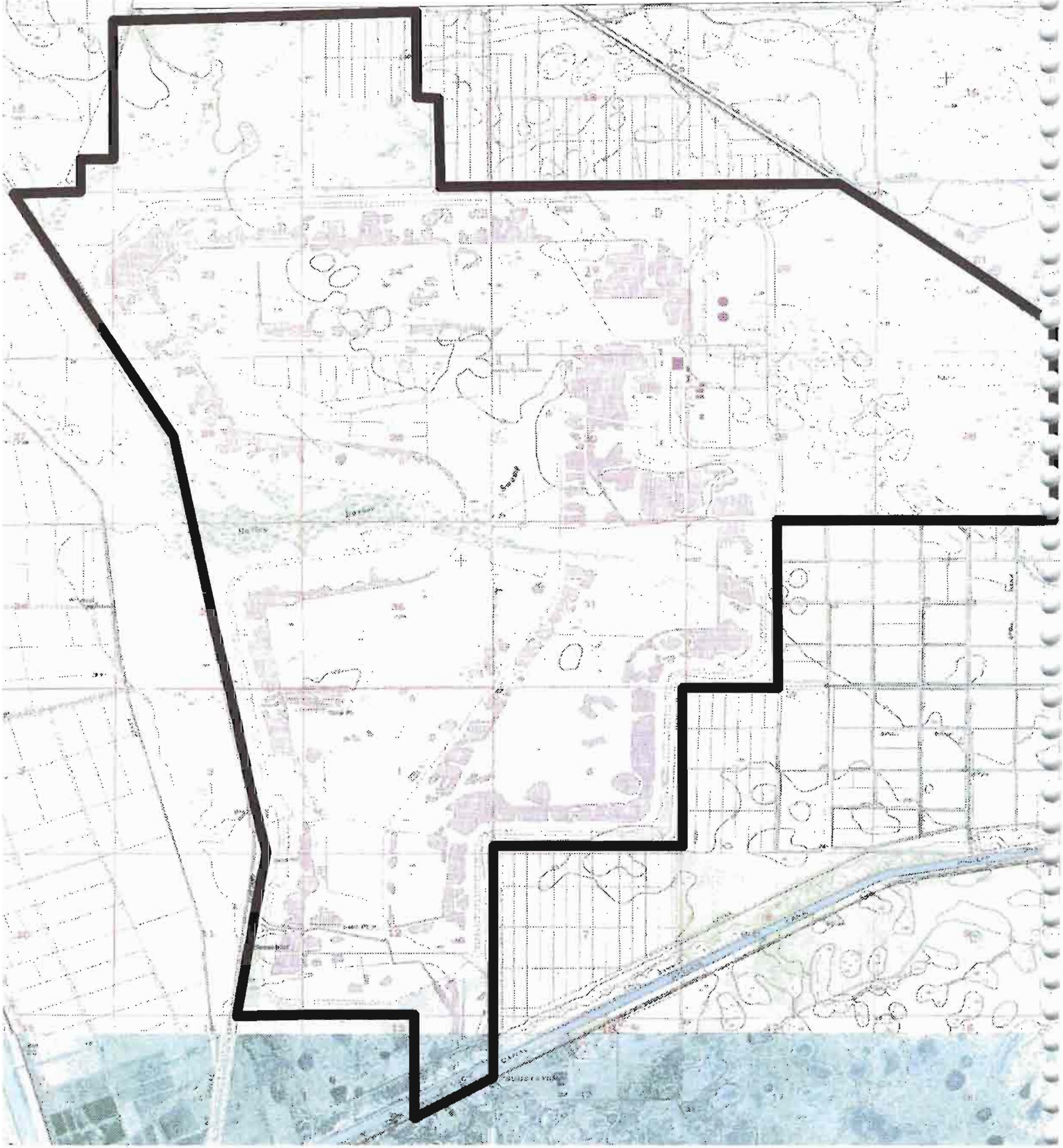


Figure IV.F.10

Martin Plant Site Plan Showing Location of New Facility

FPL Martin Plant Site



N
W E
S
3000 0 3000 6000 Feet

Figure IV.F.11

G I S

Environmental and Land Use Information: Supplemental Information

Preferred Site: Midway Plant

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Midway Site

600 0 600 Feet

N
W E
S

Figure IV.F.12

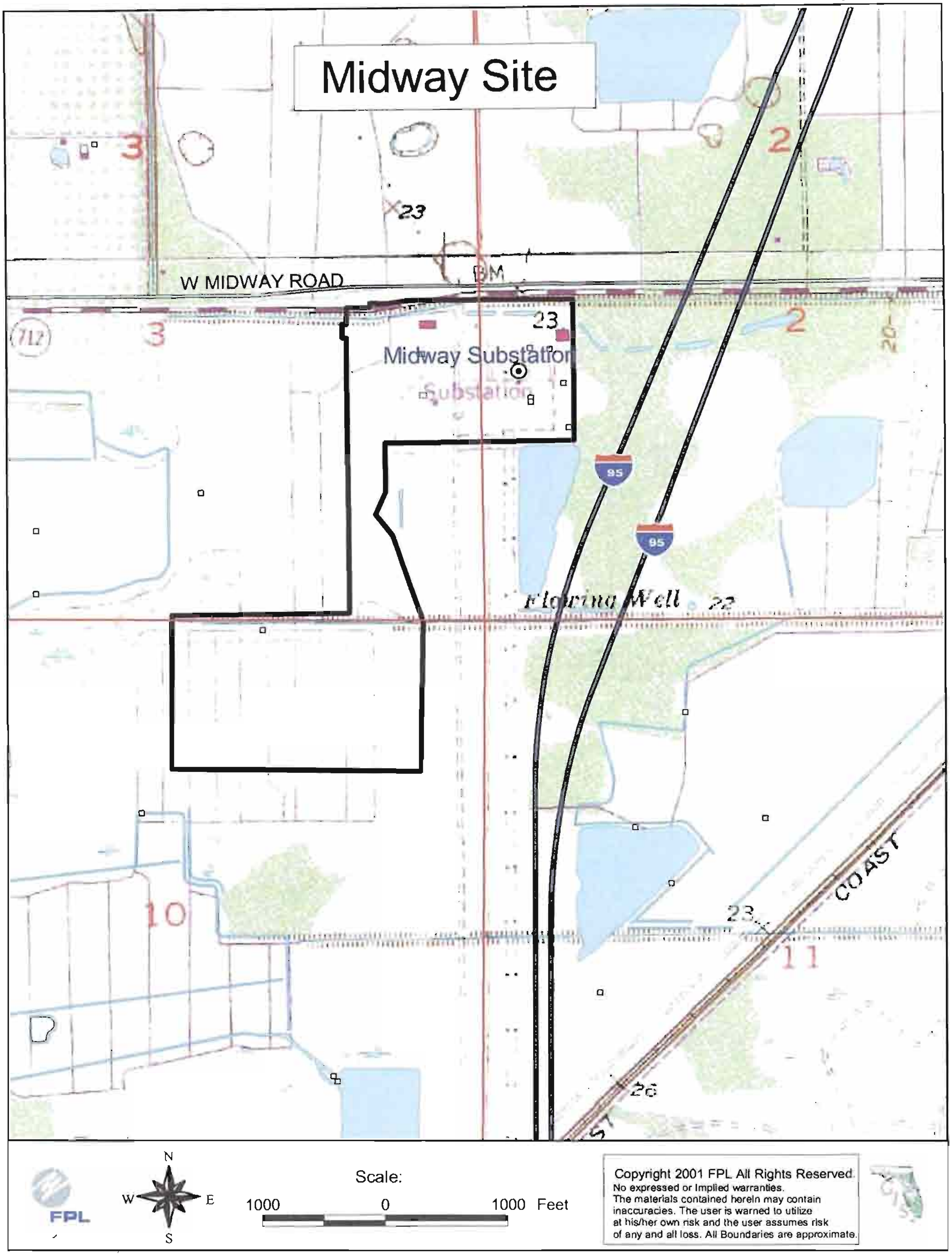

Figure IV.F.13

Environmental and Land Use Information: Supplemental Information

Potential Sites

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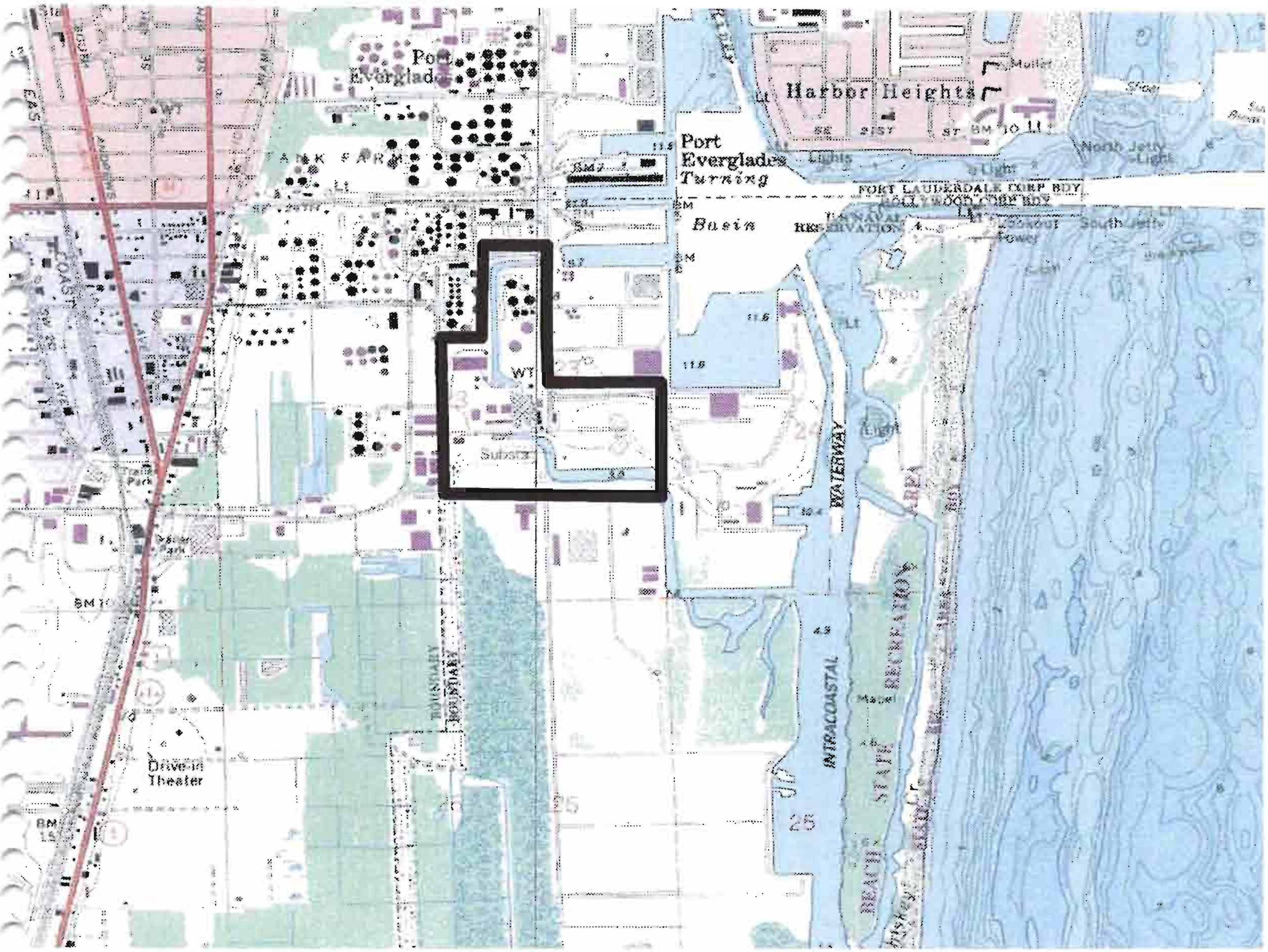
FPL Port Everglades Plant Site



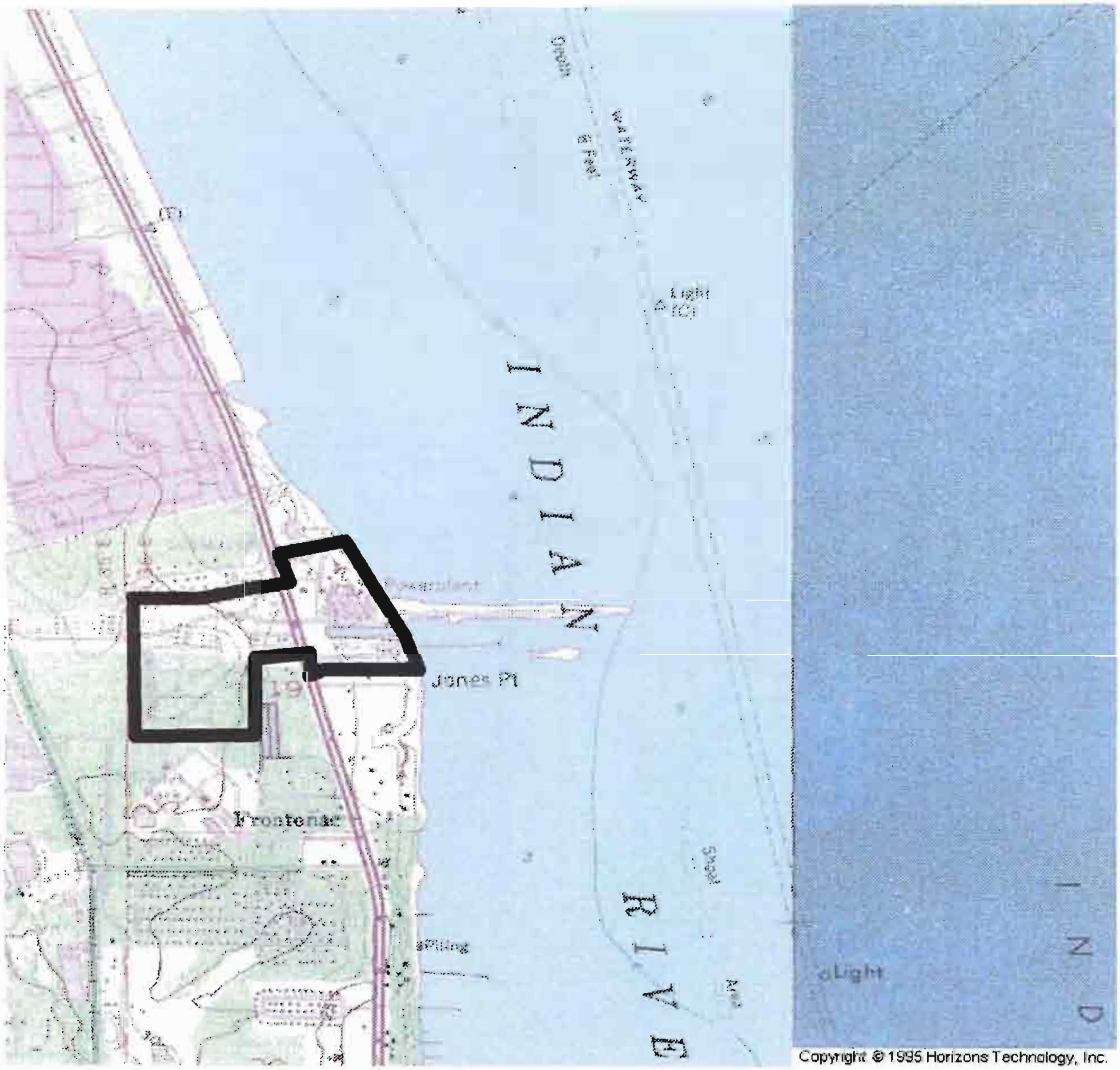
N
W E
S

Figure IV.F.14

2000 0 2000 Feet

G I S

FPL Canaveral Plant Site



N W E S

Figure IV.F.15

2000 0 2000 Feet

GIS

FPL Riviera Plant Site

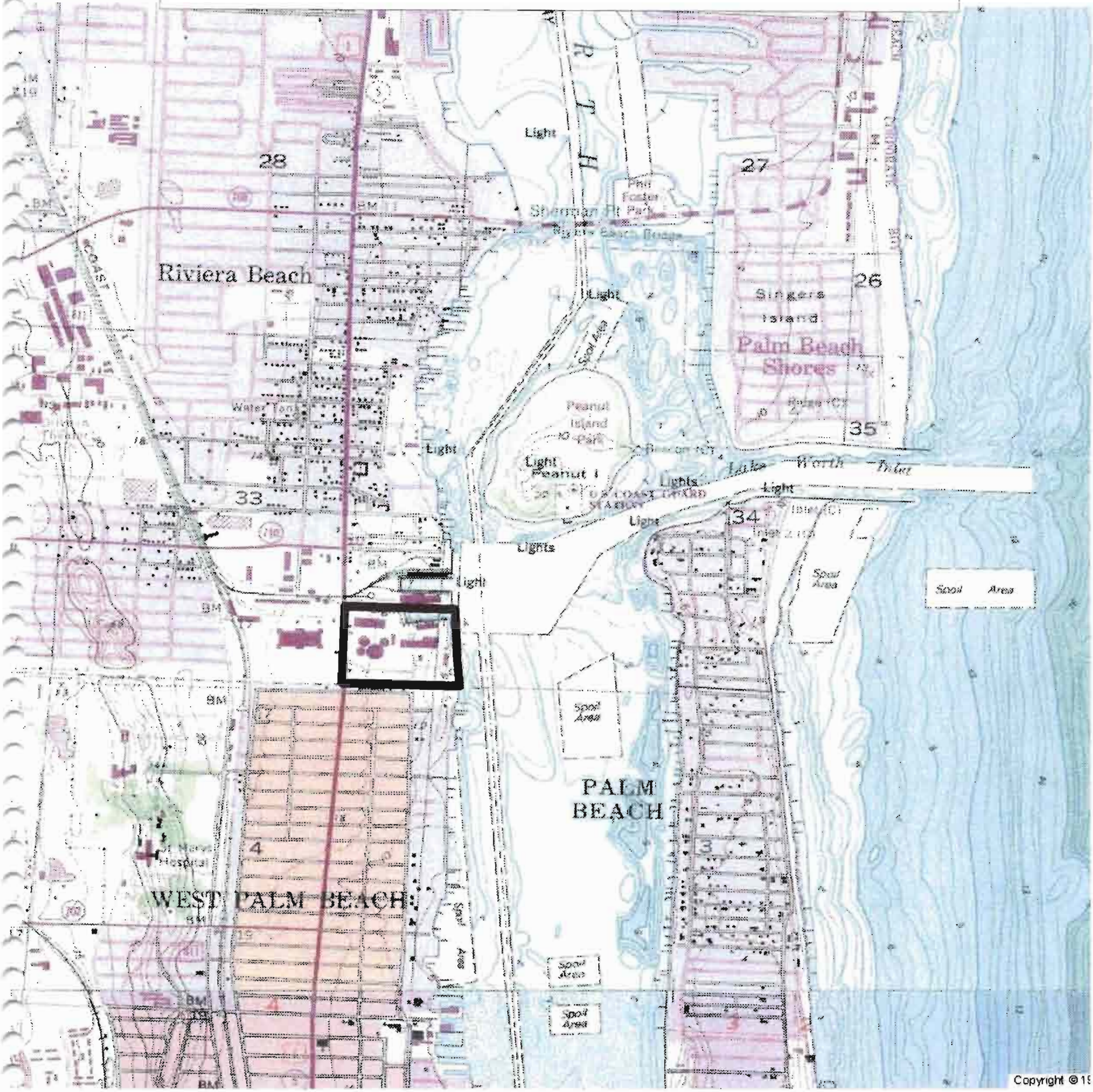


Figure IV.F.16

N
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2000 0 2000 Feet

G
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CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information". These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning considers two type of transmission constraints. External constraints deal with FPL's ties to its neighboring systems. Internal constraints deal with the flow of electricity within the FPL system.

The external constraints are important since they affect the development of assumptions for the amount of external assistance which is available and the amount and price of economy energy purchases. Therefore, these external constraints are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the transfer capability as well as historical levels of available assistance. FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission constraints or limitations are addressed in developing the costs for siting new units at different locations. Site-specific transmission costs are developed for each different unit/unit location option.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. *Discuss any changes in the generation expansion plan as a result of sensitivity tests* to the base case load forecast.

As discussed in Chapter III of this document, FPL performs economic analyses of competing resource plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI) and Stone and Webster Management Consultants, Inc. The resource plan reflected in this document emerged as the resource plan with the least impact on FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach) and on the present value of revenue requirements for the FPL system.[7]

FPL performed three sensitivity analyses as part of its 2000 resource planning work or in preparation for this site plan filing. One of these analyses used a load forecast which differed from FPL's base case or "Most Likely" load forecast. (The other two sensitivity analyses are discussed in Discussion Items # 4 and # 6.)

The first sensitivity analysis examined a case in which a "High Load" forecast was combined with a "Low Price" fuel forecast In this case, FPL's need for incremental resources moved forward in time to the year **2001**. This accelerated need, if assumed to be met solely through the construction of new units (as is the primary focus of the Site Plan filing), could only be addressed by combustion turbines or new purchases in the early years. Subsequent years would likely be addressed by new combined cycle units.

In its 2000 resource planning work, FPL did not conduct a sensitivity case involving a "Low Load" forecast. Since the system reliability analysis which utilized the "Most Likely" load forecast showed that new units were not needed until 2005, it was clear that a "Low Load" case would not have shown a power plant decision needed prior to 2005. Therefore, FPL saw no value in analyzing such a "Low Load" case in its 2000 planning work.

The construction - only options selected in the resource plans (purchase options are not shown) for FPL's "Most Likely" case, and for the first sensitivity case discussed above, are presented on the following page in Table V.1.

[7] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis However, when DSM levels are considered a "given" in the analysis, the lowest rate basis and the lowest system revenue requirements basis are identical In such cases (as in FPL's 2000 resource planning work), FPL evaluates options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis.

Table V.1

Selected Power Plant Construction Options For Base and Sensitivity Cases

Year	"Most Likely" Load and "Most Likely" Fuel Price Base Case	"High" Load and "Low" Fuel Price Scenario Case
2000	----	----
2001	2 CT's at Martin Ft. Myers Repowering: Initial Phase	2 CT's at Martin Ft. Myers Repowering: Initial Phase 3 Unsited CT's
2002	Ft. Myers Repowering: Second Phase Sanford Repowering: Initial Phase	Ft Myers Repowering: Second Phase Sanford Repowering: Initial Phase
2003	Sanford Repowering: Second Phase 2 CT's at Ft. Myers	Sanford Repowering: Second Phase 2 CT's at Ft. Myers
2004	----	----
2005	Martin Unit # 5 Midway Unit # 1 Fort Myers Combustion Turbine Conversion Martin Combustion Turbine Conversion	Martin Unit # 5 Midway Unit # 1 Fort Myers Combustion Turbine Conversion Martin Combustion Turbine Conversion Martin Unit # 6
2006	Martin Unit # 6	Unsited CC Unit # 1
2007	Unsited CC Unit # 1	Unsited CC Unit # 2
2008	----	Unsited CC Unit # 3
2009	Unsited CC Unit # 2	Unsited CC Unit # 4
2010	Unsited CC Unit # 3 Unsited CC Unit # 4 Unsited CC Unit # 5	Unsited CC Unit # 5 Unsited CC Unit # 6

Key: CT = Combustion Turbine
CC = Combined Cycle Unit

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its base case or "Most Likely" fuel price forecast are discussed in Chapter III of this document.

The "High Price" and "Low Price" fuel forecasts are developed based on a review of major supply and demand assumptions for oil and natural gas The "High Price" forecast assumes that the worldwide demand for petroleum products will grow somewhat rapidly throughout the planning horizon. Non-OPEC crude oil supply will remain unchanged as improved drilling technology permits only the replacement of depleting fields. As a result, OPEC's market share will grow more rapidly than in the base case which would result in higher oil prices. In addition, this forecast assumes that domestic natural gas demand will grow somewhat rapidly, primarily due to significant increases in the construction of combined cycle generation. Domestic natural gas production will increase slowly as improved drilling technology permits only the replacement of depleting fields. This will result in higher natural gas imports, including Liquified Natural Gas (LNG), than in the base case which, in turn, results in higher natural gas prices.

The "Low Price" fuel forecast assumes that worldwide demand for petroleum products will grow slowly over the forecast horizon. It also assumes that non-OPEC crude oil supply will grow rapidly due to significant improvement in drilling technology and that OPEC's market share will only make small gains relative to the base case. In regard to natural gas, the "Low Price" forecast assumes that domestic demand for natural gas will grow slowly over the forecast horizon and that domestic production will increase faster than in the base case. These assumptions result in lower oil and gas price forecasts.

FPL did test the sensitivity of its resource plan to a "Low Price" fuel forecasts in conjunction with a "High Load" forecast. The results of these analyses are presented above in FPL's response to Discussion Item # 2. FPL did not test the sensitivity of its resource plan to a "High Price" fuel forecast in its 2000 IRP work. Although FPL typically performs a sensitivity analysis on a combined "Low Load"/ "High Price" fuel forecast, such an analysis would not have shown a need for new power plants before 2005 (as discussed in Discussion Item #2.) Consequently, this analysis was not performed in FPL's 2000 planning work.

Discussion Item # 4: **Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.**

In addition to the sensitivity analyses discussed above which examined the impact of "High Load" and "Low Price" fuel forecasts, FPL also performed a sensitivity analysis in which the differentials between oil prices, gas prices, and coal prices were kept constant over the planning horizon. FPL performed this analysis solely due to the fact that it was included in the FPSC's list of specified information for the Site Plan filing. FPL believes that the likelihood of a constant differential between fuel prices occurring over the planning horizon is very small. In order to perform this "acid test" analysis, FPL used the initial year price forecast for each fuel and kept those prices constant throughout the planning horizon

The results of this scenario analysis were identical to that of the Base Case.

Discussion Item # 5: **Describe how generating unit performance was modeled in the planning process.**

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, and capacity output ratings and heat rate information. Schedules 1 and 8 present the capacity output ratings of FPL's existing units. The values used for outages and heat rates are consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options which were considered in the resource planning work. A summary of this information for the new capacity options FPL projects to add over the planing horizon is presented on Schedule 9. Please refer to that schedule.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

The key financial assumptions used in FPL's 2000 resource planning work were 45% debt and 55% equity FPL capital structure; projected debt cost of 7.6%; and an equity return of 11.8%. These assumptions resulted in a weighted average cost of capital of 9.9% and an after-tax discount rate of 8.6%. These assumptions were used in FPL's base case or "Most Likely" forecast case analysis, and in its sensitivity analyses of alternate load and/or fuel price forecasts.

In order to test the sensitivity of the resource plan to a different set of financial assumptions, FPL performed an analysis in which the capital financing structure was changed to one which might be more typical of a case involving third-party financing of a new power plant. This alternate financing structure was assumed to be one made of 80% debt and 20% equity. The returns on debt and equity were assumed to be the same as for FPL's "Most Likely" case 7.6% and 11.8% respectively. These assumptions result in a weighted average cost of capital of 8.4% and an after-tax discount rate of 6.1%.

The results of this "alternate financial case" sensitivity analysis were the same as for FPL's "Most Likely" or Base Case analysis.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM approach). However, in its 2000 planning work FPL utilized a net present value of system revenue requirements as the basis for comparing options and plans. (As discussed in response to Discussion Item # 2, both the electricity rate basis and the system revenue requirement basis are identical when DSM levels are unchanged between competing plans. Such was the case in FPL's 2000 planning work.)

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL traditionally uses two generation reliability criteria in its resource planning work. These are a minimum 15% Summer and Winter reserve margin and a maximum of 0.1 days per year loss-of-load-probability (LOLP). However, in its 2000 planning work, FPL also used a third criterion: a minimum 20% Summer and Winter reserve margin which applies starting with the Summer of 2004. This new criterion was the result of an agreement reached between FPL, FPC, TECO, and FPSC in Docket No. 981890-EU. These reliability criteria are discussed in Chapter III of this document. Please refer to that chapter.

In regard to transmission reliability, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the planning criteria established by the North American Electric Reliability Council (NERC) in its *Planning Standards*. FPL has applied these planning criteria in a manner consistent with prudent utility practice. The *NERC Planning Standards* are available on the internet (http://www.nerc.com/~filez/pss-psg.html).

In addition, FPL has developed a Facility Connection Requirements (FCR) document as well as a Facility Rating Methodology document that are also available on the internet (http://www.enx.com/FPL/fpl_home.html).

Thermal ratings for specific transmission lines or transformers are found in the load flow cases that are available on the internet (http://www.enx.com/FPL/fpl_home.html). The normal voltage criteria for FPL stations is given below:

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138, 500	0.95	1.05
230	0.95	1.06

There may have been isolated cases for which FPL may have determined it prudent to deviate from the general criteria stated above. The overall potential impact on customers, the probability of an outage actually occurring, as well as other factors may have influenced the decision in such cases.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The impact of FPL's DSM Programs on demand and energy consumption is evaluated over time. Data is collected from non-participants in order to establish a non-DSM technology baseline. Participants' data is compared against non-participants' data to establish usage patterns, demand impacts and to validate engineering assumptions.

FPL utilizes any or all of three major impact evaluation analysis methods in a manner that most cost-effectively meets the overall impact evaluation objectives. These three major impact evaluation analysis methods are: engineering analysis, statistical billing analysis, and on-site metering research. As DSM evaluations proceed over time, the components to be analyzed and the periods for which data is available will increase, resulting in continual enhancements in the scope and accuracy of reported evaluation results.

Finally, for those DSM measures which involve the utilization of load management, FPL conducts periodic tests of the load control equipment to ensure that it is functioning correctly.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

FPL's resource planning process is designed to address various "strategic concerns" or areas of uncertainty. There are 6 areas of uncertainty that FPL seeks to address in its resource planning work: load growth, fuel price, transmission system constraints, environmental regulations, evolving technology, and competitive risk.

In regard to uncertainty about both load growth and fuel price, FPL addressed this by developing a resource plan which used a combination of a "High Load" forecast and a "Low Price" fuel forecast, as is discussed in Discussion Item # 3.(In response to the list of information specified by the FPSC for inclusion in the Site Plan filing, FPL also developed a resource plan which used an "acid test" fuel price forecast. This is discussed in regard to Discussion Item # 4.) In addition, uncertainty about fuel prices is addressed in fuel conversion efforts such as repowering projects now planned at FPL's Fort Myers and

Sanford sites and in retaining the capability to burn more than one fuel in a number of FPL generating units.

Uncertainty regarding transmission system constraints is addressed by annually updating assumptions about how much assistance may be available to FPL from outside FPL's service territory as well as assumptions relating to transmission constraints within FPL's system. In regard to uncertainty about environmental regulations, FPL's policy has always been that it will comply with all existing environmental laws and regulations. In that regard, FPL's resource planning analyses include all reasonably known costs of complying with these laws and regulations. Furthermore, in regard to potential new environmental regulations, FPL believes that its efforts to maintain the ability to burn varying grades of oil or burning either oil or natural gas at numerous plants, and to expand the use of natural gas (through the planned repowering projects at Fort Myers and Sanford, and the planned addition of new natural gas-fired combined cycle units), should allow FPL to reasonably respond to a variety of potential environmental regulations.

Uncertainty about evolving technology's potential impact on resource plans is best addressed by not committing to resource additions before it is necessary to do so. (In most cases, this approach also benefits the economics of the resource plan.) This minimizes the chance that a newly emerged technology will turn out to be a more economical choice than what the utility has already committed to. Uncertainty about evolving technology is also reduced by maintaining close contact with equipment vendors in order to better understand what the developmental status is of various generating technologies.

Finally, an increasingly important consideration in FPL's planning process is that of competitive risk. FPL's resource planning process is designed to identify the resource plan which best minimizes system average electric rates in order to keep FPL's service competitive in the evolving utility industry. Also, because of the inherent uncertainty associated with an evolving industry, long-term purchase commitments are undesirable. FPL seeks to avoid/minimize such commitments in its planning.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As has been discussed, the near - term elements of FPL's capacity additions are the repowering of its Fort Myers and Sanford plants, the addition of new combustion turbines (CT's) at Martin and Fort Myers (which will later be converted into CC units), and a number of firm capacity, short-term purchases. The incremental capacity from the two repowering projects comes from the addition of new CT's and heat recovery steam generators (HRSG's). FPL is acquiring the repowering-related CT's, plus the other CT's for Martin and Fort Myers, and the HRSG's through a bid process which will combine cost and performance considerations. The firm capacity short-term purchases are being acquired through negotiations.

The later capacity additions projected in FPL's Site Plan document will likely be carried out following the issuance of a capacity solicitation to potential suppliers at an appropriate time, if that approach represents the best vehicle to offer the lowest cost new generating capacity. FPL notes that its experience in 2000 in obtaining transmission cost estimates (after the FERC – required separation of its transmission planning group) leads FPL to question whether a solicitation process can still provide total cost estimates to a meaningful number of parties in the relatively short time a solicitation decision will be needed.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

FPL's plans do not include any new or upgraded transmission lines during the 2001 – 2010 time period which would need to be certified under the Transmission Line Siting Act (403.52 – 403.536, F.S.)

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CHAPTER VI

Summary of Required Schedules

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Schedule 1

Existing Generating Facilities
As of December 31, 2000

(1) Plant Name	(2) Unit No	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen Max Nameplate KW	(13) Net Capability 1/ Summer MW	(14) Net Capability 1/ Winter MW
Turkey Point		Dade County 27/57S/40E									2,338,100	2,208	2,260
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	410	411
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	400	403
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	760,000	693	717
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	760,000	693	717
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	14,000	12	12
Cutler		Dade County 27/55S/40E									236,500	215	217
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	74,500	71	72
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	162,000	144	145
Lauderdale		Broward County 30/50S/42E									1,863,972	1,694	1,952
	4		CC	NG	FO2	PL	PL	Unknown	Oct-57	Unknown	521,250	427	467
	5		CC	NG	FO2	PL	PL	Unknown	Apr-58	Unknown	521,250	427	467
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,736	420	509
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,736	420	509
Port Everglades		City of Hollywood 23/50S/42E									1,665,086	1,662	1,757
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	225,250	221	222
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	225,000	221	222
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	390	392
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	410	412
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,736	420	509

1/ These ratings are peak capability

Schedule 1

Existing Generating Facilities
As of December 31, 2000

(1) Plant Name	(2) Unit No	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen Max Nameplate KW	(13) Net Capability 1/ Summer MW	(14) Net Capability 1/ Winter MW
Riviera		City of Riviera Beach 33/42S/43E									620,840	563	565
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	283	283
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	280	282
Martin		Martin County 29/29S/38E									2,950,000	2,588	2,674
	1		ST	NG	FO6	PL	PL	Unknown	Dec-80	Unknown	863,000	824	843
	2		ST	NG	FO6	PL	PL	Unknown	Jun-81	Unknown	863,000	816	831
	3		CC	NG	FO2	PL	PL	Unknown	Feb-94	Unknown	612,000	474	500
	4		CC	NG	FO2	PL	PL	Unknown	Apr-94	Unknown	612,000	474	500
St Lucie		St Lucie County 16/36S/41E									1,553,000	1,553	1,579
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	839,000	839	853
	2	2/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	714,000	714	726
Cape Canaveral		Brevard County 19/24S/36F									804,100	806	812
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	403	406
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	403	406
Sanford		Volusia County 16/19S/30E									1,022,450	914	919
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	150,250	142	144
	4		ST	FO6	NG	WA	PL	Unknown	Jul-72	Unknown	436,100	381	384
	5		ST	FO6	No	WA	No	Unknown	Jul-73	Unknown	436,100	391	391

1/ These ratings are peak capability
2/ Total capability is 839/853 MW Capabilities shown represent the company's share of the unit and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of 14.89551%.

Schedule 1

Existing Generating Facilities
As of December 31, 2000

(1) Plant Name	(2) Unit No	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt.	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen Max Nameplate KW	(13) Net Capability 1/ Summer MW	(14) Net Capability 1/ Winter MW
Putnam		Putnam County 16/10S/27E									580,000	498	594
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,000	249	297
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,000	249	297
Fort Myers		Lee County 35/43S/25E									1,302,250	1,626	1,856
	1		ST	FO6	No	WA	No	Unknown	Nov-58	Unknown	156,250	141	142
	2		ST	FO6	No	WA	No	Unknown	Jul-69	Unknown	402,000	402	402
	1-12		GT	FO2	No	WA	No	Unknown	May-74	Unknown	744,000	636	769
	Repowering CT's (3)		GT	NG	FO2	PL	PL	Unknown	Dec-00	Unknown	543,000	447	543
Manatee		Manatee County 18/33S/20E									1,726,600	1,625	1,639
	1		ST	FO6	No	WA	No	Unknown	Oct-76	Unknown	863,300	815	822
	2		ST	FO6	No	WA	No	Unknown	Dec-77	Unknown	863,300	810	817
St Johns River Power Park 2/		Duval County 12/15/28E									250,000	254	260
	1		BIT	BIT	No	RR	No	Unknown	Mar-87	Unknown	125,000	127	130
	2		BIT	BIT	No	RR	No	Unknown	May-88	Unknown	125,000	127	130
Scherer 3/		Monroe, GA									891,000	658	666
	4		BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	891,000	658	666
									Total System as of December 31, 2000 =			16,864	17,750

1/ These ratings are peak capability.
2/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No 1 and No 2, excluding Jacksonville Electric Authority (JEA) share of 80%.; SJRPP receives coal by water (WA) in addition to rail
3/ These ratings represent Florida Power & Light Company's share of Scherer Unit No 4, adjusted for transmission losses

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					Commercial		
Year	Population**	Members per Household	GWH	Average*** No of Customers	Average KWH Consumption Per Customer	GWH	Average*** No of Customers	Average KWH Consumption Per Customer
1991	6,211,996	2 17	34,617	2,863,198	12,090	27,232	343,834	79,200
1992	6,314,005	2 17	34,198	2,911,807	11,745	26,991	350,269	77,058
1993	6,380,715	2 14	36,360	2,975,479	12,220	28,508	358,679	79,481
1994	6,516,879	2 15	38,716	3,037,629	12,745	29,946	366,409	81,729
1995	6,639,165	2 14	40,556	3,097,192	13,094	30,719	374,005	82,135
1996	6,754,084	2 14	41,302	3,152,625	13,101	31,211	380,860	81,949
1997	6,884,909	2 15	41,849	3,209,298	13,040	32,942	388,906	84,703
1998	7,014,152	2 15	45,482	3,266,011	13,926	34,618	396,749	87,255
1999	7,133,361	2 14	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,282,933	2.13	46,320	3,414,002	13,568	37,001	415,295	89,096
2001 *	7,406,700	2 13	46,949	3,471,810	13,523	39,840	426,053	93,508
2002 *	7,527,519	2 13	48,497	3,538,346	13,706	41,421	437,810	94,608
2003 *	7,645,392	2 12	49,807	3,603,435	13,822	43,654	448,835	97,262
2004 *	7,760,318	2 12	50,558	3,666,716	13,788	44,537	459,199	96,989
2005 *	7,872,296	2 11	51,302	3,727,940	13,762	45,404	469,038	96,803
2006 *	7,983,660	2.11	52,026	3,786,871	13,738	46,220	478,234	96,647
2007 *	8,095,024	2 11	52,730	3,843,274	13,720	47,004	487,101	96,498
2008 *	8,208,083	2 11	53,425	3,897,570	13,707	47,799	495,697	96,427
2009 *	8,322,839	2 11	54,141	3,950,803	13,704	48,619	504,107	96,446
2010 *	8,437,594	2 11	54,952	4,003,154	13,727	49,516	512,269	96,660

* Forecasted values for these years reflect the Most Likely economic scenario
** Population represents only the area served by FPL.
*** Average No of Customers is the annual average of the twelve month values

Schedule 2.2
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)		(10)	(11)	(12)	(13)	(14)	(15)	(16)
		Industrial			Railroads & Railways	Street & Highway Lighting	Other Sales to Public Authorities	Total*** Sales to Ultimate Consumers
Year		GWH	Average** No of Customers	Average KWH Consumption Per Customer	GWH	GWH	GWH	GWH
1991		4,090	15,348	266,493	81	345	733	67,098
1992		4,054	14,788	274,135	77	353	721	66,393
1993		3,889	14,866	261,602	79	330	665	69,830
1994		3,845	15,588	246,658	85	353	664	73,608
1995		3,883	15,140	256,481	84	358	648	76,248
1996		3,792	14,783	256,515	83	368	577	77,334
1997		3,894	14,761	263,830	85	383	702	79,855
1998		3,951	15,126	261,233	81	373	625	85,131
1999		3,948	16,040	246,112	79	473	465	84,676
2000		3,768	16,410	229,592	81	408	381	87,959
2001	*	3,953	15,631	252,888	80	406	500	91,728
2002	*	3,987	15,637	255,005	81	404	523	94,913
2003	*	4,016	15,665	256,344	82	404	540	98,503
2004	*	4,047	15,743	257,072	83	405	553	100,183
2005	*	4,084	15,836	257,914	84	408	563	101,845
2006	*	4,111	15,901	258,540	83	411	571	103,421
2007	*	4,135	15,966	258,995	83	414	577	104,944
2008	*	4,158	16,029	259,397	84	419	582	106,466
2009	*	4,175	16,075	259,699	84	423	586	108,028
2010	*	4,199	16,280	257,919	83	428	589	109,767

* Forecasted values for these years reflect the Most Likely economic scenario
** Average No of Customers is the annual average of the twelve month values
*** Total Sales GWH = Col 4 + Col 7 + Col 10 + Col. 13 + Col 14 + Col 15

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year		(17) Sales for Resale GWH	(18) Utility Use & Losses GWH	(19) Net*** Energy For Load GWH	(20) Average ** No of Other Customers	(21) Total Average**** Number of Customers
1991		716	5,346	73,160	4,076	3,226,455
1992		702	6,002	73,097	4,374	3,281,238
1993		958	4,988	75,776	3,086	3,352,110
1994		1,400	5,367	80,376	2,560	3,422,187
1995		1,437	6,276	83,961	2,460	3,488,796
1996		1,353	5,984	84,671	2,480	3,550,748
1997		1,228	5,770	86,853	2,520	3,615,485
1998		1,326	6,205	92,662	2,584	3,680,470
1999		953	5,829	91,458	2,605	3,756,009
2000		970	7,059	95,989	2,694	3,848,401
2001	*	992	6,837	99,557	2,604	3,916,098
2002	*	1,215	7,087	103,215	2,601	3,994,394
2003	*	1,434	7,369	107,306	2,598	4,070,533
2004	*	1,455	7,493	109,131	2,595	4,144,253
2005	*	1,474	7,617	110,936	2,592	4,215,407
2006	*	1,474	7,733	112,628	2,589	4,283,595
2007	*	1,407	7,913	114,264	2,586	4,348,927
2008	*	1,073	8,360	115,899	2,583	4,411,879
2009	*	1,073	8,476	117,577	2,580	4,473,566
2010	*	1,073	8,607	119,447	2,577	4,534,280

* Forecasted values for these years reflect the Most Likely economic scenario.
** Average Number of Customers is the annual average of the twelve month values
*** Net Energy for Load GWH = Col. 16 + Col 17 + Col. 18
**** Average No of Customers Total = Col 5 + Col 8 + Col 11 + Col. 20

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
1991	14,123	281	13,842	0	160	129	177	38	13,786
1992	14,661	223	14,438	0	234	151	248	51	14,179
1993	15,266	397	14,869	0	311	182	320	79	14,635
1994	15,179	409	14,770	0	392	220	354	125	14,433
1995	16,172	435	15,737	0	466	259	391	193	15,315
1996	16,064	364	15,700	0	531	339	414	296	15,119
1997	16,613	380	16,233	0	615	440	432	341	15,566
1998	17,897	426	17,471	0	656	480	441	359	16,800
1999	17,615	169	17,446	0	722	565	450	397	16,443
2000	17,808	161	17,647	0	767	626	456	432	16,585
2001	18,150	148	18,003	0	784	87	480	55	16,744
2002	18,801	225	18,576	0	793	128	490	74	17,316
2003	19,507	227	19,280	0	799	169	499	93	17,947
2004	19,964	229	19,735	0	805	211	510	113	18,325
2005	20,433	231	20,201	0	811	254	519	134	18,715
2006	20,918	231	20,687	0	817	298	527	154	19,122
2007	21,392	231	21,160	0	822	343	535	174	19,518
2008	21,788	156	21,632	0	827	389	543	193	19,836
2009	22,220	156	22,063	0	831	436	549	212	20,192
2010	22,722	156	22,565	0	832	451	550	219	20,670

Historical Values (1991 - 2000):

Cols. (2) - (4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Cols (7&9)), and MAY incorporate the effects of load control IF load control was operated on these peak days Therefore, Col. (2) represents the actual Net Firm Demand
Cols (5) - (9) represent actual DSM capabilities starting from January 1988
Note that the values for FPL's former Interruptible Rate are incorporated into Col (8), which also includes CILC and GS-LC
Col (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak Col (10) is derived by the formula Col. (10) =Col (2) - Col.(6) - Col (8)

Projected Values (2001 - 2010):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control The effects of conservation implemented prior to 2000 are incorporated into the forecast.
Cols. (5) - (9) represent all incremental conservation and cumulative load control. These values are projected August values and are based on projections with a 1/2000 starting point.
Col (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak Col (10) is derived by using the formula Col (10) =Col (2) - Col (5) - Col (6) - Col (7) - Col (8) - Col (9)

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
1991/92	13,319	105	13,214	0	174	170	193	38	12,952
1992/93	12,964	102	12,862	0	242	195	275	48	12,447
1993/94	12,594	278	12,316	0	317	231	342	67	11,935
1994/95	16,563	635	15,928	0	393	265	360	93	15,810
1995/96	18,096	698	17,398	0	459	310	406	143	17,231
1996/97	16,490	626	15,864	0	731	368	418	154	15,341
1997/98	13,060	239	12,821	0	823	403	429	168	11,807
1998/99	16,802	149	16,653	0	1,218	438	417	182	15,167
1999/00	17,057	142	16,915	0	1,296	469	441	193	15,320
2000/01	18,219	150	18,069	0	972	493	448	201	16,799
2001/02	19,333	130	19,203	0	1,403	81	459	26	17,364
2002/03	20,122	206	19,915	0	1,414	107	465	33	18,103
2003/04	20,555	208	20,347	0	1,425	132	471	41	18,486
2004/05	20,986	210	20,776	0	1,436	156	477	50	18,867
2005/06	21,413	210	21,203	0	1,446	181	483	59	19,244
2006/07	21,841	210	21,631	0	1,455	205	487	68	19,626
2007/08	22,186	135	22,051	0	1,464	228	492	77	19,925
2008/09	22,586	135	22,451	0	1,473	251	497	86	20,279
2009/10	22,978	135	22,843	0	1,480	272	500	93	20,633

Historical Values (1991/92 - 2000/01):

Cols (2) - (4) are actual values for historical winter peaks As such, they incorporate the effects of conservation (Cols. (7&9)), and MAY incorporate the effects of load control IF load control was operated on these peak days. Therefore, Col (2) represents the actual Net Firm Demand
Cols (5) - (9) represent actual DSM capabilities starting from January 1988
Note that the values for FPL's former Interruptible Rate are incorporated into Col (8), which also includes CILC and GS - LC
Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak Col. (10) is derived by the formula: Col.(10) = Col (2) - Col (6) - Col (8)

Projected Values (2001/02-2009/10):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 1997 are incorporated into the forecast
Cols. (5) - (9) represent all incremental conservation and cumulative load control These values in are projected August values and are based on projections with a 1/2000 starting point.
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak Col (10) is derived by using the formula: Col (10) = Col (2) - Col (5) - Col (6) - Col (7) - Col (8) - Col (9)
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak Col (10) is derived by using the formula: Col (10) = Col (2) - Col.(5) - Col (6) - Col (7) - Col (8) - Col (9)

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH: Base Case

(1) Year	(2) Total	(3) Residential Conservation	(4) C/I Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy For Load	(9) Load Factor(%)
1991	73,743	397	186	73,027	716	5,346	73,160	59 1%
1992	73,778	460	221	73,076	702	6,002	73,097	56 9%
1993	76,632	553	303	75,674	958	4,988	75,776	56 7%
1994	81,493	661	456	80,093	1,400	5,367	80,376	60 4%
1995	85,415	777	677	83,978	1,437	6,276	83,961	59 3%
1996	86,708	971	1,039	85,355	1,353	5,984	84,698	60 2%
1997	89,240	1,213	1,174	88,012	1,228	5,770	86,853	59 7%
1998	95,316	1,374	1,279	93,990	1,326	6,205	92,663	63 0%
1999	94,361	1,542	1,362	93,408	953	5,829	91,458	63 5%
2000	99,094	1,674	1,431	98,123	970	7,059	95,989	66 1%
2001	99,557	56	15	98,565	992	6,837	99,486	67 8%
2002	103,215	152	46	102,000	1,215	7,087	103,017	67 9%
2003	107,306	250	77	105,872	1,434	7,369	106,979	68 0%
2004	109,131	349	110	107,676	1,455	7,493	108,672	67 7%
2005	110,936	450	145	109,462	1,474	7,617	110,341	67 3%
2006	112,628	554	180	111,155	1,474	7,733	111,894	66.8%
2007	114,264	659	213	112,857	1,407	7,913	113,392	66 3%
2008	115,899	765	245	114,826	1,073	8,360	114,889	66 1%
2009	117,577	874	276	116,504	1,073	8,476	116,427	65 8%
2010	119,447	919	291	118,374	1,073	8,607	118,237	65 3%

Historical Values (1991 - 2000):

Col (2) represents derived "Total Net Energy For Load w/o DSM" The values are calculated using the formula. Col.(2) = Col (8) + Col.(3) + Col.(4).
Cols. (3) & (4) are DSM values starting in January, 1988 through 1997 which contributed to the values in Cols (5) - (9)
Cols. (5) & (6) are a breakdown of Net Energy For Load in Col (2) into Retail and Wholesale
Col (9) is calculated using Col (8) from this page and Col. (2), "Total", from Schedule 3.1

Projected Values (2001 - 2010):

Col (2) represents Net Energy for Load w/o DSM values
Cols (3) - (4) are forecasted values of the reduction on sales from incremental conservation.
Cols (5) & (6) are a breakdown of Net Energy For Load in Col (2) , into Wholesale and Retail
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented the values for Col (8) above and the values for Col (10) on Schedule 3.1

Schedule 4
Previous Year Actual and Two-Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2000 ACTUAL		2001 * FORECAST		2002 * FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	17,057	6,947	18,840	7,427	19,333	7,700
FEB	12,755	6,377	16,776	6,783	17,259	7,033
MAR	13,411	7,099	14,529	7,282	14,948	7,550
APR	14,959	7,424	14,120	7,494	14,626	7,769
MAY	16,856	8,287	15,487	8,036	16,042	8,332
JUN	16,979	9,336	17,099	9,351	17,712	9,695
JUL	17,778	9,216	17,749	9,675	18,386	10,031
AUG	17,808	9,743	18,150	10,168	18,801	10,542
SEP	17,701	9,694	17,625	9,861	18,257	10,223
OCT	16,920	7,712	16,358	8,430	16,944	8,739
NOV	13,804	7,184	15,257	7,646	15,696	7,927
DEC	14,858	6,971	15,593	7,402	16,042	7,674
TOTALS		95,989		99,557		103,215

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation.

Schedule 5
Fuel Requirements 1/

			Actual 2/		Forecasted									
	Fuel Requirements	Units	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Nuclear	Trillion BTU	268	268	257	263	258	258	263	258	257	263	258	257
(2)	Coal	1,000 TON	3,107	4,170	3,788	3,552	3,705	3,556	3,629	4,019	3,795	3,817	4,073	3,821
(3)														
(4)	Residual(FO6)- Total	1,000 BBL	36,475	36,859	32,769	26,951	24,455	26,018	19,352	14,059	12,416	12,546	11,973	9,188
(5)	Steam	1,000 BBL	36,475	36,859	32,769	26,951	24,455	26,018	19,352	14,059	12,416	12,546	11,973	9,188
(6)	Distillate(FO2)- Total	1,000 BBL	488	461	505	315	2,350	2,642	449	381	212	316	181	46
(7)	CC	1,000 BBL	3	14	0	0	0	0	0	0	0	0	0	0
(8)	CT	1,000 BBL	405	1	0	74	1,959	2,118	406	356	195	289	160	33
(9)	Steam	1,000 BBL	80	446	505	241	391	524	42	25	17	27	21	13
(10)	Natural Gas -Total	1,000 MCF	193,723	203,234	248,439	299,368	319,720	321,203	378,635	423,640	446,604	452,639	468,918	519,426
(11)	Steam	1,000 MCF	73,309	80,967	100,772	76,589	9,521	9,519	7,046	5,361	4,919	4,795	4,736	3,888
(12)	CC	1,000 MCF	3,535	117,684	139,066	214,673	308,615	310,455	371,466	418,226	441,651	447,780	464,137	515,507
(13)	CT	1,000 MCF	116,879	4,583	8,601	8,106	1,584	1,229	124	54	34	63	45	32

1/ Reflects fuel requirements for FPL only
2/ Source A Schedules

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 1/ 1999	2000	Forecasted 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Annual Energy Interchange 2/	GWH	8,180	10,092	12,386	11,509	9,611	10,029	9,169	8,492	8,452	8,332	8,282	5,582
(2)	Nuclear	GWH	24,706	24,584	23,776	24,284	23,873	23,844	24,284	23,874	23,778	24,331	23,874	23,778
(3)	Coal	GWH	6,146	6,977	6,906	6,504	6,711	6,541	6,660	7,307	6,942	6,980	7,398	6,986
(4)	Residual(FO6) -Total	GWH	22,903	23,230	20,706	16,871	15,375	16,370	12,211	8,869	7,833	7,911	7,556	5,828
(5)	Steam	GWH	22,903	23,230	20,706	16,871	15,375	16,370	12,211	8,869	7,833	7,911	7,556	5,828
(6)	Distillate(FO2) -Total	GWH	167	193	213	159	1,674	1,865	331	282	156	232	131	31
(7)	CC	GWH	2	9	0	0	0	0	0	0	0	0	0	0
(8)	CT	GWH	165	1	0	58	1,461	1,581	312	271	149	220	123	26
(9)	Steam	GWH	0	183	213	101	212	284	19	11	7	11	9	5
(10)	Natural Gas -Total	GWH	23,098	24,217	28,259	37,053	43,976	44,209	52,388	58,883	62,148	63,034	65,297	72,491
(11)	Steam	GWH	7,038	7,840	9,398	7,226	851	849	626	474	435	423	418	346
(12)	CC	GWH	15,863	16,064	18,120	29,105	42,983	43,251	51,753	58,406	61,711	62,608	64,876	72,143
(13)	CT	GWH	197	313	741	723	143	110	9	3	2	4	3	2
(14)	Other 3/	GWH	6,349	6,696	7,240	6,636	5,759	5,814	5,298	4,187	4,082	4,069	3,888	3,540
	Net Energy For Load 4/	GWH	91,549	95,989	99,486	103,017	106,979	108,672	110,341	111,894	113,392	114,889	116,427	118,237

1/ Source A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies
3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc
4/ Net Energy For Load is Column 2 on Schedule 3 3 and Column 1 on EIA411 Form 11C

Schedule 6.2
Energy % by Fuel Type

	Energy Source	Units	Actual 1/ 1999	2000	Forecasted 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Annual Energy Interchange 2/	%	8 9	10 5	12 4	11 2	9.0	9 2	8 3	7 6	7 5	7 3	7 1	4 7
(2)	Nuclear	%	27 0	25 6	23 9	23 6	22 3	21 9	22 0	21 3	21 0	21 2	20 5	20 1
			0 0											
(3)	Coal	%	6 7	7 3	6 9	6 3	6 3	6 0	6 0	6 5	6 1	6 1	6 4	5 9
(4)	Residual(FO6) -Total	%	25 0	24 2	20 8	16 4	14 4	15.1	11 1	7 9	6 9	6 9	6 5	4 9
(5)	Steam	%	25 0	24 2	20 8	16 4	14 4	15 1	11 1	7.9	6 9	6 9	6 5	4 9
(6)	Distillate(FO2) -Total	%	0 2	0 2	0 2	0 2	1 6	1 7	0 3	0 3	0.1	0.2	0 1	0 0
(7)	CC	%	0 0	0 0	0 0	0 0	0.0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
(8)	CT	%	0 2	0 0	0 0	0 1	1 4	1.5	0.3	0.2	0.1	0 2	0 1	0 0
(9)	Steam	%	0 0	0 2	0 2	0 1	0.2	0 3	0 0	0 0	0 0	0 0	0 0	0 0
(10)	Natural Gas -Total	%	25 2	25 2	28 4	36 0	41 1	40 7	47 5	52.6	54 8	54 9	56 1	61 3
(11)	Steam	%	7 7	8.2	9 4	7 0	0 8	0 8	0.6	0 4	0 4	0 4	0 4	0 3
(12)	CC	%	17 3	16 7	18 2	28 3	40 2	39 8	46 9	52 2	54 4	54 5	55.7	61 0
(13)	CT	%	0.2	0 3	0.7	0 7	0 1	0 1	0.0	0.0	0 0	0 0	0 0	0 0
(14)	Other 3/	%	6 9	7 0	7 3	6 4	5 4	5 4	4 8	3.7	3.6	3 5	3 3	3 0
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies
3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capacity MW	Firm Capacity Import 2/ MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 3/ MW	Total Peak 4/ Demand MW	DSM 5/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 6/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 7/ MW	% of Peak
2001	17,704	1,509	0	886	20,099	18,150	1,406	16,744	3,355	20 0	0	3,355	20 0
2002	17,915	2,288	0	877	21,080	18,801	1,485	17,316	3,764	21 7	0	3,764	21.7
2003	19,170	2,288	0	877	22,335	19,507	1,560	17,947	4,388	24 4	0	4,388	24 4
2004	19,170	2,288	0	877	22,335	19,964	1,639	18,325	4,010	21 9	0	4,010	21.9
2005	20,762	1,313	0	867	22,942	20,433	1,718	18,715	4,227	22 6	0	4,227	22 6
2006	21,309	1,313	0	734	23,356	20,918	1,796	19,122	4,234	22 1	0	4,234	22 1
2007	21,856	1,313	0	734	23,903	21,392	1,874	19,518	4,385	22 5	0	4,385	22 5
2008	21,856	1,313	0	734	23,903	21,788	1,952	19,836	4,067	20 5	0	4,067	20 5
2009	22,403	1,313	0	683	24,399	22,220	2,028	20,192	4,207	20 8	0	4,207	20 8
2010	24,044	382	0	640	25,066	22,722	2,052	20,670	4,396	21.3	0	4,396	21 3

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated All values are Summer net MW

2/ Firm Capacity Imports include all firm capacity purhcases whether from out - of - state or in - state

3/ Total Capacity Available=Col (2) + Col (3) - Col (4) + Col (5)

4/ These forecasted values reflect the Most Likely forecast without DSM

5/ The MW shown represent cumulative load management capability plus incremental conservation from 1/99 - on They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based

6/ Margin (%) Before Maintenance = Col (10)/Col (9)

7/ Margin (%) After Maintenance =Col (13) /Col (9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled
Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Total Installed 1/ Capability	Firm Capacity Import 2/	Firm Capacity Export	Firm QF	Total Capacity Available 3/	Total Peak 4/ Demand	DSM 5/	Firm Winter Peak Demand	Reserve Margin Before Maintenance 6/		Scheduled Maintenance	Reserve Margin After Maintenance 7/	
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2000/01	17,785 *	1,319	0	886	19,990	18,840 *	1,902	16,938	3,052	18 0	0	3,052	18 0
2001/02	17,752	1,369	0	886	20,007	19,333	1,969	17,364	2,643	15 2	0	2,643	15 2
2002/03	20,019	2,394	0	877	23,290	20,122	2,019	18,103	5,187	28 7	0	5,187	28 7
2003/04	20,381	2,394	0	877	23,652	20,555	2,069	18,486	5,166	27 9	0	5,166	27 9
2004/05	20,381	2,344	0	867	23,592	20,986	2,119	18,867	4,725	25 0	0	4,725	25 0
2005/06	22,041	1,319	0	734	24,094	21,413	2,169	19,244	4,850	25 2	0	4,850	25 2
2006/07	22,637	1,319	0	734	24,690	21,841	2,215	19,626	5,064	25 8	0	5,064	25 8
2007/08	23,233	1,319	0	734	25,286	22,186	2,261	19,925	5,361	26 9	0	5,361	26 9
2008/09	23,233	1,319	0	734	25,286	22,586	2,307	20,279	5,007	24 7	0	5,007	24 7
2009/10	23,829	1,319	0	683	25,831	22,978	2,345	20,633	5,198	25 2	0	5,198	25 2

* Denotes actual installed capability and total peak demand All other assumptions are projections

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecasted to occur during January of the "second" year indicated All values are Winter net MW

2/ Firm Capacity Imports include all firm capacity purhcases whether from out - of - state or in - state

3/ Total Capacity Available = Col (2) + Col (3) - Col (4) + Col (5)

4/ These forecasted values reflect the Most Likely forecast without DSM

5/ The MW shown represent cumulative load management capability plus incremental conservation They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based

6/ Margin (%) Before Maintenance = Col (10) /Col (9)

7/ Margin (%) After Maintenance = Col (13) /Col (9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm	Expected	Gen Max	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter	Summer	
Plant Name	No	Location	Type	Pri	Alt	Pri	Alt	Mo /Yr	Mo /Yr	Mo /Yr	KW	MW	MW	Status
ADDITIONS														
2001														
Martin Combustion Turbines	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-99	Jun-01	Unknown	190,000	—	149	P
Martin Combustion Turbines	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-99	Jun-01	Unknown	190,000	—	149	P
											2001 Total:	**0**	**298**	
2002														
Martin Combustion Turbines	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-99	Jun-01	Unknown	190,000	181	—	P
Martin Combustion Turbines	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-99	Jun-01	Unknown	190,000	181	—	P
											2002 Total:	**362**	**---**	
2003														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	Apr-03	Unknown	190,000	---	149	P
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	May-03	Unknown	190,000	---	149	P
											2003 Total:	**---**	**298**	
2004														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	Apr-03	Unknown	190,000	181	—	P
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	May-03	Unknown	190,000	181	---	P
											2004 Total:	**362**	**---**	
2005														
Martin Combined Cycle Unit	5	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	—	547	P
Midway Combined Cycle Unit	1	St Lucie County 2/36S/39E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	—	547	P
											2005 Total:	**---**	**1094**	

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm	Expected	Gen Max	Net Capability		
Plant Name	Unit No	Location	Unit Type	Pri	Alt	Pri	Alt	Start Mo /Yr	In-Service Mo /Yr	Retirement Mo /Yr	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS														
2006														
Martin Combined Cycle Unit	5	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	596	---	P
Midway Combined Cycle Unit	1	St Lucie County 2/36S/39E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	596	---	P
Martin Combined Cycle Unit	6	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	Jun-03	Jun-06	Unknown	470,000	---	547	P
											2006 Total:	**1192**	**547**	
2007														
Martin Combined Cycle Unit	6	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	Jun-03	Jun-06	Unknown	470,000	596	---	P
Unsited Combined Cycle Unit #1	1	Unknown	CC	NG	FO2	PL	PL	Jun-04	Jun-07	Unknown	470,000	---	547	P
											2007 Total:	**596**	**547**	
2008														
Unsited Combined Cycle Unit #1	1	Unknown	CC	NG	FO2	PL	PL	Jun-04	Jun-07	Unknown	470,000	596	---	P
											2008 Total:	**596**	**0**	
2009														
Unsited Combined Cycle Unit #2	2	Unknown	CC	NG	FO2	PL	PL	Jun-06	Jun-09	Unknown	470,000	---	547	P
											2009 Total:	**0**	**547**	
2010														
Unsited Combined Cycle Unit #2	2	Unknown	CC	NG	FO2	PL	PL	Jun-06	Jun-09	Unknown	470,000	596	---	P
Unsited Combined Cycle Unit #3	3	Unknown	CC	NG	FO2	PL	PL	Jun-07	Jun-10	Unknown	470,000	---	547	P
Unsited Combined Cycle Unit #4	4	Unknown	CC	NG	FO2	PL	PL	Jun-07	Jun-10	Unknown	470,000	---	547	P
Unsited Combined Cycle Unit #5	5	Unknown	CC	NG	FO2	PL	PL	Jun-07	Jun-10	Unknown	470,000	---	547	P
											2010 Total:	**596**	**1641**	

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (Cont.)

(1) Plant Name	(2) Unit No	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Const Start Mo /Yr	(10) Comm In-Service Mo /Yr	(11) Expected Retirement Mo /Yr	(12) Gen Max Nameplate KW	(13) Net Capability Winter [1),2)] MW	(14) Net Capability Summer [1) 2)] MW	(15) Status
CHANGES/UPGRADES														
2001														
Martin	1	Martin County 29/29S/38E	ST	NG	FO6	PL	PL	N/A	May-01	Unknown	863,000	0	(30)	OT
Martin	2	Martin County 29/29S/38E	ST	NG	FO6	PL	PL	N/A	May-01	Unknown	863,000	0	(20)	OT
Martin	3	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	N/A	May-01	Unknown	612,000	0	(7)	OT
Martin	4	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	N/A	May-01	Unknown	612,000	0	(7)	OT
Cape Canaveral	2	Brevard County 19/24S/36F	ST	FO6	NG	WA	PL	Nov-00	Nov-00	Unknown	402,050	8	8	OT
Ft Myers Repowering Initial Phase	1 & 2	Lee County 35/43S/25E	CC	NG	No	PL	No	Nov-00	Jan-01	Unknown	161,700	543	894	RP,U
											2001 Total:	**551**	**838**	
2002														
Sanford Repowering Initial Phase	4	Volusia County 16/19S/30E	ST	FO6	NG	WA	PL	Jan-00	N/A	Unknown	106,600	0	(390) [3)]	RP
Sanford Repowering Initial Phase	5	Volusia County 16/19S/30E	ST	FO6	NG	WA	PL	Jan-00	N/A	Unknown	106,600	(394) [3)]	0	RP
Sanford Repowering Second Phase	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	N/A	Jul-02	Unknown	106,600	0	567	RP
Fort Myers Repowering Second Phase	1 & 2	Lee County 35/43S/25E	CC	NG	No	PL	No	Sep-01	Jan-02	Unknown	161,700	(1)	35	RP,U
											2002 Total:	**(395)**	**212**	
2003														
Sanford Repowering Second Phase	4	Volusia County 16/19S/30E	CC	NG	No	PL	No	N/A	Dec-02	Unknown	106,600	671	957	RP
Sanford Repowering Second Phase	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	N/A	Jul-02	Unknown	106,600	1,065	0	RP
Fort Myers Repowering Second Phase	1 & 2	Lee County 35/43S/25E	CC	NG	No	PL	No	Sep-01	Jun-02	Unknown	161,700	531	0	RP,U
											2003 Total:	**2,267**	**957**	
2004														
—		—	—	—	—	—	—	—	—	—	—	—	—	—
											2004 Total:	**0**	**0**	
2005														
Martin Combustion Turbine Conversion	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	—	124 5	P
Martin Combustion Turbine Conversion	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	—	124 5	P
Fort Myers Combustion Turbine Conversion	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	—	124 5	P
Fort Myers Combustion Turbine Conversion	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	—	124 5	P
											2005 Total:	**0**	**498**	

1)The Winter Total MW value consists of all generation additions and changes achieved by January The Summer Total MW value consists of all generation additions and changes achieved by July All other MW will be picked up in the following year This is done for reserve margin calculation

2) All MW differences are calculated based on using IRP 2000 Submittal (for the year 2000) as the base for all other years

3) Negative values for Sanford and Ft Myers reflect the existing steam units being temporarily out of service during that seasonal period for repowering efforts

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (Cont.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm	Expected	Gen Max	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter [1]	Summer [1]	
Plant Name	No	Location	Type	Pri	Alt	Pri	Alt	Mo /Yr	Mo /Yr	Mo /Yr	KW	MW	MW	Status
CHANGES/UPGRADES														
2006														
Martin Combustion Turbine Conversion	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	117 0	---	P
Martin Combustion Turbine Conversion	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	117 0	---	P
Fort Myers Combustion Turbine Conversion	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	117 0	---	P
Fort Myers Combustion Turbine Conversion	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Jan-04	Jun-05	Unknown	190,000	117 0	---	P
											2006 Total:	**468**	**0**	
2007														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2007 Total:	**0**	**0**	
2008														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2008 Total:	**0**	**0**	
2009														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2009 Total:	**0**	**0**	
2010														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2010 Total:	**0**	**0**	

1)The Winter Total MW value consists of all generation additions and changes achieved by January The Summer Total MW value consists of all generation additions and changes achieved by July All other MW will be picked up in the following year This is done for reserve margin calculation

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Martin Combustion Turbines No. 8A and No. 8B *	
(2)	**Capacity**		
	a. Summer	149 MW	
	b. Winter	181 MW	
(3)	**Technology Type:**	Combustion Turbine	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	1999	
	b. Commercial In-service date:	2001	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Air Coolers	
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	1%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	98%	
	Resulting Capacity Factor (%):	Approx. 10%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	10,430	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	477.98	
	Direct Construction Cost ($/kW):	449.20	
	AFUDC Amount ($/kW):	29.30	
	Escalation ($/kW):	-0.53	
	Fixed O&M ($/kW -Yr.):	0.68	
	Variable O&M ($/MWH):	0.86	
	K Factor:	1.5134	

* Values shown are per unit values for the two units being added.
** $/KW values are based on Summer capacity.
*** Fixed O&M includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Fort Myers Repowering

(2) **Capacity**

a. Summer	929	MW Incremental (1473 MW Total After Repowering)
b. Winter	1,073	MW Incremental (1617 MW Total After Repowering)

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2000
b. Commercial In-service date:	2002

(5) **Fuel**

a. Primary Fuel	Natural Gas
b. Alternate Fuel	None

(6) **Air Pollution and Control Strategy:** Dry Low Nox Combustors, Natural Gas

(7) **Cooling Method:** Once-through Cooling

(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	96%	
Resulting Capacity Factor (%):	96%	(First Year)
Average Net Operating Heat Rate (ANHOR):	6,830	Btu/kWh

(13) **Projected Unit Financial Data, *,**,*****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	655.96	
Direct Construction Cost ($/kW):	560.71	
AFUDC Amount ($/kW):	94.59	
Escalation ($/kW):	0.66	
Fixed O&M ($/kW -Yr.):	13.30	
Variable O&M ($/MWH):	0.37	
K Factor:	1.5419	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Sanford Unit 4 Repowering	
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	671	MW Incremental (1065 MW Total After Repowering)
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	None	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors and Natural Gas	
(7)	**Cooling Method:**	Cooling Pond	
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	6,860	Btu/kWh
(13)	**Projected Unit Financial Data *,**,*** **		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	708.12	
	Direct Construction Cost ($/kW):	595.11	
	AFUDC Amount ($/kW):	112.45	
	Escalation ($/kW):	0.56	
	Fixed O&M ($/kW -Yr.):	14.25	
	Variable O&M ($/MWH):	0.37	
	K Factor:	1.4701	

* $/kW values are based on incremental Summer capacity.

** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.

*** Fixed O&M includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Sanford Unit 5 Repowering	
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	671	MW Incremental (1065 MW Total After Repowering)
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Cooling Pond	
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	6,860	Btu/kWh
(13)	**Projected Unit Financial Data *,**,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	678.08	
	Direct Construction Cost ($/kW):	595 11	
	AFUDC Amount ($/kW):	82.41	
	Escalation ($/kW):	0.56	
	Fixed O&M ($/kW -Yr.):	14.25	
	Variable O&M ($/MWH):	0.37	
	K Factor:	1.5341	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Fort Myers Combustion Turbines No. 13 and No. 14 *	
(2)	**Capacity**		
	a. Summer	149 MW	
	b Winter	181 MW	
(3)	**Technology Type:**	Combustion Turbine	
(4)	**Anticipated Construction Timing**		
	a Field construction start-date:	2002	
	b. Commercial In-service date:	2003	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Air Coolers	
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	1%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	98%	
	Resulting Capacity Factor (%):	Approx. 10%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	10,430	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	542.80	
	Direct Construction Cost ($/kW).	509.94	
	AFUDC Amount ($/kW):	31.30	
	Escalation ($/kW):	1.56	
	Fixed O&M ($/kW -Yr.):	0.68	
	Variable O&M ($/MWH):	0.86	
	K Factor:	1.5247	

* Values shown are per unit values for the two units being added.
** $/KW values are based on Summer capacity.
*** Fixed O&M includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:** Martin No. 5		
(2)	**Capacity**		
	a Summer	547	MW
	b. Winter	596	MW
(3)	**Technology Type:** Combined Cycle		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2002	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Cooling Pond	
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	503.31	
	Direct Construction Cost ($/kW):	411.88	
	AFUDC Amount ($/kW):	82.95	
	Escalation ($/kW):	8.48	
	Fixed O&M ($/kW -Yr.):	9.30	
	Variable O&M ($/MWH):	0.74	
	K Factor:	1.5489	

* $/KW values are based on Summer capacity.
** Fixed O&M includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Martin Combustion Turbine Conversion	
(2)	**Capacity**		
	a. Summer	249	MW
	b Winter	234	MW
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2004	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Cooling Pond	
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data ***		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	481.36	
	Direct Construction Cost ($/kW):	433.91	
	AFUDC Amount ($/kW):	31.29	
	Escalation ($/kW):	16.16	
	Fixed O&M ($/kW -Yr.):	9.30	•
	Variable O&M ($/MWH):	0.74	*
	K Factor:	1.5147	

• Values represent an operational combined cycle unit after the conversion is completed.
** $/KW values are based on Summer incremental capacity.
*** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Fort Myers Combustion Turbine Conversion	
(2)	**Capacity**		
	a. Summer	249	MW
	b. Winter	234	MW
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2004	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Cooling Tower	
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data ***		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	481.36	
	Direct Construction Cost ($/kW):	433.91	
	AFUDC Amount ($/kW):	31.29	
	Escalation ($/kW):	16.16	
	Fixed O&M ($/kW -Yr):	9.30	*
	Variable O&M ($/MWH):	0.74	*
	K Factor.	1.5147	

* Values represent an operational combined cycle unit after the conversion is completed.
** $/KW values are based on Summer incremental capacity.
*** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Midway Combined Cycle	
(2)	**Capacity**		
	a. Summer	547 MW	
	b. Winter	596 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2002	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Grey water or groundwater	
(8)	**Total Site Area:**	122	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	439.57	
	Direct Construction Cost ($/kW):	362.93	
	AFUDC Amount ($/kW):	68.27	
	Escalation ($/kW):	8.37	
	Fixed O&M ($/kW -Yr.):	9.30	
	Variable O&M ($/MWH):	0.74	
	K Factor:	1.5457	

* $/KW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:** Martin No 6		
(2)	**Capacity**		
	a. Summer	547	MW
	b. Winter	596	MW
(3)	**Technology Type:** Combined Cycle		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2006	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Cooling Pond	
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	454.41	
	Direct Construction Cost ($/kW):	367.96	
	AFUDC Amount ($/kW):	71.07	
	Escalation ($/kW):	15.38	
	Fixed O&M ($/kW -Yr.):	9.30	
	Variable O&M ($/MWH):	0.74	
	K Factor:	1.5460	

* $/KW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 1	
(2)	**Capacity**		
	a. Summer	547 MW	
	b. Winter	596 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2004	
	b. Commercial In-service date:	2007	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	532.83	
	Direct Construction Cost ($/kW):	419.24	
	AFUDC Amount ($/kW):	85.38	
	Escalation ($/kW):	28.21	
	Fixed O&M ($/kW -Yr.):	12.10	
	Variable O&M ($/MWH):	0.74	
	K Factor:	1.5473	

* $/KW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:** Unsited Combined Cycle No. 2		
(2)	**Capacity**		
	a. Summer	547 MW	
	b Winter	596 MW	
(3)	**Technology Type:** Combined Cycle		
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2006	
	b. Commercial In-service date:	2009	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	554.71	
	Direct Construction Cost ($/kW):	419.24	
	AFUDC Amount ($/kW):	88.86	
	Escalation ($/kW):	46.61	
	Fixed O&M ($/kW -Yr.):	12.10	
	Variable O&M ($/MWH):	0.74	
	K Factor:	1.5473	

* $/KW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 3, No 4, and No. 5 *	
(2)	**Capacity**		
	a. Summer	547 MW	
	b. Winter	596 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date	2007	
	b. Commercial In-service date:	2010	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Dry Low Nox Combustors, Natural Gas, 0.05% S Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	96%	(First Year)
	Average Net Operating Heat Rate (ANHOR):	7,150	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	566.41	
	Direct Construction Cost ($/kW):	419.24	
	AFUDC Amount ($/kW):	90.72	
	Escalation ($/kW):	56.45	
	Fixed O&M ($/kW -Yr.):	12.10	
	Variable O&M ($/MWH):	0.74	
	K Factor:	1.5473	

* Values shown are per unit values for the three units being added.
** $/KW values are based on Summer capacity.
*** Fixed O&M cost includes capital replacement.

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Martin: 2 CT's

(1)	Point of Origin and Termination:	Not Applicable
(2)	Number of Lines:	Not Applicable
(3)	Right-of-way	FPL Owned
(4)	Line Length:	Not Applicable
(5)	Voltage:	Not Applicable
(6)	Anticipated Construction Timing:	Start date: Not Applicable End date: Not Applicable
(7)	Anticipated Capital Investment:	Not Applicable
(8)	Substations:	Not Applicable
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Ft. Myers Repowering

(1)	Point of Origin and Termination:	From Ft. Myers – To Calusa
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	1.58 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: May 1, 2000 End date: April 1, 2001
(7)	Anticipated Capital Investment:	$354,000
(8)	Substations:	Ft. Myers and Calusa
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	From Ft. Myers – To Orange River
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	2.57 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: March 1, 2000 End date: October 1, 2000
(7)	Anticipated Capital Investment:	$706,750
(8)	Substations:	Ft. Myers and Orange River
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Sanford Repowering

(1)	Point of Origin and Termination:	From Sanford – To Poinsett
(2)	Number of Lines:	2
(3)	Right-of-way	FPL Owned
(4)	Line Length:	45 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: January 1, 2001 End date: June 1, 2001
(7)	Anticipated Capital Investment:	$20,360,000
(8)	Substations:	Sanford and Poinsett
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Ft. Myers: 2 CT's

(1) Point of Origin and Termination: From Ft. Myers GT Collector bus – To Orange River

(2) Number of Lines: 1

(3) Right-of-way FPL Owned

(4) Line Length: 2.5 miles

(5) Voltage: 230 kV

(6) Anticipated Construction Timing: Start date: January 1, 2003
End date: May 1, 2003

(7) Anticipated Capital Investment: $1,050,000

(8) Substations: Orange River and Ft. Myers GT collector bus

(9) Participation with Other Utilities: None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Martin 5

(1)	Point of Origin and Termination:	a. From Pratt & Whitney – To Indiantown b. From Pratt & Whitney – To Ranch c. From Martin – To Indiantown
(2)	Number of Lines:	3
(3)	Right-of-way	FPL Owned
(4)	Line Length:	a. 8.45 miles b. 20.74 miles c. 11.8 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: June 1, 2004 End date: June 1, 2005
(7)	Anticipated Capital Investment:	$6,725,000
(8)	Substations:	Pratt & Whitney, Ranch, Martin, and Indiantown
(9)	Participation with Other Utilities:	None

Note:The existing lines (a & b) will be upgraded to a higher current rating. The line from Martin to Indiantown (c) will be a new circuit integrated with this project.

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Martin: Conversion of CT's into a Combined Cycle Unit

(1)	Point of Origin and Termination:	Not Available
(2)	Number of Lines:	Not Available
(3)	Right-of-way	FPL Owned
(4)	Line Length:	Not Available
(5)	Voltage:	Not Available
(6)	Anticipated Construction Timing:	Start date: Not Available End date: Not Available
(7)	Anticipated Capital Investment:	Not Available
(8)	Substations:	Not Available
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Ft. Myers: Conversion of CT's into a Combined Cycle Unit

(1)	Point of Origin and Termination:	Not Available
(2)	Number of Lines:	Not Available
(3)	Right-of-way	FPL Owned
(4)	Line Length:	Not Available
(5)	Voltage:	Not Available
(6)	Anticipated Construction Timing:	Start date: Not Available End date: Not Available
(7)	Anticipated Capital Investment:	Not Available
(8)	Substations:	Not Available
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Midway: Combined Cycle Unit

(1)	Point of Origin and Termination:	Not Available
(2)	Number of Lines:	Not Available
(3)	Right-of-way	FPL Owned
(4)	Line Length:	Not Available
(5)	Voltage:	Not Available
(6)	Anticipated Construction Timing:	Start date: Not Available End date: Not Available
(7)	Anticipated Capital Investment:	Not Available
(8)	Substations:	Not Available
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Integrated Transmission Lines

Martin 6

(1)	Point of Origin and Termination:	Not Applicable
(2)	Number of Lines:	Not Applicable
(3)	Right-of-way	FPL Owned
(4)	Line Length:	Not Applicable
(5)	Voltage:	Not Applicable
(6)	Anticipated Construction Timing:	Start date: Not Applicable End date: Not Applicable
(7)	Anticipated Capital Investment:	Not Applicable
(8)	Substations:	Not Applicable
(9)	Participation with Other Utilities:	None

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Ten Year Site Plan Fact Summary

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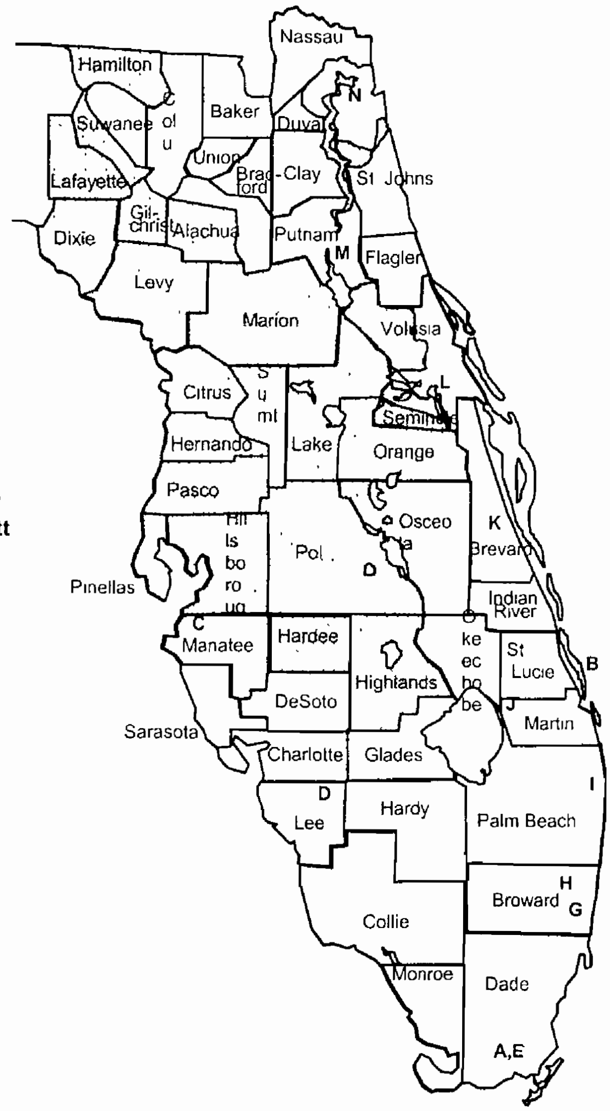
Capacity Resources
(as of December 31, 2000)

☐ Non-FPL Territory



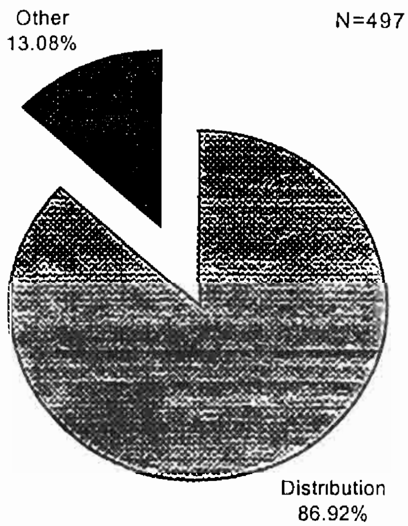
Unit		Uni	Fuel Type	Summe Megawatt
A	Turkey Point	2	Nuclear	1,386
B.	St Lucie	2	Nuclear	1,553
C.	Manatee	2	Oı	1,625
D.	Ft.	2	Oı	543
E.	Turkey Point	2	Oil/Ga	810
F.	Cutler	2	Gas	215
G.	Lauderdale	2	Oil/Ga	854
H.	Port Everglades	4	Oil/Ga	1,242
I.	Riviera	2	Oil/Ga	563
J.	Martin	4	Gas/Oi	2,588
K.	Cape Canaveral	2	Oil/Ga	806
L.	Sanford	3	Oil/Ga	914
M.	Putna	2	Oil/Ga	498
N.	St. Johns River	2	Coal	254
Scherer **		1	Coal	658
Peaking Units				2,355
FPL				**16,864**

** Represents FPL's ownership share St. Lucie nuclear: 100% unit 1, 85% unit 2; St Johns River: 20% of two*

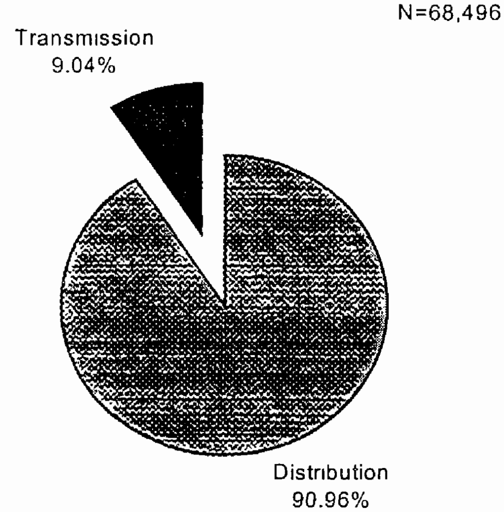
*** The Scherer unit is located in Georgia and is not shown on this map.*

	2000 Actual	2001 Projection	2010 Projection
Average Number of Customers			Source: FPL Schedule 2
Residential	3,414,002	3,471,810	4,003,154
Commercial	415,295	426,053	512,269
Indusrial	16,410	15,631	16,280
Other	2,694	2,604	2,577
Total:	**3,848,401**	**3,916,098**	**4,534,280**
Peak Demand			Source: FPL Schedule 4
Winter	17,057	18,840	19,333
Summer	17,808	18,150	18,801
Installed Capability (MW)			Source: FPL Schedule 7.1 & 7.2
Winter	17,750	17,785	23,957
Summer	16,684	17,704	24,093

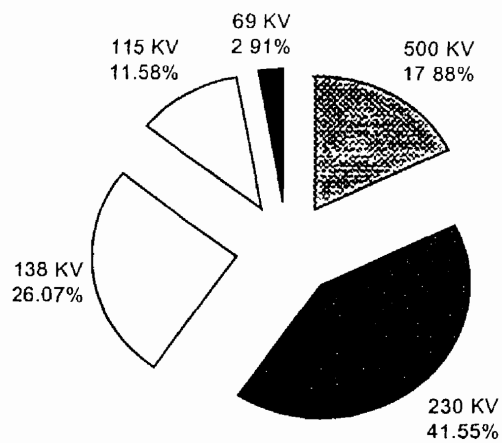
Number Of Substations



Miles of Lines



Miles of Bulk Transmission Lines (By Voltage Level)

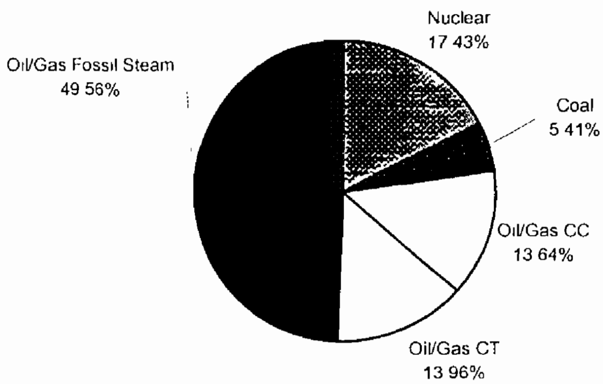


GENERATION RESOURCES

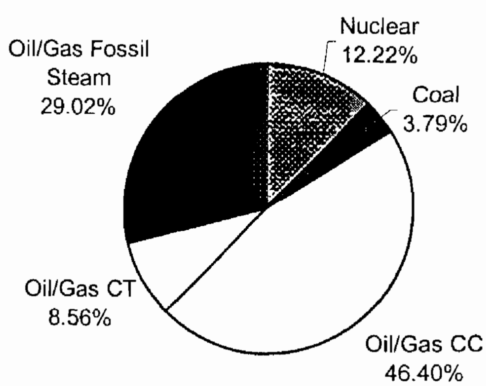
	2000 Actual	2001 Projection	2010 Projection
Facilities			Source: FPL Schedule 5
Coal 1,000 Ton	4,170	3,788	3,821
Oil 1,000 BBL	37,320	33,274	9,234
Gas 1,000 MCF	203,234	248,439	519,426
Nuclear Trillion BTU	268	257	257

INSTALLED GENERATION MW BY FUEL TYPE

2000



2010

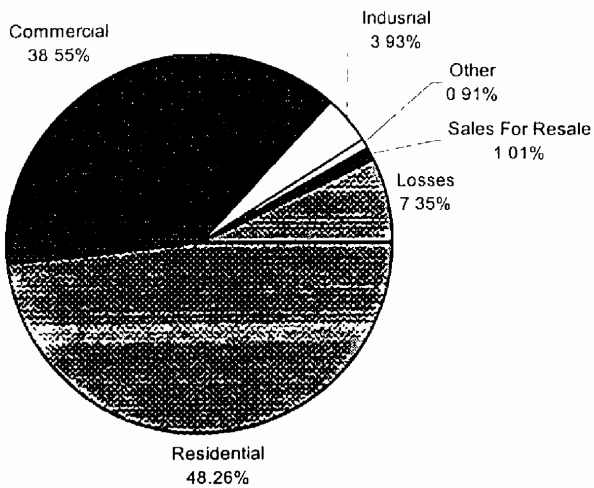


NET ENERGY FOR LOAD

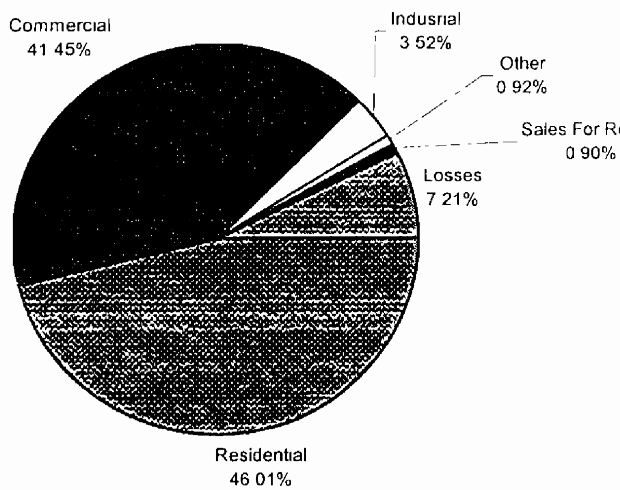
	2000 Actual	2001 Projection	2010 Projection
Consumption (GWH)			Source: FPL Schedule 2
Residential	46,320	46,949	54,952
Commercial	37,001	39,840	49,516
Indusrial	3,768	3,953	4,199
Other	870	986	1,100
Sales For Resale	970	992	1,073
Losses	7,059	6,837	8,607
Total:	**87,959**	**91,728**	**109,767**

NET ENERGY FOR LOAD

2000



2010

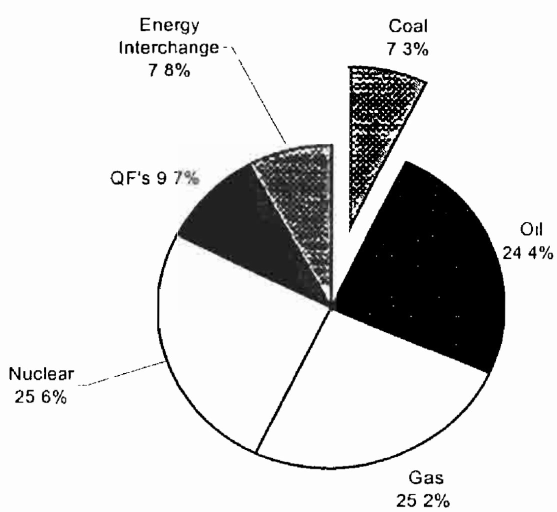


	2000 Actual	2001 Projection	2010 Projection
Per Capita Consumption (KWH)			Source: FPL Schedule 2
Residential	13,568	13,523	13,727
Commercial	89,096	93,508	96,660
Indusrial	229,592	252,888	257,919

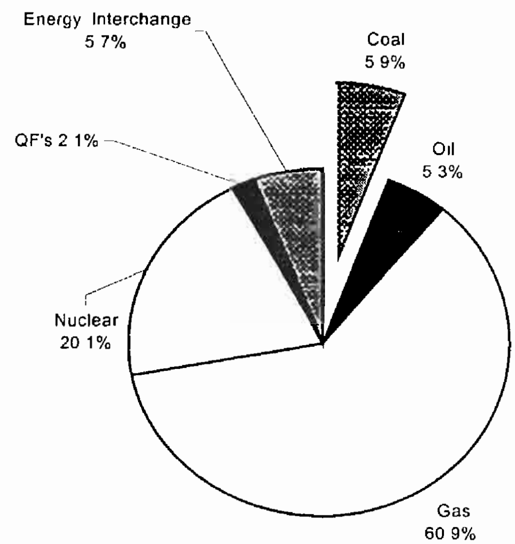
ENERGY BY FUEL TYPE

Energy By Fuel Type (GWH)	2000 Actual	2001 Projection	2010 Projection
			Source: FPL Schedule 6.1
FPL Facilities			
Coal-Fired	6,977	6,906	6,995
Oil-Fired	23,423	20,919	6,224
Gas-Fired	24,217	28,259	71,987
Nuclear	24,584	23,776	23,778
QFs	9,345	7,260	2,482
Net Energy Interchange	7,443	12,366	6,771
Net Energy For Load (NEL)	95,989	99,486	118,237

2000



2010



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Docket No. 150196-EI
2002 10-year site plan
Exhibit KRR-3-B, Page 1 of 282

ORIGINAL

FPL

P.O. Box 029100, Miami, FL 33102-9100

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COMMISSION CLERK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 37
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-B

April 1, 2002

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk
and Administrative Services
Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Fl 32399-0850

BY HAND DELIVERY

020000-PU

Dear Ms. Bayó,

In accordance with Chapter 186, Section 186.801 (Ten Year Power Plant Site Plans) of the Florida Statutes, enclosed are an original and fifteen (15) copies of Florida Power & Light Company's Ten-Year Power Plant Site Plan.

If you have any questions, please do not hesitate to contact me at (305) 552-4332 or Millie Gonzalez at (305) 552-2279.

Sincerely,

Anne M. Grealy
Director, Regulatory Affairs

AMG/mg
Enclosures

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FPSC-BUREAU OF RECORDS

DOCUMENT NUMBER-DATE
03700 APR-1 02
FPSC-COMMISSION CLERK

an FPL Group company

Ten Year Power Plant Site Plan

2002 - 2011

FPL

FPL

Ten Year Power Plant Site Plan

2002-2011

Submitted To:

Florida Public Service Commission

***Miami, Florida
April, 2002***

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Table of Contents

Table of Contents

List of Figures and Tables

List of Figures and Tables

List of Schedules

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Overview of The Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten - Year Power Plant Site Plan. This plan includes an estimate of the utility's electric power generating needs, a projection of how those needs will be met, and a disclosure of information pertaining to the utility's preferred and potential power plant sites. This information is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (FAC).

This Ten - Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) 2001 planning analyses and the forecasted information presented in this plan addresses the 2002 – 2011 time frame.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information, especially for the latter years of the ten - year time horizon, and is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is data on other FPL resources, including its transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, as determined in FPL's 2001 IRP work.

Chapter IV – Environmental and Land Use Information

This chapter discusses various environmental information as well as preferred and potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional specific information which is to be included in a Site Plan filing.

Chapter VI – Summary of Required Schedules

This chapter contains Schedules 1 thru 10. It also contains FPL's Ten Year Site Plan Fact Summary.

FPL
List of Abbreviations
Used in FPL Forms

Reference	***Abbreviation***	***Definition***
Unit Type	IC	Internal Combustion
	NP	Nuclear Power
	ST	Steam Unit
	CT	Combustion Turbine
	CC	Combined Cycle
	BIT	Bituminous Coal
Fuel Type	UR	Uranium
	NG	Natural Gas
	FO6	#4,#5,#6 Oil (Heavy)
	FO2	#1, #2 or Kerosene Oil (Distillate)
	BIT	Bituminous Coal
	No	None
Fuel Transportation	TK	Truck
	RR	Railroad
	PL	Pipeline
	WA	Water
	No	None
Unit/Site Status	A	Generation Unit Capability Increased (Rerated or Relicensed)
	P	Planned Unit
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete

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Executive Summary

Florida Power & Light Company's (FPL) 2002 Ten - Year Power Plant Site Plan (Site Plan) addresses FPL's plans to increase its electric generation capability as part of its efforts to meet its projected incremental resource needs for the 2002 – 2011 time period.

FPL's total generation capability will significantly increase during the 2002 – 2011 time period as is shown in Table ES.1. This table also shows the resulting Summer and Winter reserve margins for FPL over this ten-year time horizon.

Table ES.1 reflects FPL's efforts to repower existing units at its Fort Myers and Sanford sites, planned changes to existing generation units (due to unit overhauls, etc.), and scheduled changes in the delivered amounts of purchased power. The table also reflects the planned additions of new generating units. Although not specifically shown in this table, FPL's approved DSM goals are assumed to be implemented on schedule.

The number of these new generating units that will be added is driven in part by the outcome of the Florida Public Service Commission docket No. 981890-EU. This docket ended with a stipulated agreement that resulted in FPL, along with Tampa Electric Company and Florida Power Corporation, switching from a minimum reserve margin planning criterion of 15% to one of 20% beginning with the Summer of 2004. As a consequence, FPL is now planning to add significantly more new generation capacity than was shown in its Site Plans filed prior to this agreement.

As shown in Table ES.1, FPL plans to add two new combustion turbines (CT's) at FPL's existing Fort Myers plant site in 2003. Also during the 2002 – 2003 time period, FPL will be completing its work to repower its two existing steam units at its Fort Myers site and two (unit Nos. 4 & 5) of its existing three steam units at its Sanford site.

FPL has also secured capacity for the time period from 2002 through early 2007 through a number of firm capacity, short-term purchases from utilities and other entities. (Please see Chapter III for a further discussion of these purchases.)

In 2005, FPL will be adding a large (1,107 Summer MW) new combined cycle (CC) unit at its existing Manatee plant site. Also in 2005, the two combustion turbines (CT's) that were added at FPL's existing Martin plant site in mid - 2001 will be converted into a 1,107 Summer MW CC unit by the addition of two additional CT's, heat recovery steam generators, and associated equipment. This conversion will add another 789 Summer MW of capability above the present capability of the existing two CT's. The additions for 2005 were selected as the best options among other FPL construction alternatives and numerous outside proposals received in response to a Request for Proposals FPL issued in August 2001.

In the 2007 through 2011 time frame, FPL tentatively plans to add 4 more CC units each with a projected Summer capability of 1,107 MW.[4] One unit will be added in each of the following years: 2007, 2009, 2010, and 2011 to meet projected load growth and to account for the scheduled end in 2010 of FPL's UPS contract with Southern Company. Sites for these four additional CC units have not yet been selected.

These planned increases in electric generation capability will allow FPL to continue to maintain system reliability and integrity at a reasonable cost.

[4] FPL's current planning studies have identified new combined cycle units as the generally preferred option to meet future load growth However, repowering of existing FPL sites remains an alternative to new construction, and FPL will continue to examine this option

Projected Capacity Changes and Reserve Margins for FPL (1)

		Net Capacity Changes (MW)		FPL Reserve Margin (%)	
		Winter (2)	Summer (3)	Winter	Summer
2002	Fort Myers Repowering:Second Phase (4)	(1)	35	18%	19%
	Sanford Repowering # 5: Initial Phase (5)	(390)	---		
	Sanford Repowering # 5: Second Phase (5)	---	567		
	Sanford Repowering # 4: Initial Phase (5)	---	(390)		
	Changes to existing units	10	30		
	New purchases (6)	593	897		
	Changes to existing QF's	---	(9)		
2003	Fort Myers Repowering:Second Phase	531	---	31%	23%
	Sanford Repowering # 5: Second Phase	1,065	---		
	Sanford Repowering # 4: Second Phase (7)	675	957		
	Combustion Turbines (2) Fort Myers (8)	---	318		
	Changes to existing QF's	(9)	---		
	Changes to existing units	20	---		
	New purchases (6)	724	71		
2004	Combustion Turbines (2) Fort Myers	362	---	31%	21%
	New purchases (6)	39	---		
2005	Changes to existing QF's	(10)	(10)	28%	24%
	New purchases (6)	(50)	(717)		
	Manatee Combined Cycle	---	1,107		
	Conversion of MR CT's to CC	---	789		
2006	Manatee Combined Cycle	1,197		31%	21%
	Conversion of MR CT's to CC	835	---		
	New purchases (6)	(763)	---		
	Changes to existing QF's	(133)	(133)		
2007	New purchases (6)	---	(447)	29%	22%
	Unsited Combined Cycle #1 (9)		1,107		
2008	New purchases (6)	(543)		30%	21%
	Unsited Combined Cycle #1 (9)	1,197	---		
2009	Unsited Combined Cycle #2 (9)	---	1,107	28%	24%
	Changes to existing QF's	(51)	(51)		
2010	Changes to existing purchases (10)	---	(975)	31%	23%
	Unsited Combined Cycle #2 (9)	1,197	---		
	Unsited Combined Cycle #3 (9)	---	1,107		
2011	Unsited Combined Cycle #3 (9)	1,197	---	30%	25%
	Unsited Combined Cycle #4 (9)	---	1.107		
	TOTALS =	***7,692***	***6,467***		

Table ES.1

Projected Capacity Changes and Reserve Margins for FPL

(1) Additional information about these capacity changes and resulting reserve margins is found in Chapter III of this document.

(2) Winter values are values for January of year shown.

(3) Summer values are values for August of year shown.

(4) The initial phase of the Fort Myers repowering project consists of the introduction of operational combustion turbines followed by taking existing steam units out-of-service. The second phase of repowering consists of completing the integration of the combustion turbines, heat recovery steam generators, and steam turbines.

(5) The initial phase of the Sanford repowering project consists solely of taking existing steam units # 4 and # 5 out-of-service; combustion turbine operation is not introduced at this time. The second phase of the repowering consists of integrating the combustion turbines, heat recovery steam generators, and steam turbines.

(6) These are firm capacity, shorter - term purchases. See Section I.D and III.A. for more details.

(7) The values shown reflect the schedule for the repowering of Sanford Unit # 4 that was used in FPL's 2001 resource planning work. That schedule has recently changed. Please refer to Section III.A, "Step 1" for more information. The only reserve margin effect will be to lower FPL's Winter 2003 reserve margin from 31% to 29%.

(8) The two CTs at Fort Myers are scheduled to be in-service in the Spring of 2003. Therefore, the CTs are included in the 2003 Summer reserve margin calculation and are included in the 2004 - on reserve margin included in the calculations for Summer and Winter.

(9) All new combined cycle units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

(10) FPL will be determining at a later date whether to extend or replace the UPS purchases (928 MW) from Southern Company. However, for purposes of this Site Plan, FPL has assumed that the 2010 needs would be met through the addition of unsited combined cycles.

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 7.7 million people. FPL served an average of 3,935,281 customer accounts in thirty-five counties during 2001. These customers were served from a variety of resources including: FPL-owned fossil and nuclear generating units, non-utility-owned generation, demand side management, and interchange/purchased power.

I.A. FPL- Owned Resources

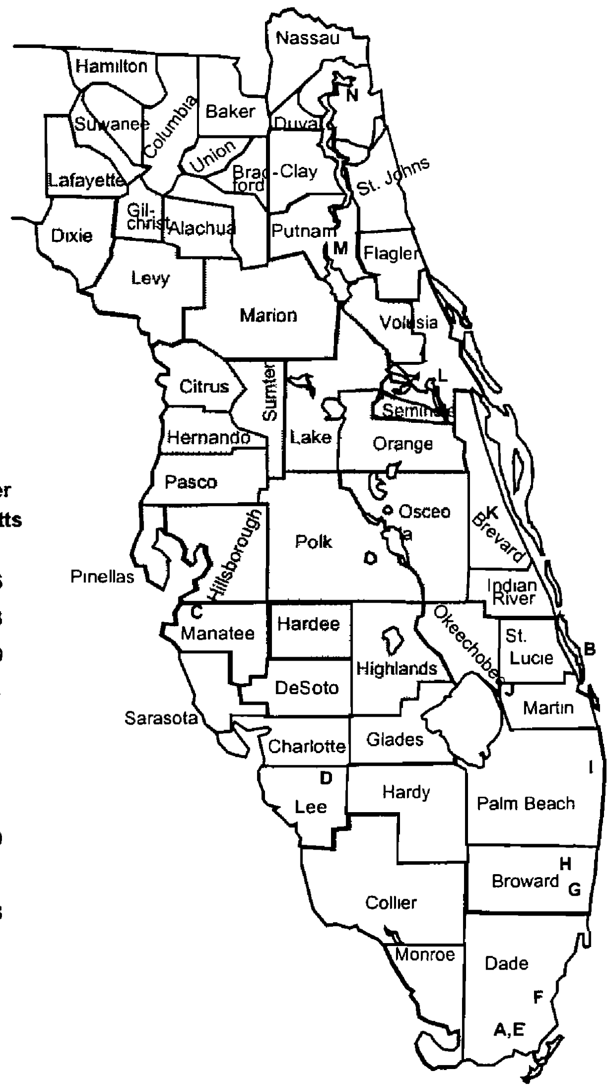
The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory and also include partial ownership of one unit located in Georgia and two units located in Jacksonville. The current generating facilities consist of four nuclear steam units, three coal units, six combined cycle units, twenty-one fossil steam units, fifty-six combustion gas turbines, and five diesel units. (Six of these fifty-six turbines are at Fort Myers and will be utilized later this year for the repowering project and another two of these fifty-six are at Martin and are planned to be used in a CT-to-CC conversion in 2005.) The location of these units is shown on Figure I.A.1.

The bulk transmission system is composed of 1,107 circuit miles of 500 Kilovolt (KV) lines (including 75 miles of 500 KV lines [two 37-1/2 mile lines] between Duval Substation and the Florida-Georgia state line, which are jointly owned with Jacksonville Electric Authority) and 2,644 circuit miles of 230 KV lines. The underlying network is composed of 1,578 circuit miles of 138 KV lines, 717 circuit miles of 115 KV lines, and 164 circuit miles of 69 KV transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 505 substations.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I A.2. In addition, Figure I.A.3. shows FPL's interconnection ties with other utilities.

Capacity Resources
(as of December 31, 2001)

☐ Non-FPL Territory



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F.	Cutler	2	Gas	213
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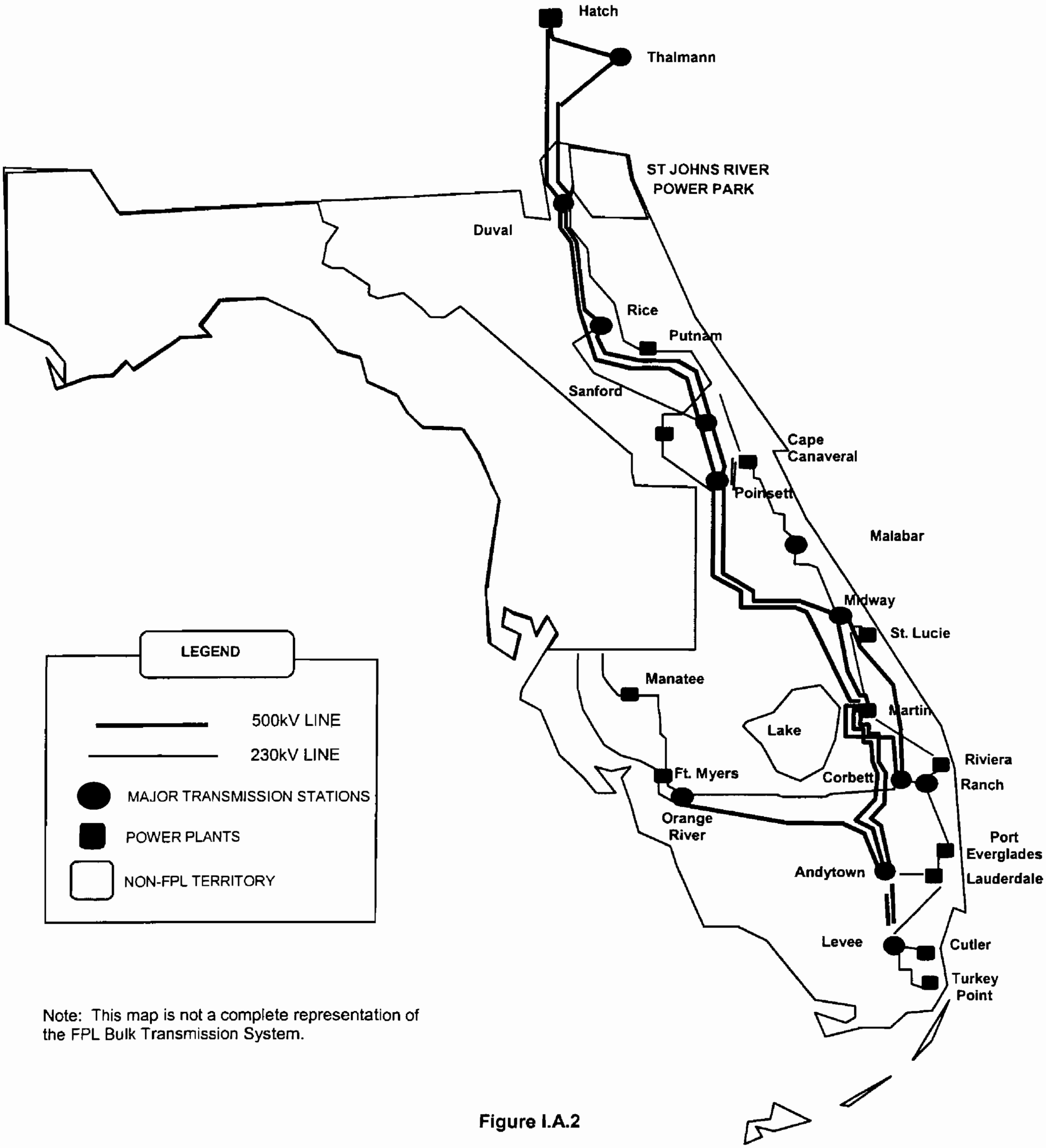
** Represents FPL's ownership share: St. Lucie nuclear: 100% unit 1, 85% unit 2; St. Johns River: 20% of two units*

*** The Scherer unit is located in Georgia and is not shown on this map.*

Figure I.A.1

FPL Substation and Transmission System Configuration



Note: This map is not a complete representation of the FPL Bulk Transmission System.

Figure I.A.2

FPL Interconnection Diagram
(115 to 500KV)

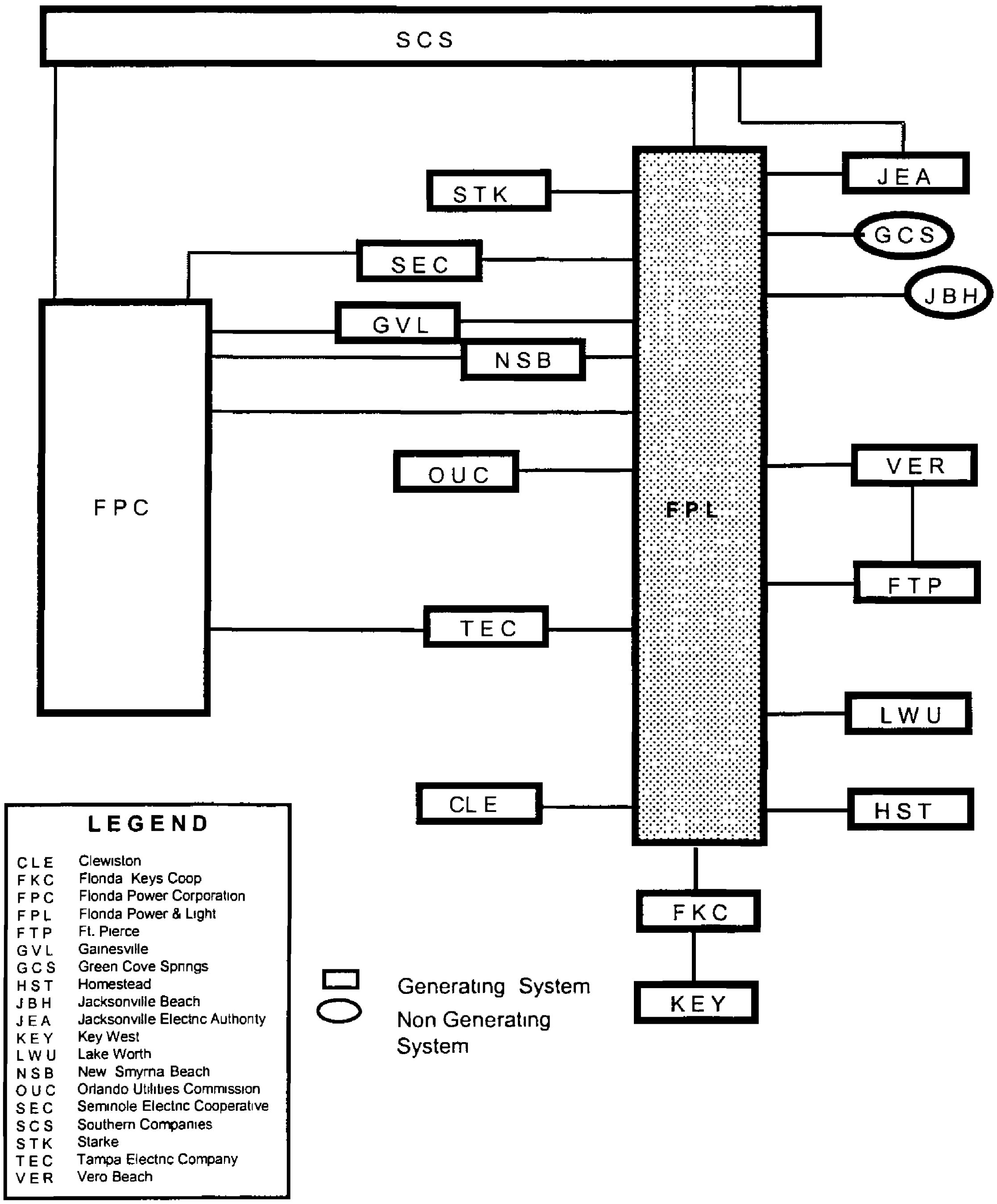


Figure I.A.3

I.B Non-Utility Generation

Non-utility generation is an important part of FPL's resource mix. FPL currently has contracts with eight cogeneration/small power production facilities to purchase firm capacity and energy. A listing of these facilities appears in Table I.B.1. In addition, FPL purchases as-available (non-firm) energy from several cogeneration facilities and small power production facilities as shown in Table I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

Florida Power & Light Company ***Firm Capacity and Energy Contracts with*** ***Cogeneration/Small Power Production Facilities***					
Project	***County***	***Fuel***	***MW Capacity***	***In-Service Date***	***End Date***
Bio-Energy	Broward	Landfill Gas	10.0	5/1/98	1/1/05
Broward South	Broward	Solid Waste	50.6	4/1/91	8/1/09
			1.4	1/1/93	12/31/26
			1.5	1/1/95	12/31/26
			0.6	1/1/97	12/31/26
Broward North	Broward	Solid Waste	45.0	4/1/92	12/31/10
			7.0	1/1/93	12/31/26
			1.5	1/1/95	12/31/26
			2.5	1/1/97	12/31/26
Royster Mulberry	Polk	Waste Heat	8.0	4/1/92	3/31/02
			1.0	12/1/95	3/31/02
Cedar Bay Generating Co.	Duval	Coal (CFB)	250.0	1/25/94	12/31/24
Indiantown Cogen., LP	Martin	Coal (PC)	330.0	12/22/95	12/1/25
Palm Beach SWA	Palm Beach	Solid Waste	43.5	4/1/92	3/31/10
Florida Crushed Stone	Hernando	Coal (PC)	110.0	4/1/92	10/31/05
			11.0	1/1/94	10/31/05
			12.0	1/1/95	10/31/05

Table I.B.1

As-Available Energy Purchases From Non-Utility Generators in 2001				
Project	***County***	***Fuel***	***In-Service Date***	***Energy (MWH) Delivered to FPL in 2001***
US Sugar-Bryant	Palm Beach	Bagasse	2/80	4,473
Tropicana	Manatee	Natural Gas	2/90	5,686
Okeelanta	Palm Beach	Bagasse/Wood	11/95	179,116
Tomoka Farms	Volusia	Landfill Gas	7/98	21,246
Georgia Pacific	Putnam	Paper By- Product	2/94	9,452

Table I.B.2

I.C. Demand Side Management (DSM)

FPL's DSM activities continue what has been FPL's practice since 1978 of encouraging cost-effective conservation and load management. FPL's DSM efforts through 2001 have resulted in a cumulative Summer peak reduction of approximately 3,076 MW at the meter and an estimated cumulative energy saving of 19,713 GWH at the meter.

FPL's current DSM Plan was approved by the Florida Public Service Commission in late 1999 and reflects FPL's new DSM Goals for the 2000 – 2009 time frame. FPL's 2001 resource plan and the schedule for new generation additions presented in this document, are based on these approved DSM levels.

I.D. Purchased Power

Purchased power remains an important part of FPL's resource mix. FPL has a unit power sales (UPS) contract to purchase 928 MW, with a minimum of 380 MW, of coal-fired generation from the Southern Company. In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 382 MW (Summer) and 389 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Unit Nos. 1 and 2 (FPL also has an ownership interest in these units; that ownership amount is reflected in FPL's installed capacity shown on Schedule 1).

Finally, FPL has new firm capacity purchase contracts for the 2002 to early 2007 time period. These firm capacity purchase contracts are with a variety of suppliers. Table I.D.1 presents the Summer and Winter MW resulting from all firm purchased power contracts through the year 2011.

	FPL's Purchased Power MW (1)							
	UPS		***SJRPP***		***New Firm Capacity Purchases*** (3)		***Total***	
Year	***Winter***	***Summer***	***Winter***	***Summer***	***Winter***	***Summer***	***Winter***	***Summer***
2001 (2)	928	928	389	382	0	196	1317	1506
2002	928	928	389	382	593	1093	1910	2403
2003	928	928	389	382	1317	1164	2634	2474
2004	928	928	389	382	1356	1164	2673	2474
2005	928	928	389	382	1306	447	2623	1757
2006	928	928	389	382	543	447	1860	1757
2007	928	928	389	382	542	0	1859	1310
2008	928	928	389	382	0	0	1317	1310
2009	928	928	389	382	0	0	1317	1310
2010	928	0	389	382	0	0	1317	382
2011	0	0	389	382	0	0	389	382

Note:

(1) Total reflects total resource entitlements resulting from existing agreements between FPL, Southern Companies, JEA, and from new firm purchase agreements.

(2) Values for 2001 are actual.

(3) A discussion of these new firm capacity purchases can also be found in Section III.A.

Table I.D.1

Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Summer	Winter
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Use	Month/Year	Month/Year	KW	MW	MW
Turkey Point		Dade County 27/57S/40E									2,338,100	2,198	2,253
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	400	404
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	400	403
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	760,000	693	717
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	760,000	693	717
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	14,000	12	12
Cutler		Dade County 27/55S/40E									236,500	213	216
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	74,500	71	71
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	162,000	142	145
Lauderdale		Broward County 30/50S/42E									1,863,972	1,694	1,804
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	521,250	425	443
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	521,250	429	447
	1-12		CT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,736	420	457
	13-24		CT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,736	420	457
Port Everglades		City of Hollywood 23/50S/42E									1,665,086	1,660	1,701
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	225,250	221	222
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	225,000	221	222
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	390	392
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	408	408
	1-12		CT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,736	420	457
Riviera		City of Riviera Beach 33/42S/43E									620,840	567	569
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	283	283
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	284	286

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Summer MW	(14) Net Capability 1/ Winter MW
Martin		Martin County 29/29S/38E									3,312,000	2,846	2,979
	1		ST	NG	FO6	PL	PL	Unknown	Dec-80	Unknown	863,000	814	826
	2		ST	NG	FO6	PL	PL	Unknown	Jun-81	Unknown	863,000	799	812
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	467	489
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	468	490
	8 A & B		CT	NG	FO2	PL	PL	Unknown	Jun-01	Unknown	362,000	298	362
St. Lucie		St Lucie County 16/36S/41E									1,553,000	1,553	1,579
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	839,000	839	853
	2	2/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	714,000	714	726
Cape Canaveral		Brevard County 19/24S/36E									804,100	806	812
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	403	406
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	403	406
Sanford		Volusia County 16/19S/30E									1,022,450	532	528
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	150,250	142	144
	4		ST	FO6	NG	WA	PL	Unknown	Jul-72	Unknown	436,100	390	384
	5	3/	ST	FO6	No	WA	No	Unknown	Jul-73	Unknown	436,100	0	0
Putnam		Putnam County 16/10S/27E									580,000	498	520
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,000	249	260
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,000	249	260

1/ These ratings are peak capability
2/ Total capability is 839/853 MW. Capabilities shown represent the company's share of the unit and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of 14.89551%.
3/ This unit was removed from service as part of the repowering project

Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel				Net Capability 1/	
Plant Name	Unit No.	Location	Unit Type	Fuel Pri.	Fuel Alt	Transport Pri	Transport Alt	Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen.Max. Nameplate KW	Summer MW	Winter MW
Fort Myers		Lee County 35/43S/25E									2,388,250	1,530	1,668
	1	4/	ST	FO6	No	WA	No	Unknown	Nov-58	Unknown	156,250	0	0
	2	4/	ST	FO6	No	WA	No	Unknown	Jul-69	Unknown	402,000	0	0
	1-12		CT	FO2	No	WA	No	Unknown	May-74	Unknown	744,000	636	690
	Repowering CT A		CT	NG	FO2	PL	PL	Unknown	Oct-00	Unknown	181,000	149	163
	Repowering CT B		CT	NG	FO2	PL	PL	Unknown	Nov-00	Unknown	181,000	149	163
	Repowering CT C		CT	NG	FO2	PL	PL	Unknown	Dec-00	Unknown	181,000	149	163
	Repowering CT D		CT	NG	FO2	PL	PL	Unknown	Apr-01	Unknown	181,000	149	163
	Repowering CT E		CT	NG	FO2	PL	PL	Unknown	May-01	Unknown	181,000	149	163
	Repowering CT F		CT	NG	FO2	PL	PL	Unknown	May-01	Unknown	181,000	149	163
Manatee		Manatee County 18/33S/20E									1,726,600	1,619	1,633
	1		ST	FO6	No	WA	No	Unknown	Oct-76	Unknown	863,300	809	816
	2		ST	FO6	No	WA	No	Unknown	Dec-77	Unknown	863,300	810	817
St. Johns River Power Park 2/		Duval County 12/15/28E (RPC4)									250,000	254	260
	1		BIT	BIT	No	RR	No	Unknown	Mar-87	Unknown	125,000	127	130
	2		BIT	BIT	No	RR	No	Unknown	May-88	Unknown	125,000	127	130
Scherer 3/		Monroe, GA									891,000	658	666
	4		BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	891,000	658	666
								Total System as of December 31, 2001 =				16,628	17,188

1/ These ratings are peak capability.
2/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80%.; SJRPP receives coal by water (WA) in addition to rail.
3/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.
4/ These units were removed from service as part of the repowering project

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CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are developed on an annual basis for resource planning work at FPL. These forecasts are a key input to the models used to develop the Integrated Resource Plan. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

The primary drivers to develop these forecasts are demographic trends, weather, economic conditions, and prices of electricity. In addition to these drivers, the resulting forecasts are an integration of economic evaluations, inputs of local economic development boards, weather assessments from NOAA, and inputs from FPL's own customer service planning areas. In the area of demographics, population trends by county, plus housing characteristics such as housing starts, housing size, and vintage of homes, are assessed.

Forecasts for electric usage in the residential and commercial classes include end-use information such as appliance saturation studies, efficiencies, and intensity of energy use. In addition to these inputs, residential forecasts also make use of household characteristics such as ages of members in household, number of members in households, and income distributions.

The projections for the National and Florida economy are obtained from DRI-WEFA. Population projections for the counties served by FPL are obtained from the Bureau of Economic and Business Research (BEBR) of the University of Florida. In addition, FPL actively participates with local development councils and universities to obtain their assessments of the local economy, specifically in the area of expansion of new businesses and retention of the current business base. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is a key factor that affects the company's sales and peak demand. Weather variables are used in the forecasting models for energy sales and peak demand. There are two sets of weather variables developed and used in forecasting models:

1. Cooling and Heating Degree Days are used to forecast energy sales.
2. Temperature data is used to forecast Summer and Winter peaks.

The Cooling & Heating Degree Days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric heaters. A composite temperature is derived using hourly temperatures across FPL's service territory (Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained) weighted by regional energy sales. This composite temperature is used to derive Cooling and Heating Degree Days which are based on starting point temperatures of 72°F and 66°F, respectively. Similarly, the maximum and minimum of the composite temperature is used for the Summer and Winter peak models.

II.A. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for each revenue class for the forecasting period of 2001 – 2020 and are adjusted to match the NEL forecast. The results of these sales forecasts for the years 2002 – 2011 are presented in Schedules 2.1 – 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical tool Metrix ND. The methodologies used to develop sales forecasts for each jurisdictional revenue class are outlined below.

The first five years of the forecasts were developed using monthly models for Net Energy For Load, Residential, Commercial and Industrial Sales. For the subsequent years the growth rates from the annual models are applied for Net Energy for Load and energy sales by class.

1. Residential Sales

Residential energy sales are forecast by multiplying the residential use per customer forecast by the number of residential customers forecasted. Residential electric usage per customer is estimated by using a regression model which contains the real residential price of electricity, Florida per capita income, and Cooling and Heating Degree Days as explanatory variables. The price of electricity plays a role in explaining electric usage since electricity, like all other goods and services, will be purchased in greater or lesser quantities depending upon its price. The Cooling & Heating Degree Days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric heaters. The Cooling Degree Days variable is multiplied by the level of air conditioning saturations and the Heating Degree Days variable is multiplied by the level of electric heating saturations. To capture economic conditions the model includes Florida's per capita income. The degree of economic prosperity can, and does, affect residential electricity sales. For the short-term period (first five years) a similar econometric model is developed using monthly data. The monthly model is a function of the same variables such as Cooling Degree Days, Heating Degree Days, price of electricity, Florida's total personal income and a dummy variable for the months of April, May and June along with an autoregressive term.

2. Commercial Sales

The commercial sales forecast is also developed using a regression model for the long and short term. Commercial sales are a function of the following variables: Florida's commercial employment, commercial real price of electricity, Cooling Degree Days and an autoregressive term. Florida's commercial employment is used to capture the economic activity in FPL's service territory. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. Cooling Degree Days are used to capture weather-sensitive load in the commercial sector. The first five years of the forecast are developed from a monthly model using the same explanatory variables, and for the following years, growth rates from the annual model are applied.

3. Industrial Sales

Industrial sales were forecasted through a linear multiple regression model using Florida manufacturing employment, the price of electricity and an autoregressive term as explanatory variables. Energy sales in this revenue class are primarily due to manufacturers; therefore, employment in this sector is a key variable in capturing the economic activity. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. The first five years of the forecast are developed from a monthly model using the same explanatory variables, and for the following years, growth rates from the annual model are applied.

4. Other Public Authority Sales

At present this class consists of sports fields and one government account. The forecast for this class is based on historical knowledge of its characteristics.

5. Street & Highway Sales and Railroad & Railways Sales

The forecast of Street & Highway sales are was developed using a constant use per customer, which is multiplied by the number of customers projected.

The growth in sales for Railroads & Railways are held constant since there are no plans for expansion.

6. Resales Sales

Resale (Wholesale) customers are composed of municipalities and/or electric cooperatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers.

Contract Rate

Currently, there are four customers in this class: the Florida Keys Electric Cooperative (Florida Keys), City Electric System of the Utility Board of the City of Key West, Florida (City of Key West), Metro-Dade County, and FMPA. Sales to the Florida Keys are forecasted using a regression model. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor. Metro-Dade County sells 60 MW to Florida Power Corporation. Line losses are billed to Metro-Dade under a wholesale contract. The forecast is calculated based on assumptions about the magnitude of line losses, the sales monthly capacity factor, and the number of hours in a particular month. FMPA has contracted for delivery of 75 MW for the period of June 2002 through October 2007.

Total Sales

Sales forecasts by revenue class are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, an expansion factor is applied to generate a forecast of annual Net Energy for Load (NEL).

II.B. Net Energy for Load

An annual econometric model is developed to produce a Net Energy for Load (NEL) forecast. The key inputs to the model are: the price of electricity, Heating & Cooling Degree Days, and Florida Non-Agricultural Employment. The Cooling Degree Days are multiplied by cooling saturation; similarly the Heating Degree Days are multiplied by heating saturation. The monthly model is similar except the economic variable utilized is Florida's per capita income, since the model is estimated on a per customer basis. Like the sales forecasts, the first five years are obtained from the short-term model and forecasts for subsequent years are generated using the growth rates from the annual model.

Once an annual NEL forecast is obtained using the above-mentioned methodology, the results are then compared for reasonableness to the NEL forecast generated using the total sales forecast. The sales by class are then adjusted to match the NEL from the annual NEL model.

The forecasted NEL values for 2002 – 2011 are presented in Schedule 3.3 which appears at the end of this chapter. (While the forecasted value for 2001 was used during the 2001 IRP process, the form reflects the actual value for 2001.)

II.C. System Peak Forecasts

The rate of absolute growth in FPL system load has been a function of a larger customer base, varying weather conditions, continued economic growth, changing patterns of customer behavior (including an increasing stock of electricity-consuming appliances), and more efficient heating and cooling appliances. FPL developed the Peak Forecast models to capture these behavioral relationships.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2002 - 2011 are presented in Schedules 3.1 and 3.2, as well as in Schedules 7.1 and 7.2. (While the forecasted value for 2001 was used during the 2001 IRP process, the form reflects the actual value for 2001.)

System Summer Peak

The Summer peak forecast is developed using an econometric model. The model is a per customer model that includes: the total number off FPL Summer customers, the price of electricity, real Florida income as an economic driver, and the maximum temperature as a weather variable. The model is estimated using an autoregressive term.

System Winter Peak

Like the system Summer peak model, the Winter peak model is also an econometric model. The Winter peak model is a per customer model which consists of three weather-related variables: (1) the minimum temperature on the peak day, (2) a weather term which is a product of heating saturation and minimum Winter day temperature, and (3) Heating Degree Hours for the prior day until 9:00 a.m. of the peak day. In addition, the model also has an economic term, Real Florida Income. A dummy variable, which is used to capture the effects of larger homes, is multiplied by the minimum temperature.

Monthly Peak Forecasts

Monthly peaks for the 2001 - 2020 period are forecasted to provide information for the scheduling of maintenance for power plants and fuel budgeting. The forecasting process is basically the same as for the monthly NEL forecast; and consists of the following actions:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to seasonal peak (Summer = April-October, Winter = November-March).

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.D The Hourly Load Forecast

Forecasted values for system hourly load for the period 2001 - 2020 are produced using a System Load Forecasting "shaper" program. This model uses sixteen years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. These daily load shapes are ranked and used with forecasted monthly peaks, NEL, and calendars in developing an hourly forecast. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

Schedule 2.1
History and Forecast of Energy Consumption And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					Commercial		
Year	Population*	Members per Household	GWH	Average** No of Customers	Average KWH Consumption Per Customer	GWH	Average** No. of Customers	Average KWH Consumption Per Customer
1992	6,375,204	2.19	34,198	2,911,807	11,745	26,991	350,269	77,058
1993	6,486,127	2.18	36,360	2,975,479	12,220	28,508	358,679	79,481
1994	6,660,137	2.19	38,716	3,037,629	12,745	29,946	366,409	81,729
1995	6,806,337	2.20	40,556	3,097,192	13,094	30,719	374,005	82,135
1996	6,948,942	2.20	41,302	3,152,625	13,101	31,211	380,860	81,949
1997	7,105,582	2.21	41,849	3,209,298	13,040	32,942	388,906	84,703
1998	7,249,617	2.22	45,482	3,266,011	13,926	34,618	396,749	87,255
1999	7,412,734	2.22	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,603,543	2.23	46,320	3,414,002	13,568	37,001	415,295	89,096
2001	7,749,031	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,891,055	2.22	49,065	3,552,211	13,813	38,360	433,999	88,387
2003	8,029,615	2.22	51,340	3,616,387	14,196	39,745	444,604	89,395
2004	8,164,713	2.22	53,568	3,676,476	14,570	40,913	456,688	89,587
2005	8,296,344	2.22	55,902	3,739,451	14,949	42,018	468,420	89,702
2006	8,433,429	2 22	58,241	3,801,791	15,319	43,210	479,587	90,098
2007	8,570,515	2.22	59,857	3,858,417	15,513	44,317	488,478	90,724
2008	8,709,688	2.23	61,401	3,912,926	15,692	45,391	497,099	91,313
2009	8,850,948	2.23	62,961	3,966,369	15,874	46,461	505,533	91,905
2010	8,992,209	2.24	64,628	4,018,926	16,081	47,571	513,718	92,602
2011	9,134,785	2.24	66,282	4,070,702	16,283	48,478	521,756	92,913

* Population represents only the area served by FPL.
** Average No. of Customers is the annual average of the twelve month values

Schedule 2.2
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial					Other	Total**
		Average* No of	Average KWH Consumption	Railroads & Railways	Street & Highway Lighting	Sales to Public Authorities	Sales to Ultimate Consumers
Year	GWH	Customers	Per Customer	GWH	GWH	GWH	GWH
1992	4,054	14,788	274,135	77	353	721	66,393
1993	3,889	14,866	261,602	79	330	665	69,830
1994	3,845	15,588	246,658	85	353	664	73,608
1995	3,883	15,140	256,481	84	358	648	76,248
1996	3,792	14,783	256,515	83	368	577	77,334
1997	3,894	14,761	263,830	85	383	702	79,855
1998	3,951	15,126	261,233	81	373	625	85,131
1999	3,948	16,040	246,112	79	473	465	84,676
2000	3,768	16,410	229,592	81	408	381	87,959
2001	4,091	15,445	264,872	86	419	67	90,212
2002	3,947	15,147	260,552	81	417	61	91,930
2003	3,960	15,176	260,942	81	428	60	95,615
2004	3,969	15,143	262,106	82	438	60	99,030
2005	3,971	15,105	262,875	82	446	60	102,479
2006	3,977	15,077	263,746	83	455	60	106,024
2007	3,974	15,122	262,795	83	461	60	108,752
2008	3,956	15,168	260,821	83	468	60	111,360
2009	3,933	15,213	258,530	84	474	60	113,973
2010	3,912	15,259	256,386	84	481	60	116,736
2011	3,891	15,305	254,215	85	487	60	119,282

*Average No.of Customers is the annual average of the twelve month values.
**GWH=Column 4 + Column 7 + Column 10 + Column 13 + Column 14 + Column 15.

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWH	(18) Utility Use & Losses GWH	(19) Net* Energy For Load GWH	(20) Average ** No. of Other Customers	(21) Total Average*** Number of Customers
1992	702	6,002	73,097	4,374	3,281,238
1993	958	4,988	75,776	3,086	3,352,110
1994	1,400	5,367	80,376	2,560	3,422,187
1995	1,437	6,276	83,961	2,460	3,488,796
1996	1,353	5,984	84,671	2,480	3,550,748
1997	1,228	5,770	86,853	2,520	3,615,485
1998	1,326	6,205	92,662	2,584	3,680,470
1999	953	5,829	91,458	2,605	3,756,009
2000	970	7,059	95,989	2,694	3,848,401
2001	970	7,222	98,404	2,722	3,935,281
2002	1,207	7,021	100,158	2,805	4,004,161
2003	1,425	7,373	104,414	2,872	4,079,038
2004	1,446	7,567	108,042	2,931	4,151,237
2005	1,463	7,831	111,772	2,985	4,225,960
2006	1,482	8,097	115,602	3,036	4,299,491
2007	1,415	7,990	118,157	3,077	4,365,095
2008	1,081	8,108	120,549	3,116	4,428,309
2009	1,081	7,869	122,922	3,155	4,490,271
2010	1,081	7,631	125,448	3,193	4,551,096
2011	1,081	7,149	127,512	3,231	4,610,993

* GWH = Column 16 + Column 17 + Column 18
** Average Number of Customers is the annual average of the twelve month values.
*** Total = Column 5 + Column 8 + Column 11 + Column 20

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1992	14,661	223	14,438	0	234	151	248	51	14,179
1993	15,266	397	14,869	0	311	182	320	79	14,635
1994	15,179	409	14,770	0	392	220	354	125	14,433
1995	16,172	435	15,737	0	466	259	391	193	15,315
1996	16,064	364	15,700	0	531	339	414	296	15,119
1997	16,613	380	16,233	0	615	440	432	341	15,566
1998	17,897	426	17,471	0	656	480	441	359	16,800
1999	17,615	169	17,446	0	722	565	450	397	16,443
2000	17,808	161	17,647	0	767	626	456	432	16,585
2001	18,754	169	18,585	0	798	673	483	463	17,473
2002	19,131	146	18,985	0	805	83	487	39	17,717
2003	19,765	223	19,542	0	810	125	497	59	18,274
2004	20,226	225	20,002	0	817	167	507	79	18,656
2005	20,719	227	20,493	0	824	211	517	99	19,068
2006	21,186	227	20,959	0	829	255	525	120	19,457
2007	21,556	227	21,329	0	834	300	533	140	19,749
2008	21,870	152	21,718	0	839	347	541	159	19,984
2009	22,271	152	22,119	0	842	394	547	179	20,309
2010	22,687	152	22,535	0	844	410	548	185	20,700
2011	23,106	152	22,954	0	844	410	548	185	21,119

Historical Values (1992 - 2001):

Cols. (2) - (4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Cols. (7&9)), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.
Cols. (5) - (9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes GS-LC, CDR and GSD-LC.
Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: (10) = (2) -(6) -(8).

Projected Values (2002 - 2011):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2001 are incorporated into the forecast.
Cols. (5) - (9) represent all incremental conservation and cumulative load control. These values are projected August values and are based on projections with a 1/2001 starting point.
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: (10) = (2) - (5) - (6) - (7) - (8) - (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1992/93	12,964	102	12,862	0	242	195	275	48	12,447
1993/94	12,594	278	12,316	0	317	231	342	67	11,935
1994/95	16,563	635	15,928	0	393	265	360	93	15,810
1995/96	18,096	698	17,398	0	459	310	406	143	17,231
1996/97	16,490	626	15,864	0	731	368	418	154	15,341
1997/98	13,060	239	12,821	0	823	403	429	168	11,807
1998/99	16,802	149	16,653	0	1,218	438	417	182	15,167
1999/00	17,057	142	16,915	0	1,296	469	441	193	15,320
2000/01	18,199	150	18,049	0	972	493	448	201	16,779
2001/02	17,597	145	17,452	0	1,081	534	489	242	16,028
2002/03	19,551	121	19,430	0	1,085	78	458	22	17,908
2003/04	19,976	198	19,779	0	1,093	104	464	30	18,285
2004/05	20,418	199	20,218	0	1,102	128	470	38	18,680
2005/06	20,854	199	20,654	0	1,109	153	476	48	19,068
2006/07	21,204	199	21,005	0	1,116	177	481	57	19,373
2007/08	21,538	124	21,414	0	1,123	200	486	66	19,663
2008/09	21,966	124	21,841	0	1,129	223	491	75	20,048
2009/10	22,366	124	22,242	0	1,134	245	494	82	20,411
2010/11	22,785	124	22,661	0	1,134	245	494	82	20,830

Historical Values (1992/93 - 2001/02):

Cols. (2) - (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Cols. (7&9)), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.
Cols. (5) - (9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col (8), which also includes GS-LC, CDR and GSD - LC.
Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: (10) = (2) -(6) -(8).

Projected Values (2002/03 - 2010/11):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2001 are incorporated into the forecast.
Cols. (5) - (9) represent all incremental conservation and cumulative load control. These values are projected August values and are based on projections with a 1/2001 starting point.
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula. (10) = (2) - (5) - (6) - (7) - (8) - (9)

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	C/I Conservation	Retail	Sales for Resale GWH	Utility Use & Losses	Net Energy For Load	Load Factor(%)
1992	73,778	460	221	73,076	702	6,002	73,097	56.8%
1993	76,632	553	303	75,674	958	4,988	75,776	56.7%
1994	81,493	661	456	80,093	1,400	5,367	80,376	60.4%
1995	85,415	777	677	83,978	1,437	6,276	83,961	59.3%
1996	86,708	971	1,039	85,355	1,353	5,984	84,698	60.0%
1997	89,240	1,213	1,174	88,012	1,228	5,770	86,853	59.7%
1998	95,316	1,374	1,279	93,990	1,326	6,205	92,663	59.1%
1999	94,361	1,542	1,362	93,408	953	5,829	91,458	59.3%
2000	99,094	1,674	1,431	98,123	970	7,059	95,989	61.5%
2001	101,736	1,789	1,542	100,765	970	7,222	98,404	59 9%
2002	100,158	58	15	98,951	1,207	7,021	100,085	59.8%
2003	104,414	156	47	102,988	1,425	7,373	104,211	60 3%
2004	108,042	256	80	106,597	1,446	7,567	107,706	61 0%
2005	111,772	358	115	110,310	1,463	7,831	111,299	61.6%
2006	115,602	462	150	114,121	1,482	8,097	114,990	62.3%
2007	118,157	568	184	116,743	1,415	7,990	117,405	62.6%
2008	120,549	675	216	119,468	1,081	8,108	119,658	62.9%
2009	122,922	785	247	121,842	1,081	7,869	121,890	63.0%
2010	125,448	830	262	124,367	1,081	7,631	124,356	63.1%
2011	127,512	830	262	126,432	1,081	7,149	126,420	63 0%

Historical Values (1992 - 2001):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula. (2) =(3) + (4) + (8).
Cols. (3) & (4) are DSM values starting in January, 1988 through 2001 which contributed to the values in Cols (5) - (9).
Cols (5) & (6) are a breakdown of Net Energy For Load in Col (2) into Retail and Wholesale .
Col. (9) is calculated using Col. (8) from this page and Col (2), "Total", from Schedule 3.1. (9) = ((8)*1000) / ((2) * 8760)

Projected Values (2002 - 2011):

Col (2) represents Net Energy for Load w/o DSM values The values are calculated using the formula: (2) =(3) + (4) + (8).
Cols. (3) - (4) are forecasted values of the reduction on sales from incremental conservation.
Cols. (5) & (6) are a breakdown of Net Energy For Load in Col (2) into Wholesale and Retail .
Col. (9) is calculated using Col. (2) from this page and Col (2) "Total". from Schedule 3 1. (9) = ((8)*1000) / ((2) * 8760)

Schedule 4
Previous Year Actual and Two-Year Forecast of Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2001 ACTUAL		2002 * FORECAST		2003 * FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	18,199	8,074	18,968	7,375	19,551	7,708
FEB	13,268	6,541	16,070	6,859	16,563	7,190
MAR	14,611	7,442	14,353	7,368	14,793	7,703
APR	15,831	7,797	15,645	7,683	16,163	8,020
MAY	16,280	7,722	17,373	8,442	17,948	8,810
JUN	18,342	9,476	18,218	9,299	18,821	9,690
JUL	17,803	9,120	18,727	9,710	19,347	10,110
AUG	18,754	10,086	19,131	9,881	19,765	10,263
SEP	18,707	9,413	18,494	9,608	19,107	9,982
OCT	15,971	8,185	17,266	8,578	17,837	8,927
NOV	13,781	7,217	15,721	7,737	16,204	8,068
DEC	14,590	7,331	16,317	7,618	16,818	7,942
TOTALS		98,404		100,158		104,414

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation.

CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990's and has since utilized the process to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of potential new power plants, the primary subjects of this document, are determined as part of the IRP process work. This section discusses how FPL applied this process in its 2001 planning work.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental "steps" to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

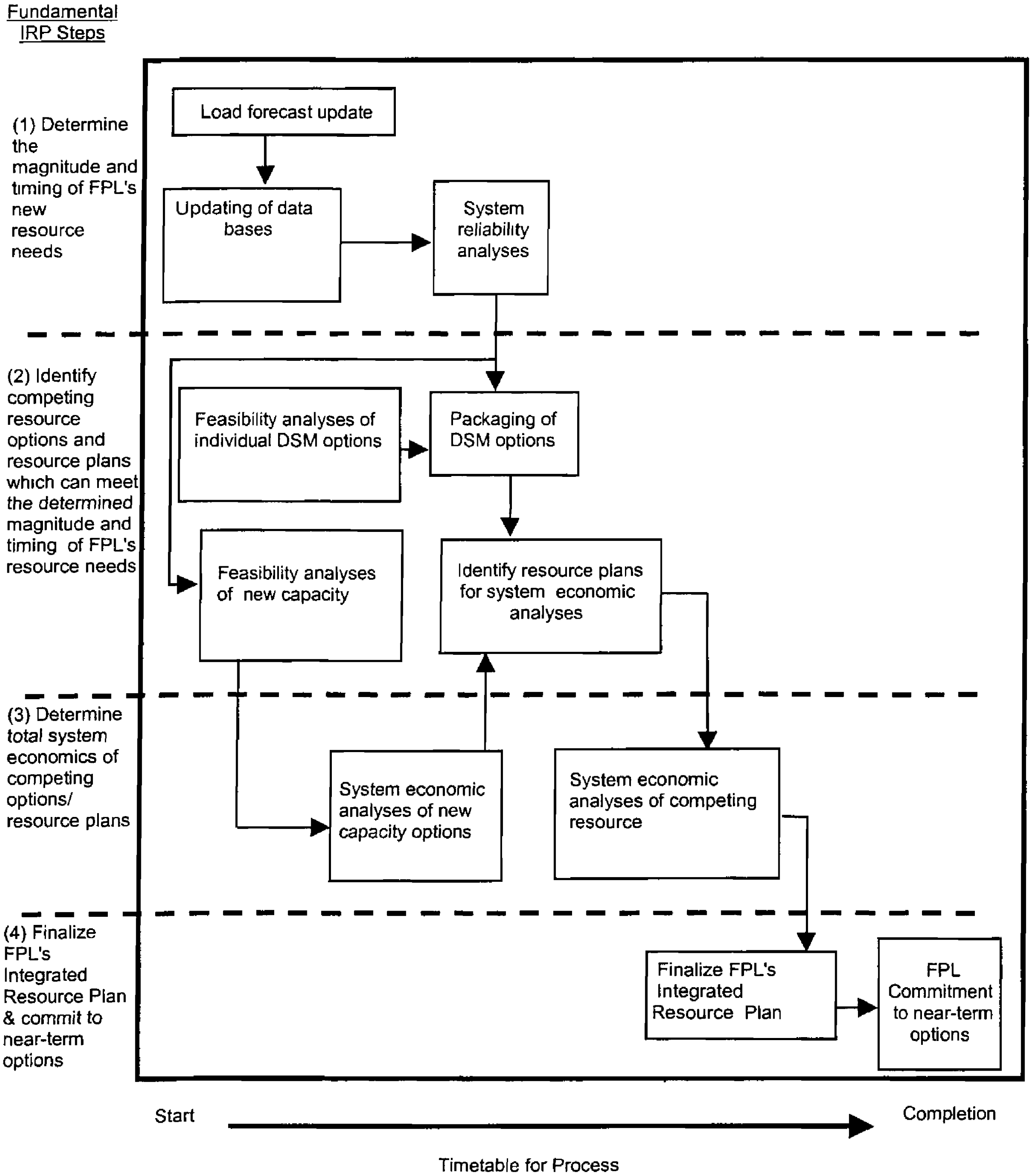
Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans;

Step 3: Determine the economics for the total utility system with each of the competing options and resource plans; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process



(Normal time period: approx. 6-7 months)

Figure III.A.1

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of these four resource planning steps – determining the magnitude and timing of FPL's resource needs – is essentially a determination of how many megawatts (MW) of load reduction, new capacity, or a combination of both load reduction and new capacity options are needed. Also determined in this step is when the MW are needed to meet FPL's planning criteria. This step is often referred to as a reliability assessment for the utility system.

Step 1 starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information which is used in many of the fundamental steps in resource planning. Examples of this new information include: delivered fuel price projections, current financial and economic assumptions, and power plant capability and reliability assumptions. Three assumptions made by FPL during its 2001 IRP work involved near-term construction capacity additions, near-term firm capacity purchase additions, and long-term DSM implementation.

The first of these assumptions included FPL's announced plans to add near-term capacity through various construction projects. These construction projects include the repowering of several existing units and the addition of several new CT's. FPL committed in 1998 to repower both existing steam units at its Fort Myers plant site and two of the three existing steam units at its Sanford plant site. These two repowering efforts will add significant capacity to FPL's system and will greatly increase the efficiency of the capacity at those two sites. The repowered Fort Myers capacity is scheduled to come in-service by the Summer, 2002. CT's, which are components of the repowering effort, began coming in-service at Fort Myers in late 2000 and through their initial operation in a stand-alone mode have already increased FPL's system capacity. A somewhat different schedule is planned for the two Sanford units which will be repowered. Both of these units will be repowered without the combustion turbine components coming in-service during the process. Sanford Unit # 5 came out-of-service in the Fall, 2001, and will return fully repowered by Summer, 2002. Sanford Unit # 4 was projected to come out-of-service in the Spring, 2002, and was assumed to return fully repowered at the end of 2002. As a result of this commitment, FPL assumed that these capacity additions resulting from the Fort Myers and Sanford repowerings were a "given" in its 2001 resource planning work.

Another part of FPL's construction capacity addition assumption was its previously announced (in last year's Site Plan) decision to add two new CT's 2003 at FPL's existing Fort Myers site. FPL's 2001 resource planning work assumed that these new CT construction capacity additions would also be a "given".

The second of these assumptions involved a decision which was made during FPL's 2000 resource planning work to secure an amount of capacity for the next few years through firm capacity, short-term purchases. These firm capacity purchases are from a combination of utility and independent power producers. These capacity purchases were not finalized at the time FPL filed last year's (2001) Site Plan, but were finalized later in 2001. The total capacity and duration of these purchase totals are both greater than projected in last year's Site Plan. The annual total capacity values for these purchases are presented in Table I.D.1. These purchase amounts are also assumed as a "given" in FPL's 2001 resource planning work.

The third of these assumptions involved DSM. Since 1994, FPL's resource planning work has used the DSM MW called for in FPL's approved DSM goals as a "given" in its analyses. This was again the case in FPL's 2001 planning work as its recently approved new DSM goals through the year 2009 were taken as a given.

The first place in which these assumptions and much of the other updated information and assumptions are used is the first fundamental step: the determination of the magnitude and the timing of FPL's resource needs. This determination is accomplished by system reliability analyses which are typically based on a dual planning criteria of a minimum peak period reserve margin of 15% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 days/year criteria. Both of these criteria are commonly used throughout the utility industry. The reserve margin criterion increases from 15% to 20% starting in mid - 2004 due to a voluntary agreement reached among FPL, FPC, and TECO, and accepted by the FPSC in the FPSC's Docket No. 981890-EU.

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analyses. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple calculation can be performed on a spreadsheet. It provides an indication of how well a generating system can meet its native load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as: unit reliability; unit numbers and sizes (i.e., two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time); and the value of being part of an interconnected system.

Therefore, probabilistic methodologies have been used to provide additional information on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss-of-load probability or LOLP. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does reserve margin analysis. Reserve margin analyses are typically carried out on a spreadsheet. The more complicated LOLP analyses are carried out using the Tie Line Assistance and Generation Reliability (TIGER) model.

The end result of the first fundamental step of resource planning is a projection of how many MW are needed to maintain system reliability and of when the MW are needed. This information is used in the second fundamental step: identifying resource options and resource plans which can meet the determined magnitude and timing of FPL's resource needs

Step 2: Identify Resource Options and Plans Which Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, feasibility analyses of new capacity options are carried out to determine which new capacity options appear to be the most competitive on FPL's system. These analyses also establish capacity size (MW) values, projected construction / permitting schedules, and operating parameters and costs.

The individual new capacity options are then "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new resource needs are met. The creation of these competing resource plans is typically carried out using dynamic programming techniques.

In recent years, FPL's analysis of new capacity options in its annual resource planning work has included only FPL construction options. The earliest date new capacity options were projected to be needed was in 2005. Prior to the 2001 planning cycle, the 2005 date was distant enough so that no actual construction/purchase decision was needed. However, in 2001, that was no longer the case. Furthermore, the type of new units FPL had been projecting for construction (combined cycle units) are among those addressed in the Florida Public Service Commission's "Bidding Rule" and thus require the issuance of a Request for Proposals (RFP) for meeting this capacity need.

FPL issued a Capacity RFP in mid – August of 2001. The RFP sought 1,150 MW of additional capacity by mid – 2005 and another 600 MW of additional capacity by mid – 2006. Fifteen (15) developers submitted one or more proposals in response to the RFP. In all, 81 proposals from these developers were evaluated along with 13 FPL construction options. Consequently, a much larger than usual number of generation options were evaluated in FPL's 2001 planning work.

At the conclusion of the second fundamental resource planning step in 2001, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs were identified. These resource plans were then compared on an economic basis.

Step 3: Determining the Total System Economics:

At the completion of fundamental Steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for comparing the system economics of these resource plans. FPL combines the resource options into resource plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI) and Stone & Webster Management Consultants, Inc. The EGEAS model is also used to perform the basic economic analyses of the resource plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of the competing resource plans is the competing resource plans' impact on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM methodology). However, in cases such as existed for FPL's 2001 planning work in which the DSM contribution was taken as a "given" and the only competing options were new generating units or purchases, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. Consequently, for FPL's 2001 resource planning work, the competing options and plans were evaluated on a present value system revenue requirement basis.

The basic economics analyses carried out with the EGEAS model focus on the capital and operating costs of new capacity options plus the impact these new capacity options have on FPL's system fuel costs. In FPL's 2001 analyses, three other costs were also evaluated. These three additional costs were: generator startup costs, transmission integration costs, and equity penalty costs. Once these three costs were calculated for the competing resource plans, they were added to the EGEAs costs to derive total costs.

In addition to FPL's own work that was carried out with the EGEAS model, an independent evaluator, Sedway Consulting, performed its own analyses of the outside proposals and FPL construction options. Sedway Consulting utilized its won Response Surface Model (RSM) to perform its basic economic analyses, then added in the generator startup costs, transmission integration costs, and equity penalty costs utilized by FPL. Finally Sedway Consulting used its RSM-derived estimate of residual benefits for FPL's construction options to derive its own total cost projections for the competing resource plans. Sedway Consulting's analyses came to the same conclusion as FPL analyses: FPL's Martin Conversion project and Manatee CC unit were the most cost-effective alternatives.

At the conclusion of the analyses carried out in Step 3, a determination of FPL's preferred resource plan was made.

Step 4: Finalizing FPL's 2001 Resource Plan

The results of the previous three fundamental steps' activities were evaluated by FPL management and a decision was made as to what FPL's 2001 resource plan would be. This plan is presented in the following section.

This evaluation focused both on the economics of the competing resource plans and on various non – price factors that essentially address risks associated with these plans. Both the economics and risk considerations favored the construction of the Manatee and Martin units.

III.B Incremental Resource Additions

FPL's projected incremental generation capacity additions/changes for 2002 through 2011 are depicted in Table III.B.1. (The planned DSM additions are shown separately in Table III.C.1.) These capacity additions/changes will result from a variety of actions including: changes to existing units (which are typically achieved as a result of plant component replacements during major overhauls), changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, repowering of existing units, projected construction of new units, and conversion of CT's into CC's.

As shown in Table III.B.1, the bulk of the capacity additions are made up of the following items: the repowering of both existing steam units at FPL's Fort Myers site by Summer, 2002; a similar repowering of FPL's Sanford Unit # 5 and # 4 projected by the Summer, 2002, and the end of 2002, respectively; the construction of two new CT's by mid – 2003, the conversion of two CT's into a larger CC unit in 2005 at FPL's Martin site; the addition of a new CC unit also in 2005 at FPL's Manatee site, new firm capacity, shorter-term purchases through early 2007; and the construction of four additional unsited CC units in the 2007 through 2011 time frame.[1] (Note that during FPL's 2001 resource planning work the projected schedule for repowering Sanford Unit # 4 was for the unit to come off-line in March, 2002 and return to service in December, 2002. These dates have recently been changed to August, 2002 and June, 2003, respectively. This schedule change has no effect on the 2002 Summer reserve margin shown in this document, but will lower FPL's Winter 2003 reserve margin from approximately 28% to 26%.)

The number of CC units which are projected to be built in FPL's 2002 Site Plan has decreased compared to the number of CC units shown in the 2001 Site Plan. This is due to the fact that the projected capacity of the new CC units has approximately doubled (i.e., approximately 1,100 MW from 550 MW) from last year's projections due to a preferred new design approach that utilizes 4 CT's instead of 2 CT's for each CC unit.

As first presented in last year's site plan, this site plan also shows capacity additions needed in 2010 to replace approximately 930 MW of firm capacity purchases from the Southern Company that are scheduled to end in 2010. The end of these purchases requires FPL to replace this capacity, as well as to meet projected load growth for 2010, in a way which meets a minimum 20% reserve margin requirement. While FPL has not yet determined whether it would extend or replace these purchases, or build new capacity to meet its needs, for purposes of this Site Plan it was assumed that the 2010 needs would be met through the addition of unsited CC units.

[1] FPL's current planning studies have identified new combined cycle units as the generally preferred option to meet future load growth However, repowering of existing FPL sites remains an alternative to new construction, and FPL will continue to examine this option.

Projected Capacity Changes for FPL [1]			
		Net Capacity Changes (MW)	
		Winter [2]	***Summer*** [3]
2002	Fort Myers Repowering:Second Phase [4]	(1)	35
	Sanford Repowering # 5: Initial Phase [5]	(390)	---
	Sanford Repowering # 5: Second Phase [5]	---	567
	Sanford Repowering # 4: Initial Phase [5]	---	(390)
	Changes to existing units	10	30
	New purchases [6]	593	897
	Changes to existing QF's	---	(9)
2003	Fort Myers Repowering:Second Phase	531	---
	Sanford Repowering # 5: Second Phase	1,065	---
	Sanford Repowering # 4: Second Phase [7]	675	957
	Combustion Turbines (2) Fort Myers [8]	---	318
	Changes to existing QF's	(9)	---
	Changes to existing units	20	---
	New purchases [6]	724	71
2004	Combustion Turbines (2) Fort Myers	362	---
	New purchases [6]	39	---
2005	Changes to existing QF's	(10)	(10)
	New purchases [6]	(50)	(717)
	Manatee Combined Cycle	---	1,107
	Conversion of MR CT's to CC	---	789
2006	Manatee Combined Cycle	1,197	
	Conversion of MR CT's to CC	835	---
	New purchases [6]	(763)	---
	Changes to existing QF's	(133)	(133)
2007	New purchases [6]	---	(447)
	Unsited Combined Cycle #1 [9]		1,107
2008	New purchases [6]	(543)	
	Unsited Combined Cycle #1 [9]	1,197	---
2009	Unsited Combined Cycle #2 [9]	---	1,107
	Changes to existing QF's	(51)	(51)
2010	Changes to existing purchases [10]	---	(975)
	Unsited Combined Cycle #2 [9]	1,197	---
	Unsited Combined Cycle #3 [9]	---	1,107
2011	Unsited Combined Cycle #3 [9]	1,197	---
	Unsited Combined Cycle #4 [9]	---	1,107
	TOTALS =	***7,692***	***6,467***

Table III.B.1

Projected Capacity Changes for FPL

Note:

(1) Additional information about these capacity changes and resulting reserve margins is found in Chapter III of this document.

(2) Winter values are values for January of year shown.

(3) Summer values are values for August of year shown.

(4) The initial phase of the Fort Myers repowering project consists of the introduction of operational combustion turbines followed by taking existing steam units out-of-service. The second phase of repowering consists of completing the integration of the combustion turbines, heat recovery steam generators, and steam turbines.

(5) The initial phase of the Sanford repowering project consists solely of taking existing steam units # 4 and # 5 out-of-service; combustion turbine operation is not introduced at this time. The second phase of the repowering consists of integrating the combustion turbines, heat recovery steam generators, and steam turbines.

(6) These are firm capacity, short - term purchases. See Section I.D and III.A. for more details.

(7) The values shown reflect the schedule for the repowering of Sanford Unit # 4 that was used in FPL's 2001 resource planning work. That schedule has recently changed. Please refer to Section III.A, "Step 1" for more information. The only reserve margin effect will be to lower FPL's Winter 2003 reserve margin from 31% to 29%.

(8) The two CT's at Fort Myers are scheduled to be in-service in the Spring of 2003. Therefore, the CT's are included in the 2003 Summer reserve margin calculation and are included in the 2004 - on reserve margin included in the calculations for Summer and Winter.

(9) All new combined cycle units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

(10) FPL will be determining at a later date whether to extend or replace the UPS purchases (928 MW) from Southern Company. However, for purposes of this Site Plan, FPL has assumed that the 2010 needs would be met through the addition of unsited combined cycles.

III.C Demand Side Management (DSM)

1. FPL's Current DSM Programs

FPL's currently approved DSM programs are summarized as follows:

Residential Conservation Service: This is an energy audit program which is designed to assist residential customers in understanding how to make their homes more energy-efficient through the installation of conservation measures/practices.

Residential Building Envelope: This program encourages the installation of energy-efficient ceiling insulation in residential dwellings that utilize whole-house electric air-conditioning.

Duct System Testing and Repair: This program encourages demand and energy conservation through the identification of air leaks in whole-house air conditioning duct systems and by the repair of those leaks by qualified contractors.

Residential Air Conditioning: This is a program to encourage customers to purchase higher efficiency central cooling and heating equipment.

Residential Load Management (On Call): This program offers load control of major appliances/household equipment to residential customers in exchange for monthly electric bill credits.

New Construction (BuildSmart): This program encourages the design and construction of energy-efficient homes that cost-effectively reduce coincident peak demand and energy consumption.

Business Energy Evaluation: This program encourages energy efficiency in both new and existing commercial and industrial facilities by identifying DSM opportunities and providing recommendations to the customer.

Commercial/Industrial Heating, Ventilating, and Air Conditioning: This program encourages the use of high-efficiency heating, ventilating, and air conditioning (HVAC) systems in commercial/industrial facilities.

Commercial/Industrial Efficient Lighting: This program encourages the installation of energy-efficient lighting measures in commercial/industrial facilities.

Business Custom Incentive: This program encourages commercial/industrial customers to implement unique energy conservation measures or projects not covered by other FPL programs.

Commercial/Industrial Load Control: This program reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits. (This program was closed to new participants in 2000).

Commercial/Industrial Demand Reduction: This program (which started in 2001) is similar to the Commercial/Industrial Load Control mentioned above by continuing the objective to reduce peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits.

Commercial/Industrial Building Envelope: This program encourages the installation of energy-efficient building envelope measures such as window treatments and roof/ceiling insulation for commercial/industrial facilities.

Business On Call: This program offers load control of central air conditioning units to both small, non-demand-billed and medium, demand - billed commercial/industrial customers in exchange for monthly electric bill credits.

2. Research and Development

FPL's DSM Plan continues to support research and development activities. Historically, FPL has performed extensive DSM research and development. FPL will continue such activities not only through its Conservation Research and Development program, but also through individual research projects. These efforts will examine a wide variety of technologies which build on prior FPL research where applicable and will expand the research to new and promising technologies as they emerge.

Conservation Research and Development Program

FPL's Conservation Research and Development Program is designed to evaluate emerging conservation technologies to determine which are worthy of pursuing for program development and approval. FPL has researched a wide variety of technologies and from that research has been able to develop new programs such as Residential New Construction, Commercial/Industrial Building Envelope, and Business On Call.

Low Income Weatherization Retrofit Project

This R&D project is investigating cost-effective methods of increasing the energy efficiency of FPL's low - income customers. The research project addresses the needs of low - income housing retrofits by providing monetary incentives to various housing authorities including weatherization agency providers (WAPS), and non-weatherization agency providers (non-WAPS). These incentives are used by the housing authorities to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting. FPL either conducts a home energy survey, trains housing authority employees to perform FPL home energy surveys, accepts the National Energy Audit (NEAT) (as supplemented to capture water heating recommendations not included in the NEAT audit), or approves similar FPL - approved audits conducted by weatherization providers to determine the need for energy efficient retrofit measures for each home. FPL has designed the project so as to minimize extra work for the retrofit housing authorities.

Photovoltaic Research, Development and Education Project

Photovoltaic (PV) roof-tile systems are a relatively new technology which directly replaces existing roofing materials such as shingles and standing-rib roofing with PV materials. These PV materials have the same water - proofing characteristics as conventional roofing materials. This project is consistent with the Federal Government's Million Solar Roofs initiative. However, based on FPL's research to - date, a primary hurdle to the physical installation of PV systems, whether roofing materials or flat plate modules, is the lack of awareness, understanding, and acceptance by local building officials. For the most part, these officials are unclear about how these systems work and how to address these systems as part of the building, permitting, and inspection process. This creates barriers toward the use of this technology.

Green Energy Project

FPL finished an R&D project addressing customer acceptance of green energy where donations were used as the funding mechanism for the purchase and installation of utility - grid connected PV systems. This project raised in excess of $89,500 and a 10.1 kW (dc) PV system has been constructed at FPL's Martin power plant site.

FPL is now investigating potential customer acceptance of green pricing rates in its Green Energy Project. Under this project, FPL is examining the feasibility of purchasing electric energy generated from new renewable resources including solar-powered technologies, biomass energy, landfill methane, wind energy, low impact hydroelectric energy, and/or other renewable resources. Participating customers would then be charged higher "green" electric rates for utilizing electric energy derived from these sources.

FPL's Request for Proposals (RFP) solicitation previously mentioned in Section III.A. also included a separate request for proposals that would supply energy only (MWH) from new, renewable energy sources. Several proposals were received in response to the RFP and the proposals are now being evaluated. This evaluation will determine whether the proposals are suitable for providing renewable energy that could be offered in a Green Energy program. A decision on this is expected by mid – 2002.

Real-Time Pricing

Although not part of FPL's approved DSM Plan, FPL continues to research new conservation/efficiency options such as Real-Time Pricing. This option is an experimental service offering for large C/I customers designed to evaluate customer load response to hourly, marginal cost-based energy prices provided on a day-ahead basis.

3. FPL's DSM MW Goals

FPL's DSM implementation plan is designed to meet currently approved DSM Goals for 2000 – 2009. The combined total residential and commercial/industrial Summer MW reduction values from FPL's DSM Goals for 2000 – 2009 are presented in Table III.C.1. FPL has already implemented approximately 2,790 MW at the meter of DSM through 2001.

FPL's Summer MW Reduction Goals for DSM
(At the Meter)

Year	Cumulative Summer MW
2000	122
2001	200
2002	269
2003	339
2004	410
2005	484
2006	554
2007	625
2008	697
2009	765

Table III.C.1

III.D Independent Power Producers Generation Additions

As previously mentioned in Section III.A, FPL has entered into a number of new firm capacity, shorter - term purchases that extend through early 2007. The capacity supplied by these purchases are summarized in Table I.D.1. All but 50 MW of these purchases are from independent power producers.

Tables I.B.1 and I.B.2 present the previously contracted cogeneration/small power production facilities which are addressed in FPL's resource planning.

III.E Transmission Plan

The 2002 - 2011 transmission plan will allow for the reliable delivery of the required capacity and energy for FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV and 500 kV bulk transmission lines.

List of Proposed Power Lines
2002 – 2011

OWNER	LINE TERMINAL (FROM)	LINE TERMINAL (TO)	NET NEW CIRCUIT MILES	COMMERCIAL IN-SERVICE DATE (Mo/YR)	NOMINAL OPERATING VOLTAGE (KV)
FPL	Fort Myers GT's	Orange River	2.56	Mar-02	230
FPL	Greynolds (Aventura)	Laudania	6.70	Mar-02	230
FPL	Brevard	Malabar #2	25.79	Jun-02	230
FPL	Brevard	Malabar #3	25.79	Jun-02	230
FPL	Broward-Corbett	Marymount-Yamato	0.25	Jun-03	230
FPL	Broward-Corbett	Rainberry-Yamato	10.50	Jun-03	230
FPL	Broward-Goolsby	Yamato	2.50	Jun-03	230
FPL	Cortez	Johnson	11.00	Jun-03	230
FPL	Delmar	Yamato	2.00	Jun-03	230
FPL	Duval-Kingsland	Yulee-Oneil	6.50	Jun-03	230
FPL	Midway	Turnpike	2.00	Jun-03	230
FPL	Charlotte-Laurelwood	Coast-Peachland	6.70	Dec-03	230
FPL	Andytown	Pennsuco	2.00	Jun-04	230
FPL	Dade	Overtown	11.00	Jun-04	230
FPL	Indiantown	Martin #2	11.80	Jun-05	230
FPL	Conservation	OaklandPark	13.00	Jun-07	230
FPL	Conservation	Levee	36.00	Jun-08	500

Table III.E.1

In addition, there will be transmission facilities needed to connect FPL's projected capacity additions to the system transmission grid. These transmission facilities for the projected capacity additions at FPL's existing Fort Myers, Sanford, Martin, and Manatee sites are described below. Since the projected capacity additions for 2007 through 2011 are as-yet unsited, no transmission facilities information is provided. This information will be provided in future Site Plan documents once a site is selected.

III.E.1 Transmission Facilities at Fort Myers

The transmission work required for the repowering capacity addition at Fort Myers is as follows:

I. Substation:

1. Substation work is complete.

II. Transmission:

1. Transmission work is complete.

III.E.2 Transmission Facilities at Sanford

The transmission work required for the repowering capacity additions at Sanford is as follows:

I. Substation:

1. Substation work is complete.

II. Transmission:

1. Upgrade the Volusia #2 transmission line to 1475 Amps.

III.E.3 Transmission Facilities at Fort Myers

The transmission work required for the two new CT units at Fort Myers is projected to be as follows:

I. Substation:

1. Build one collector bus with 2 breakers each to connect 2 CT's on each one. Add another breaker to the collector bus to connect the start-up transformer.
2. Add the two main step-up transformers (200MVA/each), one for each CT.
3. Add the start-up transformer.
4. Disconnect the existing Fort Myers GT collector bus from the Fort Myers 230kV switchyard.
5. Add two breakers at Orange River 230 kV substation to connect the new line from the Fort Myers GT collector bus.
6. Connect the new Fort Myers collector bus to the Fort Myers 230kV switchyard.
7. Connect the Fort Myers collector bus to the Fort Myers 230kV switchyard.
8. Replace 4 breakers at the existing Fort Myers 230 kV switchyard.
9. Add relay and other protective equipment at Fort Myers and Orange River substations.

II. Transmission:

1. Build a new 230 kV line from the Fort Myers GT collector bus to Orange River (approximately 2.57 miles) similar to the existing circuits which are bundle 2-1431 ACSR 2580 Amps (1028 MVA) each.
2. Add protection and control equipment for the new line.

III.E.4 Transmission Facilities at Manatee

The transmission work required for the new combined cycle unit at Manatee is projected to be as follows:

II. Substation:

1. Build new collector yard containing two collector busses with 7 breakers to connect the four CT's, one ST, and the two start-up transformers.
2. Construct two string busses to connect the collectors and main switchyard.
3. Add five main step-up transformers (4-200MVA, 450MVA) one for each CT, and one for the ST.
4. Add the start-up transformers.
5. Add two breakers in bay # 6 to connect the collector bus at the Manatee switchyard.
6. Add three breakers in bay # 5 at the Manatee switchyard to connect the other collector bus and a new transmission line to Johnson # 2.
7. Add relays and other protective equipment.
8. Upgrade 230kV circuit breakers to 2 cycle Independent Pole breakers at Manatee switchyard.
9. Add a new line terminal at Johnson.

II. Transmission:

1. Construct 230kV Manatee-Johnson # 2 transmission line.
2. Add protection and control equipment for the new lines.
3. Upgrade the Johnson- JohnsonTap 138kV transmission line to 656 Amps.
4. Upgrade the Charlotte- Fort Myers 230kV transmission line to 1081 Amps.

III.E.5 Transmission Facilities at Martin

The transmission work required for the Martin Conversion project (convert the existing two CT's to a new four -on- one combined cycle unit) is projected to be as follows:

I. Substation:

1. Build new collector yard containing one collector buss with 4 breakers each to connect the two CT's, one ST, and the start-up transformer.
2. Add three main step-up transformers (2-200 MVA, 450MVA) one for each CT, and one for the ST.
3. Add the start-up transformer.
4. Add two breakers in bay #3 to connect the collector bus in the main switchyard.
5. Add relays and other protective equipment.
6. Install phase reactors and string buss in main switchyard to limit fault current.
7. Add breaker in bay #7 (7WE) for new Indiantown #2 transmission line. Tap existing 69kV auto-transformer off east 230kV operating buss.
8. Add breaker in Bay #3 (3WS) at Indiantown Substation for Martin line.
9. Create new bay 1a. Add breakers 1aWM, 1aWS for Indiantown-Bridge#2 line at Indiantown Substation.
10. Create new bay#1 at Bridge Substation with breakers 1WW and 1WM. Add breakers 2WW and 2WE to convert station configuration from ring buss.
11. Construct one string bus to connect the collector and main switchyard.

II. Transmission:

1. Construct 230kV Martin-Indiantown #2 transmission line.
2. Construct 230kV Indiantown – Bridge #2 transmission line.
3. Various OHGW replacements due to increased fault current.
4. Upgrade the Ranch - Marlin(2005) 230kV transmission line to 2052 Amps.
5. Upgrade the Cedar - Marlin (2005) 230kV transmission line to 1965 Amps. (Note that this line is necessary only if both Manatee & Martin are constructed and it is presented here for ease of presentation.)

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to utilize renewable energy technologies to meet its customers' current and future needs. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various technologies.

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970's in demonstrating the first residential solar photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities on both a daily and annual basis in Florida. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10 kilowatt (KW) system was placed into operation in 1984. The testing of this PV installation was completed, and the system was removed in 1990 to make room for substation expansion.

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant site. The FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's recent Green Pricing effort (which is discussed on the following page).

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first and only utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was not cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980's, FPL introduced another renewable energy program. FPL's Passive Home Program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. Complete designs and construction blueprints for 6 passive homes were created by 3 Florida architectural firms with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building code. This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the Florida Public Service Commission to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test may be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, as well as customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

More recently, FPL has analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach does not require all of its customers to bear PV's high cost, but allows customers who are interested in facilitating the use of renewable energy the means to do so. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund, which FPL used to make PV purchases in bulk quantities. PV modules were then installed and delivered PV-generated electricity directly into the FPL grid. Thus, when sunlight is available at this site(s), the PV-generated electricity displaces an equivalent amount of fossil fuel-generated electricity.

FPL's basic approach, which has been termed Green Pricing, was initially discussed with the FPSC in 1994. FPL's initial efforts to implement this approach were then formally presented to the FPSC as part of FPL's DSM Plan in 1995 and FPL received approval from the FPSC in 1997 to proceed. FPL initiated the effort in 1998 and received approximately $89,000 in contributions which significantly exceeded the goal of $70,000. FPL has purchased the PV modules and installed them at FPL's Martin plant site.

As previously discussed, FPL initiated two new renewable efforts in 2000. FPL's first new initiative in 2000 was the Green Energy Project which is a second, different attempt to implement the basic Green Pricing approach. Under this project FPL would purchase electric energy generated from new renewable resources. The project would offer to supply to FPL's electrical grid the equivalent of all, or part of, a customer's monthly Kwh usage with electricity generated from new renewable resources, with the remaining portion of that load being served by the Company's conventional generating facilities. Participants would be residential (and possibly commercial) customers who would pay higher ("green" rates) for electricity provided from these renewable sources. As discussed in Section III.1, FPL issued a Request for Proposals (RFP) in 2001 to solicit proposals to supply energy only (MWH) from new renewable sources. Proposals have been received and are now being evaluated. Program feasibility is also being assessed.

The second effort initiated in 2000 is FPL's Photovoltaic Research, Development and Education Project. This demonstration project's objectives are to increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks as well as the energy capabilities of roof tile PV systems, and assess the homeowner's financial benefits and costs of PV roof tile systems for our customers.

Finally, FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy, and as-available energy, have been purchased by FPL from these developers. (Please refer to Tables I.B.1 and I.B.2).

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980's, FPL relied primarily on a combination of oil, natural gas, and nuclear energy to generate electricity. In 1986, coal was first added to the fuel mix, allowing FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources have been added with the partial acquisition (76%) of Scherer Unit # 4. In 1997, petroleum coke was added to the fuel mix as a blend stock with coal at the St. Johns River Power Park.

2. Fuel Price Forecasts

FPL's long-term oil price forecast assumes that worldwide demand for petroleum products will grow moderately throughout the planning horizon. Non-OPEC crude oil supply is projected to increase as new and improved drilling technology and seismic information will reduce the cost of producing crude oil and increase both recovery from existing fields and new discoveries. However, the rate of increase in non-OPEC supply is projected to be slower than that of petroleum demand, resulting in an increase in OPEC's market share throughout the planning horizon. As OPEC gains market share, prices for petroleum products are projected to increase.

FPL's natural gas price forecast assumes that domestic demand for natural gas will grow throughout the planning horizon, primarily due to increased requirements for electric generation. Domestic natural gas production will increase as new and improved drilling technology and seismic information will reduce the cost of finding, developing, and producing natural gas fields. The rate of increase in domestic natural gas production is assumed to be slower than that of demand, with the balance being supplied by increased Canadian and liquefied natural gas (LNG) imports. As demand for natural gas in Florida grows, it is anticipated that based on natural gas users' commitments, the Florida Gas Transmission (FGT) pipeline system will be augmented/expanded. This anticipated expansion of FGT's pipeline, combined with the new Gulfstream pipeline, should result in sufficient gas for FPL's continued needs.

Schedule 5
Fuel Requirements 1/

	Fuel Requirements	Units	Actual 2/		Forecasted									
			2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Nuclear	Trillion BTU	268	263	263	258	258	263	258	257	264	258	257	263
(2)	Coal	1,000 TON	4,170	3,078	3,460	3,584	3,416	3,396	3,479	3,194	3,513	3,110	3,113	3,281
(4)	Residual (FO6)- Total	1,000 BBL	36,859	40,995	57,569	26,714	23,538	20,417	18,661	17,222	16,514	11,535	9,609	7,905
(5)	Steam	1,000 BBL	36,859	40,995	57,569	26,714	23,538	20,417	18,661	17,222	16,514	11,535	9,609	7,905
(6)	Distillate (FO2)- Total	1,000 BBL	461	381	538	2,750	4,114	799	792	537	612	20	9	5
(7)	CC	1,000 BBL	1	75	124	2,220	3,404	683	677	486	549	10	3	3
(8)	CT	1,000 BBL	446	306	415	529	711	116	115	51	63	11	6	2
(9)	Steam	1,000 BBL	14	0	0	0	0	0	0	0	0	0	0	0
(10)	Natural Gas -Total	1,000 MCF	203,234	212,956	297,272	303,963	308,493	362,745	406,236	434,737	445,987	495,736	555,295	594,673
(11)	Steam	1,000 MCF	80,967	79,157	80,432	17,368	20,648	16,698	17,897	15,280	17,064	10,769	7,970	6,199
(12)	CC	1,000 MCF	117,684	109,778	196,898	274,488	277,953	337,081	384,738	414,787	424,908	482,040	546,027	587,265
(13)	CT	1,000 MCF	4,583	24,022	19,942	12,107	9,891	8,966	3,601	4,670	4,015	2,927	1,298	1,209

1/ Reflects fuel requirements for FPL only
2/ Source: A Schedules

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 2000	Actual 2001	Forecasted 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Annual Energy Interchange 2/	GWH	7,443	7,701	8,061	7,912	7,973	7,832	7,645	7,573	7,605	7,371	2,873	0
(2)	Nuclear	GWH	24,584	24,070	24,284	23,873	23,845	24,284	23,873	23,776	24,344	23,857	23,776	24,274
(3)	Coal	GWH	6,977	6,267	6,503	6,674	6,396	6,396	6,514	6,071	6,577	5,901	5,900	6,187
(4)	Residual(FO6) -Total	GWH	23,230	25,802	9,861	11,881	14,885	12,943	11,813	10,922	10,453	7,349	6,109	5,045
(5)	Steam	GWH	23,230	25,802	9,861	11,881	14,885	12,943	11,813	10,922	10,453	7,349	6,109	5,045
(6)	Distillate(FO2) -Total	GWH	193	163	278	1,979	2,979	592	581	408	461	13	5	3
(7)	CC	GWH	1	41	101	1,681	2,588	536	529	387	433	8	2	2
(8)	CT	GWH	183	122	177	298	391	55	52	22	28	5	3	1
(9)	Steam	GWH	9	0	0	0	0	0	0	0	0	0	0	0
(10)	Natural Gas -Total	GWH	24,217	24,496	40,313	41,995	41,809	49,873	56,309	60,446	62,208	69,722	78,684	84,556
(11)	Steam	GWH	7,840	7,588	11,524	2,340	1,881	1,527	1,643	1,402	1,577	996	734	569
(12)	CC	GWH	16,064	14,849	26,923	38,510	38,989	47,498	54,339	58,611	60,259	68,450	77,830	83,874
(13)	CT	GWH	313	2,060	1,866	1,144	940	848	327	433	372	275	120	113
(14)	Other 3/	GWH	9,345	9,905	10,858	10,101	10,155	9,852	8,867	8,961	8,901	8,710	8,101	7,446
	Net Energy For Load 4/	GWH	95,989	98,404	100,158	104,414	108,042	111,772	115,602	118,157	120,549	122,922	125,448	127,512

1/ Source: A Schedules.

2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.

3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc

4/ Net Energy For Load is Column 2 on Schedule 3.3 and Column 1 on EIA411 Form 11C.

Schedule 6.2
Energy % by Fuel Type

			Actual		Forecasted									
	Energy Source	**Units**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
(1)	Annual Energy Interchange 2/	%	7.8	8.0	8.0	7.6	7.4	7.0	6.6	6.4	6.3	6.0	2.3	0.0
(2)	Nuclear	%	25.6	24.5	24.2	22.9	22.1	21.7	20.7	20.1	20.2	19.4	19.0	19.0
(3)	Coal	%	7.3	6.4	6.5	6.4	5.9	5.7	5.6	5.1	5.5	4.8	4.7	4.9
(4)	Residual (FO6) -Total	%	24.2	26.2	9.8	11.4	13.8	11.6	10.2	9.2	8.7	6.0	4.9	4.0
(5)	Steam	%	24.2	26.2	9.8	11.4	13.8	11.6	10.2	9.2	8.7	6.0	4.9	4.0
(6)	Distillate (FO2) -Total	%	0.2	0.2	0.3	1.9	2.8	0.5	0.5	0.3	0.4	0.0	0.0	0.0
(7)	CC	%	0.0	0.0	0.1	1.6	2.4	0.5	0.5	0.3	0.4	0.0	0.0	0.0
(8)	CT	%	0.2	0.1	0.2	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	25.2	24.9	40.2	40.2	38.7	44.6	48.7	51.2	51.6	56.7	62.7	66.3
(11)	Steam	%	8.2	7.7	11.5	2.2	1.7	1.4	1.4	1.2	1.3	0.8	0.6	0.4
(12)	CC	%	16.7	15.1	26.9	36.9	36.1	42.5	47.0	49.6	50.0	55.7	62.0	65.8
(13)	CT	%	0.3	2.1	1.9	1.1	0.9	0.8	0.3	0.4	0.3	0.2	0.1	0.1
(14)	Other 3/	%	9.7	10.1	10.8	9.7	9.4	8.8	7.7	7.6	7.4	7.1	6.5	5.8
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules.

2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.

3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	Reserve Margin Before Maintenance 5/ % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	Reserve Margin After Maintenance 6/ % of Peak
2002	17,860	2,403	0	877	21,140	19,131	1,414	17,717	3,423	19.3	0	3,423	19.3
2003	19,135	2,474	0	877	22,486	19,765	1,491	18,274	4,212	23.0	0	4,212	23.0
2004	19,135	2,474	0	877	22,486	20,226	1,570	18,656	3,830	20.5	0	3,830	20.5
2005	21,031	1,758	0	867	23,656	20,719	1,651	19,068	4,588	24.1	0	4,588	24.1
2006	21,031	1,757	0	734	23,522	21,186	1,729	19,457	4,065	20.9	0	4,065	20.9
2007	22,138	1,310	0	734	24,182	21,556	1,807	19,749	4,433	22.4	0	4,433	22.4
2008	22,138	1,310	0	734	24,182	21,870	1,886	19,984	4,198	21.0	0	4,198	21.0
2009	23,245	1,310	0	683	25,238	22,271	1,962	20,309	4,929	24.3	0	4,929	24.3
2010	24,352	382	0	639	25,373	22,687	1,987	20,700	4,673	22.6	0	4,673	22.6
2011	25,459	382	0	594	26,435	23,106	1,987	21,119	5,316	25.2	0	5,316	25.2

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. All values are Summer net MW.

2/ Total Capacity Available=Col.(2) + Col (3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation from 1/99 - on. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance =Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	% of Peak
2001/02	17,730	1,910	0	886	20,526	18,968	1,589	17,379	3,147	18.1	0	3,147	18.1
2002/03	20,007	2,634	0	877	23,518	19,551	1,643	17,908	5,610	31.3	0	5,610	31.3
2003/04	20,369	2,673	0	877	23,919	19,976	1,691	18,285	5,634	30.8	0	5,634	30.8
2004/05	20,369	2,623	0	867	23,859	20,418	1,738	18,680	5,179	27.7	0	5,179	27.7
2005/06	22,402	1,860	0	734	24,996	20,854	1,786	19,068	5,928	31.1	0	5,928	31.1
2006/07	22,402	1,860	0	734	24,996	21,204	1,831	19,373	5,623	29 0	0	5,623	29.0
2007/08	23,598	1,317	0	734	25,649	21,538	1,875	19,663	5,986	30.4	0	5,986	30.4
2008/09	23,598	1,317	0	734	25,649	21,966	1,918	20,048	5,601	27.9	0	5,601	27.9
2009/10	24,795	1,317	0	683	26,795	22,366	1,955	20,411	6,384	31.3	0	6,384	31.3
2010/11	25,992	389	0	595	26,976	22,785	1,955	20,830	6,146	29.5	0	6,146	29.5

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col (4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based

5/ Margin (%) Before Maintenance = Col (10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col (9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No	Location	Unit Type	Pri	Alt	Pri	Alt	Start Mo./Yr	In-Service Mo./Yr	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS														
2002														
————		————	—	—	—	—	—	—	—	—	—	—	—	—
2003														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-00	Apr-03	Unknown	190,000	—	159	P
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	May-03	Unknown	190,000	—	159	P
2004														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	Apr-03	Unknown	190,000	181	—	P
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-00	May-03	Unknown	190,000	181	—	P
2005														
Manatee Combined Cycle Unit	3	Manatee County 18/33S/20E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	—	1,107	P
2006														
Manatee Combined Cycle Unit	3	Manatee County 18/33S/20E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	1,197	—	P
2007														
Unsited Combined Cycle Unit #1	1	Unknown	CC	NG	FO2	PL	PL	Jan-04	Jun-07	Unknown	470,000	—	1,107	P
2008														
Unsited Combined Cycle Unit #1	1	Unknown	CC	NG	FO2	PL	PL	Jan-04	Jun-07	Unknown	470,000	1,197	—	P
2009														
Unsited Combined Cycle Unit #2	2	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-09	Unknown	470,000	—	1,107	P
2010														
Unsited Combined Cycle Unit #2	2	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-09	Unknown	470,000	1,197	—	P
Unsited Combined Cycle Unit #3	3	Unknown	CC	NG	FO2	PL	PL	Jan-07	Jun-10	Unknown	470,000	—	1,107	P
2011														
Unsited Combined Cycle Unit #3	3	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-10	Unknown	470,000	1,197	—	P
Unsited Combined Cycle Unit #4	4	Unknown	CC	NG	FO2	PL	PL	Jan-07	Jun-11	Unknown	470,000	—	1,107	P

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (Cont.)

(1) Plant Name	(2) Unit No	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Const Start Mo/Yr	(10) Comm In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen Max Nameplate KW	(13) Net Capability Winter [1) 2)] MW	(14) Net Capability Summer [1), 2)] MW	(15) Status
CHANGES/UPGRADES														
2002														
Sanford Repowering Initial Phase [3)]	4	Volusia County 16/19S/30E	ST	FO6	NG	WA	PL	Mar-02	----	Unknown	106,600	0	(390) [4)]	RP
Sanford Repowering. Initial Phase	5	Volusia County 16/19S/30E	ST	FO6	NG	WA	PL	Oct-01	----	Unknown	106,600	(390) [4)]	0	RP
Sanford Repowering Second Phase	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	May-02	Jul-02	Unknown	106,600	0	567	RP
Ft Myers Repowering Second Phase	1&2	Lee County 35/43S/25E	CC	NG	No	PL	No	Nov-01	Jan-02	Unknown	161,700	(1)	35	RP,U
Riviera	4	City of Riviera Beach 33/42S/43E	ST	FO6	NG	WA	PL	Nov-01	Jan-02	Unknown	310,420	10	10	P
Martin Combustion Turbines	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	---	10	P
Martin Combustion Turbines	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	---	10	P
											2002 Total:	**(381)**	**242**	
2003														
Sanford Repowering Second Phase	4	Volusia County 16/19S/30E	CC	NG	No	PL	No	Sep-02	Dec-02	Unknown	106,600	675	957	RP
Sanford Repowering Second Phase	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	Sep-02	Dec-02	Unknown	106,600	1,065	0	RP
Ft. Myers Repowering Second Phase	1 & 2	Lee County 35/43S/25E	CC	NG	No	PL	No	Nov-02	Jan-03	Unknown	161,700	531	0	RP,U
Martin Combustion Turbines	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	10	---	P
Martin Combustion Turbines	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	10	---	P
											2003 Total:	**2,291**	**957**	
2004														
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											2004 Total:	**0**	**0**	
2005														
Martin Combustion Turbine Conversion	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	---	394 5	P
Martin Combustion Turbine Conversion	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	---	394.5	P
											2005 Total:	**0**	**789**	

1)The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by July All other MW will be picked up in the following year This is done for reserve margin calculation

2) All MW differences are calculated based on using IRP 2001 Submittal (for the year 2001) as the base for all other years

3) The values shown reflect the schedule for the repowering of Sanford Unit # 4 that was used in FPL's 2001 resource planning work. That schedule has recently changed Please refer to Section III A, "Step 1" for more information.

4) Negative values for Sanford and Ft Myers reflect the existing steam units being temporarily out of service during that seasonal period for repowering efforts

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (Cont.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm.	Expected	Gen Max	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter [1]	Summer [1]	
Plant Name	No	Location	Type	Pri	Alt	Pri	Alt	Mo /Yr	Mo /Yr	Mo /Yr	KW	MW	MW	Status
CHANGES/UPGRADES														
2006														
Martin Combustion Turbine Conversion	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	417 5	---	P
Martin Combustion Turbine Conversion	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	417 5	---	P
											2006 Total:	835	0	
2007														
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											2007 Total:	0	0	
2008														
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											2008 Total:	0	0	
2009														
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											2009 Total:	0	0	
2010														
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											2010 Total:	0	0	
2011														
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											2011 Total:	0	0	

1)The Winter Total MW value consists of all generation additions and changes achieved by January The Summer Total MW value consists of all generation additions and changes achieved by July All other MW will be picked up in the following year This is done for reserve margin calculation

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Fort Myers Repowering
(2)	**Capacity**		
	a. Summer	929	MW Incremental (1473 MW Total After Repowering)
	b. Winter	1,073	MW Incremental (1617 MW Total After Repowering)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	1999	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		None
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors
(7)	**Cooling Method:**		Once-through Cooling w/ Helper Cooling Tower
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	V	(Under Construction > 50% Complete)
(10)	**Certification Status:**	V	(Under Construction > 50% Complete)
(11)	**Status with Federal Agencies:**	V	(Under Construction > 50% Complete)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	Approx. 90%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	6,830	Btu/kWh
(13)	**Projected Unit Financial Data, *,**,*** **		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	559	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001$/kW-Yr)	13.45	
	Variable O&M ($/MWH): (2001 $/MWH)	0.37	
	K Factor:	1.5395	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Sanford Unit 4 Repowering
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	671	MW Incremental (1065 MW Total After Repowering)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		None
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	U	(Under Construction ≤ 50% Complete)
(10)	**Certification Status:**	U	(Under Construction ≤ 50% Complete)
(11)	**Status with Federal Agencies:**	U	(Under Construction ≤ 50% Complete)

(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	Approx. 96%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	6,918	Btu/kWh
(13)	**Projected Unit Financial Data *,**,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	656	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	14.41	
	Variable O&M ($/MWH): (2001 $/MWH)	0.374	
	K Factor:	1.4637	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Sanford Unit 5 Repowering
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	671	MW Incremental (1065 MW Total After Repowering)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	V	(Under Construction > 50% Complete)
(10)	**Certification Status:**	V	(Under Construction > 50% Complete)
(11)	**Status with Federal Agencies:**	V	(Under Construction > 50% Complete)

(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	Approx. 96%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	6,918	Btu/kWh
(13)	**Projected Unit Financial Data *,**,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	656	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	14.41	
	Variable O&M ($/MWH): (2001 $/MWH)	0.374	
	K Factor:	1.5395	

* $/kW values are based on incremental Summer capacity.

** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.

*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Fort Myers Combustion Turbines No. 13 and No. 14 *
(2)	**Capacity**		
	a. Summer	159	MW each for a total of 318 MW
	b. Winter	181	MW each for a total of 362 MW
(3)	**Technology Type:**		Combustion Turbine
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2001	
	b. Commercial In-service date:	2003	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NOx Combustors, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Air Coolers
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	U	(Under Construction ≤ 50% Complete)
(10)	**Certification Status:**	U	(Under Construction ≤ 50% Complete)
(11)	**Status with Federal Agencies:**	U	(Under Construction ≤ 50% Complete)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	1%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	98%	
	Resulting Capacity Factor (%):	Approx. 25%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	10,430	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	414	per Combustion Turbine
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	0.69	
	Variable O&M ($/MWH): (2001 $/MWH)	0.87	
	K Factor:	1.5394	

* Values shown are per unit values for the two units being added.
** $/kW values are based on Summer capacity.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Martin Combustion Turbine Conversion to Combined Cycle
(2)	**Capacity**		
	a. Summer	789	MW Incremental (1107 MW Total)
	b. Winter	835	MW Incremental (1197 MW Total)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Pond/Tower
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	L	(Regulatory Approval Pending)
(11)	**Status with Federal Agencies:**	L	(Regulatory Approval Pending)

(12)	**Projected Unit Performance Data ***		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	
	Resulting Capacity Factor (%):	Approx. 80%	(First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh
	Base Operation 75F	100%	
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	599	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	9.07	
	Variable O&M ($/MWH): (2001 $/MWH)	0.037	
	K Factor:	1.5397	

* Values represent an operational combined cycle unit after the conversion is completed.
** $/kW values are based on Summer incremental capacity.
*** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Manatee Combined Cycle
(2)	**Capacity**		
	a. Summer	1,107	MW
	b. Winter	1,197	MW
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		None
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	9,500	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	L	(Regulatory Approval Pending)
(11)	**Status with Federal Agencies:**	L	(Regulatory Approval Pending)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	
	Resulting Capacity Factor (%):	Approx. 71%	(First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh
	Base Operation 75F	100%	
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	511	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	12.96	
	Variable O&M ($/MWH): (2001 $/MWH)	0.037	
	K Factor:	1.5397	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 1		
(2)	**Capacity**			
	a. Summer	1,107	MW	
	b. Winter	1,197	MW	
(3)	**Technology Type:**	Combined Cycle		
(4)	**Anticipated Construction Timing**			
	a. Field construction start-date:	2005		
	b. Commercial In-service date:	2007		
(5)	**Fuel**			
	a. Primary Fuel		Natural Gas	
	b. Alternate Fuel		Distillate	
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Unknown		
(8)	**Total Site Area:**	Unknown	Acres	
(9)	**Construction Status:**	P	(Planned)	
(10)	**Certification Status:**	P	(Planned)	
(11)	**Status with Federal Agencies:**	P	(Planned)	
(12)	**Projected Unit Performance Data:**			
	Planned Outage Factor (POF):		2%	
	Forced Outage Factor (FOF):		1%	
	Equivalent Availability Factor (EAF):		97%	
	Resulting Capacity Factor (%):		Approx. 65%	(First Year)
	Average Net Operating Heat Rate (ANOHR):		7,021	Btu/kWh
(13)	**Projected Unit Financial Data *,****			
	Book Life (Years):		25	years
	Total Installed Cost (In-Service Year $/kW):		568	
	Direct Construction Cost ($/kW):			
	AFUDC Amount ($/kW):			
	Escalation ($/kW):			
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)		15.47	
	Variable O&M ($/MWH): (2001 $/MWH)		0.037	
	K Factor:		1.5399	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Combined Cycle No. 2

(2) **Capacity**
a. Summer 1,107 MW
b. Winter 1,197 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2007
b. Commercial In-service date: 2009

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Unknown

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 60%	(First Year)
Average Net Operating Heat Rate (ANOHR):	7,021	Btu/kWh

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	587	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	15.47	
Variable O&M ($/MWH): (2001 $/MWH)	0.037	
K Factor:	1.5399	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Combined Cycle No. 3

(2) **Capacity**
a. Summer 1,107 MW
b. Winter 1,197 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2008
b. Commercial In-service date: 2010

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Unknown

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 60%	(First Year)
Average Net Operating Heat Rate (ANOHR):	7,021	Btu/kWh

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	597	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	15.47	
Variable O&M ($/MWH): (2001 $/MWH)	0.037	
K Factor:	1.5400	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 4	
(2)	**Capacity**		
	a. Summer	1,107 MW	
	b. Winter	1,197 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2009	
	b. Commercial In-service date:	2011	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)

(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	
	Resulting Capacity Factor (%):	Approx. 52%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	7,021	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	607	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	15.47	
	Variable O&M ($/MWH): (2001 $/MWH)	0.037	
	K Factor:	1.5400	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Fort Myers Repowering

The transmission line work for this project has been completed.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sanford Repowering

The transmission line work for this project has been completed.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Ft. Myers: 2 CT's

(1)	Point of Origin and Termination:	From Ft. Myers GT Collector bus – To Orange River
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	2.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: January 1, 2003 End date: May 1, 2003
(7)	Anticipated Capital Investment:	$1,050,000
(8)	Substations:	Orange River and Ft. Myers GT collector bus
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Manatee CC Unit

(1)	Point of Origin and Termination:	Manatee – Johnson
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	18 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: June 1, 2004 End date: June 1, 2005
(7)	Anticipated Capital Investment:	$12,700,000
(8)	Substations:	Manatee and Johnson
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Martin CT – to - CC Conversion

(1)	Point of Origin and Termination:	Martin – Indiantown #2
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned & New acquisitions
(4)	Line Length:	12.9 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBA End date: TBA
(7)	Anticipated Capital Investment:	$9,400,000
(8)	Substations:	Martin 230kV and Indiantown
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	Indiantown – Bridge
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	10.0 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBA End date: TBA
(7)	Anticipated Capital Investment:	$10,300,000
(8)	Substations:	Indiantown and Bridge
(9)	Participation with Other Utilities:	None

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered plant and animal species. Population growth in our service area is continuing, which heightens competition for air, land, and water resources which are necessary to meet the increased demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

FPL has been recognized for many years as one of the leaders among electric utilities for our commitment to the environment. Our environmental leadership has been heralded by many outside organizations. For example, FPL was recently ranked first out of 30 major electric utilities surveyed in an environmental assessment conducted by Innovest, an independent advisory group. In 2001, FPL was awarded the 2001 Waste Reduction and Pollution Prevention Award from the Solid Waste Association of North America. We also received the 2001 Program Champion Award from the Environmental Protection Agency's Wastewise Program. The Florida Department of Environmental Protection named FPL a "Partner for Ecosystem Protection" for our emission-reducing "repowering" projects at our Fort Myers and Sanford plants. In addition, FPL has been recognized by numerous federal and state agencies for our innovative endangered species programs which include such species as manatees, crocodiles and sea turtles.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Statement in 1992 to clearly define the Company's position. This statement reflects how FPL incorporates environmental values into all aspects of the Company's activities and serves as a framework for new environmental initiatives throughout the Company. The FPL environmental statement further establishes a long-term direction of environmental responsibility for the Company. FPL's Environmental Statement is:

> It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:

- Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
- Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
- Encourage the wise use of energy to minimize the impact on the environment.
- Communicate effectively on environmental issues.
- Conduct periodic self-evaluations, report performance, and take appropriate actions.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an environmental management system to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program which is discussed below. Other components include: written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident/emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to: evaluate environmental performance, verify compliance with Company policy as well as with legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to: 1) facilitate management control of environmental practices; and, 2) assess compliance with existing environmental regulatory requirements and Company policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and public education. Some of FPL's 2001 environmental outreach activities are noted in Table IV.E.1.

2001 FPL Environmental Outreach Activities *

Site	Activity	# of Participants (approx.)
St. Lucie Plant	Turtle Beach Nature Trail Visitation	2,000
Riviera Plant & Fort Myers Plant	Manatee Awareness Activities	155,000
St. Lucie Plant	Turtle Walk Participation	802
St. Lucie Plant	FPL Energy Encounter	28,000
Not applicable	Inquiries - 800 enviromental information line and e-mails	3,800
Martin Plant	Barley Barber Swamp Visitation	2,200

Table IV.E.1

* A reduction in attendance at some of these facilities was observed due to changes in operation as a result of the events of September 11, 2001.

IV.F Preferred And Potential Sites

Based upon its projection of future resource needs, FPL has identified preferred and potential sites for future generation additions. These preferred and potential sites are discussed in separate sections below.

IV.F.1 Preferred Sites

FPL has identified four preferred sites: the existing Fort Myers plant site, the existing Sanford plant site, the existing Martin plant site, and the existing Manatee plant site. These four sites are currently the expected known locations for capacity additions that FPL projects to make during the 2002 – 2005 period. (Other capacity additions, in the form of new combined cycle units, are projected to be made in the 2007 through 2011 time period. Selection of sites for these later capacity additions is not yet needed and has not been made. Please see Table III.B.1).

The four preferred sites are discussed below. FPL has committed to repower existing units at both its Fort Myers and Sanford sites, to add new combustion turbine (CT) capacity at the Fort Myers site, to convert existing CT capacity into combined cycle (CC) capacity at the Martin site, and to add new CC capacity at the Manatee site.

Preferred Site # 1: Fort Myers Plant, Lee County

The site is located on the 460-acre Fort Myers property. Current facilities on the site include two steam electric generating units, nominally 150 MW and 400 MW respectively (which have recently been decommissioned as part of the repowering work), six CT's (that along with heat recovery steam generating (HRSG) units and the existing steam turbines will comprise the repowered facility); and a bank of 12 simple-cycle combustion turbine peaking units. The site has direct access to a four-lane highway, State Road (SR) 80, and barge access is available. The nearest town is Tice, which is approximately 4 miles west of the site. The City of Fort Myers is approximately 8 miles west of the site. The Fort Myers site has been listed as a potential or preferred site in previous FPL Site Plans.

Beyond the current repowering effort, FPL is planning to add two CT's at the site. The CT's are expected to be in service in the Spring of 2003 and will add 318 MW (Summer) and 362 MW (Winter) to FPL's system.

The repowering project currently underway at the site will add approximately 929 MW during Summer conditions and approximately 1,073 MW during Winter conditions. This project is expected to be completed in mid-2002.

The output capability of the existing bank of 12 CT's at the site will be unaffected by the repowering project and the addition of the two new CT's.

a. and b. U.S. geological Survey (USGS) Map and Proposed Facilities Layout Map

A USGS map of the Fort Myers plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter. It is pertinent to note that several designations on the current South Florida Water Management District Florida Land Use, Cover, and Forms Classification System (FLUCCS) appear to be in error, or to require some clarification. For example, the freshwater marsh identified toward the western boundary of the site is actually FPL's 50-acre evaporation/percolation pond. Similarly, while there are scattered mangroves along the shore, the "Central Mangrove" area shown is not mangrove but is the FPL switchyard for that site. The "Improved Pasture" shown towards the east of the site is currently the location of a tree nursery.

d. Existing Land Uses of Site and Adjacent Areas

The land on the site is primarily dedicated to industrial use with surrounding grassy and landscaped areas. There is the previously mentioned 50-acre evaporation/percolation pond on the site. Much of the site is currently being used for either direct construction activities or in support of the repowering project.

FPL has recently donated an 18-acre island, located north of the plant in the Caloosahatchee River, to the United States Fish & Wildlife Service (USFWS) for the purpose of wildlife conservation. This island has been owned by FPL since the 1950's, but has never been developed. The USFWS plans to incorporate the island into the Caloosahatchee National Wildlife Refuge.

Lee County operates Manatee Park (approximately 5 acres) with a manatee viewing area on FPL property to the east side of the discharge canal where it adjoins the Orange River south of SR 80. This manatee viewing area provides public viewing and education about the species. FPL leases the property to the county for a nominal amount.

The adjacent land uses are light commercial and retail to the south of the property and some residential areas located toward the west. Mixed scrub with some hardwoods and wetlands, plus agriculture land, can be found to the east and further to the south. The Caloosahatchee National Wildlife Refuge is located across the Caloosahatchee River, northwest of the power plant.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

The site is adjacent to the south bank of the Caloosahatchee River near the confluence of the Orange River and the Caloosahatchee. Much of the site is no longer in its original natural condition. However, a scattering of mangroves can be found along the river shoreline. Some mixed scrub with some hardwoods and wetlands can be found to the east and further to the south. Other than the occasional congregation of manatees noted below, FPL is not aware of any significant environmental features on the site or in the vicinity.

2. Listed Species

Construction and operation of the repowered facility, plus the new CT's at the site, are not expected to affect any rare, endangered, or threatened species. The only known listed species associated with the site are the West Indian Manatees (Trichechus manatus: Federal - and - State listed as Endangered) which are attracted to the warmed waters in the vicinity of the site discharge and can be found congregating in the area during cool weather.

The Florida Natural Areas Inventory (FNAI) reports the presence of the Eastern Indigo Snake (Drymarchons corais couperi: Federal - and - State listed as Threatened) and Tricolored Heron (Egretta tricolor: State - listed as a Species of Special Concern) within a two-mile radius of the site.

3. Natural Resources of Regional Significance Status

No Natural Resource of Regional Significance is identified on the plant site in the Southwest Florida Regional Strategic Policy Plan.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design options currently being pursued for the Fort Myers site are the repowering of the two existing oil-fired boilers with natural gas-fired CT's and HRSG's, plus the installation of two stand-alone CT's. All of this new generation equipment will be installed on the existing facility property and will make effective use of existing transmission facilities and infrastructure although some transmission line upgrades will be required. Steam developed in the new HRSG's will be directed to the existing steam turbines. FPL has contracted with Florida Gas Transmission (FGT) for a firm natural gas supply to the plant.

Mitigation options being planned for the capacity additions at Fort Myers include: the capture and reuse of plant process water, the use of combustion technology that is inherently low in air pollutant emissions, the reduction of oil barge traffic on the Caloosahatchee River, plumbing the sanitation system to Lee County's system and closing the on-site septic tanks, and closing the on-site ash basins.

g. Local Government Future Land Use Designations

The Local Government Future Land Use Plan designates the major portion of the site as Public Facilities and a small area as Resource Protection. Since there are no significant environmental resources on the site, and the "Resource Protection" designated area appears to be the location of a current tree nursery, FPL believes that this designation is in error.

h. Site Selection Criteria and Process

For the past several years, many of FPL's existing power plant sites have been considered potentially suitable sites for new, expanded, or repowered generation. The Fort Myers plant has been selected as a preferred site due to consideration of various factors including electrical transmission, system load, and economics. Environmental issues were not a deciding factor in FPL's site evaluation since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All of these sites are considered permittable.

i. Water Resources

The available surface water source is the Caloosahatchee River and the available groundwater source is the shallow aquifer.

j. Geological Features of Site and Adjacent Areas

The geology underlying the Fort Myers Plant consists of Quaternary Holocene and Pleistocene undifferentiated materials. The upper part of these undifferentiated materials consists of fine-to-medium-grained quartz sand with varying percentages of shell and clay. Hardpan frequently occurs at the base of the quartz sands. The lower section consists of shell beds with interbedded limestones. Underlying the undifferentiated materials are the Pliocene Tamiami formations, the Miocene Hawthorn formation, Oligocene Suwanee Limestone, the Eocene Crystal River and Williston formations, the Avon Park Limestone, and the Lake City Limestone.

Several stratigraphic units can be differentiated based upon shallow borings drilled on the plant property. Sand with some heterogeneous fill material related to past site construction activity covers most of the surface. It is underlain by layers of clayey sand and clay to a depth of approximately 23 feet. These units mantle a thicker clay unit with numerous shell fragments that occurs from 15 feet to about 55 feet below the surface. A silty sand with a trace of clay was encountered at 55 feet near the termination depth of one deep boring on the site.

The water table at the site occurs at levels from just under the surface to about 5 feet below grade. Locally, the surficial aquifer and surface water will generally flow toward the Caloosahatchee River. However, at the site, the intake and discharge canal will affect groundwater near the power block area. A drainage canal that borders the plant property on the west will affect groundwater flow along the western portion of the waste treatment area.

k. Projected Water Quantities For Various Uses

It is estimated that 150 gallons per minute (gpm) will be needed for industrial processing water for uses such as boiler makeup and service water. For industrial cooling (once-through cooling water), no significant increase is projected in the current 451,000 gpm usage rate. Other facility water uses may include irrigation, potable use, etc. The total volume of these uses is estimated to be about 5 gpm.

l. Water Supply Sources By Type

For industrial processing, FPL anticipates that groundwater will be available. For cooling water, for the repowered unit, FPL plans to continue to use its existing allocation from the Caloosahatchee River in a once-through cooling mode. The new CT's will be air-cooled.

m. Water Conservation Strategies Under Consideration

A plan to treat and recycle equipment wash water, boiler blowdown, and equipment area runoff for use as service water would reduce ground water consumption. FPL would anticipate this site being designed and classified as a wastewater zero-discharge site following the completion of the repowering work.

n. Water Discharges and Pollution Control

Heated water discharge will be dissipated using both the existing once-through cooling water system and a multi-cell cooling tower. Treating and recycling equipment wash water, boiler blowdown, and equipment area runoff will minimize industrial discharges. Storm water runoff will be collected and used to recharge the surficial aquifer via a stormwater management system. Design elements will be included to capture suspended sediments. Various facility permits mandate various sampling and testing activities, which will provide indication of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

A combustion turbine-based repowering project, plus the addition of the new CT's, requires a natural gas pipeline to be installed. Florida Gas Transmission has initiated permitting to install and operate such a facility. Virtually no waste is associated with natural gas firing.

p. Air Emissions and Control Systems

A natural gas-fired facility would generally have air pollutant emissions, that are substantially lower than emissions from the current oil-fired boilers. While several technologies are available for nitrogen oxide (NO_x) emissions control, FPL is using a dry-low-NO_x combustion turbine design. In these devices, combustion is staged in order to reduce the formation of combustion-derived oxides of nitrogen. FPL has proposed NO_x emission limits for this facility that will be among the lowest in the state once the facility is constructed. Sulfur dioxide and particulate emissions are intrinsically low due to the lack of sulfur and solids in natural gas fuel. Carbon monoxide and volatile organic compound emissions can each be controlled via the use of efficient combustion rather than through the use of add-on control devices. Carbon dioxide emission rates associated with burning natural gas are well below those of other liquid or solid fuels. While the Fort Myers plant site is located within 100 kilometers of a Class I area (Everglades National Park), the reduction in emissions associated with repowering is expected to improve the air quality in the area as compared to current levels. CC and CT facilities have been permitted at several locations throughout the state of Florida including near Class I areas. Dry-low-NO_x combustor systems have been repeatedly demonstrated to be the Best Available Control Technology (BACT) for the control of NO_x emissions for this technology pursuant to the requirements of the Clean Air Act.

q. Noise Emissions and Control systems

Lee County has a noise ordinance which limits noise at the receiving property line to 75 decibels. Noise emissions from the Fort Myers project are not anticipated to approach this level based upon demonstrated noise control at similar natural gas-fired facilities (the Lauderdale plant in Broward County and the Martin plant in Martin County) and computer modeling of the anticipated noise emissions from the Fort Myers repowered plant. FPL will undertake studies to assure that noise level associated with the new CT's comply with Lee County noise standard.

r. Status of Applications

FPL has received all the permits necessary to construct and start up the repowered plant and the two new CT units.

Preferred Site # 2: Sanford Plant, Volusia County

The site is located on the 1,718–acre FPL Sanford property just west of Lake Monroe on the north bank of St. Johns River in Volusia County. Current facilities on the site include three steam electric generating units (one with a nominal rating of 150 MW and two with nominal ratings of 400 MW). The site is within the city limits of Debary and the community of Debary is located approximately 2 miles to the northwest. The town of Deland is approximately 4 miles west of the site. The site has direct access to a four-lane highway, State Road (SR) 17-92, and barge access is available. The Sanford site has been listed as a potential or preferred site in previous FPL Site Plans.

FPL is currently in the process of adding new capacity at the Sanford site by replacing two existing oil-and gas-fired units (i.e., existing units # 4 and # 5) with advanced natural gas-fired combustion turbines (CT's) and heat recovery steam generators (HRSG's). This type of steam generation replacement is commonly called "repowering".

This repowering will enable FPL to produce significantly more electrical output with nearly the same environmental impact. The repowering of units # 4 and # 5 will each produce approximately 567 additional MW during Summer conditions, and approximately 671 additional MW of generation during Winter conditions, beyond the current capabilities of these units. The two repowered units # 5 and # 4 were projected to be in-service by mid-2002 and late-2002, respectively. The existing 150 MW unit # 3 at Sanford will be unaffected by the repowering of units # 5 and # 4.

a. and b. U.S. Geological Survey (USGS) Map and Proposed Facilities Layout Map

A USGS map of the Sanford plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A large part of the property is covered by the 1,100-acre closed-cycle-cooling pond which occupies almost all of the northern portion of the site. The remainder of the site is primarily rangeland and the power plant facilities.

The surrounding land use is largely crop land and pasture. To the east of the plant there is a small residential area and some commercial/industrial land use. There are some residential areas mixed in with the agricultural areas located between the site and the St. John's River to the west. To the south is the St. Johns River and residential homes and commercial/industrial businesses are located along the south side of the river.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

Small, scattered wooded areas can be found on the site. There are two small areas of wetland marsh on the site and a few acres of wetland forest along the riverbank. There are some wooded areas on the site, primarily upland coniferous forest. Forested and non-forested wetlands can be found to the west, adjacent to the river. Rover and wetland areas towards the northwest are designated as part of the Wekiwa River Aquatic Preserve and Wekiwa River State Preserve.

2. Listed Species

One inactive bald eagle (Haliaeetus leucocephalus: Federal - and - State listed as Threatened) nest has been found on the site. Bald eagles have also nested in the Lake Monroe area. There are a number of other eagle nests in the vicinity of the site, primarily along the St. Johns river. The Florida Natural Areas Inventory (FNAI) reports several Scrub Jay populations (Aphelocoma coerulescens: Federal - and - State listed as Threatened) located in scrub vegetation to the northwest of the site. West Indian Manatees (Trichechus manatus: Federal - and - State listed as Endangered) have also been found in this area.

3. Natural Resources of Regional Significance Status

The Wekiwa River Aquatic Preserve extends along the St. John's River in the vicinity of the plant.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option for the Sanford site is the repowering of two existing oil-and gas-fired boilers with natural gas-fired combustion turbines (CT's) and heat recovery steam generators (HRSG's). Advanced CT's can be installed on the existing facility property to make effective use of existing transmission facilities and infrastructure although some transmission line upgrades will be required. Steam produced in the new HRSG's will be directed to two of the existing steam turbines. Natural gas-fired facilities represent one of the cleanest, most efficient technologies currently available for capacity additions to FPL's system.

Mitigation options being considered in the repowering project at Sanford include the reduction in the use of ground water, the use of combustion technology that is inherently low in air pollutant emissions, reduction in the amount of solid waste generated, plumbing the sanitary waste system into the Volusia county system, and the significant reduction of oil barge traffic on the St. Johns River.

g. Local Governmental Future Land Use Designations

The site is designated as "Industrial Utilities" in the Local Government land use plan. The city is currently updating its Land Use Plan. It is expected that the name, but not the expected use designation, may change. Land use designation of the surrounding area is primarily Agricultural. There is an area of "Public Institution" around Lake Monroe to the southeast and a small area of "Mixed Use" to the west along Barwick Road.

h. Site Selection Criteria and Process

The Sanford plant has been selected as a preferred site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor in FPL's site evaluation since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All are considered permittable.

i. Water Resources

For surface water supply, the available water resource is the St. John's River and / or the on-site cooling pond, which is periodically refilled from the St. John's River. For groundwater supply, the available resources are the shallow aquifer or the Floridan Aquifer.

j. Geological Features of Site and Adjacent Areas

The near-surface geology of Volusia County, like that of most of north central Florida, is represented by late Tertiary and Quaternary geologic units. Soils in the vicinity of the plant include unconsolidated Pleistocene to Recent sands, with intervening beds of shells and clay. These deposits form the reservoir for the surficial aquifer in the county. Deposits of Pliocene or Miocene clay with some sand underlie the aquifer. These low-permeability units serve to confine groundwater under pressure in the underlying porous limestone formations of Eocene age. These formations are part of the principal hydrologic unit referred to as the Floridian Aquifer. This aquifer, the top of which generally occurs through the region at or below 100 feet, is the major source of potable groundwater in Volusia County. Two faults, one trending north-to-south, the other trending east-to west, intersect a number of miles north of the site. Downward displacement of the fault is hypothesized as being approximately 60 to 100 feet.

k. Projected Water Quantities for Various Uses

FPL has estimated that 150 gallons per minute (gpm) would be required for industrial processing purposes (boiler makeup, service water, etc.). Note that Units # 5 and # 4 both currently take their cooling water directly from an on-site FPL cooling pond and are expected to continue to do so once the units are repowered. The cooling water needs for the repowered facilities are expected to increase over what is currently used, due primarily to the increased heat loading to the cooling pond that will result from operating the larger repowered units more than they have been operated in the past, and corresponding evaporative losses. Therefore, greater quantities of water may be used. Existing Unit # 3 will use water from the St. John's River in a once-through cooling mode.

FPL also evaluated alternative sources of water to meet the expected needs of the site. It is anticipated that the existing off-site wells and the existing once-through cooling water system and cooling pond would continue to be used after the repowering project is completed, albeit the use of groundwater is expected to decrease significantly from past usage.

l. Water Supply Sources by Type

The available surface water supply source is the St. Johns River. The Floridan Aquifer is an available groundwater source for service water and boiler water.

m. Water Conservation Strategies Under Consideration

In 2000 FPL obtained a revised Consumptive Use permit from the St. Johns Water Management District. This permit reduced the quantity of water that FPL has historically been permitted to withdraw from the ground, in favor of additional use of surface water (preferred).

n. Water Discharges and Pollution Control

Heated water discharge will be dissipated using the existing once-through cooling water system. Non-point source discharges are not anticipated to be an issue because surface water runoff is planned to be collected and reused. Treating and recycling equipment wash water, boiler blowdown, and equipment area runoff will minimize industrial discharges. Storm water runoff will be collected and used to recharge the surficial aquifer via a stormwater management system. Design elements will be included to capture suspended sediments. Various facility permits mandate various sampling and testing activities, which will provide indication of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The repowered facilities at the Sanford site would require a larger natural gas pipeline to be installed. FPL has contracted with Florida Gas Transmission Company (FGT) to permit, install, and operate such a facility. Virtually no waste is associated with natural gas firing.

p. Air Emissions and Control Systems

A natural gas-fired facility would generally have air pollutant emissions which are substantially lower than emissions from the current oil-fired boilers. While several technologies are available for nitrogen oxide (NO_x) emissions control, the most appropriate candidate for the Sanford site is a dry-low-NO_x combustion turbine design type. In these types of devices, combustion is staged in order to reduce the formation of combustion-derived oxides of nitrogen. Sulfur dioxide and particulate emissions are intrinsically low, due to the lack of sulfur and solids in natural gas fuel. Carbon monoxide and volatile organic compound emissions can each be controlled via the use of efficient combustion, rather than through the use of add-on control devices. CC and CT facilities have been permitted at several locations throughout the state of Florida. Dry-low-NO_x combustor systems have been repeatedly demonstrated to be the Best Available Control Technology (BACT) for the control of NO_x emissions for this technology pursuant to the requirements of the Clean Air Act.

q. Noise Emissions and Control Systems

Noise emissions from the project are not anticipated to be significantly different from current levels at the existing plant. FPL will install appropriate sound attenuation devices such as insulation on high-energy piping systems in order to ensure that sound levels do not exceed allowable levels. Similar natural gas-fired facilities (the Lauderdale plant in Broward County and the Martin plant in Martin County) have been constructed and operated without exceeding allowable noise levels.

r. Status of Applications

FPL has now acquired all permits needed to commence construction. Modifications to operating permits will continue to be pursued as necessary through 2002.

Preferred Site # 3: Manatee Plant, Manatee County

The site is located in unincorporated north-central Manatee County approximately 2.5 miles south of The Hillsborough-Manatee County line. It is 5 miles east of Parrish, Florida and is approximately 5 miles east of U.S. Hwy. 301 and 9.5 miles east of Interstate 75 (I-75). State Road 62 (S.R.62) is about 0.5 miles south of the site. Safford Road marks the eastern boundary of the site.

FPL's Manatee Plant occupies a portion of the approximately 9,500 acre Manatee Site, which is owned wholly by FPL. The site includes a 4,000 acre cooling pond including the dike area. The existing approx.1,625 MW (net summer) of generating capacity is made up of two steam units (Units # 1 and # 2) which have been in service since 1976 (Unit # 1) and 1977 (Unit # 2). These units currently burn fuel oil (residual) with a maximum sulfur content of 1 percent. A recent agreement between FPL and Gulfstream Natural Gas Systems will provide an alternative fuel source (natural gas) for these units.

Additional generating capacity will be added to the site to meet projected energy needs for 2005 and 2006. Four new combustion turbines (CT's), four new heat recovery steam generators (HRSG's), and a new steam turbine generator are scheduled for in-service operation beginning in June, 2005. The four new CT's, HRSGs and steam turbine will ultimately be operating in combined cycle (CC) configuration. This new CC unit will add 1,107 MW (Net Summer) and 1,197 MW (Net Winter) capability to the site. This new CC Unit will be designated as "Manatee Unit # 3".

Unit # 3 will be located west of the existing generating Units # 1 and # 2. The location of the new combined cycle Unit # 3 at the Manatee Plant site and the selection of the highly efficient combined cycle technology (firing clean natural gas) will maximize the beneficial use of the site while minimizing environmental, and land use impacts otherwise associated with the development of a new generating plant of this capacity.

a.and b. Map of the Manatee Plant Site and Land use

A map indicating the Manatee plant site showing the general layout of the facilities and a map indicating the land use of the site are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a 4,000 acre cooling pond. Manatee Units # 1 and # 2 will not be affected by the addition of Unit # 3. The area for Unit # 3 is expected to comprise approximately 73 acres. The site and surrounding land uses are almost exclusively agricultural with the exception of the Willow Shores residential area located northwest of the Manatee Plant site. Individual homes are located in the larger of two outparcels within the Manatee Plant site, along SR 62 at the northeast corner of the site. The vast majority of the Manatee Plant site is located in the Agricultural/Rural land use category. Other portions of the site are designated as Major Public/Semi Public (1) (P/SP). Electric generating plants are specifically allowed in the Agricultural/R and P/SP category in accordance with the Manatee County Local

Government Comprehensive Plan and Land Development Regulation Act, Chapter 163, Part II, Florida Statues (FS).

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

There are no incorporated areas within 5 miles of the Manatee Plant site. Unincorporated communities in the area include Willow, located about 2 miles north of the Manatee Plant; Parrish, located about 5 miles southwest of the plant; and in Hillsborough County, Sundance, located 3 miles northwest of the plant, Sun City Center, located 7 miles north of the plant; and Wimauma, located 8 miles northeast of the plant.

The Manatee Plant site includes areas of improved pasture with forested land southeast of the Project area. This forested area is comprised of flatwoods and oak habitat. The western side of the Manatee Plant site is currently used for row crops (tomato farm). There are also wetlands to the southeast of the Project area containing wet pine flatwoods mixed with dry pine flatwoods. There will not be any disturbance of existing wetlands associated with this project.

2. Listed Species

Construction and operation of the new Unit # 3 at the site is not expected to affect any rare, endangered, or threatened species. The majority of the site is cleared, grassed and periodically mowed. The project area has been significantly altered by the construction and operation of the existing plant facilities, as a result wildlife utilization of this area is expected to be minimal. Common wading birds utilizing the plant site outside of the project area, include the great blue heron, little blue heron, great egret, snowy egret and the white ibis. Typical mammals found in the habitats surrounding the project area are common bobcat, raccoon, deer, feral hog, opossum, armadillo, skunk and gray squirrel. Avian species observed in the vicinity of the project include a variety of songbirds, red-shouldered hawk and marsh hawk.

3. Natural Resources of Regional Significance Status

There are no County, State or Federally designated areas located within 1 mile of the plant site. The construction and operation of Manatee Unit # 3 is not expected to have any adverse impacts on parks, recreation areas or environmentally sensitive lands that are associated with the Little Manatee River within a 5 mile radius of the project site. These lands include: Little Manatee River State Recreation Area, Little Manatee River State Canoe Trail, Florida Gulf Coast Railroad Museum, Cockroach Bay Aquatic Preserve, Critical Manatee Habitat, South Hillsborough Wildlife Corridor, Hillsborough County ELAPP Parcels and SOR-Little Manatee River.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design for Manatee Unit # 3 is the addition of four new CT's, with four new HRSGs and one new steam turbine generator in combined cycle configuration (creating a 4X1 configuration). Manatee Unit # 3 will begin operation in mid – 2005. Natural gas, delivered via pipeline, will be the sole fuel for this unit. Natural gas fired facilities are among the cleanest, most efficient technologies currently available.

Mitigation options being planned for Manatee Unit # 3 include the capture and reuse of plant process water and rainwater. In addition, other mitigating options include the use of combustion technology that is very efficient and low in air pollutant emissions, combined with pollution control technology (dry-low NO_x burners and selected catalytic reduction equipment).

g. Local government Future Land Use Designations

As mentioned above the Local Government Future Land Use Plan is consistent with the existing Designated uses of the Manatee Plant Site as major portions of the site are Agriculture/R and the remainder is designated as Major Public/Semi Public (1) – P/PS. Electric generating plants are specifically allowed in these land use categories .

h. Site Selection Criteria and Process

For the past several years, many of FPL's existing power plant sites have been considered potentially suitable sites for new, expanded, or repowered generation. The Manatee site has been selected as a preferred site due to consideration of various factors including system load and economics. The projected availability of a natural gas pipeline that will be available to Unit # 3 as well as Units # 1 and # 2 in the near future was also a major factor in the selection of the Manatee site for the new 4x1 CC unit. Environmental issues were not a deciding factor in FPL's site evaluation since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All of these site are considered permittable.

i. Water Resources

The available surface water source is the Little Manatee River. Make up water for the 4,000 acre cooling pond will continue to be provided from the Little Manatee River. Plant process and service water requirements are currently supplied by the cooling pond, there are three wells in the Floridan aquifer that are reserved for standby purposes.

j. Geological Features of Site and Adjacent Areas

The Geology underlying the Manatee Plant consist of unconsolidated sediments comprised of sand, clay silt, marl shell, limestone and phosphorite (terrace deposits) from the Pleistocene age to Recent. Undifferentiated Deposits comprised of sand and clay with Pliocene age and includes the Bone Valley Formation which is generally described to be less than 25 feet thick. Underlying the undifferentiated materials are the Miocene Hawthorn Formation, the Tampa Member, the Suwannee Limestone of the Oligocene age, the Ocala Limestone of the Eocene Age, the Avon Park Formation, the Oldsmar Formation of the Eocene age and the Cedar Key Formation of the Paleocene age.

k. Projected Water Quantities For Various Uses

The estimated additional quantity of water for industrial processing is estimated to be 150 gpm (gallons per minute) plant process and service water. FPL operates on-site water treatment systems for each of these uses. Water quantities for other uses such as irrigation and potable water are estimated to be approximately 5 gpm.

l. Water Supply Sources by Type

Manatee Unit # 3 will utilize the existing on-site cooling pond as its source of cooling water. The cooling pond operates as a "closed cycle" system, any makeup water is provided from the Little Manatee River to replace net evaporation and seepage loses from the pond. These makeup needs are within the existing agreement between FPL and the Southwest Florida Water Management District (SWFWMD). There are three wells, currently on Reserve (standby) that are in the Floridan Aquifer.

FPL is currently evaluating alternative water sources for use at the Manatee Plant site.

m. Water Conservation Strategies Under Consideration

Available water including non-contact storm water, treated industrial wastewater, treated sanitary wastewater, and recovered service water are captured and returned to the cooling pond. Storm water from the equipment areas is also treated and returned to the cooling pond.

n. Water Discharges and Pollution Control

The Manatee Plant employs a Best Management Practices (BMP) plan, a Spill Prevention, Control and Countermeasure (SPCC) plan to assist in the control of inadvertent release of pollutants. Stormwater runoff will be collected and routed to detention ponds. Construction activities will be managed so that equipment maintenance and fueling are designated areas to conduct these activities so that in the event of a spill or release of any contaminant, impacts to any surface water or the cooling pond are minimized.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by fuel delivery services and facilities for residual, low sulfur (1 percent) fuel oil. FPL has an agreement with Gulfstream Natural Gas Systems to install a natural gas lateral to the Manatee Plant that will provide the availability of natural gas for existing Units # 1 and # 2. The addition of Unit # 3, that will be solely fueled by natural gas, will require further negotiations or agreements with Gulfstream or some other supplier.

p. Air Emissions and Control Systems

The use of clean fuels and combustion controls will minimize air emissions from Unit # 3 and ensure compliance with applicable emission limiting standards. Using clean fuels minimizes emissions of sulfur dioxide (SO2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x), and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of Manatee Unit # 3 will incorporate features that will make it one of the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise emissions from the project are not anticipated to be significantly different from the current levels at the existing plant. Similar natural gas-fired facilities in Broward and Martin Counties have been constructed and operated without exceeding allowable noise levels.

r. Status of Applications

FPL filed the Site Certification Application (SCA) for the Manatee Plant Unit # 3 with the Florida Department of Environmental Protection (FDEP) on February 20, 2002.

Preferred Site # 4: Martin Plant, Martin County

The Martin site is located approximately 40 miles northwest of West Palm Beach, 5 miles east of Lake Okeechobee, and 7 miles northwest of Indiantown in Martin County, Florida. The site is bounded on the west by the Florida East Coast Railway (FEC) and the adjacent South Florida Water Management District (SFWMD) L-65 Canal, on the south by the St. Lucie Canal (C-44 or Okeechobee Waterway), and on the northeast by SR 710 and the adjacent CSX Railroad.

The Martin site was identified in 1987 as a preferred location for development of coal gasification/combined cycle electric generation facilities and subsequent FPL Site Plans have continued to identify this site as a preferred site.

The existing 2,906 MW (net Summer) of generating capacity at FPL's Martin site occupies a portion of the approximately 11,300 acres that are wholly owned by FPL. The generating capacity is made up of two steam units (Units # 1 and # 2), plus two combined cycle units (Units # 3 and # 4), and two combustion turbine units (Units # 8a and # 8b). The site includes a 6,800-acre cooling pond (6,500 acres of water surface and 300 acres of dike area) and approximately 300 acres for the existing power plant units and related facilities.

Additional generating capacity will be added to the site. The existing two CT's at the site will be converted into a four on one (4X1) combined cycle (CC) unit with the addition of two new CTs and four new HRSGs and a new steam turbine generator in mid - 2005. The two existing CT's total capabilities are 318 MW (Summer) and 362 MW (Winter). The later conversion of these two CT's to a (4X1) CC will add approximately 789 MW (Summer) and 835 MW (Winter) of capacity. The new CC unit will be designated as Unit # 8.

a) and b) U.S. Geological Survey (USGS) Map and Proposed Facilities Layout Map

A USGS map of the Martin plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c) Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d) Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a 6,800-acre cooling pond. The existing power plant facilities are located on approximately 300 acres. To the east of the power plant there is an area of mixed pine flatwood with a scattering of small wetlands. To the north of the reservoir there is a 1,200-acre area which has been set aside as a mitigation area. There is peninsula of wetland forest on the west side of the reservoir which is named the Barley Barber Swamp. The Barley Barber Swamp encompasses

400 acres and is preserved as a natural area. There is also a 10 kilowatt (KW) photovoltaic energy facility at the south end of this site.

e) General Environment Features On and In The Site Vicinity

1) Natural Environment

As noted above, the Barley Barber Swamp is located on the site. There is also a 1,200-acre mitigation area in the northern area of the site where wetlands and uplands have been restored. Along the south and west sides of the cooling pond is an area where the vegetation has been allowed to return to its natural state in order to serve as a wildlife corridor. FPL has preserved a Florida Panther corridor along the west side of the cooling pond. There are pine flatwoods and small scattered wetlands to the east of the plant.

2) Listed Species

Construction and operation of new units at the site are not expected to affect any rare, endangered, or threatened species. There are two active Bald Eagle (Haliaeetus leucocephalus: Federal - and - State listed as Threatened) nests that have been on the site for many years. The Florida Natural Areas Inventory (FNAI) database notes a record of Eastern Indigo Snakes (Drymachon coralis coupert which are Federal - and - State listed as Threatened) in the Barley Barber Swamp. A number of other Bald Eagle nests and sightings of Eastern Indigo Snakes are reported by the FNAI database within a two-mile radius of the site. Infrequent sightings of Florida Panther have been made in the site area.

3) Natural Resources of Regional Significance Status

The Treasure Coast Regional Planning Council lists the "FPL Preserve", including the Barley Barber Swamp, as a Significant Regional Facility. Natural communities such as uplands and wetlands are also generically listed as Resources of Regional Significance.

4) Other significant features

FPL is not aware of any other significant features of the site.

f) Design Features and Mitigation Options

The design options are to add two new CT's and four new HRSG's and a new steam turbine that, together with the two existing CT's, will comprise Martin Unit # 8. This unit is scheduled to be in service in mid-2005. Natural gas delivered via pipeline is envisioned as the fuel type for this unit (with light oil serving as a backup fuel). Natural gas-fired facilities are among the cleanest, most efficient technologies currently available.

Mitigation options being considered include the capture and reuse of plant process water and rainwater. The facility already encompasses several preserved areas where wildlife is abundant.

g) Local Government Future Land Use Designations

Local government future land use designation for the site is "Public Utilities". Designations for the surrounding area are primarily "Agricultural". There are also limited areas of "Agricultural Ranchette", "Industrial", and a small "Commercial" area designation. To the southeast of the property, fronting on the St. Lucie Canal, there is an area designated for "Public Conservation".

h) Site Selection Criteria and Process

For the past several years, a number of FPL's existing power plant sites have been considered as potentially suitable sites for new or repowered generation. The Martin plant has been selected as a preferred site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor in FPL's site evaluation since none of the existing preferred and potential site exhibit significant environmental sensitivity or other environmental issues. All of these sites are considered permittable.

i) Water Resources

Surface water resources currently used at the Martin facility include the cooling pond, which takes its water from the St. Lucie canal. The available groundwater resource is the shallow aquifer which is used as a source of potable water and for service water for Units # 1 and # 2. Both of these sources are available for use with the site expansion.

j) Geological Features of Site and Adjacent Areas

FPL's Martin site is underlain by approximately 13,000 feet of sedimentary rock strata. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine in origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, or clay. The deepest formation in Martin County on which significant published data are available is the Eocene Age Avon Park. Limited information is available from wells penetrating the underlying Lake City formation. The published information on the sediments comprising the formations below the Avon Park Limestone in western Martin County is based on projections from deep wells in Okeechobee, St. Lucie, and Palm Beach counties.

k) Projected Water Quantities for Various Uses

The estimated additional quantity of water required for industrial processing is 130 gallons per minute (gpm) for uses such as boiler water and service water. FPL operates on-site water treatment systems for each of these uses. Cooling water for new Unit # 8, will be supplied from the on-site 6,800-acre cooling pond. Makeup water for the pond is taken from the St. Lucie canal. The current makeup water quantity to the cooling pond (approximately 4,800 gpm) is expected to be adequate for the proposed expansion. Water quantities needed for other uses such as irrigation and potable water are estimated to be approximately 5 gpm.

l) Water Supply Sources by Type

All additional capacity at the site will utilize the existing on-site cooling pond as the source of cooling water and as a heat sink for the dissipation of cooling water heat. The cooling pond operates as a "closed cycle" system in which heated water from the generating units loses its heat as it is circulated within the pond and back around to the plant intake. A cooling tower may also be utilized. Makeup water to the pond is withdrawn from the St. Lucie Canal as needed to replace net evaporation and seepage losses from the pond. Such needs will comply with the existing agreement between FPL and the South Florida Water Management District (SFWMD) regarding allocation of cooling water to the pond and with SFWMD's regulations for consumptive water use.

The existing water treatment system at the plant, which provides treated water for use in the Unit # 1 and # 2 boilers, as well as the HRSG's associated with Units # 3 and # 4, will be expanded to provide treated water for new Unit # 8. FPL will discuss Unit # 8 requirements with SFWMD as the project moves forward in the licensing process.

m) Water Conservation Strategies Under Consideration

Impacts on the surficial aquifer will be reduced by changing the source of plant process water to the Floridan aquifer, upon completion of Unit # 8. In addition, the facility captures and reuses process water whenever feasible, and manages stormwater in such a manner so as to recharge the surficial aquifer.

n) Water Discharges and Pollution Control

Heated water discharges will be dissipated in the cooling pond. Non-point source discharges are not an issue since there are none at this facility. Industrial discharges will be minimized by treating and recycling equipment wash water, boiler blowdown water, and equipment area runoff. Storm water runoff is collected and used to recharge the surficial aquifer via a stormwater management system. Design elements have been included to capture suspended sediments. Facility permits mandate various sampling and testing activities, which provide indication of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o) Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by multiple fuel delivery facilities. There are currently two pipelines with the capability of supplying of natural gas into the facility. The additional capacity due to the conversion of the CT's into a CC unit will require an enlargement of an existing pipeline(s), the installation of a new pipeline, or the addition of another natural gas pipeline compressor station.

p) Air Emissions and Control Systems

The use of clean fuels and combustion controls will minimize air emissions from Unit # 8 and ensure compliance with applicable emission limiting standards. Using clean fuels minimizes emissions of sulfur dioxide (SO2), particulate matter and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x), and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during CC operation when firing light oil. These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of Martin Unit # 8 will incorporate features that will make it one of the most efficient and cleanest power plants in the State of Florida.

q) Noise Emissions and Control Systems

A field survey and impact assessment of noise expected to be caused by unit construction at the site indicated that construction noise will be below current noise levels for the residents nearest the site. Noise from the operation of the new units will also be within allowable levels.

r) Status of Applications

A Site Certification application was filed in December, 1989, for the construction and operation of the Martin Coal Gasification/Combined Cycle project under the Florida Electrical Power Plant Siting Act.

On June 15, 1990, the Public Service Commission issued a Determination of Need Order for proposed Martin Units # 3 and # 4. This determination of need applies only to the first phase of the Project, or 832 MW of combined cycle generation. The Siting Board issued a Land Use Order on June 27, 1990. The Certification Hearing was held on November 5-7, 1990. As mentioned earlier, on February 12, 1991, the Governor and Cabinet, serving as the Siting Board, approved the construction and operation of natural gas-fired combined cycle Units # 3 and # 4 and determined that the Martin Site has capacity to accommodate additional combined cycle units fueled by natural gas, fuel oil, or coal-derived gas produced at the site.

Since the initial certification in 1991, the Site Certification has been modified five times to provide authorization for items such as CT testing, increasing the cooling pond elevation, incorporating changes from other permits, and incorporating a custom fuel monitoring program. For the addition of the two CT's, FPL obtained a sixth modification to the existing Site Certification in August 2000.

In order to convert these two CT's from simple cycle to CC configuration, a seventh modification to the Site Certification will be required. FPL filed the Site Certification Application on February 1, 2002 with the FDEP.

IV.F.2. Potential Sites

Four FPL-owned sites are identified as the next most likely potential sites for future generation after the four preferred sites just discussed. These four sites are considered the next most likely potential sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are located in Brevard, Palm Beach, Broward, and St. Lucie Counties. These sites are suitable for different capacity levels and technologies, and they will remain as potential sites pending future decisions on how best to meet the timing and magnitude of FPL's future capacity needs.[2]

Each of these potential sites offers advantages and disadvantages relative to engineering considerations and/or costs associated with the construction and operation of feasible technologies. In addition, each potential site has different characteristics, which could require further definition and attention. For purposes of estimating water usage amounts, it

[2] As has been described in previous FPL Plant Site Plans, FPL also considers a number of other sites as possible sites for future generation additions These include the remainder of FPL's existing generation sites.

is assumed that a natural gas-fired CC unit would be the technology of choice for any capacity additions at the sites.

Permits are presently considered to be obtainable for all four sites, assuming measures can be taken to mitigate any particular site-specific environmental concerns. None of the sites exhibit any significant environmental constraints. The potential sites are briefly discussed below. (Note: The order in which the sites are discussed below does not reflect a relative ranking of these sites in regard to how likely it is for FPL to add capacity at the site.)

Potential Site # 1: Cape Canaveral Plant, Brevard County

The site is located on the FPL Cape Canaveral property in unincorporated Brevard County. The city of Port St. Johns is located less than a mile away. The site has direct access to a four-lane highway, US 1, and barge access is available. A rail line is located near the plant. The existing facility consists of two 400 MW (nominal) steam boiler type generating units.

a) U.S. Geological Survey (USGS) Map

A USGS map of the Cape Canaveral plant site is found at the end of this chapter.

b) and c) Land Uses and Environmental Features

This site is located on the Indian River. The land is primarily dedicated to industrial use with surrounding grassy areas and a few acres of remnant pine forest. The land adjacent to the site is dedicated to light commercial and residential use. There are no significant environmental features on the site.

d) and e) Water Quantities and Supply Sources

FPL projects that an increase of up to 260 gallons per minute (gpm) would be required for industrial processing use (boiler makeup, service water, etc.) It is expected that industrial cooling water needs could be met using the current 550,000 gpm once-through cooling water quantity. For industrial processing, FPL would use existing on-site wells. For industrial cooling, the Indian River would continue to be utilized.

Potential Site # 2: Riviera Plant, Palm Beach County

This site is located on the FPL Riviera Plant property in Riviera Beach, Palm Beach County. The site has direct access to a four-lane highway, US 1, and barge access is available. A rail line is located near the plant. The facility currently houses two operational 300 MW (nominal) steam boiler generating units and one retired 50 MW generating unit.

a) U.S. Geological Survey (USGS) Map

A USGS map of the Riviera plant site is found at the end of this chapter.

b) and c) Land Uses and Environmental Features

The land on the site is primarily covered by the existing generation facilities with some open maintained grass areas. There is a small manatee viewing area on the site which is operated seasonally by FPL. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development. The site is located on the Intracoastal Waterway near the Lake Worth Inlet.

d) and e) Water Quantities and Supply Sources

Additional industrial processing water needs are estimated to be up to 40 gallons per minute (gpm). Industrial cooling water needs are estimated to be up to 54,000 gpm using the existing once-through cooling water system. The existing municipal water supply would be used for industrial processing water if additional generating capacity is placed at Riviera. For once-through cooling water, FPL would continue to use Lake Worth as a source of water.

Potential Site # 3: Port Everglades Plant, Broward County

This site is located on the 94-acre FPL Port Everglades plant site in Port Everglades, Broward County. The site has convenient access to State Road (SR) 84 and Interstate 595. A rail line is located near the plant. The existing plant consists of four steam boiler generating units: two 200 MW (nominal) and two 400 MW (nominal) sized units.

a) U.S. Geological Survey (USGS) Map

A USGS map of the Port Everglades plant site is found at the end of this chapter.

b) and c) Land Uses and Environmental Features

The land on the site is primarily industrial. The adjacent land uses are port facilities and associated industrial activities, oil storage, cruise ships, and light commercial.

d) and e) Water Quantities and Supply Sources

FPL estimates that up to 130 gallons per minute (gpm) of industrial processing water would be required for uses such as boiler makeup, fogger usage, and service water. FPL would expect to use the existing municipal water supply for industrial process water. For cooling water, FPL would anticipate that the existing 320,000 gpm once-through cooling seawater source would continue to be used.

Potential Site # 4: Midway Substation Property, St. Lucie County

The site is located on the 122-acre Midway Substation property. Current facilities on the site include an electric substation. The site has direct access to a two-lane highway, State Road 712 (SR 712). The nearest town is White City, which is approximately 5 miles east of the site. The City of Fort Pierce is approximately 9 miles northeast of the site. The Midway site was previously listed as a preferred site in the FPL 2001-2010 Ten Year Power Plant Site Plan.

a) U.S. Geological Survey (USGS) Map

A map is provided of the Midway Site area and a land use map is provided at the end of this chapter.

b) and c) Land Uses and Environmental Features

The land on the site is currently dedicated to industrial and agricultural use. Much of the site is currently not being used. Developed portions of the adjacent properties are primarily agricultural (orange groves and cattle grazing). Undeveloped portions include mixed scrub with some hardwoods and wetlands.

d) and e) Water Quantities and Supply Sources

No surface water source is available at this site. The groundwater source would either be the shallow aquifer or a local source of gray water. It is estimated that 150 gallons per minute (gpm) will be needed for industrial processing water for uses such as inlet air-cooling, NO_x control during light oil firing and for service water. Other facility water uses may include irrigation, potable use, etc. The total volume of these uses is estimated to be about 5 gpm.

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Environmental and Land Use Information: Supplemental Information

Preferred Site: Fort Myers Plant

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FT. MYERS PLANT SITE
SHOWING LANDUSE
0 400 Feet
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inaccuracies The user is warned to utilize
at his/her own risk and the user assumes risk
of any and all loss All Boundaries are approximate

Figure IV.F.1

Figure IV.F.2

LEGEND FOR LANDUSE MAPS

Plant Site Boundary

Level 3 Landuse Categories 1995

- Residential Low Density
- Residential Medium Density
- Residential High Density
- Commercial and Services
- Industrial
- Extractive
- Institutional
- Recreational
- Open Land
- Cropland and Pastureland
- Tree Crops
- Feeding Operations
- Nurseries and Vineyards
- Specialty Farms
- Other Open Lands <Rural>
- Herbaceous
- Shrub and Brushland
- Mixed Rangeland
- Upland Coniferous Forests
- Upland Hardwood Forests
- Tree Plantations
- Streams and Waterways
- Lakes
- Reservoirs
- Bays and Estuaries
- Major Springs
- Slough Waters
- Oceans Seas and Gulfs
- Wetland Hardwood Forests
- Wetland Coniferous Forests
- Wetland Forested Mixed
- Vegetated Non-Forested Wetlands
- Non-Vegetated
- Wetland Shrub
- Beaches OtherThan Swimming Beaches
- Sand Other Than Beaches
- Exposed Rock
- Disturbed Lands
- Riverine Sandbars
- Transportation
- Communications
- Utilities
- Vegetation-Sea Grass

FPL

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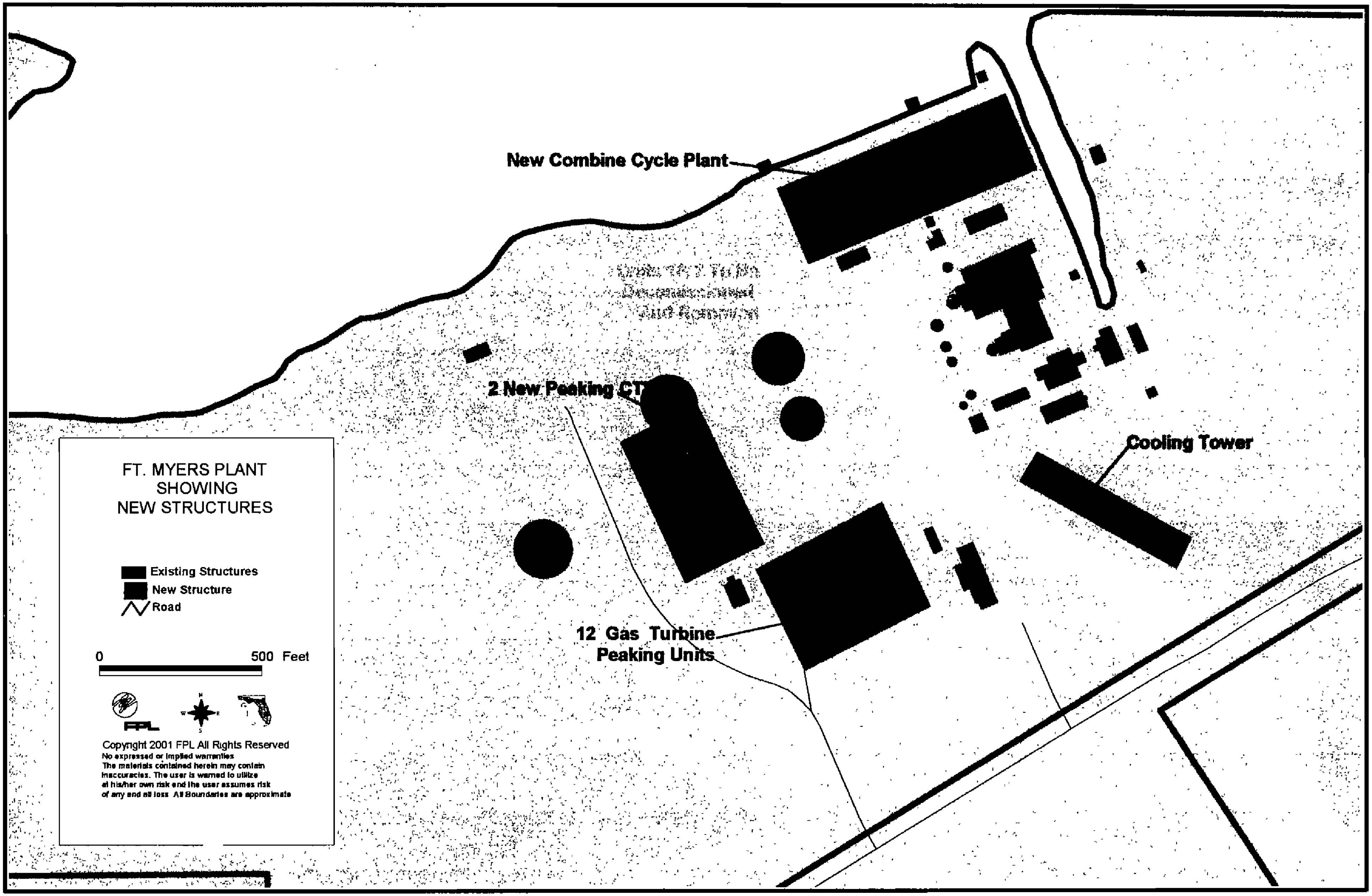

Figure IV.F.3

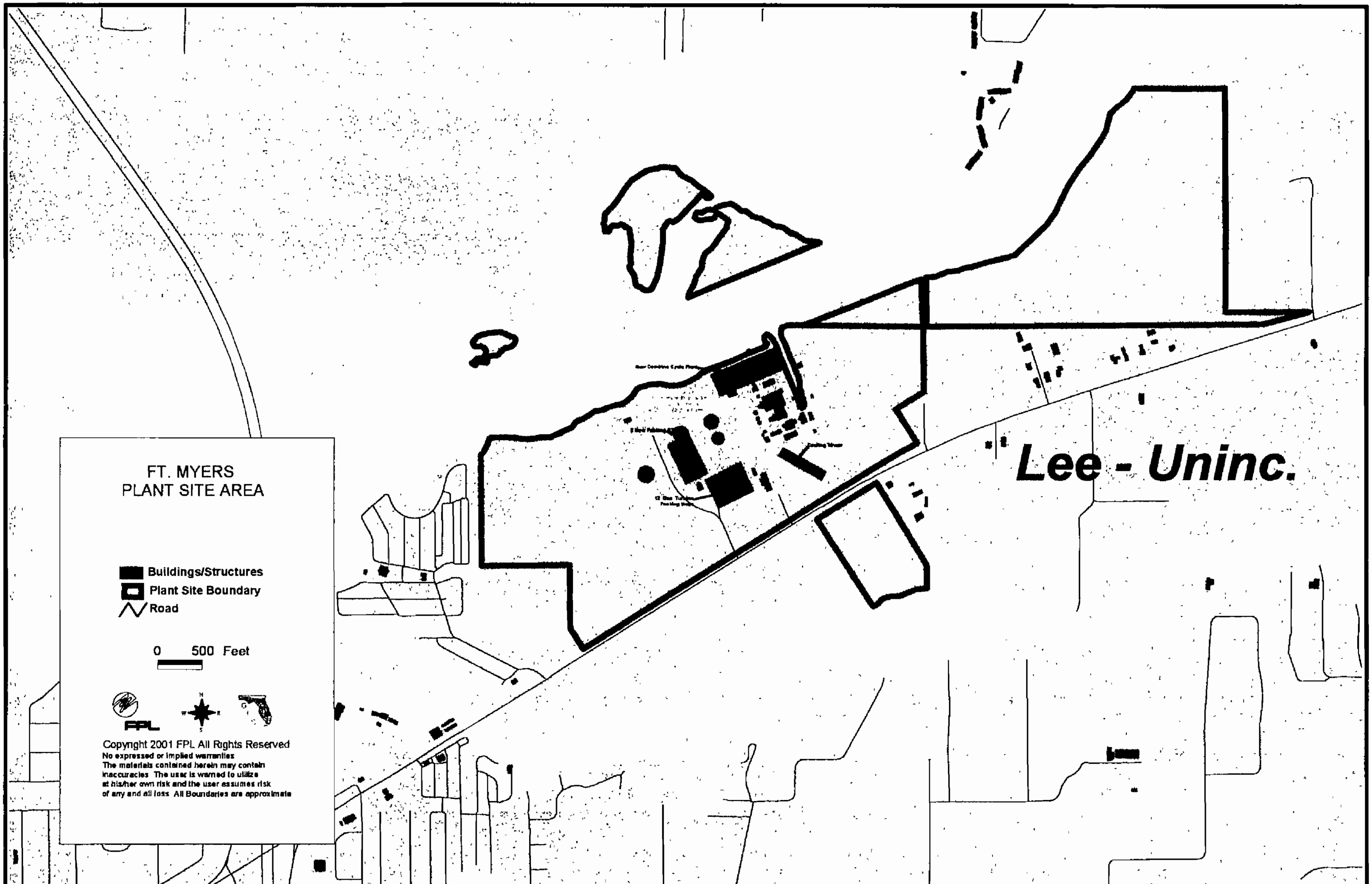
Lee - Uninc.
FT. MYERS
PLANT SITE AREA
Buildings/Structures
Plant Site Boundary
Road
0 500 Feet
FPL
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Figure IV.F.4

Environmental and Land Use Information: Supplemental Information

Preferred Site: Sanford Plant

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Figure IV.F.5


SANFORD PLANT SITE
SHOWING LANDUSE
0 1000 Feet
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FPL
G
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S
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at his/her own risk and the user assumes risk
of any and all loss. All Boundaries are approximate.

Figure IV.F.6

LEGEND FOR LANDUSE MAPS

Plant Site Boundary

Level 3 Landuse Categories 1995

- **Residential Low Density**
- **Residential Medium Density**
- **Residential High Density**
- **Commercial and Services**
- **Industrial**
- **Extractive**
- **Institutional**
- **Recreational**
- **Open Land**
- **Cropland and Pastureland**
- **Tree Crops**
- **Feeding Operations**
- **Nurseries and Vineyards**
- **Specialty Farms**
- **Other Open Lands <Rural>**
- **Herbaceous**
- **Shrub and Brushland**
- **Mixed Rangeland**
- **Upland Coniferous Forests**
- **Upland Hardwood Forests**
- **Tree Plantations**
- **Streams and Waterways**
- **Lakes**
- **Reservoirs**
- **Bays and Estuaries**
- **Major Springs**
- **Slough Waters**
- **Oceans Seas and Gulfs**
- **Wetland Hardwood Forests**
- **Wetland Coniferous Forests**
- **Wetland Forested Mixed**
- **Vegetated Non-Forested Wetlands**
- **Non-Vegetated**
- **Wetland Shrub**
- **Beaches OtherThan Swimming Beaches**
- **Sand Other Than Beaches**
- **Exposed Rock**
- **Disturbed Lands**
- **Riverine Sandbars**
- **Transportation**
- **Communications**
- **Utilities**
- **Vegetation-Sea Grass**

FPL

Figure IV.F.7

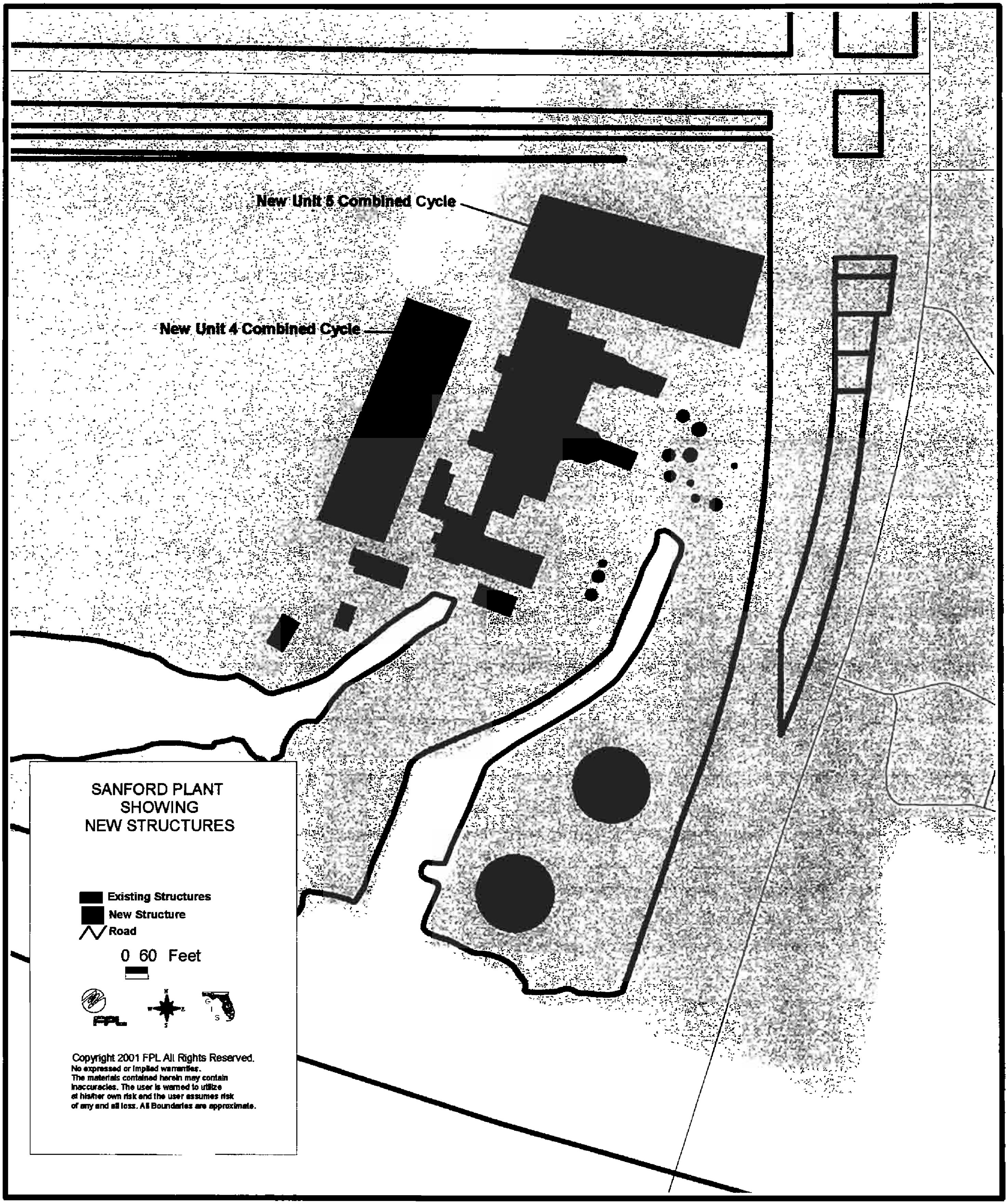
New Unit 5 Combined Cycle
New Unit 4 Combined Cycle
SANFORD PLANT
SHOWING
NEW STRUCTURES
Existing Structures
New Structure
Road
0 60 Feet
FPL
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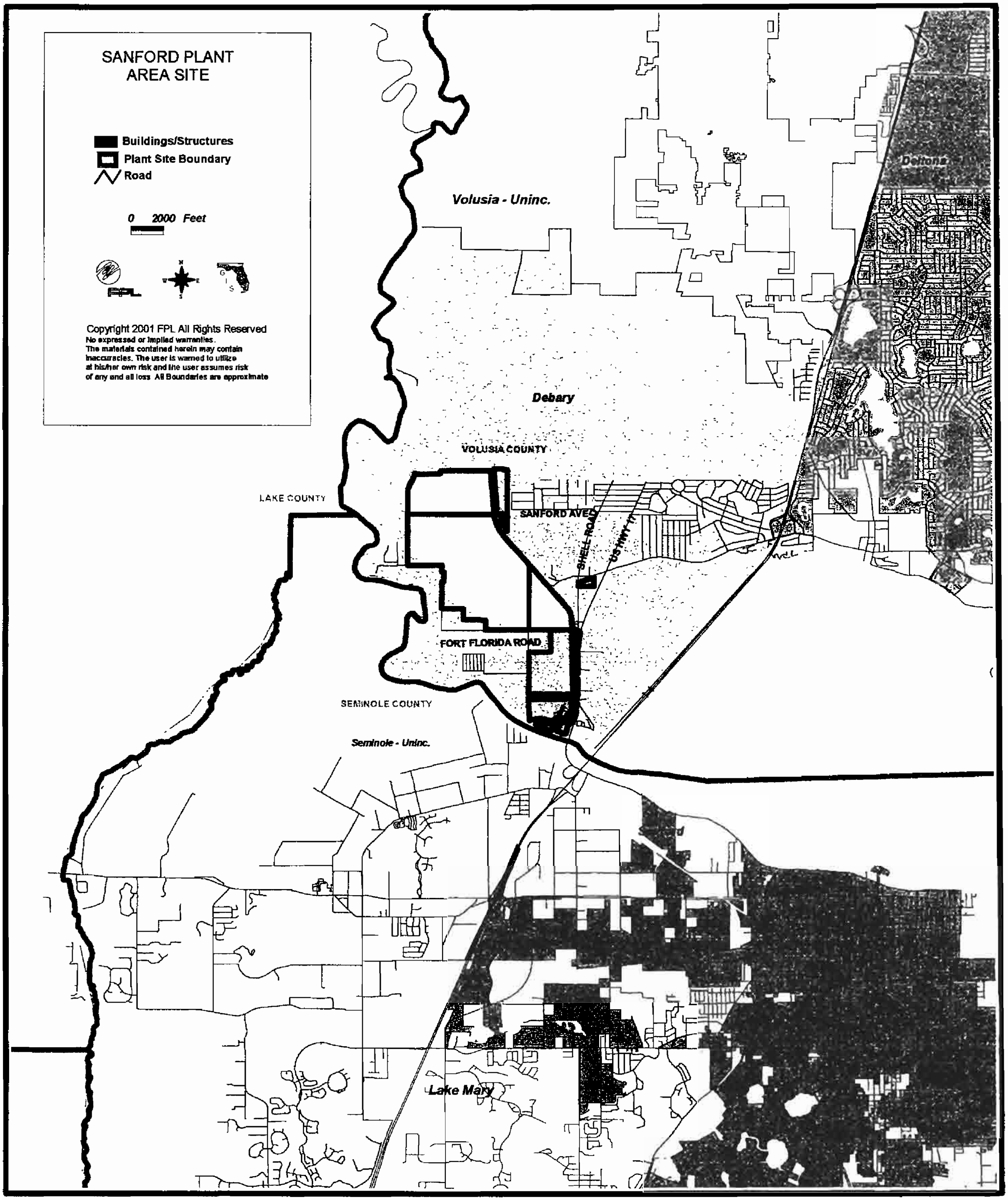
Figure IV.F.8


SANFORD PLANT
AREA SITE
Buildings/Structures
Plant Site Boundary
Road
0 2000 Feet
FPL
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Volusia - Uninc.
Deltona
Debary
VOLUSIA COUNTY
LAKE COUNTY
SANFORD AVE
SHELL ROAD
US HWY 17
FORT FLORIDA ROAD
SEMINOLE COUNTY
Seminole - Uninc.
Lake Mary

Environmental and Land Use Information: Supplemental Information

Preferred Site: Manatee Plant

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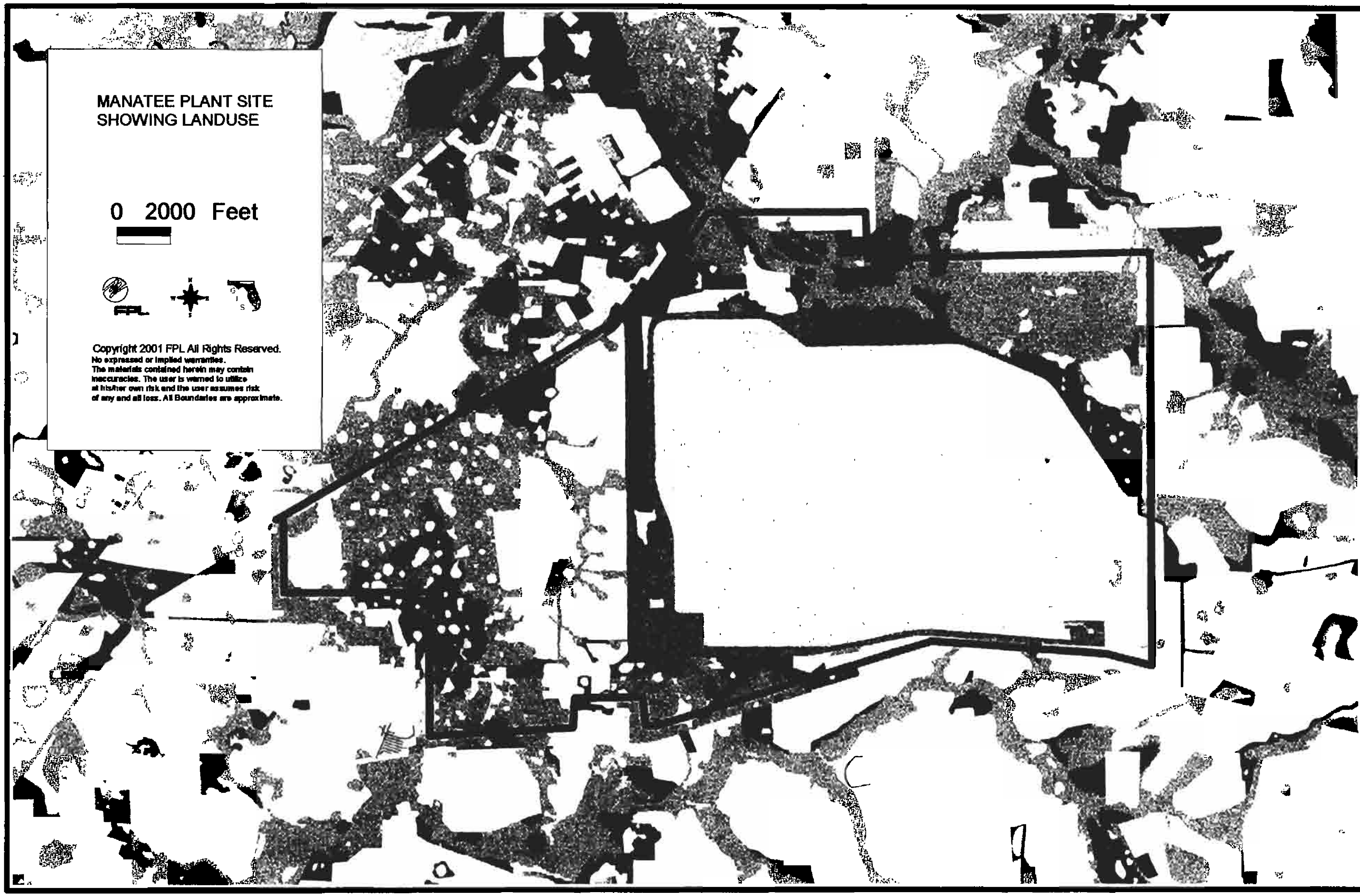
MANATEE PLANT SITE
SHOWING LANDUSE
0 2000 Feet
FPL
GIS
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Figure IV.F.9

Figure IV.F.10

LEGEND FOR LANDUSE MAPS

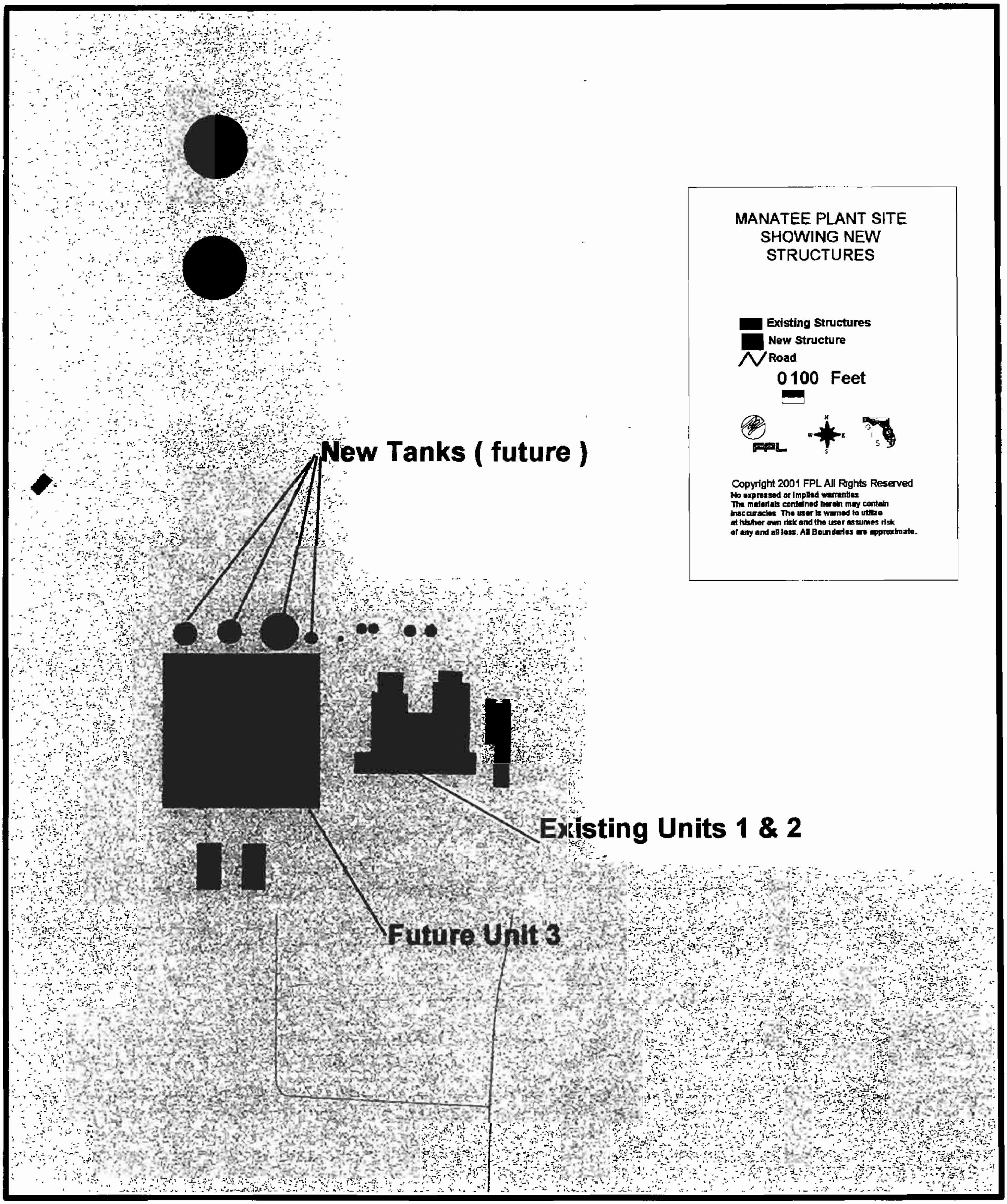
Plant Site Boundary

Level 3 Landuse Categories 1995

- Residential Low Density
- Residential Medium Density
- Residential High Density
- Commercial and Services
- Industrial
- Extractive
- Institutional
- Recreational
- Open Land
- Cropland and Pastureland
- Tree Crops
- Feeding Operations
- Nurseries and Vineyards
- Specialty Farms
- Other Open Lands <Rural>
- Herbaceous
- Shrub and Brushland
- Mixed Rangeland
- Upland Coniferous Forests
- Upland Hardwood Forests
- Tree Plantations
- Streams and Waterways
- Lakes
- Reservoirs
- Bays and Estuaries
- Major Springs
- Slough Waters
- Oceans Seas and Gulfs
- Wetland Hardwood Forests
- Wetland Coniferous Forests
- Wetland Forested Mixed
- Vegetated Non-Forested Wetlands
- Non-Vegetated
- Wetland Shrub
- Beaches OtherThan Swimming Beaches
- Sand Other Than Beaches
- Exposed Rock
- Disturbed Lands
- Riverine Sandbars
- Transportation
- Communications
- Utilities
- Vegetation-Sea Grass

FPL

Figure IV.F.11



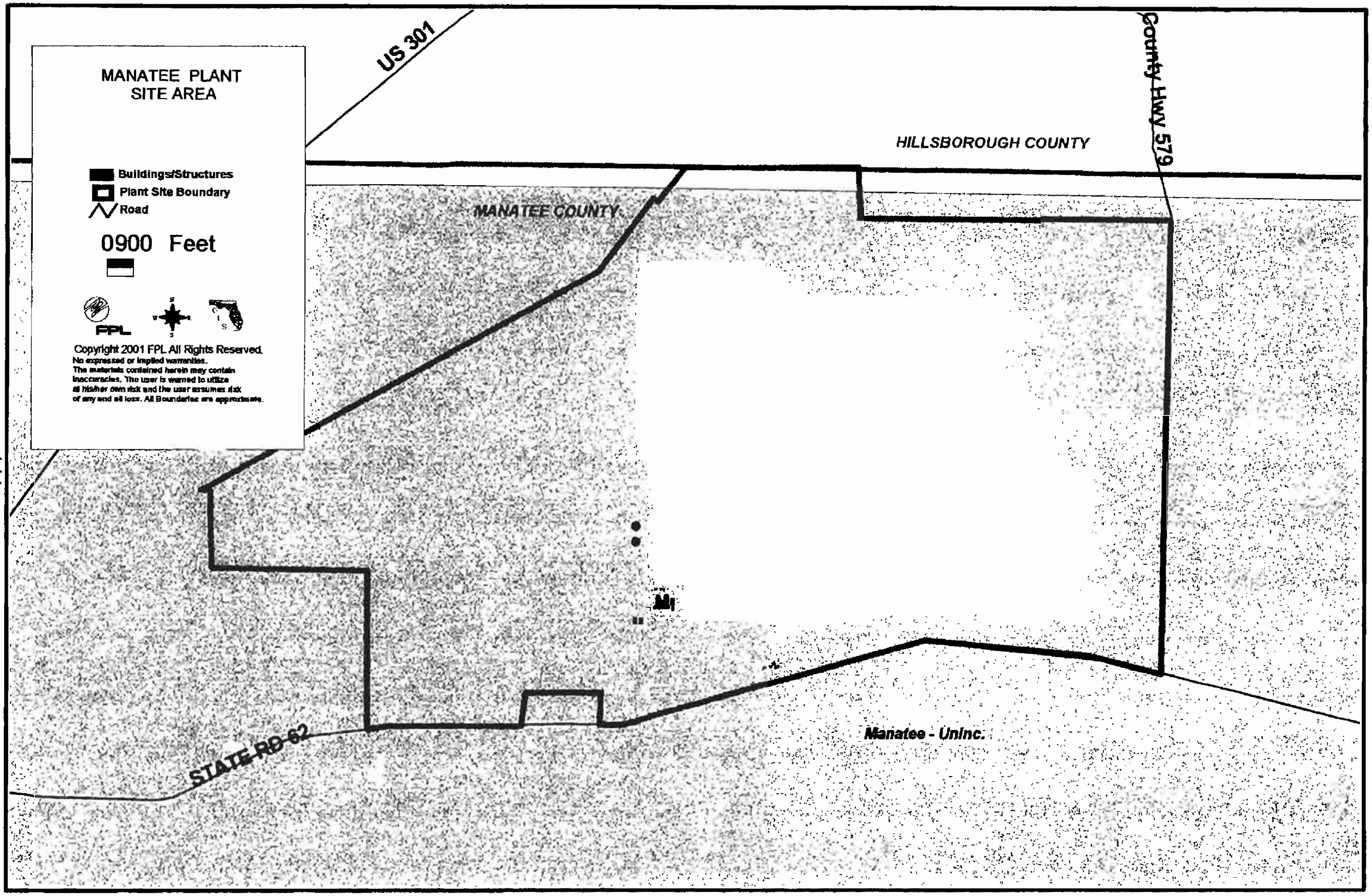


Figure IV.F.12

Environmental and Land Use Information: Supplemental Information

Preferred Site: Martin Plant

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Figure IV.F.13

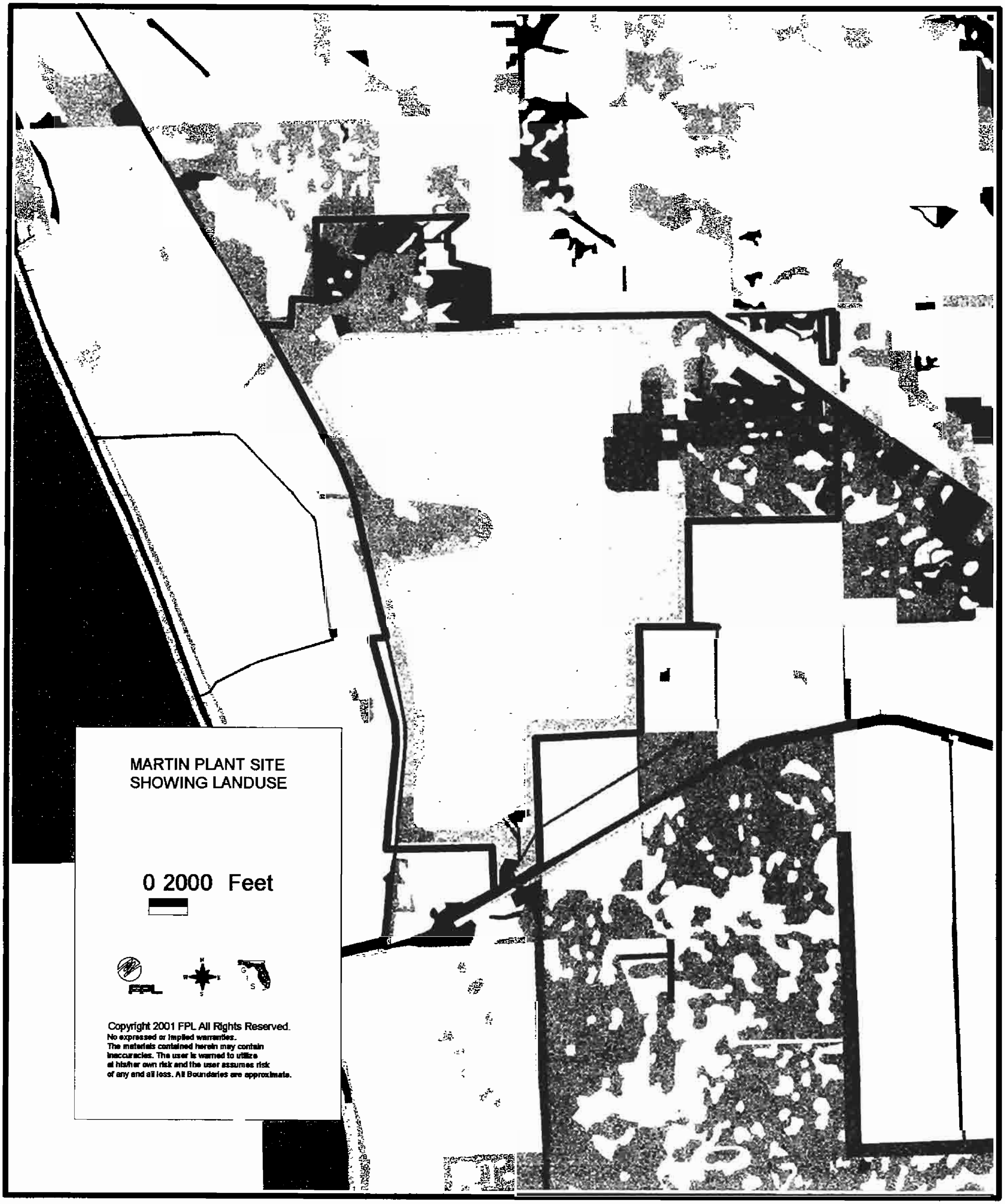

Figure IV.F.14

LEGEND FOR LANDUSE MAPS

Plant Site Boundary

Level 3 Landuse Categories 1995

Residential Low Density
Residential Medium Density
Residential High Density
Commercial and Services
Industrial
Extractive
Institutional
Recreational
Open Land
Cropland and Pastureland
Tree Crops
Feeding Operations
Nurseries and Vineyards
Specialty Farms
Other Open Lands <Rural>
Herbaceous
Shrub and Brushland
Mixed Rangeland
Upland Coniferous Forests
Upland Hardwood Forests
Tree Plantations
Streams and Waterways
Lakes
Reservoirs
Bays and Estuaries
Major Springs
Slough Waters
Oceans Seas and Gulfs
Wetland Hardwood Forests
Wetland Coniferous Forests
Wetland Forested Mixed
Vegetated Non-Forested Wetlands
Non-Vegetated
Wetland Shrub
Beaches OtherThan Swimming Beaches
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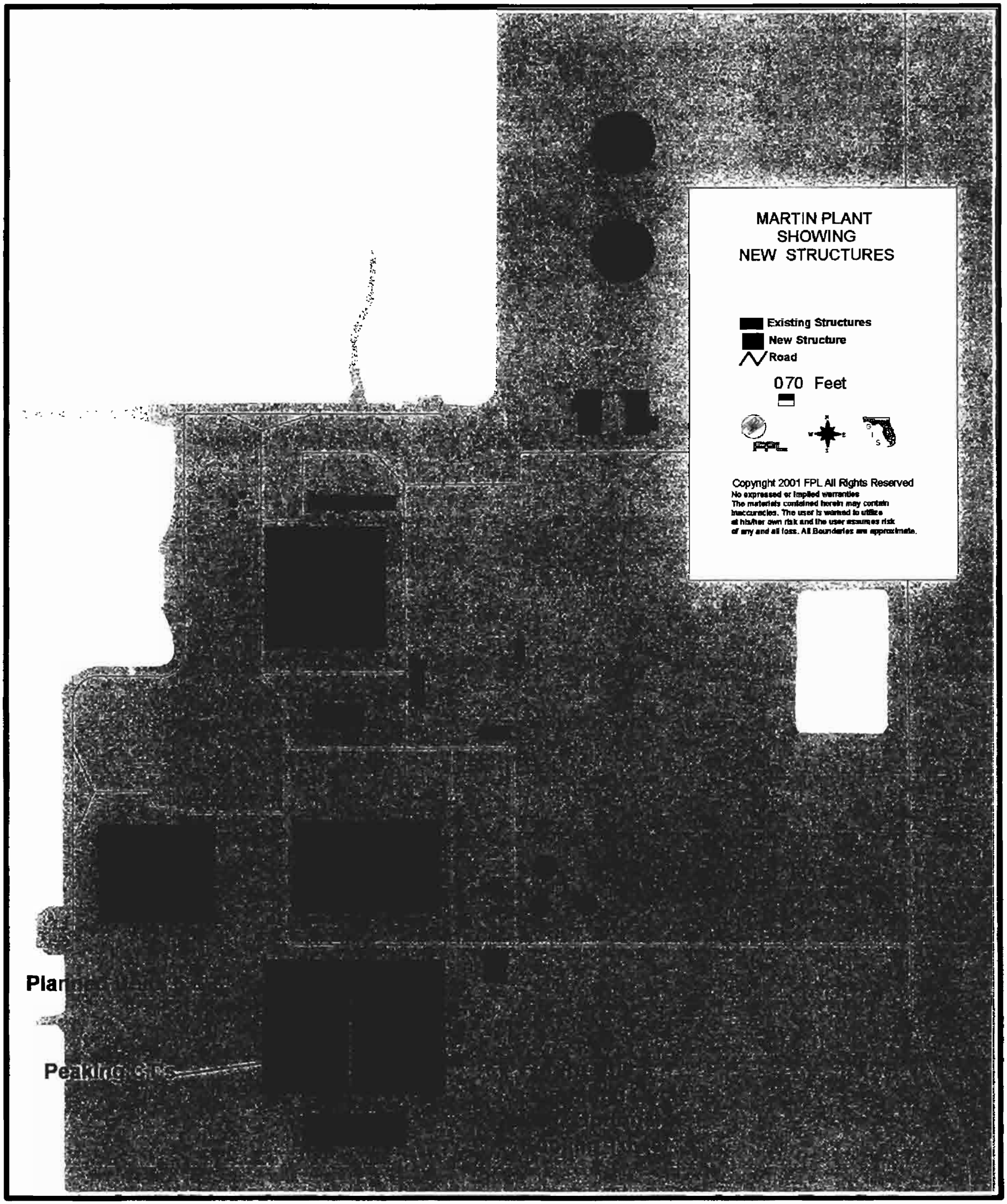
Disturbed Lands
Riverine Sandbars
Transportation
Communications
Utilities
Vegetation-Sea Grass

FPL

Figure IV.F.15



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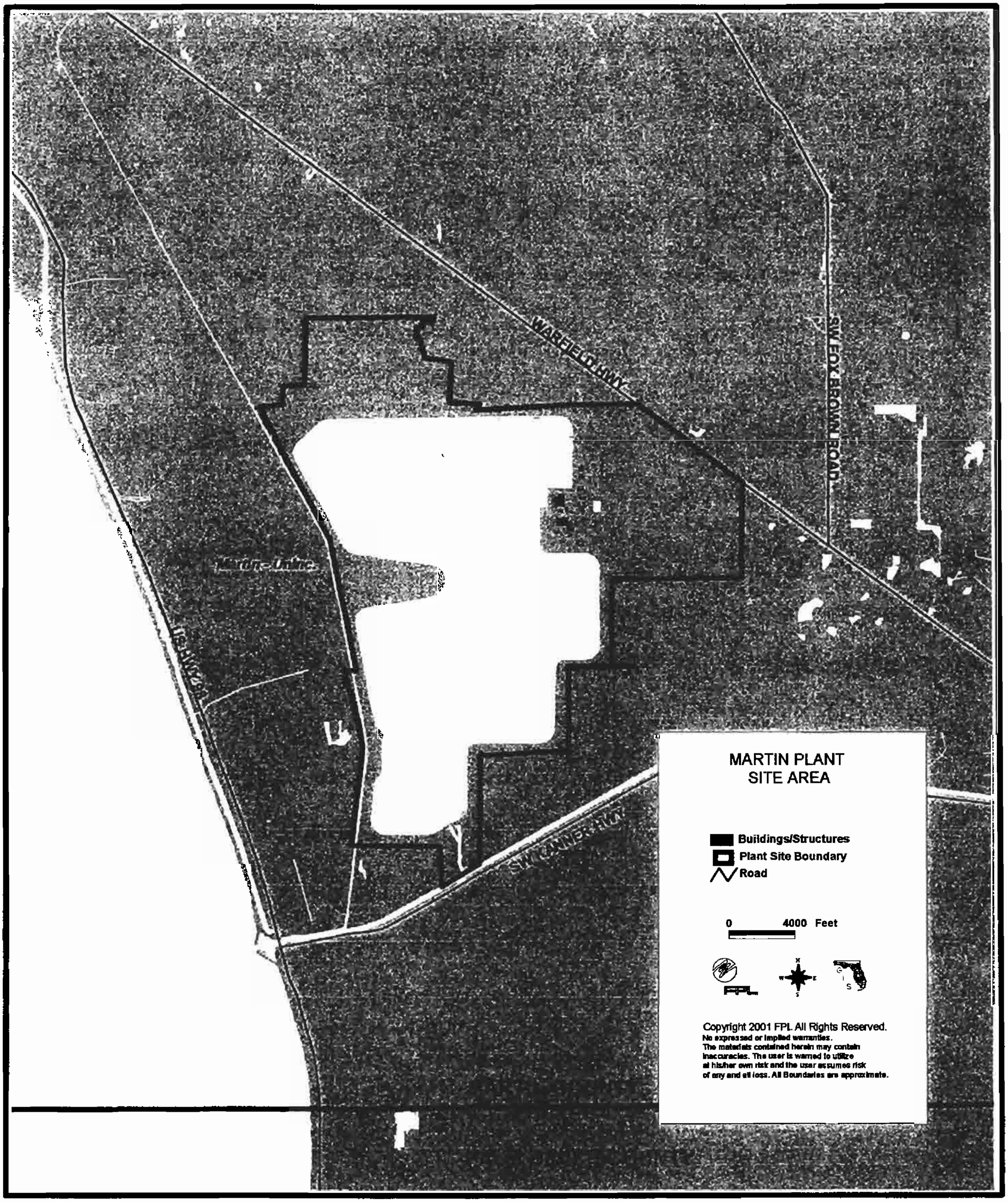

Environmental and Land Use Information: Supplemental Information

Potential Sites

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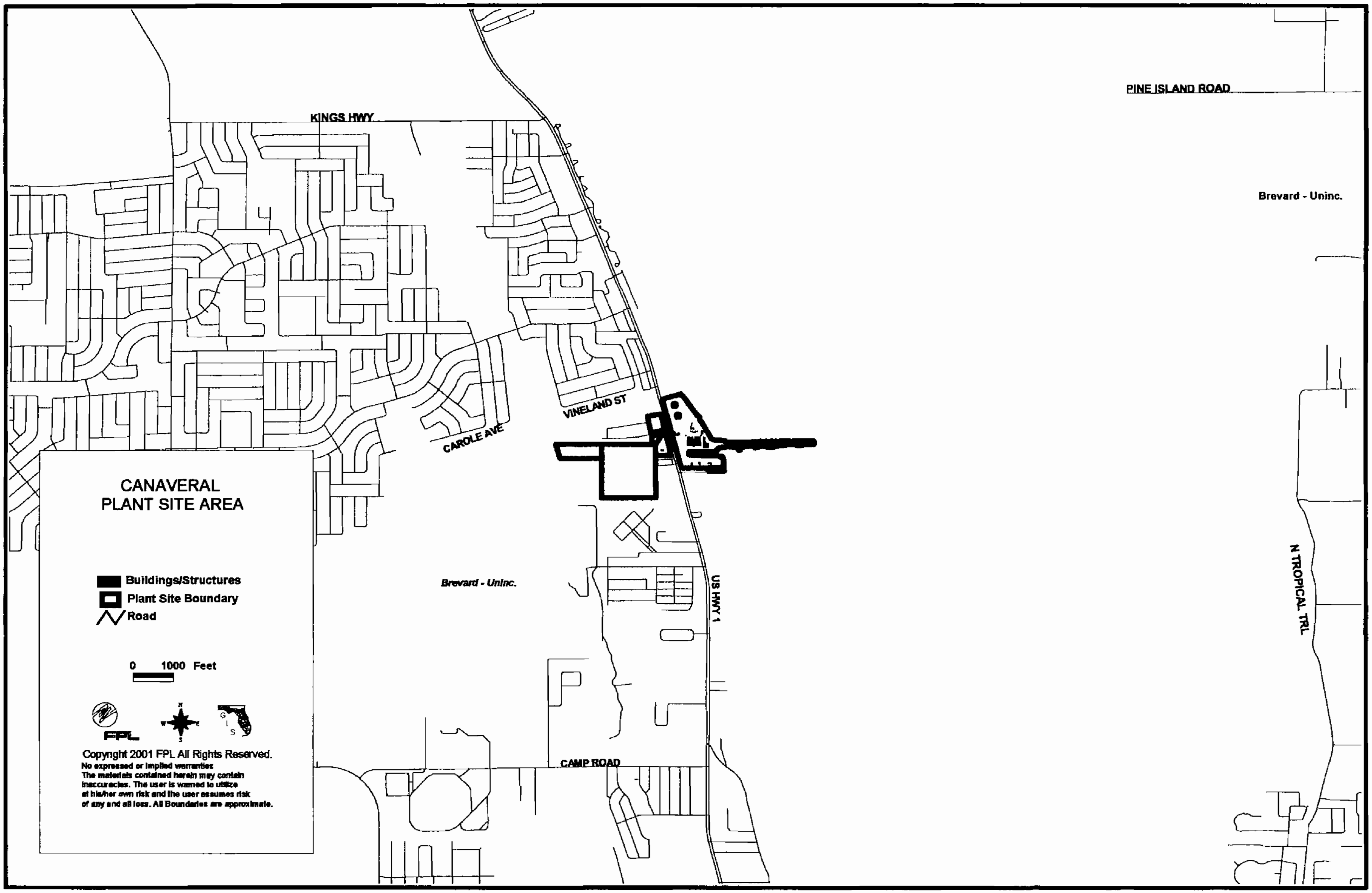

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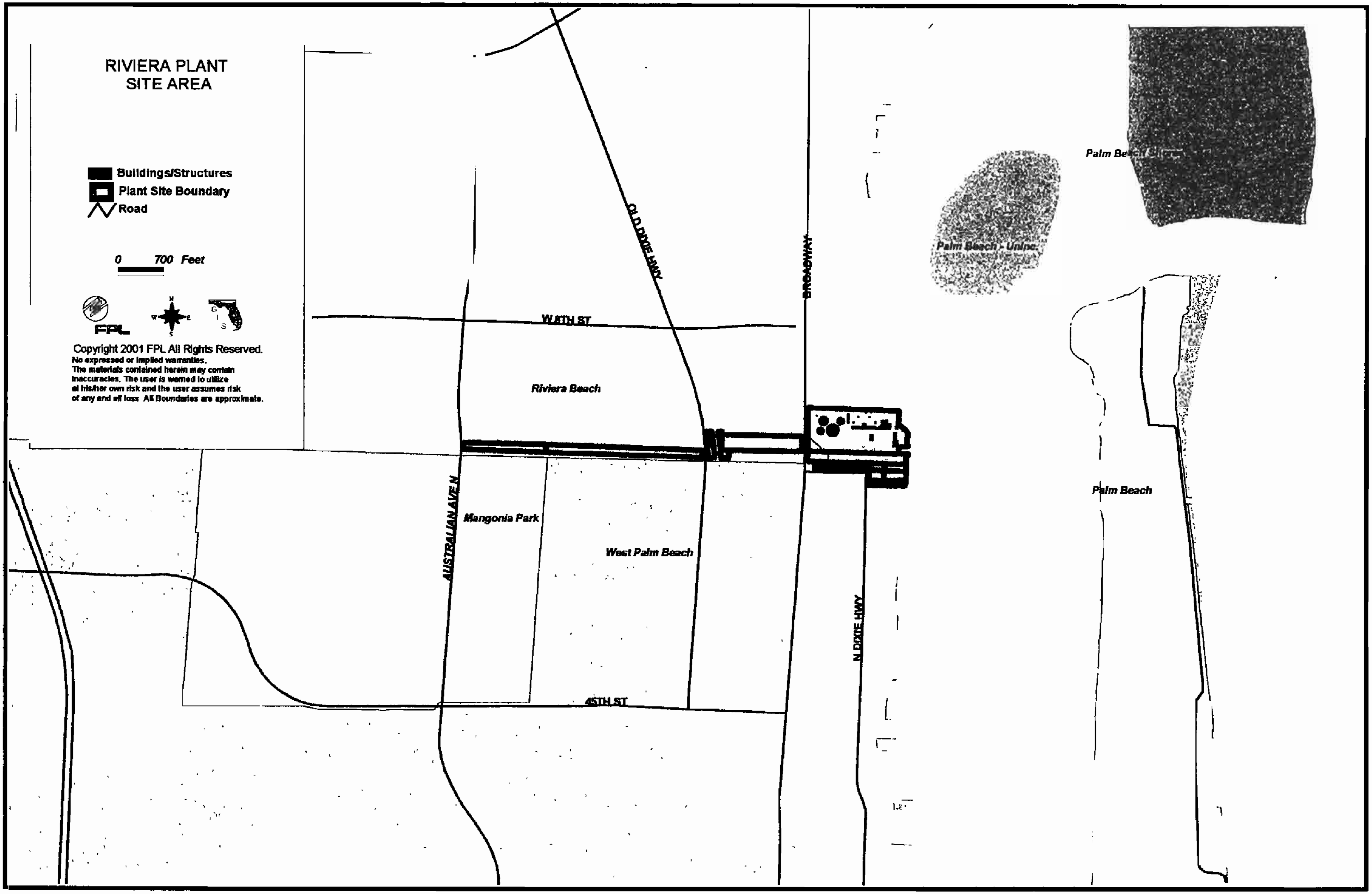
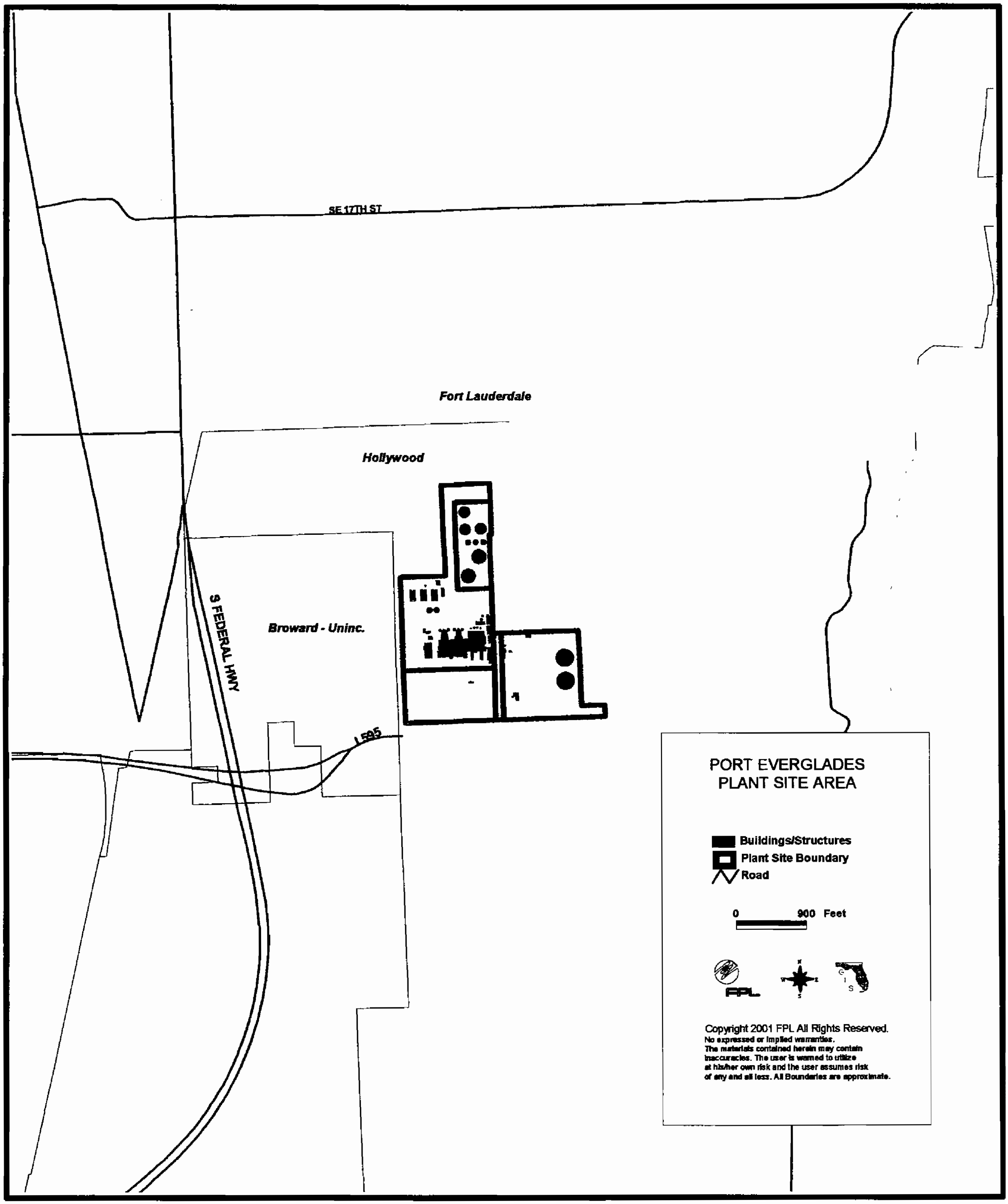


Figure IV.F.18

Figure IV.F.19



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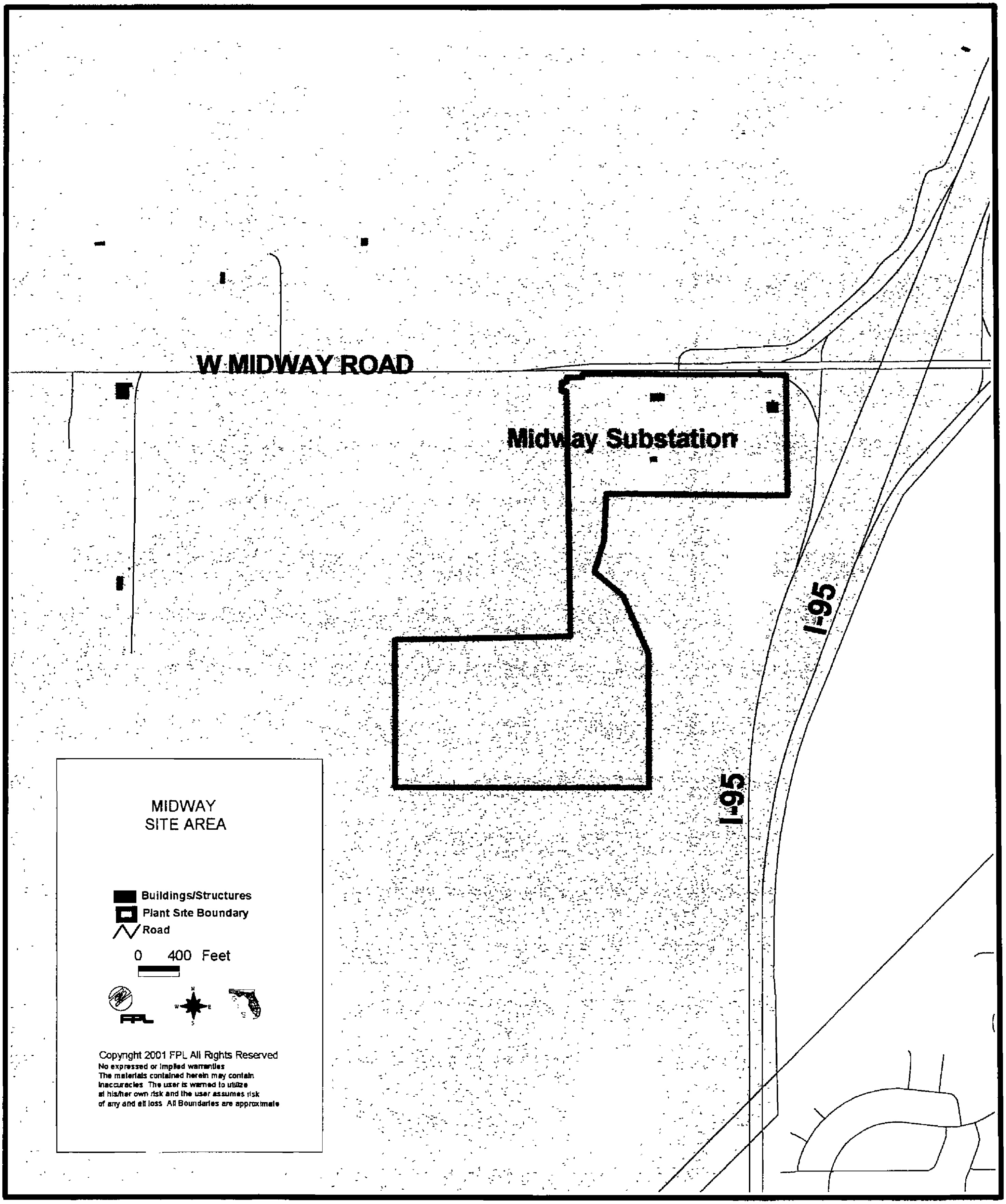

CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information". These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission constraints. External constraints deal with FPL's ties to its neighboring systems. Internal constraints deal with the flow of electricity within the FPL system. The projected effects of these constraints are modeled in FPL's resource planning work.

The external constraints are important since they affect the development of assumptions for the amount of external assistance which is available and the amount and price of economy energy purchases. Therefore, these external constraints are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission constraints or limitations are addressed in developing the costs for siting new units at different locations. Site-specific transmission costs are developed for each different unit/unit location option or groups of options.

FPL's annual transmission planning work determines transmission additions needed to address constraints and to maintain/enhance system reliability. FPL's transmission plans are presented in Section III.E.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

As discussed in Chapter III of this document, FPL typically performs economic analyses of competing resource plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI) and Stone and Webster Management Consultants, Inc. The resource plan reflected in this document emerged as the resource plan with the least impact on FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach) and on the present value of revenue requirements for the FPL system.[3]

As part of its 2001 resource planning work, FPL issued a Request for Proposals (RFP) for firm capacity offerings designed to address FPL 2005 and 2006 capacity needs. FPL received 81 proposals in response to the RFP. These outside proposals, and 13 FPL construction options, were subsequently evaluated by FPL using the EGEAS model. Following the EGEAS calculations, three other calculations designed to determine generator startup costs, transmission integration costs, and equity penalty costs were made. These other costs were then added to the EGEAS costs to develop total costs (in terms of the cumulative present value of revenue requirements) for the competing options. A similar analysis of the outside proposals and FPL construction options was performed independently by an outside consultant.

No sensitivity case analyses based on different load forecasts were carried out during 2001. This is due to the fact that the vast majority of the options studied, including the two most economical options (the Martin Conversion project and the new Manatee unit), are combined cycle (CC) units. If higher – than – projected loads begin to appear, the combustion turbine components of any of the CC options could be placed in service early in simple cycle mode. FPL believed that this fact qualitatively enabled it to be able to address higher – than – projected loads. A quantitative analysis of this occurrence was not possible since the proposals did not include costs for such a scenario.

[3] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis, the lowest rate basis and the lowest system revenue requirements basis are identical. In such cases (as in FPL's 2001 resource planning work), FPL evaluates options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its base case or "Most Likely" fuel price forecast are discussed in Chapter III of this document.

In its 2001 planning work, FPL did not test the sensitivity of its resource plan to a "Low Price" fuel forecast in conjunction with a "High Load" forecast. The reason given in response to Discussion Item # 2 explains why FPL felt that a high load forecast scenario was not needed. Similarly, since the vast majority of the options considered in the RFP analysis were gas-fired units, any change in the fuel costs projections would have affected these proposals in essentially the same way. Consequently, FPL did not believe that a fuel price sensitivity case was needed.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

For the same reason given in response to Discussion Item #3, FPL did not conduct a "constant fuel differential" sensitivity analysis in its 2001 planning work.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, and capacity output ratings and heat rate information. Schedule 1 and Schedule 8 present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options which were considered in the resource planning work. A summary of this information for the new capacity options FPL projects to add over the planing horizon is presented on Schedule 9.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

The key financial assumptions used in FPL's 2001 resource planning work were 45% debt and 55% equity FPL capital structure, projected debt cost of 7.4%, and an equity return of 11.7%. These assumptions resulted in a weighted average cost of capital of 9.8% and an after-tax discount rate of 8.5%. In its 2001 planning work, FPL did not test the sensitivity of its resource plan to varying financial assumptions. The reason for this is that in recent years FPL's planning work has focused on FPL construction options only. Results between higher capital cost options and lower capital cost options could have changed as financial (primarily capital cost) assumptions changed.

However, in its 2001 planning work, outside proposals were analyzed versus the FPL construction options. While FPL could have examined the effect of different financial assumptions on its options, there simply is no practical way to request, receive and reanalyze new cost information for the outside proposals based on a common set of new financial assumptions (such as higher debt rates). The complexity and length of time inherent in an RFP-based process precludes this analysis.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM approach). However, in its 2001 planning work FPL utilized a net present value of system revenue requirements as the basis for comparing options and plans. (As discussed in response to Discussion Item # 2, both the electricity rate basis and the system revenue requirement basis are identical when DSM levels are unchanged between competing plans. Such was the case in FPL's 2001 planning work.)

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses two generation reliability criteria in its resource planning work. One of these is a minimum 15% Summer and Winter reserve margin for years up to mid – 2004 that changes to a minimum 20% Summer and Winter reserve margin for the mid – 2004 – on time period. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the planning criteria established by the North American Electric Reliability Council (NERC) in its *Planning Standards.* FPL has applied these planning criteria in a manner consistent with prudent utility practice. The *NERC Planning Standards* are available on the internet (http://www.nerc.com/~filez/pss-psg.html).

In addition, FPL has developed a Facility Connection Requirements (FCR) document as well as a Facility Rating Methodology document that are also available on the internet (http://www.enx.com/FPL/fpl_home.html).

Thermal ratings for specific transmission lines or transformers are found in the load flow cases that are available on the internet (http://www.enx.com/FPL/fpl_home.html). The normal voltage criteria for FPL stations is given below:

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138, 500	0.95	1.05
230	0.95	1.06

There may have been isolated cases for which FPL may have determined it prudent to deviate from the general criteria stated above. The overall potential impact on customers, the probability of an outage actually occurring, as well as other factors may have influenced the decision in such cases.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The impact of FPL's DSM Programs on demand and energy consumption are revised periodically. Engineering models, calibrated with field-metered data, are updated when significant efficiency changes occur in the marketplace. Participation trends are tracked for all the FPL programs in order to adjust impacts each year for changes in the mix of efficiency measure being installed by program participants.

Survey data is collected from non-participants in order to establish the baseline efficiency. Participant data is compared against non-participant data to establish the demand and energy saving benefits of the utility program versus what would be installed in the absence of the program. Finally, FPL is careful to only claim program savings for the average life of the installed efficiency measure. For these DSM measures which involve the utilization of load management, FPL conducts periodic tests of the load control equipment to ensure that it is functioning correctly.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The strategic or non-price factors FPL considers when choosing between resource options include: (1) fuel diversity; (2) technology risk; and (3) environmental risk.

Fuel diversity relates to two concepts, the diversity of sources of fuel (e.g., coal vs. oil vs. natural gas), and the diversity of supply for a single fuel source (for example alternative pipeline suppliers for natural gas). All other factors being equal, supply options that increase fuel supply diversity would be favored over those that do not.

Technology risk is an assessment of the relative maturity competing technologies, For example, a prototype technology which has not achieved general commercial acceptance has a higher risk than a technology in wide use, and, therefore, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of competing technologies. Technologies which might be regarded as more acceptable from an environmental perspective (e.g., natural gas) might be considered more favorably.

When choosing between an FPL self-build option and buying power, the strategic or non-price factors FPL considers also include: (1) the financial strength of the supplier; (2) the feasibility of licensing and construction requirements; (3) the delivery risk related to firmness of fuel supply and the experience of the seller; and (4) the degree of control offered, including dispatchability and rights to sell power.

The financial strength of the supplier is an assessment of the ability of a project developer to marshal the financial resources required to bring a capital-intensive project to completion. While it has always been a concern, this issue has become even more prominent in light of the collapse of Enron and the generally declining strength of independent power developers following that collapse. It is FPL's customers that ultimately bear the risk of nonperformance of a project resulting from the financial instability of a developer.

Feasibility of licensing and construction plans is an assessment of the reasonableness of the timing of a proposal, given lead times required to site, license, and construct a power plant, and considering the possibility of delay or cancellation resulting from opposition or any other factor. For example, the possibility of delay in licensing and construction is greater for a nuclear plant than a gas turbine. As another example, a combined cycle not "fully committed" to serving retail load might fact greater difficulty in securing a determination of need than a fully committed plant. Again, FPL's customers bear the risk associated with any potential delay.

Delivery risk related to firmness of fuel supply, the construction schedule, and the experience of the seller relate to an assessment of whether a proposed project will deliver power on schedule and reliably. Firmness of fuel supply relates to reliability of the electricity from a facility. A proposed unit that offers power without firm fuel suppliers, for example a gas-fired unit without firm gas transportation, is a higher risk than that same facility with firm transportation. The experience of the seller must also be assessed to assure that the proposed. A proposal offered by a developer that has not shown a history of bringing projects in on time would obviously be less favored than one from a developer with a strong project management record.

The degree of control offered to FPL, including dispatchability and rights to sell power from a project, involves a comparison of a proposed contractual structure to the characteristics FPL would have with its self-built units. For example, an FPL-owned unit is fully controllable by FPL' system operator, within technology limits, so that the unit can be turned on or off, up or down, to meet system requirements. When the unit is not needed to meet system native load requirements, it is available to provide power for system sales, providing gains back to FPL's customers.

All of these factors play a part in FPL's planning and decisions, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As has been discussed, the near - term elements of FPL's capacity additions are the repowering of its Fort Myers and Sanford plants, the addition of new combustion turbines (CT's) at Fort Myers, and a number of firm capacity, short-term purchases. The incremental capacity from the two repowering projects comes from the addition of new CT's and heat recovery steam generators (HRSG's). FPL acquired the repowering-related CT's, plus the other CT's for Fort Myers, and the HRSG's through a bid process which combined cost and performance considerations. The firm capacity short-term purchases were acquired through negotiations.

The 2005 capacity addition decision was arrived at after evaluating 81 bids received in response to a capacity Request for Proposals (RFP) issued by FPL in mid-2001. (Please see Section III for a further discussion of the RFP effort.)

The later (2007 – on) capacity additions projected in FPL's Site Plan document will likely be carried out following the issuance of a similar capacity solicitation to potential suppliers at an appropriate time, if that approach represents the best vehicle to offer the lowest cost new generating capacity.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

FPL's plans do not include any new or upgraded transmission lines during the 2002 – 2011 time period which would need to be certified under the Transmission Line Siting Act (403.52 – 403.536, F.S.)

CHAPTER VI

Summary of Required Schedules

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Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Summer	Winter
Plant Name	No.	Location	Type	Pri.	Alt	Pri	Alt	Use	Month/Year	Month/Year	KW	MW	MW
Turkey Point		Dade County 27/57S/40E									2,338,100	2,198	2,253
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	400	404
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	400	403
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	760,000	693	717
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	760,000	693	717
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	14,000	12	12
Cutler		Dade County 27/55S/40E									236,500	213	216
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	74,500	71	71
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	162,000	142	145
Lauderdale		Broward County 30/50S/42E									1,863,972	1,694	1,804
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	521,250	425	443
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	521,250	429	447
	1-12		CT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,736	420	457
	13-24		CT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,736	420	457
Port Everglades		City of Hollywood 23/50S/42E									1,665,086	1,660	1,701
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	225,250	221	222
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	225,000	221	222
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	390	392
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	408	408
	1-12		CT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,736	420	457
Riviera		City of Riviera Beach 33/42S/43E									620,840	567	569
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	283	283
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	284	286

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1) Plant Name	(2) Unit No	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Summer MW	(14) Net Capability 1/ Winter MW
Martin		Martin County 29/29S/38E									3,312,000	2,846	2,979
	1		ST	NG	FO6	PL	PL	Unknown	Dec-80	Unknown	863,000	814	826
	2		ST	NG	FO6	PL	PL	Unknown	Jun-81	Unknown	863,000	799	812
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	467	489
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	468	490
	8 A & B		CT	NG	FO2	PL	PL	Unknown	Jun-01	Unknown	362,000	298	362
St. Lucie		St Lucie County 16/36S/41E									1,553,000	1,553	1,579
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	839,000	839	853
	2	2/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	714,000	714	726
Cape Canaveral		Brevard County 19/24S/36F									804,100	806	812
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	403	406
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	403	406
Sanford		Volusia County 16/19S/30E									1,022,450	532	528
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	150,250	142	144
	4		ST	FO6	NG	WA	PL	Unknown	Jul-72	Unknown	436,100	390	384
	5	3/	ST	FO6	No	WA	No	Unknown	Jul-73	Unknown	436,100	0	0
Putnam		Putnam County 16/10S/27E									580,000	498	520
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,000	249	260
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,000	249	260

1/ These ratings are peak capability.

2/ Total capability is 839/853 MW Capabilities shown represent the company's share of the unit and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of 14.89551%.

3/ This unit was removed from service as part of the repowering project.

Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel	Commercial	Expected	Gen.Max	Net Capability 1/	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Summer	Winter
Plant Name	No	Location	Type	Pri	Alt	Pri	Alt	Use	Month/Year	Month/Year	KW	MW	MW
Fort Myers		Lee County 35/43S/25E									2,388,250	1,530	1,668
	1	4/	ST	FO6	No	WA	No	Unknown	Nov-58	Unknown	156,250	0	0
	2	4/	ST	FO6	No	WA	No	Unknown	Jul-69	Unknown	402,000	0	0
	1-12		CT	FO2	No	WA	No	Unknown	May-74	Unknown	744,000	636	690
	Repowering CT A		CT	NG	FO2	PL	PL	Unknown	Oct-00	Unknown	181,000	149	163
	Repowering CT B		CT	NG	FO2	PL	PL	Unknown	Nov-00	Unknown	181,000	149	163
	Repowering CT C		CT	NG	FO2	PL	PL	Unknown	Dec-00	Unknown	181,000	149	163
	Repowering CT D		CT	NG	FO2	PL	PL	Unknown	Apr-01	Unknown	181,000	149	163
	Repowering CT E		CT	NG	FO2	PL	PL	Unknown	May-01	Unknown	181,000	149	163
	Repowering CT F		CT	NG	FO2	PL	PL	Unknown	May-01	Unknown	181,000	149	163
Manatee		Manatee County 18/33S/20E									1,726,600	1,619	1,633
	1		ST	FO6	No	WA	No	Unknown	Oct-76	Unknown	863,300	809	816
	2		ST	FO6	No	WA	No	Unknown	Dec-77	Unknown	863,300	810	817
St. Johns River Power Park 2/		Duval County 12/15/28E (RPC4)									250,000	254	260
	1		BIT	BIT	No	RR	No	Unknown	Mar-87	Unknown	125,000	127	130
	2		BIT	BIT	No	RR	No	Unknown	May-88	Unknown	125,000	127	130
Scherer 3/		Monroe, GA									891,000	658	666
	4		BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	891,000	658	666
								Total System as of December 31, 2001 =				16,628	17,188

1/ These ratings are peak capability.
2/ The net capability ratings represent Florida Power & Light Company's share of St Johns River Park Unit No 1 and No 2, excluding Jacksonville Electric Authority (JEA) share of 80% ; SJRPP receives coal by water (WA) in addition to rail.
3/ These ratings represent Florida Power & Light Company's share of Scherer Unit No 4, adjusted for transmission losses
4/ These units were removed from service as part of the repowering project

Schedule 2.1
History and Forecast of Energy Consumption And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					Commercial		
Year	Population*	Members per Household	GWH	Average** No. of Customers	Average KWH Consumption Per Customer	GWH	Average** No. of Customers	Average KWH Consumption Per Customer
1992	6,375,204	2.19	34,198	2,911,807	11,745	26,991	350,269	77,058
1993	6,486,127	2.18	36,360	2,975,479	12,220	28,508	358,679	79,481
1994	6,660,137	2 19	38,716	3,037,629	12,745	29,946	366,409	81,729
1995	6,806,337	2.20	40,556	3,097,192	13,094	30,719	374,005	82,135
1996	6,948,942	2.20	41,302	3,152,625	13,101	31,211	380,860	81,949
1997	7,105,582	2.21	41,849	3,209,298	13,040	32,942	388,906	84,703
1998	7,249,617	2.22	45,482	3,266,011	13,926	34,618	396,749	87,255
1999	7,412,734	2.22	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,603,543	2.23	46,320	3,414,002	13,568	37,001	415,295	89,096
2001	7,749,031	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,891,055	2.22	49,065	3,552,211	13,813	38,360	433,999	88,387
2003	8,029,615	2.22	51,340	3,616,387	14,196	39,745	444,604	89,395
2004	8,164,713	2.22	53,568	3,676,476	14,570	40,913	456,688	89,587
2005	8,296,344	2.22	55,902	3,739,451	14,949	42,018	468,420	89,702
2006	8,433,429	2.22	58,241	3,801,791	15,319	43,210	479,587	90,098
2007	8,570,515	2.22	59,857	3,858,417	15,513	44,317	488,478	90,724
2008	8,709,688	2.23	61,401	3,912,926	15,692	45,391	497,099	91,313
2009	8,850,948	2.23	62,961	3,966,369	15,874	46,461	505,533	91,905
2010	8,992,209	2.24	64,628	4,018,926	16,081	47,571	513,718	92,602
2011	9,134,785	2.24	66,282	4,070,702	16,283	48,478	521,756	92,913

* Population represents only the area served by FPL.
** Average No. of Customers is the annual average of the twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads & Railways	Street & Highway Lighting	Other Sales to Public Authorities	Total** Sales to Ultimate Consumers
Year	GWH	Average* No. of Customers	Average KWH Consumption Per Customer	GWH	GWH	GWH	GWH
1992	4,054	14,788	274,135	77	353	721	66,393
1993	3,889	14,866	261,602	79	330	665	69,830
1994	3,845	15,588	246,658	85	353	664	73,608
1995	3,883	15,140	256,481	84	358	648	76,248
1996	3,792	14,783	256,515	83	368	577	77,334
1997	3,894	14,761	263,830	85	383	702	79,855
1998	3,951	15,126	261,233	81	373	625	85,131
1999	3,948	16,040	246,112	79	473	465	84,676
2000	3,768	16,410	229,592	81	408	381	87,959
2001	4,091	15,445	264,872	86	419	67	90,212
2002	3,947	15,147	260,552	81	417	61	91,930
2003	3,960	15,176	260,942	81	428	60	95,615
2004	3,969	15,143	262,106	82	438	60	99,030
2005	3,971	15,105	262,875	82	446	60	102,479
2006	3,977	15,077	263,746	83	455	60	106,024
2007	3,974	15,122	262,795	83	461	60	108,752
2008	3,956	15,168	260,821	83	468	60	111,360
2009	3,933	15,213	258,530	84	474	60	113,973
2010	3,912	15,259	256,386	84	481	60	116,736
2011	3,891	15,305	254,215	85	487	60	119,282

*Average No.of Customers is the annual average of the twelve month values.
**GWH=Column 4 + Column 7 + Column 10 + Column 13 + Column 14 + Column 15.

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWH	(18) Utility Use & Losses GWH	(19) Net* Energy For Load GWH	(20) Average ** No. of Other Customers	(21) Total Average*** Number of Customers
1992	702	6,002	73,097	4,374	3,281,238
1993	958	4,988	75,776	3,086	3,352,110
1994	1,400	5,367	80,376	2,560	3,422,187
1995	1,437	6,276	83,961	2,460	3,488,796
1996	1,353	5,984	84,671	2,480	3,550,748
1997	1,228	5,770	86,853	2,520	3,615,485
1998	1,326	6,205	92,662	2,584	3,680,470
1999	953	5,829	91,458	2,605	3,756,009
2000	970	7,059	95,989	2,694	3,848,401
2001	970	7,222	98,404	2,722	3,935,281
2002	1,207	7,021	100,158	2,805	4,004,161
2003	1,425	7,373	104,414	2,872	4,079,038
2004	1,446	7,567	108,042	2,931	4,151,237
2005	1,463	7,831	111,772	2,985	4,225,960
2006	1,482	8,097	115,602	3,036	4,299,491
2007	1,415	7,990	118,157	3,077	4,365,095
2008	1,081	8,108	120,549	3,116	4,428,309
2009	1,081	7,869	122,922	3,155	4,490,271
2010	1,081	7,631	125,448	3,193	4,551,096
2011	1,081	7,149	127,512	3,231	4,610,993

* GWH = Column 16 + Column 17 + Column 18
** Average Number of Customers is the annual average of the twelve month values.
*** Total = Column 5 + Column 8 + Column 11 + Column 20

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
1992	14,661	223	14,438	0	234	151	248	51	14,179
1993	15,266	397	14,869	0	311	182	320	79	14,635
1994	15,179	409	14,770	0	392	220	354	125	14,433
1995	16,172	435	15,737	0	466	259	391	193	15,315
1996	16,064	364	15,700	0	531	339	414	296	15,119
1997	16,613	380	16,233	0	615	440	432	341	15,566
1998	17,897	426	17,471	0	656	480	441	359	16,800
1999	17,615	169	17,446	0	722	565	450	397	16,443
2000	17,808	161	17,647	0	767	626	456	432	16,585
2001	18,754	169	18,585	0	798	673	483	463	17,473
2002	19,131	146	18,985	0	805	83	487	39	17,717
2003	19,765	223	19,542	0	810	125	497	59	18,274
2004	20,226	225	20,002	0	817	167	507	79	18,656
2005	20,719	227	20,493	0	824	211	517	99	19,068
2006	21,186	227	20,959	0	829	255	525	120	19,457
2007	21,556	227	21,329	0	834	300	533	140	19,749
2008	21,870	152	21,718	0	839	347	541	159	19,984
2009	22,271	152	22,119	0	842	394	547	179	20,309
2010	22,687	152	22,535	0	844	410	548	185	20,700
2011	23,106	152	22,954	0	844	410	548	185	21,119

Historical Values (1992 - 2001):

Cols. (2) - (4) are actual values for historical summer peaks As such, they incorporate the effects of conservation (Cols. (7&9)), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand Cols. (5) - (9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes GS-LC, CDR and GSD-LC.
Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: (10) = (2) -(6) -(8).

Projected Values (2002 - 2011):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2001 are incorporated into the forecast.
Cols. (5) - (9) represent all incremental conservation and cumulative load control. These values are projected August values and are based on projections with a 1/2001 starting point.
Col (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col (10) is derived by using the formula: (10) = (2) - (5) - (6) - (7) - (8) - (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1992/93	12,964	102	12,862	0	242	195	275	48	12,447
1993/94	12,594	278	12,316	0	317	231	342	67	11,935
1994/95	16,563	635	15,928	0	393	265	360	93	15,810
1995/96	18,096	698	17,398	0	459	310	406	143	17,231
1996/97	16,490	626	15,864	0	731	368	418	154	15,341
1997/98	13,060	239	12,821	0	823	403	429	168	11,807
1998/99	16,802	149	16,653	0	1,218	438	417	182	15,167
1999/00	17,057	142	16,915	0	1,296	469	441	193	15,320
2000/01	18,199	150	18,049	0	972	493	448	201	16,779
2001/02	17,597	145	17,452	0	1,081	534	489	242	16,028
2002/03	19,551	121	19,430	0	1,085	78	458	22	17,908
2003/04	19,976	198	19,779	0	1,093	104	464	30	18,285
2004/05	20,418	199	20,218	0	1,102	128	470	38	18,680
2005/06	20,854	199	20,654	0	1,109	153	476	48	19,068
2006/07	21,204	199	21,005	0	1,116	177	481	57	19,373
2007/08	21,538	124	21,414	0	1,123	200	486	66	19,663
2008/09	21,966	124	21,841	0	1,129	223	491	75	20,048
2009/10	22,366	124	22,242	0	1,134	245	494	82	20,411
2010/11	22,785	124	22,661	0	1,134	245	494	82	20,830

Historical Values (1992/93 - 2001/02):

Cols (2) - (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Cols. (7&9)), and may incorporate the effects of load control if load control was operated on these peak days Therefore, Col. (2) represents the actual Net Firm Demand.
Cols. (5) - (9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col (8), which also includes GS-LC, CDR and GSD - LC.
Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: (10) = (2) -(6) -(8).

Projected Values (2002/03 - 2010/11):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2001 are incorporated into the forecast.
Cols. (5) - (9) represent all incremental conservation and cumulative load control. These values are projected August values and are based on projections with a 1/2001 starting point.
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: (10) = (2) - (5) - (6) - (7) - (8) - (9).

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH: Base Case

(1) Year	(2) Total	(3) Residential Conservation	(4) C/I Conservation	(5) Retail	(6) Sales for Resale GWH	(7) Utility Use & Losses	(8) Net Energy For Load	(9) Load Factor(%)
1992	73,778	460	221	73,076	702	6,002	73,097	56 8%
1993	76,632	553	303	75,674	958	4,988	75,776	56.7%
1994	81,493	661	456	80,093	1,400	5,367	80,376	60 4%
1995	85,415	777	677	83,978	1,437	6,276	83,961	59 3%
1996	86,708	971	1,039	85,355	1,353	5,984	84,698	60 0%
1997	89,240	1,213	1,174	88,012	1,228	5,770	86,853	59.7%
1998	95,316	1,374	1,279	93,990	1,326	6,205	92,663	59.1%
1999	94,361	1,542	1,362	93,408	953	5,829	91,458	59.3%
2000	99,094	1,674	1,431	98,123	970	7,059	95,989	61.5%
2001	101,736	1,789	1,542	100,765	970	7,222	98,404	59.9%
2002	100,158	58	15	98,951	1,207	7,021	100,085	59 8%
2003	104,414	156	47	102,988	1,425	7,373	104,211	60.3%
2004	108,042	256	80	106,597	1,446	7,567	107,706	61.0%
2005	111,772	358	115	110,310	1,463	7,831	111,299	61.6%
2006	115,602	462	150	114,121	1,482	8,097	114,990	62.3%
2007	118,157	568	184	116,743	1,415	7,990	117,405	62.6%
2008	120,549	675	216	119,468	1,081	8,108	119,658	62.9%
2009	122,922	785	247	121,842	1,081	7,869	121,890	63.0%
2010	125,448	830	262	124,367	1,081	7,631	124,356	63.1%
2011	127,512	830	262	126,432	1,081	7,149	126,420	63.0%

Historical Values (1992 - 2001):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: (2) =(3) + (4) + (8).
Cols. (3) & (4) are DSM values starting in January, 1988 through 2001 which contributed to the values in Cols (5) - (9).
Cols. (5) & (6) are a breakdown of Net Energy For Load in Col (2) into Retail and Wholesale .
Col (9) is calculated using Col. (8) from this page and Col. (2), "Total", from Schedule 3.1. (9) = ((8)*1000) / ((2) * 8760)

Projected Values (2002 - 2011):

Col. (2) represents Net Energy for Load w/o DSM values. The values are calculated using the formula. (2) =(3) + (4) + (8)
Cols. (3) - (4) are forecasted values of the reduction on sales from incremental conservation.
Cols. (5) & (6) are a breakdown of Net Energy For Load in Col (2) , into Wholesale and Retail .
Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. (9) = ((8)*1000) / ((2) * 8760)

Schedule 4
Previous Year Actual and Two-Year Forecast of Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2001 ACTUAL		2002 * FORECAST		2003 * FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	18,199	8,074	18,968	7,375	19,551	7,708
FEB	13,268	6,541	16,070	6,859	16,563	7,190
MAR	14,611	7,442	14,353	7,368	14,793	7,703
APR	15,831	7,797	15,645	7,683	16,163	8,020
MAY	16,280	7,722	17,373	8,442	17,948	8,810
JUN	18,342	9,476	18,218	9,299	18,821	9,690
JUL	17,803	9,120	18,727	9,710	19,347	10,110
AUG	18,754	10,086	19,131	9,881	19,765	10,263
SEP	18,707	9,413	18,494	9,608	19,107	9,982
OCT	15,971	8,185	17,266	8,578	17,837	8,927
NOV	13,781	7,217	15,721	7,737	16,204	8,068
DEC	14,590	7,331	16,317	7,618	16,818	7,942
TOTALS		98,404		100,158		104,414

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation.

Schedule 5
Fuel Requirements [1/]

	Fuel Requirements	Units	Actual [2/] 2000	2001	Forecasted 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Nuclear	Trillion BTU	268	263	263	258	258	263	258	257	264	258	257	263
(2)	Coal	1,000 TON	4,170	3,078	3,460	3,584	3,416	3,396	3,479	3,194	3,513	3,110	3,113	3,281
(4)	Residual (FO6)- Total	1,000 BBL	36,859	40,995	57,569	26,714	23,538	20,417	18,661	17,222	16,514	11,535	9,609	7,905
(5)	Steam	1,000 BBL	36,859	40,995	57,569	26,714	23,538	20,417	18,661	17,222	16,514	11,535	9,609	7,905
(6)	Distillate (FO2)- Total	1,000 BBL	461	381	538	2,750	4,114	799	792	537	612	20	9	5
(7)	CC	1,000 BBL	1	75	124	2,220	3,404	683	677	486	549	10	3	3
(8)	CT	1,000 BBL	446	306	415	529	711	116	115	51	63	11	6	2
(9)	Steam	1,000 BBL	14	0	0	0	0	0	0	0	0	0	0	0
(10)	Natural Gas -Total	1,000 MCF	203,234	212,956	297,272	303,963	308,493	362,745	406,236	434,737	445,987	495,736	555,295	594,673
(11)	Steam	1,000 MCF	80,967	79,157	80,432	17,368	20,648	16,698	17,897	15,280	17,064	10,769	7,970	6,199
(12)	CC	1,000 MCF	117,684	109,778	196,898	274,488	277,953	337,081	384,738	414,787	424,908	482,040	546,027	587,265
(13)	CT	1,000 MCF	4,583	24,022	19,942	12,107	9,891	8,966	3,601	4,670	4,015	2,927	1,298	1,209

1/ Reflects fuel requirements for FPL only
2/ Source A Schedules

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 2000	Actual 2001	Forecasted 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Annual Energy Interchange 2/	GWH	7,443	7,701	8,061	7,912	7,973	7,832	7,645	7,573	7,605	7,371	2,873	0
(2)	Nuclear	GWH	24,584	24,070	24,284	23,873	23,845	24,284	23,873	23,776	24,344	23,857	23,776	24,274
(3)	Coal	GWH	6,977	6,267	6,503	6,674	6,396	6,396	6,514	6,071	6,577	5,901	5,900	6,187
(4)	Residual(FO6) -Total	GWH	23,230	25,802	9,861	11,881	14,885	12,943	11,813	10,922	10,453	7,349	6,109	5,045
(5)	Steam	GWH	23,230	25,802	9,861	11,881	14,885	12,943	11,813	10,922	10,453	7,349	6,109	5,045
(6)	Distillate(FO2) -Total	GWH	193	163	278	1,979	2,979	592	581	408	461	13	5	3
(7)	CC	GWH	1	41	101	1,681	2,588	536	529	387	433	8	2	2
(8)	CT	GWH	183	122	177	298	391	55	52	22	28	5	3	1
(9)	Steam	GWH	9	0	0	0	0	0	0	0	0	0	0	0
(10)	Natural Gas -Total	GWH	24,217	24,496	40,313	41,995	41,809	49,873	56,309	60,446	62,208	69,722	78,684	84,556
(11)	Steam	GWH	7,840	7,588	11,524	2,340	1,881	1,527	1,643	1,402	1,577	996	734	569
(12)	CC	GWH	16,064	14,849	26,923	38,510	38,989	47,498	54,339	58,611	60,259	68,450	77,830	83,874
(13)	CT	GWH	313	2,060	1,866	1,144	940	848	327	433	372	275	120	113
(14)	Other 3/	GWH	9,345	9,905	10,858	10,101	10,155	9,852	8,867	8,961	8,901	8,710	8,101	7,446
	Net Energy For Load 4/	GWH	95,989	98,404	100,158	104,414	108,042	111,772	115,602	118,157	120,549	122,922	125,448	127,512

1/ Source: A Schedules.

2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.

3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

4/ Net Energy For Load is Column 2 on Schedule 3.3 and Column 1 on EIA411 Form 11C.

Schedule 6.2
Energy % by Fuel Type

	Energy Source	Units	Actual 2000	Actual 2001	Forecasted 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Annual Energy Interchange 2/	%	7.8	8.0	8.0	7.6	7.4	7 0	6.6	6.4	6.3	6.0	2.3	0.0
(2)	Nuclear	%	25.6	24 5	24 2	22.9	22 1	21.7	20.7	20.1	20.2	19.4	19.0	19.0
(3)	Coal	%	7.3	6.4	6.5	6.4	5.9	5.7	5.6	5.1	5.5	4.8	4.7	4.9
(4)	Residual (FO6) -Total	%	24.2	26.2	9 8	11 4	13 8	11.6	10.2	9.2	8.7	6.0	4.9	4.0
(5)	Steam	%	24.2	26.2	9.8	11.4	13.8	11 6	10.2	9.2	8.7	6.0	4.9	4.0
(6)	Distillate (FO2) -Total	%	0.2	0.2	0 3	1.9	2 8	0 5	0.5	0.3	0.4	0.0	0 0	0.0
(7)	CC	%	0.0	0.0	0.1	1.6	2.4	0.5	0.5	0.3	0.4	0.0	0.0	0.0
(8)	CT	%	0.2	0.1	0.2	0.3	0 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Steam	%	0.0	0.0	0 0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0 0	0.0
(10)	Natural Gas -Total	%	25.2	24.9	40.2	40.2	38.7	44.6	48 7	51.2	51.6	56.7	62.7	66.3
(11)	Steam	%	8.2	7.7	11.5	2.2	1.7	1.4	1.4	1.2	1.3	0.8	0.6	0.4
(12)	CC	%	16.7	15.1	26.9	36.9	36.1	42.5	47.0	49.6	50.0	55.7	62.0	65.8
(13)	CT	%	0.3	2 1	1.9	1.1	0.9	0.8	0 3	0.4	0.3	0.2	0.1	0.1
(14)	Other 3/	%	9.7	10.1	10.8	9.7	9.4	8.8	7.7	7.6	7.4	7.1	6.5	5.8
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source. A Schedules.

2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.

3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	% of Peak
2002	17,860	2,403	0	877	21,140	19,131	1,414	17,717	3,423	19.3	0	3,423	19.3
2003	19,135	2,474	0	877	22,486	19,765	1,491	18,274	4,212	23.0	0	4,212	23.0
2004	19,135	2,474	0	877	22,486	20,226	1,570	18,656	3,830	20.5	0	3,830	20.5
2005	21,031	1,758	0	867	23,656	20,719	1,651	19,068	4,588	24.1	0	4,588	24.1
2006	21,031	1,757	0	734	23,522	21,186	1,729	19,457	4,065	20.9	0	4,065	20.9
2007	22,138	1,310	0	734	24,182	21,556	1,807	19,749	4,433	22.4	0	4,433	22.4
2008	22,138	1,310	0	734	24,182	21,870	1,886	19,984	4,198	21.0	0	4,198	21.0
2009	23,245	1,310	0	683	25,238	22,271	1,962	20,309	4,929	24.3	0	4,929	24.3
2010	24,352	382	0	639	25,373	22,687	1,987	20,700	4,673	22.6	0	4,673	22.6
2011	25,459	382	0	594	26,435	23,106	1,987	21,119	5,316	25.2	0	5,316	25.2

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. All values are Summer net MW

2/ Total Capacity Available=Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation from 1/99 - on. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance =Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	Reserve Margin Before Maintenance 5/ % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	Reserve Margin After Maintenance 6/ % of Peak
2001/02	17,730	1,910	0	886	20,526	18,968	1,589	17,379	3,147	18.1	0	3,147	18.1
2002/03	20,007	2,634	0	877	23,518	19,551	1,643	17,908	5,610	31.3	0	5,610	31.3
2003/04	20,369	2,673	0	877	23,919	19,976	1,691	18,285	5,634	30.8	0	5,634	30.8
2004/05	20,369	2,623	0	867	23,859	20,418	1,738	18,680	5,179	27.7	0	5,179	27.7
2005/06	22,402	1,860	0	734	24,996	20,854	1,786	19,068	5,928	31.1	0	5,928	31.1
2006/07	22,402	1,860	0	734	24,996	21,204	1,831	19,373	5,623	29.0	0	5,623	29.0
2007/08	23,598	1,317	0	734	25,649	21,538	1,875	19,663	5,986	30.4	0	5,986	30.4
2008/09	23,598	1,317	0	734	25,649	21,966	1,918	20,048	5,601	27.9	0	5,601	27.9
2009/10	24,795	1,317	0	683	26,795	22,366	1,955	20,411	6,384	31.3	0	6,384	31.3
2010/11	25,992	389	0	595	26,976	22,785	1,955	20,830	6,146	29.5	0	6,146	29.5

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated All values are Winter net MW

2/ Total Capacity Available = Col (2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col (9)

6/ Margin (%) After Maintenance = Col (13) / Col (9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15
				Fuel		Fuel Transport		Const	Comm	Expected	Gen Max	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Start Mo /Yr	In-Service Mo /Yr	Retirement Mo /Yr	Nameplate KW	Winter MW	Summer MW	Stat
ADDITIONS														
2002														
---------------		--------------	---	---	---	---	---	---	---	---	---	---	---	---
2003														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-00	Apr-03	Unknown	190,000	---	159	P
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	May-03	Unknown	190,000	---	159	P
2004														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	Apr-03	Unknown	190,000	181	---	P
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-00	May-03	Unknown	190,000	181	---	P
2005														
Manatee Combined Cycle Unit	3	Manatee County 18/33S/20E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	---	1,107	P
2006														
Manatee Combined Cycle Unit	3	Manatee County 18/33S/20E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	1,197	---	P
2007														
Unsited Combined Cycle Unit #1	1	Unknown	CC	NG	FO2	PL	PL	Jan-04	Jun-07	Unknown	470,000	---	1,107	P
2008														
Unsited Combined Cycle Unit #1	1	Unknown	CC	NG	FO2	PL	PL	Jan-04	Jun-07	Unknown	470,000	1,197	---	P
2009														
Unsited Combined Cycle Unit #2	2	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-09	Unknown	470,000	---	1,107	P
2010														
Unsited Combined Cycle Unit #2	2	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-09	Unknown	470,000	1,197	---	P
Unsited Combined Cycle Unit #3	3	Unknown	CC	NG	FO2	PL	PL	Jan-07	Jun-10	Unknown	470,000	---	1,107	P
2011														
Unsited Combined Cycle Unit #3	3	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-10	Unknown	470,000	1,197	---	P
Unsited Combined Cycle Unit #4	4	Unknown	CC	NG	FO2	PL	PL	Jan-07	Jun-11	Unknown	470,000	---	1,107	P

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (Cont.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm	Expected	Gen Max	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter [1),2)]	Summer [1) 2)]	
Plant Name	No	Location	Type	Pri	Alt	Pri	Alt	Mo /Yr	Mo /Yr	Mo /Yr	KW	MW	MW	Status
CHANGES/UPGRADES														
2002														
Sanford Repowering Initial Phase [3)]	4	Volusia County 16/19S/30E	ST	FO6	NG	WA	PL	Mar-02	----	Unknown	106,600	0	(390) [4)]	RP
Sanford Repowering Initial Phase	5	Volusia County 16/19S/30E	ST	FO6	NG	WA	PL	Oct-01	----	Unknown	106,600	(390) [4)]	0	RP
Sanford Repowering Second Phase	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	May-02	Jul-02	Unknown	106,600	0	567	RP
Ft Myers Repowering Second Phase	1&2	Lee County 35/43S/25E	CC	NG	No	PL	No	Nov-01	Jan-02	Unknown	161,700	(1)	35	RP,U
Riviera	4	City of Riviera Beach 33/42S/43E	ST	FO6	NG	WA	PL	Nov-01	Jan-02	Unknown	310,420	10	10	P
Martin Combustion Turbines	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	---	10	P
Martin Combustion Turbines	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	---	10	P
											2002 Total:	**(381)**	**242**	
2003														
Sanford Repowering Second Phase	4	Volusia County 16/19S/30E	CC	NG	No	PL	No	Sep-02	Dec-02	Unknown	106,600	675	957	RP
Sanford Repowering. Second Phase	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	Sep-02	Dec-02	Unknown	106,600	1,065	0	RP
Ft Myers Repowering Second Phase	1 & 2	Lee County 35/43S/25E	CC	NG	No	PL	No	Nov-02	Jan-03	Unknown	161,700	531	0	RP,U
Martin Combustion Turbines	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	10	---	P
Martin Combustion Turbines	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	10	---	P
											2003 Total:	**2,291**	**957**	
2004														
---------------		---------------	---	---	---	---	---	---	---	---	---	---	---	---
											2004 Total:	**0**	**0**	
2005														
Martin Combustion Turbine Conversion	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	---	394.5	P
Martin Combustion Turbine Conversion	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	---	394 5	P
											2005 Total:	**0**	**789**	

1)The Winter Total MW value consists of all generation additions and changes achieved by January The Summer Total MW value consists of all generation additions and changes achieved by July All other MW will be picked up in the following year This is done for reserve margin calculation

2) All MW differences are calculated based on using IRP 2001 Submittal (for the year 2001) as the base for all other years

3) The values shown reflect the schedule for the repowering of Sanford Unit # 4 that was used in FPL's 2001 resource planning work That schedule has recently changed Please refer to Section III A, "Step 1" for more information

4) Negative values for Sanford and Ft Myers reflect the existing steam units being temporarily out of service during that seasonal period for repowering efforts

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (Cont.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm	Expected	Gen Max	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter [1]	Summer [1]	
Plant Name	No	Location	Type	Pri	Alt	Pri	Alt	Mo /Yr	Mo /Yr	Mo /Yr	KW	MW	MW	Status
CHANGES/UPGRADES														
2006														
Martin Combustion Turbine Conversion	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	417.5	---	P
Martin Combustion Turbine Conversion	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	417.5	---	P
											2006 Total:	**835**	**0**	
2007														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2007 Total:	**0**	**0**	
2008														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2008 Total:	**0**	**0**	
2009														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2009 Total:	**0**	**0**	
2010														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2010 Total:	**0**	**0**	
2011														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
											2011 Total:	**0**	**0**	

1)The Winter Total MW value consists of all generation additions and changes achieved by January The Summer Total MW value consists of all generation additions and changes achieved by July. All other MW will be picked up in the following year This is done for reserve margin calculation.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Fort Myers Repowering
(2)	**Capacity**		
	a. Summer	929	MW Incremental (1473 MW Total After Repowering)
	b. Winter	1,073	MW Incremental (1617 MW Total After Repowering)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	1999	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		None
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors
(7)	**Cooling Method:**		Once-through Cooling w/ Helper Cooling Tower
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	V	(Under Construction > 50% Complete)
(10)	**Certification Status:**	V	(Under Construction > 50% Complete)
(11)	**Status with Federal Agencies:**	V	(Under Construction > 50% Complete)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	96%	
Resulting Capacity Factor (%):	Approx. 90%	(First Year)
Average Net Operating Heat Rate (ANOHR):	6,830	Btu/kWh

(13) **Projected Unit Financial Data, *,**,*****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	559	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001$/kW-Yr)	13.45	
Variable O&M ($/MWH): (2001 $/MWH)	0.37	
K Factor:	1.5395	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Sanford Unit 4 Repowering
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	671	MW Incremental (1065 MW Total After Repowering)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		None
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	U	(Under Construction $\leq$ 50% Complete)
(10)	**Certification Status:**	U	(Under Construction $\leq$ 50% Complete)
(11)	**Status with Federal Agencies:**	U	(Under Construction $\leq$ 50% Complete)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		3%
	Forced Outage Factor (FOF):		1%
	Equivalent Availability Factor (EAF):		96%
	Resulting Capacity Factor (%):		Approx. 96% (First Year)
	Average Net Operating Heat Rate (ANOHR):		6,918 Btu/kWh
(13)	**Projected Unit Financial Data *,**,*****		
	Book Life (Years):		25 years
	Total Installed Cost (In-Service Year $/kW):		656
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)		14.41
	Variable O&M ($/MWH): (2001 $/MWH)		0.374
	K Factor:		1.4637

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Sanford Unit 5 Repowering
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	671	MW Incremental (1065 MW Total After Repowering)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	V	(Under Construction > 50% Complete)
(10)	**Certification Status:**	V	(Under Construction > 50% Complete)
(11)	**Status with Federal Agencies:**	V	(Under Construction > 50% Complete)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	Approx. 96%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	6,918	Btu/kWh
(13)	**Projected Unit Financial Data *,**,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW)	656	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	14.41	
	Variable O&M ($/MWH): (2001 $/MWH)	0.374	
	K Factor:	1.5395	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Fort Myers Combustion Turbines No. 13 and No. 14 *	
(2)	**Capacity**		
	a. Summer	159	MW each for a total of 318 MW
	b. Winter	181	MW each for a total of 362 MW
(3)	**Technology Type:**	Combustion Turbine	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2001	
	b. Commercial In-service date:	2003	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NOx Combustors, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Air Coolers
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	U	(Under Construction ≤ 50% Complete)
(10)	**Certification Status:**	U	(Under Construction ≤ 50% Complete)
(11)	**Status with Federal Agencies:**	U	(Under Construction ≤ 50% Complete)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	1%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	98%	
	Resulting Capacity Factor (%):	Approx. 25%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	10,430	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	414	per Combustion Turbine
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	0.69	
	Variable O&M ($/MWH): (2001 $/MWH)	0.87	
	K Factor:	1.5394	

* Values shown are per unit values for the two units being added.
** $/kW values are based on Summer capacity.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Martin Combustion Turbine Conversion to Combined Cycle
(2)	**Capacity**		
	a. Summer	789	MW Incremental (1107 MW Total)
	b. Winter	835	MW Incremental (1197 MW Total)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Pond/Tower
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	L	(Regulatory Approval Pending)
(11)	**Status with Federal Agencies:**	L	(Regulatory Approval Pending)
(12)	**Projected Unit Performance Data** *		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	
	Resulting Capacity Factor (%):	Approx. 80%	(First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh
	Base Operation 75F	100%	
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	599	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	9.07	
	Variable O&M ($/MWH): (2001 $/MWH)	0.037	
	K Factor:	1.5397	

* Values represent an operational combined cycle unit after the conversion is completed.
** $/kW values are based on Summer incremental capacity.
*** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Manatee Combined Cycle
(2)	**Capacity**		
	a. Summer	1,107	MW
	b. Winter	1,197	MW
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		None
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	9,500	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	L	(Regulatory Approval Pending)
(11)	**Status with Federal Agencies:**	L	(Regulatory Approval Pending)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	
	Resulting Capacity Factor (%):	Approx. 71%	(First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh
	Base Operation 75F	100%	
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	511	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	12.96	
	Variable O&M ($/MWH): (2001 $/MWH)	0.037	
	K Factor:	1.5397	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 1	
(2)	**Capacity**		
	a. Summer	1,107 MW	
	b. Winter	1,197 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2005	
	b. Commercial In-service date:	2007	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	
	Resulting Capacity Factor (%):	Approx. 65%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	7,021	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	568	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	15.47	
	Variable O&M ($/MWH): (2001 $/MWH)	0.037	
	K Factor:	1.5399	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 2	
(2)	**Capacity**		
	a. Summer	1,107 MW	
	b. Winter	1,197 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2007	
	b. Commercial In-service date:	2009	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	
	Resulting Capacity Factor (%):	Approx. 60%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	7,021	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	587	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	15.47	
	Variable O&M ($/MWH): (2001 $/MWH)	0.037	
	K Factor:	1.5399	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 3		
(2)	**Capacity**			
	a. Summer	1,107	MW	
	b. Winter	1,197	MW	
(3)	**Technology Type:**	Combined Cycle		
(4)	**Anticipated Construction Timing**			
	a. Field construction start-date:	2008		
	b. Commercial In-service date:	2010		
(5)	**Fuel**			
	a. Primary Fuel		Natural Gas	
	b. Alternate Fuel		Distillate	
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Unknown		
(8)	**Total Site Area:**	Unknown	Acres	
(9)	**Construction Status:**	P	(Planned)	
(10)	**Certification Status:**	P	(Planned)	
(11)	**Status with Federal Agencies:**	P	(Planned)	
(12)	**Projected Unit Performance Data:**			
	Planned Outage Factor (POF):		2%	
	Forced Outage Factor (FOF):		1%	
	Equivalent Availability Factor (EAF):		97%	
	Resulting Capacity Factor (%):		Approx. 60%	(First Year)
	Average Net Operating Heat Rate (ANOHR):		7,021	Btu/kWh
(13)	**Projected Unit Financial Data *,****			
	Book Life (Years):		25	years
	Total Installed Cost (In-Service Year $/kW):		597	
	Direct Construction Cost ($/kW):			
	AFUDC Amount ($/kW):			
	Escalation ($/kW):			
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)		15.47	
	Variable O&M ($/MWH): (2001 $/MWH)		0.037	
	K Factor:		1.5400	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 4	
(2)	**Capacity**		
	a. Summer	1,107 MW	
	b. Winter	1,197 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2009	
	b. Commercial In-service date:	2011	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Distillate	
(6)	**Air Pollution and Control Strategy:**	Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	
	Resulting Capacity Factor (%):	Approx. 52%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	7,021	Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	607	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	15.47	
	Variable O&M ($/MWH): (2001 $/MWH)	0.037	
	K Factor:	1.5400	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Fort Myers Repowering

The transmission line work for this project has been completed.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sanford Repowering

The transmission line work for this project has been completed.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Ft. Myers: 2 CT's

(1)	Point of Origin and Termination:	From Ft. Myers GT Collector bus – To Orange River
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	2.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: January 1, 2003 End date: May 1, 2003
(7)	Anticipated Capital Investment:	$1,050,000
(8)	Substations:	Orange River and Ft. Myers GT collector bus
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Manatee CC Unit

(1)	Point of Origin and Termination:	Manatee – Johnson
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	18 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: June 1, 2004 End date: June 1, 2005
(7)	Anticipated Capital Investment:	$12,700,000
(8)	Substations:	Manatee and Johnson
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Martin CT – to - CC Conversion

(1)	Point of Origin and Termination:	Martin – Indiantown #2
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned & New acquisitions
(4)	Line Length:	12.9 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBA End date: TBA
(7)	Anticipated Capital Investment:	$9,400,000
(8)	Substations:	Martin 230kV and Indiantown
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	Indiantown – Bridge
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	10.0 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBA End date: TBA
(7)	Anticipated Capital Investment:	$10,300,000
(8)	Substations:	Indiantown and Bridge
(9)	Participation with Other Utilities:	None

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TEN YEAR SITE PLAN FACT SUMMARY

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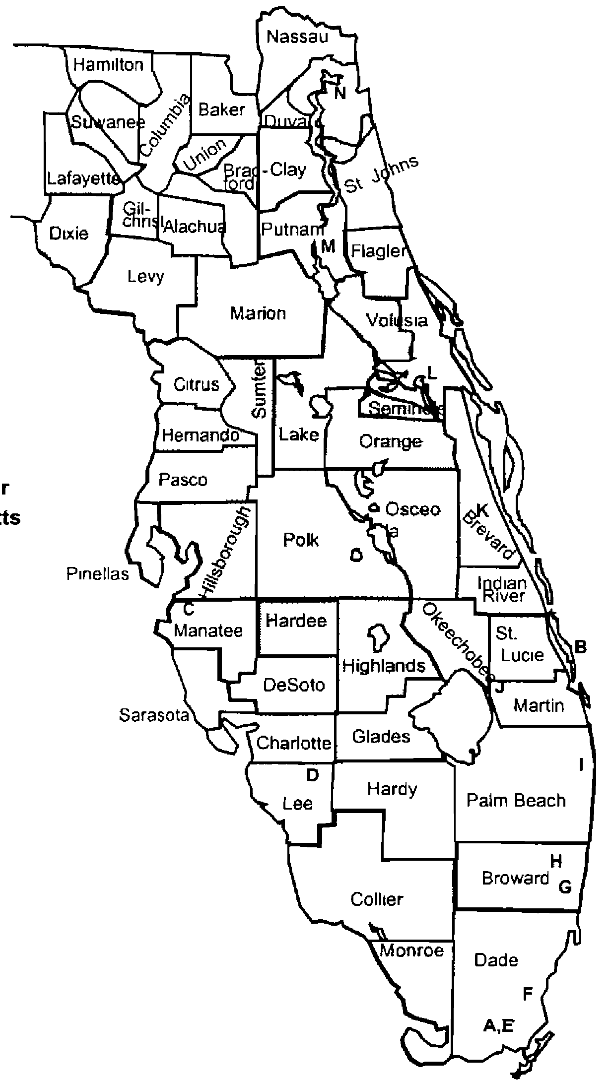
Capacity Resources
(as of December 31, 2001)

☐ Non-FPL Territory



	Unit Name	Unit	Fuel Type	Summer Megawatts
A	Turkey Point	2	Nuclear	1,386
B.	St. Lucie *	2	Nuclear	1,553
C.	Manatee	2	Oil	1,619
D.	Ft. Myers	2	Oil	894
E.	Turkey Point	2	Oil/Gas	800
F.	Cutler	2	Gas	213
G.	Lauderdale	2	Oil/Gas	854
H.	Port Everglades	4	Oil/Gas	1,240
I.	Riviera	2	Oil/Gas	567
J.	Martin	4	Gas/Oil	2,548
K.	Cape Canaveral	2	Oil/Gas	806
L.	Sanford	3	Oil/Gas	532
M.	Putnam	2	Oil/Gas	498
N.	St. Johns River *	2	Coal	254
	Scherer **	1	Coal	658
	Peaking Units			2,206
	FPL Generation			**16,628**

** Represents FPL's ownership share: St. Lucie nuclear 100% unit 1, 85% unit 2, St Johns River: 20% of two units.*

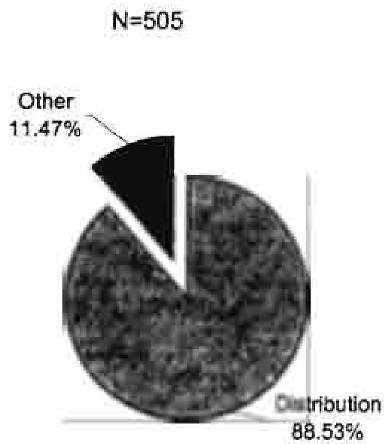
*** The Scherer unit is located in Georgia and is not shown on this map*

Figure I.A.1

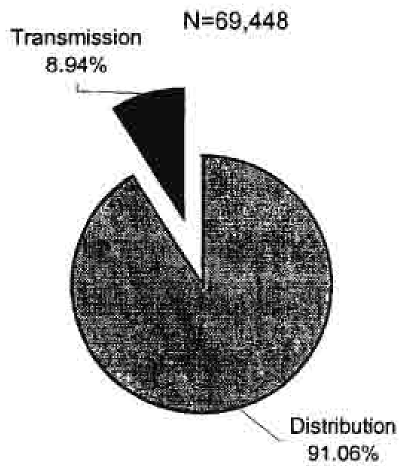
FPL OWNED RESOURCES

	2001 Actual	2002 Projection	2011 Projection
Average Number of Customers			Source: FPL Schedule 2
Residential	3,490,541	3,552,211	4,070,702
Commercial	426,573	433,999	521,756
Indusrial	15,445	15,147	15,305
Other	2,722	2,805	3,231
Total:	**3,935,281**	**4,004,162**	**4,610,994**
Peak Demand			Source: FPL Schedule 4
Winter	18,199	17,597	22,785
Summer	18,754	19,131	23,106
Installed Capability (MW)			Source: FPL Schedule 7.1 & 7.2
Winter	17,188	17,730	25,946
Summer	16,628	17,860	25,459

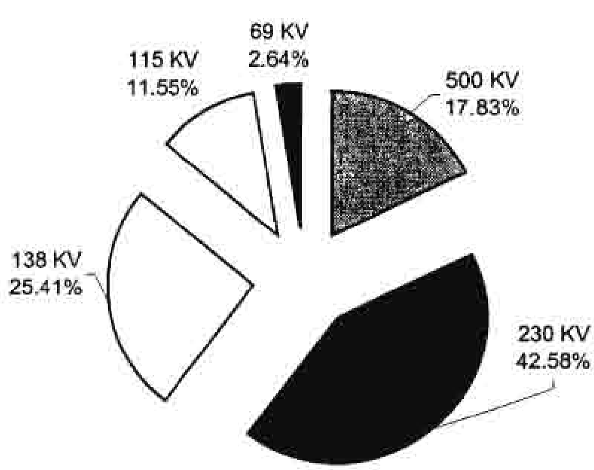
Number of Substations



Miles of Lines



Miles of Bulk Transmission Lines (By Voltage Level)

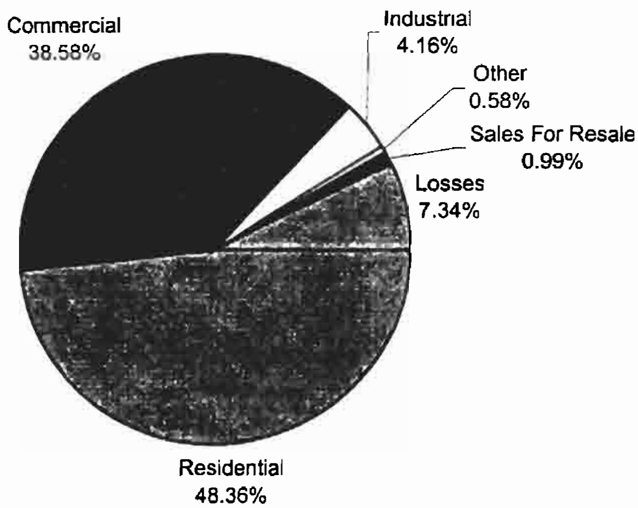


NET ENERGY FOR LOAD

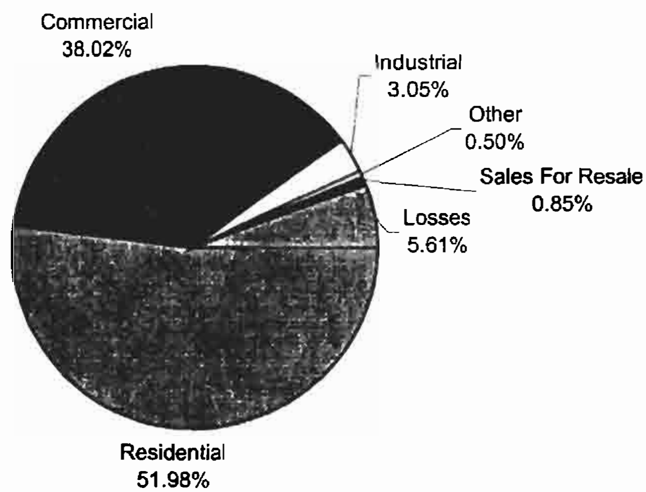
Consumption (GWH)	2001 Actual	2002 Projection	2011 Projection
			Source: FPL Schedule 2
Residential	47,588	49,065	66,282
Commercial	37,960	38,360	48,478
Industrial	4,091	3,947	3,891
Other	572	559	632
Sales For Resale	970	1,204	1,081
Losses	7,222	7,021	7,149
Total:	**98,403**	**100,156**	**127,513**

NET ENERGY FOR LOAD

2001



2011



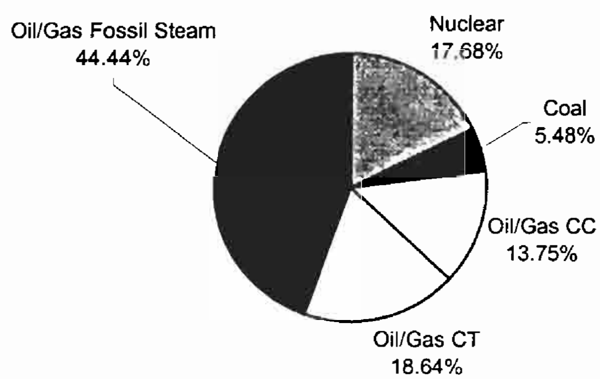
Per Capita Consumption (KWH)	Actual	Projection	Projection
			Source: FPL Schedule 2
Residential	13,633	13,813	16,283
Commercial	88,989	88,387	92,913
Indusrial	264,872	260,552	254,215

GENERATION RESOURCES

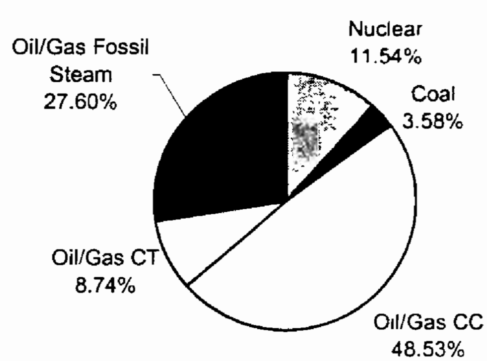
	2001 Actual	2002 Projection	2011 Projection
Facilities			Source: FPL Schedule 5
Coal 1,000 Ton	3,078	3,460	3,821
Oil 1,000 BBL	41,376	16,058	7,910
Gas 1,000 MCF	212,956	339,321	594,673
Nuclear Trillion BTU	263	263	263

INSTALLED GENERATION MW BY FUEL TYPE

2001

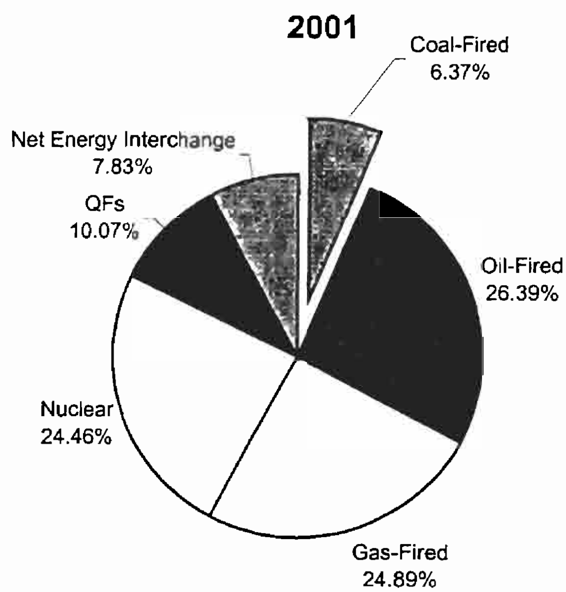


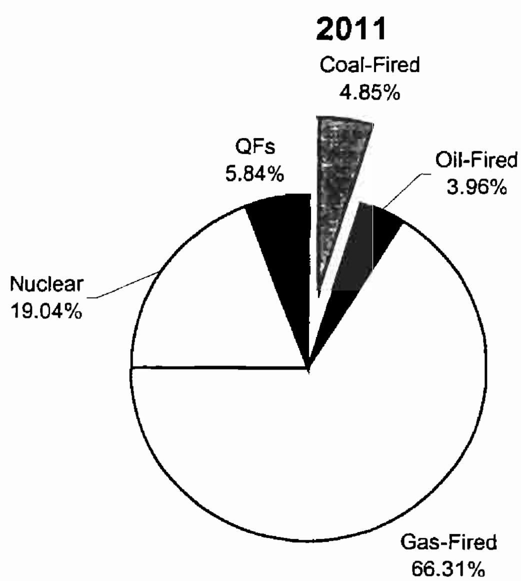
2011



ENERGY BY FUEL TYPE

	2001 Actual	2002 Projection	2011 Projection
Energy By Fuel Type (GWH)			**Source: FPL Schedule 6.1**
FPL Facilities			
Coal-Fired	6,267	6,503	6,187
Oil-Fired	25,965	10,139	5,048
Gas-Fired	24,496	40,313	84,556
Nuclear	24,070	24,284	24,274
QFs	9,905	10,858	7,446
Net Energy Interchange	7,701	8,061	0
Net Energy For Load (NEL)	98,404	100,158	127,511





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FPL

ORIGINAL

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COMMISSION CLERK

April 1, 2003

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk
and Administrative Services
Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Fl 32399-0850

BY HAND DELIVERY

Re: 2003 – 2012 Ten-Year Site Plan

Dear Ms. Bayó,

In accordance with Chapter 186 (Section 186.801 - Ten Year Plans) of the Florida Statutes, enclosed for filing are twenty-five (25) copies of Florida Power & Light Company's 2003- 2012 Ten-Year Power Plant Site Plan.

If you have any questions, please do not hesitate to contact me at (305) 552-4332 or Millie Gonzalez at (305) 552-2279.

Sincerely,

Anne M. Grealy

Anne M. Grealy
Director, Regulatory Affairs

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 38
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-C

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an FPL Group company

Ten Year Power Plant Site Plan

2003 - 2012

FPL

FPL

Ten Year Power Plant Site Plan

2003-2012

Submitted To:

Florida Public Service Commission

Miami, Florida
April, 2003

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Table of Contents

List of Figures and Tables

List of Figures and Tables

List of Schedules

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Overview of The Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten - Year Power Plant Site Plan. This plan includes an estimate of the utility's electric power generating needs, a projection of how those needs will be met, and a disclosure of information pertaining to the utility's preferred and potential power plant sites. This information is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (FAC).

This Ten - Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) planning analyses that were carried out in 2002 and that were on-going in the first quarter of 2003. The forecasted information presented in this plan addresses the 2003 – 2012 time frame.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information, especially for the latter years of the ten - year time horizon, and is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, as determined in FPL's IRP work in 2002 and early 2003.

Chapter IV – Environmental and Land Use Information

This chapter discusses various environmental information as well as preferred and potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional specific information which is to be included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	***Abbreviation***	***Definition***
Unit Type	IC	Internal Combustion
	NP	Nuclear Power
	ST	Steam Unit
	CT	Combustion Turbine
	CC	Combined Cycle
	BIT	Bituminous Coal
Fuel Type	UR	Uranium
	NG	Natural Gas
	FO6	# 4,# 5,# 6 Oil (Heavy)
	FO2	# 1, # 2 or Kerosene Oil (Distillate)
	BIT	Bituminous Coal
	Pet	Petroleum Coke
	NO	None
Fuel Transportation	TK	Truck
	RR	Railroad
	PL	Pipeline
	WA	Water
	No	None
Unit/Site Status	P	Planned Unit
	OT	Other
	RP	Proposed for repowering or life extension
	T	Regulatory approval received but not under construction
	V	Under construction, more than 50% Complete

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Executive Summary

Florida Power & Light Company's (FPL) 2003 Ten - Year Power Plant Site Plan (Site Plan) addresses FPL's plans to increase its electric generation capability as part of its efforts to meet its projected incremental resource needs for the 2003 – 2012 time period.

FPL's total generation capability is projected to significantly increase during the 2003 – 2012 time period as shown in Table ES.1. This table also shows the resulting projected Summer and Winter reserve margins for FPL over this ten-year time horizon.

Table ES.1 reflects FPL's on-going project to repower FPL's existing Sanford Unit # 4 (two existing units at Fort Myers and another existing unit at Sanford have recently been repowered), planned changes to existing generation units (due to unit overhauls, etc.), and scheduled changes in the delivered amounts of purchased power. The table also reflects the planned additions of new generating units. Although not specifically shown in this table, FPL's approved DSM goals are assumed to be implemented on schedule.

The amount of new generating capacity that will be added is driven in part by the outcome of the Florida Public Service Commission docket No. 981890-EU. This docket ended with a stipulated agreement that resulted in FPL, along with Tampa Electric Company and Florida Power Corporation, switching from a minimum reserve margin planning criterion of 15% to one of 20% beginning with the Summer of 2004. As a consequence, FPL is now planning to add significantly more new generation capacity than was shown in its Site Plans filed prior to this agreement.

As shown in Table ES.1, FPL is adding two new combustion turbines (CT's) at FPL's existing Fort Myers plant site in 2003. Also during 2003, FPL will be completing its work to repower its existing Sanford Unit # 4.

FPL has also secured capacity through early 2007 through a number of short-term, firm capacity purchases from utilities and other entities. An additional short-term, firm purchase for 2004 will replace a previous purchase agreement for this time frame that was recently terminated.

In 2005, FPL will be adding a large (1,107 Summer MW) new combined cycle (CC) unit at its existing Manatee plant site. Also in 2005, the two combustion turbines (CT's) that were added at FPL's existing Martin plant site in mid - 2001 will be converted into a 1,107

Summer MW CC unit by the addition of two additional CT's, heat recovery steam generators, and associated equipment. This conversion will add another 783 Summer MW of capability above the present capability of the existing two CT's. The additions for 2005 were selected as the best options among other FPL construction alternatives and numerous outside proposals received in response to two Request for Proposals (RFP's) FPL issued in August 2001 and April 2002, respectively. These two capacity additions were approved by the Florida Public Service Commission on November 19, 2002 and their applications for certification under the Florid Electric Power Plan Siting Act are pending.

In 2007, FPL projects a capacity need of approximately 1,050 MW of additional capacity. The results of FPL's on-going planning analyses through the first quarter of 2003 indicate that the best FPL construction option to meet this need is a new 1,107 MW (Summer) CC unit. A number of potential sites for such a unit are currently under study and these are presented in Chapter IV as a "Potential Site". FPL will continue to analyze these sites for a new CC unit, as well as other capacity options, for meeting its 2007 capacity need. FPL will inform the Florida Public Service Commission when a decision is made regarding how to best meet this need.

In regard to meeting FPL's projected capacity needs for 2008 through 2012, FPL currently projects the addition of three additional CC units: one each year in 2008, 2010, and 2012. Sites for these three additional CC units have not yet been selected. [1] These planned increases in electric generation capability will allow FPL to continue to maintain system reliability and integrity at a reasonable cost.

FPL's recent planning efforts have also identified two issues that are now receiving attention in FPL's ongoing resource planning work. Those two issues are: 1) the growing imbalance in Southeast Florida between regional load and generating capacity located within this region; and 2) maintaining/enhancing fuel diversity in the FPL system. FPL's approach to these two issues will be developed through on-going resource planning work.

[1] FPL's current planning studies have identified new combined cycle units as the generally preferred option to meet future load growth. However, this is subject to change. Repowering of existing FPL sites remains an alternative to new construction and FPL will continue to examine this, and other, options including solid fuel options.

Projected Capacity Changes and Reserve Margins for FPL [1]					
		Net Capacity Changes (MW)		FPL Reserve Margin (%)	
		Winter [2]	Summer [3]	Winter	Summer
2003	Sanford Repowering # 4: Second Phase [4]	---	957	18%	20%
	Combustion Turbines (2) Fort Myers [5]	---	298		
	Purchases [6]	1,097	(140)		
	Changes to existing Units	31	(32)		
2004	Combustion Turbines (2) Fort Myers [5]	366	---	27%	20%
	Purchases [6]	(156)	44		
	New Short-Term Purchase [7]	---	213		
	Changes to existing Units	72	283		
	Sanford Repowering # 4: Second Phase [4]	1,036	---		
2005	Changes to existing QF's	(10)	(10)	22%	23%
	Purchases [6]	(6)	(523)		
	Manatee Unit #3 Combined Cycle [8]	---	1,107		
	New Short-Term Purchase [7]	---	(213)		
	Conversion of MR #8 CT's to CC [8]	(363)	783		
2006	Manatee Unit #3 Combined Cycle [8]	1,201	---	28%	20%
	Conversion of MR #8 CT's to CC [8]	1,198	---		
	Changes to existing QF's	(133)	(133)		
	Purchases [6]	(520)	---		
2007	Purchases [6]	---	(474)	25%	20%
	Unsited Combined Cycle # 1 [8]	---	1,107		
2008	Purchases [6]	(474)	---	26%	24%
	Unsited Combined Cycle # 1 [8]	1,209	---		
	Unsited Combined Cycle # 2 [8]	---	1,107		
2009	Unsited Combined Cycle # 2 [8]	1,209	---	29%	21%
	Changes to existing QF's	---	(51)		
2010	Unsited Combined Cycle # 3 [8]	---	1,107	26%	23%
	Changes to existing QF's	(51)	(44)		
2011	Unsited Combined Cycle # 3 [8]	1,209	---	29%	20%
	Changes to existing QF's	(89)	(45)		
2012	Unsited Combined Cycle # 4 [8]	---	1,107	26%	22%
	TOTALS =	6,827	6,449		

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedule 7 & 8 respectively.

(2) Winter values are values for January of year shown.

(3) Summer values are values for August of year shown.

(4) The second phase of the repowering consists of integrating the combustion turbines, heat recovery steam generators, and steam turbines.

(5) The two CT's at Fort Myers are scheduled to be in-service in the Spring of 2003. Therefore, the CT's are included in the 2003 Summer reserve margin calculation and are included in the 2004 - on reserve margin for Summer and Winter.

(6) These are firm capacity purchases. See Section I.D and III.A. for more details.

(7) Negotiations are currently underway between FPL and several parties to secure this short - term capacity.

(8) All new combined cycle units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

Table ES.1

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CHAPTER 1

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 7.8 million people. FPL served an average of 4,019,805 customer accounts in thirty-five counties during 2002. These customers were served from a variety of resources including: FPL-owned fossil and nuclear generating units, non-utility owned generation, demand side management, and interchange/purchased power.

I.A. FPL-Owned Resources

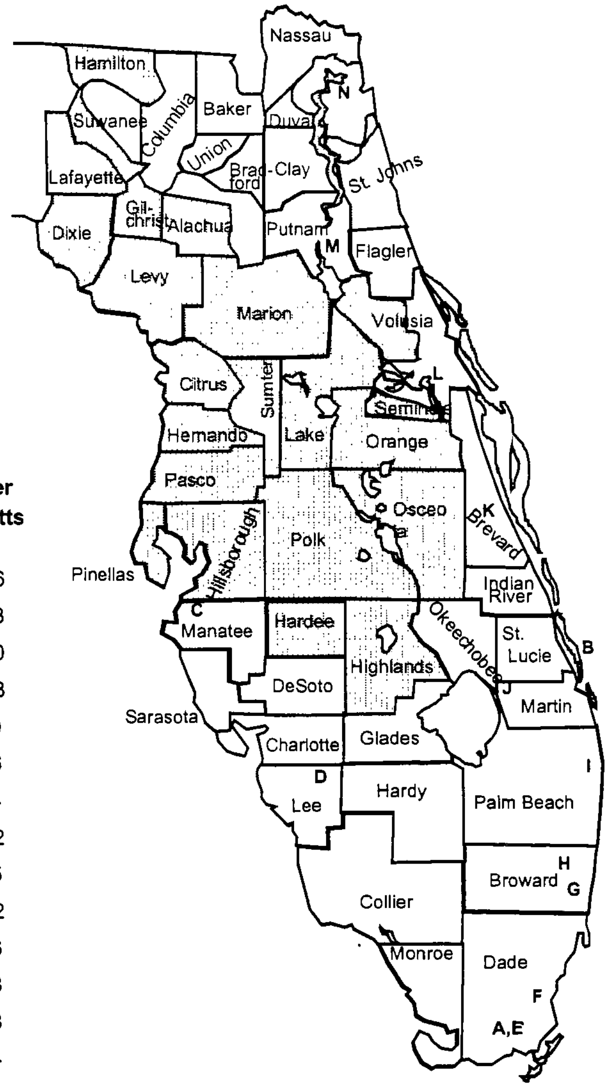
The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory and also include partial ownership of one unit located in Georgia and two units located in Jacksonville. The current generating facilities consist of four nuclear steam units, three coal units, eight combined cycle units, eighteen fossil steam units, fifty combustion gas turbines, and five diesel units. The location of these units is shown on Figure I.A.1.

The bulk transmission system is composed of 1,105 circuit miles of 500 Kilovolt (KV) lines (including 75 miles of 500 KV lines [two 37-1/2 mile lines] between Duval Substation and the Florida-Georgia state line, which are jointly owned with Jacksonville Electric Authority) and 2,702 circuit miles of 230 KV lines. The underlying network is composed of 1,630 circuit miles of 138 KV lines, 718 circuit miles of 115 KV lines, and 178 circuit miles of 69 KV transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 515 substations.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3 shows FPL's interconnection ties with other utilities.

Capacity Resources
(as of December 31, 2002)

☐ Non-FPL Territory



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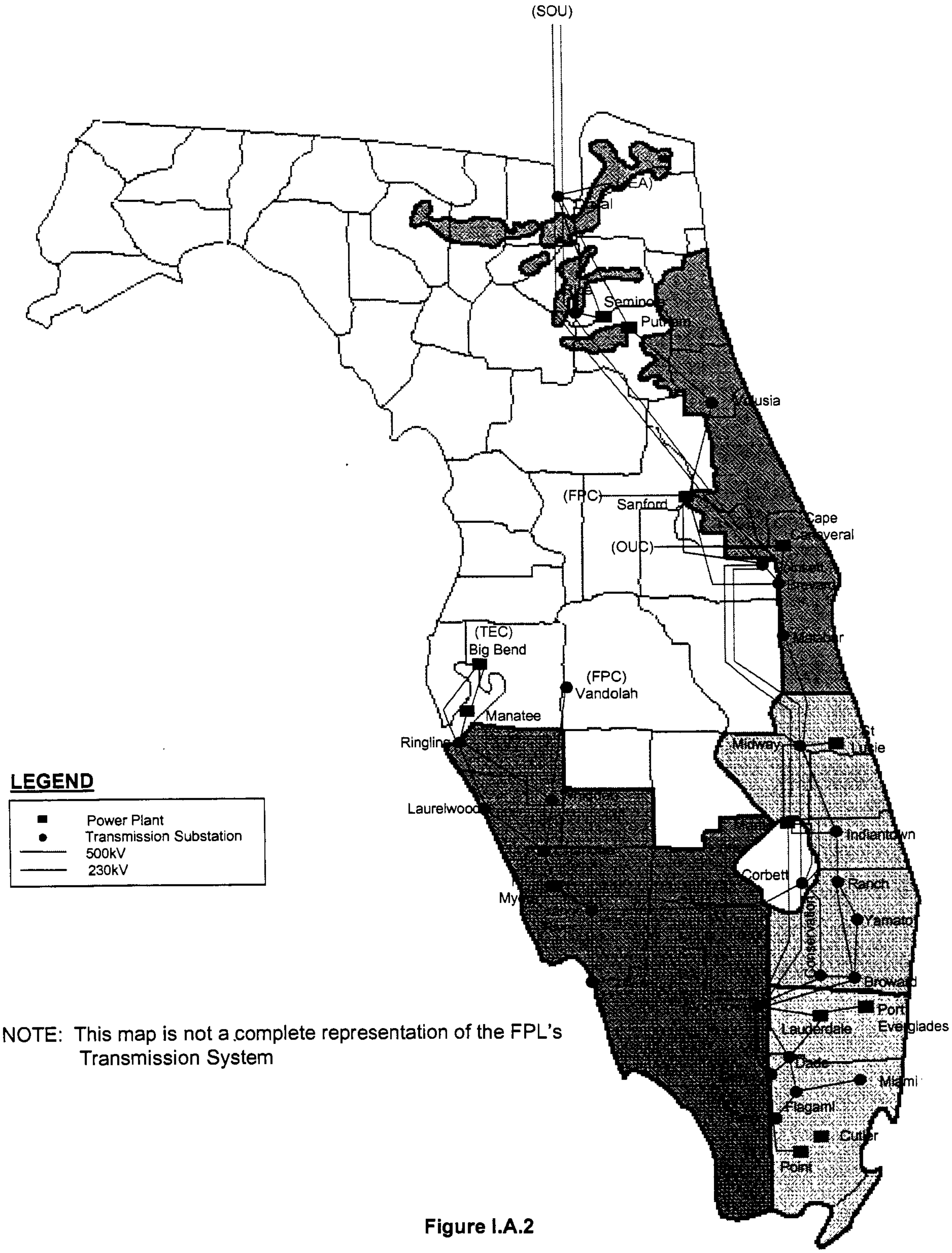
*** The Scherer unit is located in Georgia and is not shown on this map.*

Figure I.A.1

FPL Substation and Transmission System Configuration



NOTE: This map is not a complete representation of the FPL's Transmission System

Figure I.A.2

FPL Interconnection Diagram

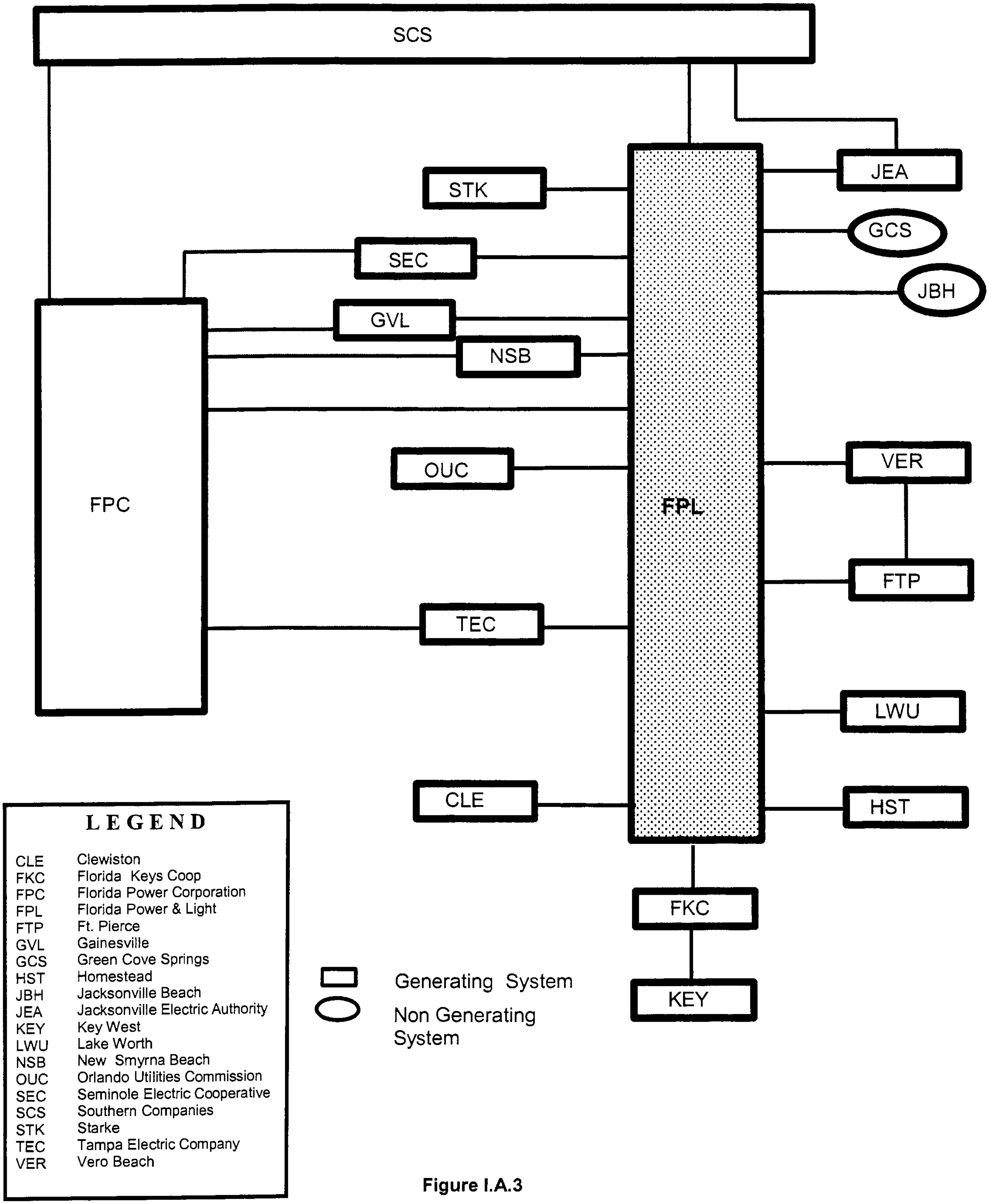


Figure I.A.3

I.B Non-Utility Generation

Non-utility generation is an important part of FPL's resource mix. FPL currently has contracts with seven cogeneration/small power production facilities to purchase firm capacity and energy. A listing of these facilities appears in Table I.B.1. In addition, FPL purchases as-available (non-firm) energy from several cogeneration facilities and small power production facilities as shown in Table I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

Florida Power & Light Company Firm Capacity and Energy Contracts with Cogeneration/Small Power Production Facilities					
Project	**County**	**Fuel**	**Capacity MW**	**In-Service Date**	**End Date**
Bio-Energy	Broward	Landfill Gas	10.0	5/1/98	01/01/05
Florida Crushed Stone	Hernando	Coal (PC)	110.0	4/1/92	10/31/05
			11.0	1/1/94	10/31/05
			12.0	1/1/95	10/31/05
Broward South	Broward	Solid Waste	50.6	4/1/91	08/01/09
Palm Beach SWA	Palm Beach	Solid Waste	43.5	4/1/92	03/31/10
Broward North	Broward	Solid Waste	45.0	4/1/92	12/31/10
Cedar Bay Generating Co.	Duval	Coal (CFB)	250.0	1/25/94	12/31/24
Indiantown Cogen., LP	Martin	Coal (PC)	330.0	12/22/95	12/01/25
Broward South	Broward	Solid Waste	1.4	1/1/93	12/31/26
			1.5	1/1/95	12/31/26
			0.6	1/1/97	12/31/26
Broward North	Broward	Solid Waste	7.0	1/1/93	12/31/26
			1.5	1/1/95	12/31/26
			2.5	1/1/97	12/31/26

Table I.B.1

As Available Energy Purchases From Non-Utility Generators in 2002				
Project	**County**	**Fuel**	**In-Service Date**	**Energy (MWH) Delivered to FPL in 2002**
US Sugar-Bryant	Palm Beach	Bagassee	2/80	4,673
Tropicana	Manatee	Natural Gas	2/90	6,516
Okeelanta	Palm Beach	Bagassee/Wood	11/95	318,457
Tomoka Farms	Volusia	Landfill Gas	7/98	14,687
Georgia Pacific	Putnam	Paper By-Product	2/94	4,184

Table I.B.2

I.C. Demand Side Management (DSM)

FPL's DSM activities continue what has been FPL's practice since 1978 of encouraging cost-effective conservation and load management. FPL's DSM efforts through 2002 have resulted in a cumulative Summer peak reduction of approximately 2,923 MW at the meter and an estimated cumulative energy saving of 5,270 GWH at the meter.

FPL's current DSM Plan was approved by the Florida Public Service Commission in late 1999 and reflects FPL's new DSM Goals for the 2000-2009 time frame. FPL's 2003 resource plan, and the schedule for new generation additions presented in this document, are based on these approved DSM levels.

I.D. Purchased Power

Purchased power remains an important part of FPL's resource mix. FPL has a unit power sales (UPS) contract to purchase 929 MW, with a minimum of 380 MW, of coal-fired generation from the Southern Company. In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 381 MW (Summer) and 390 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Unit Nos 1 and 2 (FPL also has ownership interest in these units; that ownership amount is reflected in FPL's installed capacity shown on Schedule 1).

Finally, FPL has firm capacity purchase contracts through early 2007. These firm capacity purchase contracts are with a variety of suppliers. Table I.D.1 presents the Summer and Winter MW resulting from all firm purchased power contracts through the year 2012.

	FPL's Purchased Power MW (1)							
	UPS		SJRPP		Other Firm Capacity Purchases		Total	
Year	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
2002 (2)	929	929	390	381	50	1093	1369	2403
2003	929	929	390	381	1156	953	2475	2263
2004	929	929	390	381	1000	1210	2319	2520
2005	929	929	390	381	994	474	2313	1784
2006	929	929	390	381	474	474	1793	1784
2007	929	929	390	381	474	0	1793	1310
2008	929	929	390	381	0	0	1319	1310
2009	929	929	390	381	0	0	1319	1310
2010	929	929	390	381	0	0	1319	1310
2011	929	929	390	381	0	0	1319	1310
2012	929	929	390	381	0	0	1319	1310

Note:

(1) Total reflects total resource entitlements resulting from existing agreements between FPL, Southern Companies, JEA, and from new firm purchase agreements. In addition, the UPS values reflect a projected extension or renegotiation of the UPS contracts beyond their current expiration date.

(2) Values for 2002 are actual.

Table I.D.1

Schedule 1

Existing Generating Facilities
As of December 31, 2002

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport. Pri.	(8) Fuel Transport. Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW
Turkey Point		Dade County 27/57S/40E									2,338,100	2,255	2,198
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	406	400
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	403	400
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	760,000	717	693
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	760,000	717	693
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	14,000	12	12
Cutler		Dade County 27/55S/40E									236,500	212	206
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	74,500	70	68
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	162,000	142	138
Lauderdale		Broward County 30/50S/42E									1,863,972	1,942	1,694
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	521,250	460	425
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	521,250	464	429
	1-12		CT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,736	509	420
	13-24		CT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,736	509	420
Port Everglades		City of Hollywood 23/50S/42E									1,665,086	1,725	1,632
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	225,250	222	221
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	225,000	222	221
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	392	390
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	380	380
	1-12		CT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,736	509	420
Riviera		City of Riviera Beach 33/42S/43E									620,840	569	565
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	283	281
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	286	284

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt.					
						Fuel		Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Martin		Martin County 29/29S/38E									3,312,000	2,995	2,850
	1		ST	NG	FO6	PL	PL	Unknown	Dec-80	Unknown	863,000	830	818
	2		ST	NG	FO6	PL	PL	Unknown	Jun-81	Unknown	863,000	812	799
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	495	467
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	496	468
	8 A & B		CT	NG	FO2	PL	PL	Unknown	Jun-01	Unknown	362,000	362	298
St. Lucie		St. Lucie County 16/36S/41E									1,553,000	1,579	1,553
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	839,000	853	839
	2	2/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	714,000	726	714
Cape Canaveral		Brevard County 19/24S/36F									804,100	812	806
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	406	403
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	406	403
Sanford		Volusia County 16/19S/30E									1,754,350	1,161	1,048
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	150,250	142	138
	4	3/	ST	FO6	NG	WA	PL	Unknown	Jul-72	Unknown	436,100	0	0
	5		CC	NG	No	PL	No	Unknown	Jul-73	Unknown	1,168,000	1,019	910
Putnam		Putnam County 16/10S/27E									580,000	594	498
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,000	297	249
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,000	297	249

1/ These ratings are peak capability.
2/ Total capability is 853/839 MW. Capabilities shown represent the company's share of the unit and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of 14.89551%.
3/ This unit has been temporarily removed from service as part of the repowering project.

Schedule 1

Existing Generating Facilities
As of December 31, 2002

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW
Fort Myers		Lee County 35/43S/25E									2,483,000	2,345	2,059
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,739,000	1,576	1,423
	1-12		CT	FO2	No	WA	No	Unknown	May-74	Unknown	744,000	769	636
Manatee		Manatee County 18/33S/20E									1,726,600	1,634	1,620
	1		ST	FO6	No	WA	No	Unknown	Oct-76	Unknown	863,300	817	810
	2		ST	FO6	No	WA	No	Unknown	Dec-77	Unknown	863,300	817	810
St. Johns River Power Park 2/		Duval County 12/15/28E (RPC4)									250,000	260	254
	1		BIT	BIT et Col		RR	WA	Unknown	Mar-87	Unknown	125,000	130	127
	2		BIT	BIT et Col		RR	WA	Unknown	May-88	Unknown	125,000	130	127
Scherer 3/		Monroe, GA									891,000	666	658
	4		BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	891,000	666	658
								Total System as of December 31, 2002 =				18,749	17,641

1/ These ratings are peak capability.

2/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No. 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80%.

3/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.

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CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are developed on an annual basis for resource planning work at FPL. These forecasts are a key input to the models used to develop the Integrated Resource Plan. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

The primary drivers to develop these forecasts are demographic trends, weather, economic conditions, and prices of electricity. In addition, the resulting forecasts are an integration of economic evaluations, inputs of local economic development boards, weather assessments from NOAA, and inputs from FPL's own customer service planning areas. In the area of demographics, population trends by county, plus housing characteristics such as housing starts, housing size, and vintage of homes are assessed.

Forecasts for electric usage in the residential and commercial classes include end-use information such as appliance saturation studies, efficiencies, and intensity of energy use. In addition to these inputs, residential forecasts also make use of household characteristics such as ages of members in households, number of members in households, and income distributions.

The projections for the National and Florida economy are obtained from Global Insight, formerly know as DRI - WEFA. Population projections for the counties served by FPL are obtained from the Bureau of Economic and Business Research (BEBR) of the University of Florida. In addition, FPL actively participates with local development councils and universities to obtain their assessments of the local economy, specifically in the area of expansion of new businesses and retention of the current business base. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is a key factor that affects the company's sales and peak demand. Weather variables are used in the forecasting models for energy sales and peak demand. There are two sets of weather variables developed and used in forecasting models:

1. Cooling and Heating Degree-Days are used to forecast energy sales.
2. Temperature data is used to forecast Summer and Winter peaks.

The Cooling and Heating Degree-Days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric heaters. A composite temperature is derived using hourly temperatures across FPL's service territory (Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained) weighted by regional energy sales. This composite temperature is used to derive Cooling and Heating Degree-Days which are based on starting point temperatures of 72°F and 66°F, respectively. Similarly, the maximum and minimum of the composite temperature is used for the Summer and Winter peak models.

II.A. Long-Term Sales Forecasts

Long-term forecasts of electricity sales are developed for each revenue class for the forecasting period of 2003 - 2022 and are adjusted to match the Net Energy for Load (NEL) forecast. The results of these sales forecasts for the years 2003 - 2012 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical tool MetrixND. The methodologies used to develop sales forecasts for each jurisdictional revenue class are outlined below.

The first five years of the forecasts are developed using monthly models for Net Energy for Load and energy sales by class.

1. Residential Sales

Residential energy sales are forecast by multiplying the residential use per customer forecast by the number of residential customers forecasted. Residential electric usage per customer is estimated by using a regression model which contains the real residential price of electricity, Florida per capita income, and Cooling and Heating Degree-Days as explanatory variables. The price of electricity plays a role in explaining electric usage since electricity, like all other goods and services, will be used in greater or lesser quantities depending upon its price. The Cooling Degree-Days variable is multiplied by the level of air conditioning saturation and the Heating Degree-Days variable is multiplied by the level of electric heating saturation. To capture economic conditions the model includes Florida's per capita income. The degree of economic prosperity can, and does, affect residential electricity sales. For the short-term period (first five years), an econometric model is developed using monthly data. The monthly model is a function of the same variables such as Cooling Degree-Days, Heating Degree-Days, price of electricity, Florida's per capita income, and a dummy variable for the months of April, May, and October.

2. Commercial Sales

The commercial sales forecast is also developed using a regression model for the long-and short-term. Commercial sales are a function of the following variables: Florida's commercial employment, commercial real price of electricity, Cooling Degree-Days and an autoregressive term. Florida's commercial employment is used to capture the economic activity in FPL's service territory. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. Cooling Degree-Days are used to capture weather-sensitive load in the commercial sector. The first five years of the forecast are developed from a monthly model using the same explanatory variables, and for the following years, growth rates from the annual model are applied.

3. Industrial Sales

Industrial sales are forecasted through a linear multiple regression model using Florida manufacturing employment, the price of electricity, and a dummy variable for the economic recessions. Energy sales in this revenue class are primarily due to manufacturers; therefore, employment in this sector is a key variable in capturing the economic activity. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. For the short-term period (first five years), an econometric model is developed using monthly data. The monthly model is a function of the same variables such as Florida manufacturing employment, Cooling Degree-Days, price of electricity, and an autoregressive term. For the following years, growth rates from the annual model are applied.

4. Other Public Authority Sales

At present, this class consists of sports fields and one government account. The forecast for this class is based on historical knowledge of its characteristics.

5. Street & Highway Sales and Railroad & Railways Sales

The forecast for Street and Highway sales is developed by first assuming a constant use per customer and then multiplying that value by the number of projected customers.

The forecast of sales to Railroad & Railways is based on historical knowledge of its characteristics. This class consists of Miami-Dade County's Metrorail system.

6. Resale Sales

Resale (Wholesale) customers are composed of municipalities and/or electric cooperatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers.

Contract Rate

Currently, there are four customers in this class: the Florida Keys Electric Cooperative (Florida Keys), City Electric System of the Utility Board of Key West, Florida (City of Key West), Miami-Dade County, and FMPA. Sales to the Florida Keys are forecasted using a regression model. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor. Miami-Dade County sells 60 MW to Florida Power Corporation. Line losses are billed to Miami-Dade under a wholesale contract. The forecast is calculated based on assumptions about the magnitude of line losses, the sales monthly capacity factor, and the number of hours in a particular month. FMPA has contracted for delivery of 75 MW through October 2007.

Total Sales

Sales forecasts by revenue class are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, an expansion factor is applied to generate a forecast of annual Net Energy for Load (NEL).

II.B. Net Energy for Load

An annual econometric model is developed to produce a Net Energy for Load (NEL) forecast. The key inputs to the model are: the price of electricity, Heating and Cooling Degree-Days, Florida Non-Agricultural Employment, and an autoregressive term. The monthly model is similar, except the economic variable utilized is Florida's per capita income since the model is estimated on a per customer basis. Like the sales forecasts, the first five years are obtained from the short-term model, and forecasts for subsequent years are generated using the growth rates from the annual model.

Once an annual NEL forecast is obtained using the above-mentioned methodology, the results are then compared for reasonableness to the NEL forecast generated using the total sales forecast. The sales by class are then adjusted to match the NEL from the annual NEL model.

The forecasted NEL values for 2003 – 2012 are presented in Schedule 3.3, that appears at the end of this chapter.

II.C. System Peak Forecasts

The rate of absolute growth in FPL system load has been a function of a larger customer base, varying weather conditions, continued economic growth, changing patterns of customer behavior (including an increased stock of electricity-consuming appliances), and more efficient heating and cooling appliances. FPL developed the Peak Forecast models to capture these behavioral relationships.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2003 – 2012 are presented in Schedules 3.1 and 3.2 as well as in Schedules 7.1 and 7.2.

System Summer Peak

The Summer peak forecast is developed using an econometric model. The model is a per customer model that includes: the total number of FPL's customers, the price of electricity, Real Florida income as an economic driver, and the maximum temperature as a weather variable. Also included in the model is an autoregressive term.

System Winter Peak

Like the system Summer peak model, the Winter peak model is also an econometric model. The Winter peak model is a per customer model which consists of three weather-related variables: (1) the minimum Winter day temperature, (2) a weather term, which is a ratio of heating saturation and minimum Winter day temperature, and (3) Heating Degree-Hours for the prior day until 9:00 a.m. of the peak day. In addition, the model also uses an economic variable, Real Florida Income. A dummy variable, which is used to capture the effects of larger homes, is multiplied by the minimum temperature.

Monthly Peak Forecasts

Monthly peaks for the 2003-2022 period are forecasted to provide information for the scheduling of maintenance for power plants and fuel budgeting. The forecasting process is basically the same as for the monthly NEL forecast and consists of the following actions:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to seasonal peak (Summer = April-October, Winter = November-March.)

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.D. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2003 – 2022 are produced using a System Load Forecasting "shaper" program. This model uses sixteen years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. These daily load shapes are ranked and used with forecasted monthly peaks, NEL, and calendars in developing an hourly forecast. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					Commercial		
Year	Population*	Members per Household	GWH	Average** No. of Customers	Average KWH Consumption Per Customer	GWH	Average** No. of Customers	Average KWH Consumption Per Customer
1993	6,486,127	2.18	36,360	2,975,479	12,220	28,508	358,679	79,481
1994	6,660,137	2.19	38,716	3,037,629	12,745	29,946	366,409	81,729
1995	6,806,337	2.20	40,556	3,097,192	13,094	30,719	374,005	82,135
1996	6,948,942	2.20	41,302	3,152,625	13,101	31,211	380,860	81,949
1997	7,105,582	2.21	41,849	3,209,298	13,040	32,942	388,906	84,703
1998	7,249,617	2.22	45,482	3,266,011	13,926	34,618	396,749	87,255
1999	7,412,734	2.22	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,603,543	2.23	46,320	3,414,002	13,568	37,001	415,295	89,096
2001	7,754,966	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,896,813	2.21	50,865	3,566,167	14,263	40,029	435,313	91,955
2003	8,039,781	2.21	51,350	3,632,433	14,137	41,124	444,700	92,477
2004	8,184,322	2.21	53,373	3,695,370	14,443	42,574	454,728	93,625
2005	8,328,360	2.22	55,004	3,758,193	14,636	43,701	464,926	93,995
2006	8,471,579	2.22	56,923	3,821,542	14,895	44,852	475,338	94,358
2007	8,614,099	2.22	58,245	3,882,687	15,001	45,983	484,370	94,934
2008	8,756,620	2.22	59,842	3,944,810	15,170	47,024	492,604	95,461
2009	8,898,722	2.22	60,846	4,002,441	15,202	48,065	500,486	96,036
2010	9,041,109	2.23	62,244	4,060,676	15,328	49,157	507,970	96,772
2011	9,184,069	2.23	63,629	4,118,959	15,448	50,092	515,299	97,210
2012	9,328,059	2.23	64,921	4,176,707	15,544	51,010	522,503	97,627

* Population represents only the area served by FPL.
** Average No. of Customers is the annual average of the twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial						
Year	GWH	Average* No. of Customers	Average KWH Consumption Per Customer	Railroads & Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total** Sales to Ultimate Consumers GWH
1993	3,889	14,866	261,602	79	330	665	69,830
1994	3,845	15,588	246,658	85	353	664	73,608
1995	3,883	15,140	256,481	84	358	648	76,248
1996	3,792	14,783	256,515	83	368	577	77,334
1997	3,894	14,761	263,830	85	383	702	79,855
1998	3,951	15,126	261,233	81	373	625	85,131
1999	3,948	16,040	246,112	79	473	465	84,676
2000	3,768	16,410	229,592	81	408	381	87,959
2001	4,091	15,445	264,872	86	419	67	90,212
2002	4,057	15,533	261,199	89	420	63	95,523
2003	3,974	15,663	253,732	89	434	63	97,035
2004	4,036	15,459	261,051	89	440	63	100,574
2005	4,094	15,302	267,523	90	447	63	103,397
2006	4,145	15,185	272,974	90	453	63	106,525
2007	4,165	15,186	274,281	90	463	63	109,010
2008	4,187	15,238	274,770	91	473	63	111,680
2009	4,200	15,275	274,939	91	483	63	113,748
2010	4,214	15,313	275,194	92	493	63	116,262
2011	4,231	15,372	275,212	92	503	63	118,609
2012	4,246	15,377	276,133	93	512	63	120,845

*Average No.of Customers is the annual average of the twelve month values.
**GWH Col. (16)=Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History and Forecast of Energy Consumption And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWH	(18) Utility Use & Losses GWH	(19) Net* Energy For Load GWH	(20) Average ** No. of Other Customers	(21) Total Average*** Number of Customers
1993	958	4,988	75,776	3,086	3,352,110
1994	1,400	5,367	80,376	2,560	3,422,187
1995	1,437	6,276	83,961	2,460	3,488,796
1996	1,353	5,984	84,671	2,480	3,550,748
1997	1,228	5,770	86,853	2,520	3,615,485
1998	1,326	6,205	92,662	2,584	3,680,470
1999	953	5,829	91,458	2,605	3,756,009
2000	970	7,059	95,989	2,694	3,848,401
2001	970	7,222	98,404	2,722	3,935,281
2002	1,233	7,443	104,199	2,792	4,019,805
2003	1,422	7,243	105,700	2,832	4,095,628
2004	1,441	7,510	109,525	2,865	4,168,421
2005	1,456	7,711	112,565	2,906	4,241,326
2006	1,474	7,942	115,942	2,941	4,315,007
2007	1,459	7,960	118,430	3,002	4,385,245
2008	1,092	8,126	120,899	3,061	4,455,713
2009	1,092	8,275	123,115	3,120	4,521,322
2010	1,092	8,456	125,811	3,178	4,587,137
2011	1,092	8,625	128,327	3,234	4,652,864
2012	1,092	8,787	130,724	3,289	4,717,877

* GWH Col. (19) = Col. (16) + Col. (17) + Col. (18)
** Average Number of Customers is the annual average of the twelve month values.
*** Total Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20)

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1993	15,266	397	14,869	0	311	182	320	79	14,635
1994	15,179	409	14,770	0	392	220	354	125	14,433
1995	16,172	435	15,737	0	466	259	391	193	15,315
1996	16,064	364	15,700	0	531	339	414	296	15,119
1997	16,613	380	16,233	0	615	440	432	341	15,566
1998	17,897	426	17,471	0	656	480	441	359	16,800
1999	17,615	169	17,446	0	722	565	450	397	16,443
2000	17,808	161	17,647	0	767	626	456	432	16,585
2001	18,754	169	18,585	0	798	673	483	463	17,473
2002	19,219	261	18,958	0	826	733	484	499	17,909
2003	19,773	225	19,548	0	796	43	569	22	18,343
2004	20,297	227	20,070	0	802	84	582	42	18,787
2005	20,799	230	20,569	0	809	126	592	62	19,210
2006	21,331	231	21,100	0	814	170	600	83	19,664
2007	21,851	234	21,617	0	819	214	608	103	20,107
2008	22,289	159	22,130	0	824	259	616	122	20,468
2009	22,784	159	22,625	0	828	306	622	141	20,888
2010	23,294	159	23,135	0	830	321	623	148	21,372
2011	23,783	159	23,624	0	830	321	623	148	21,861
2012	24,279	159	24,120	0	830	321	623	148	22,357

Historical Values (1993 - 2002):

Cols. (2) - (4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Cols. (7&9)), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.
Cols. (5) - (9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes GS-LC, CDR and GSD-LC.
Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula:Col. (10) =Col.(2) - Col.(6) - Col.(8).

Projected Values (2003 - 2012):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2002 are incorporated into the forecast.
Cols. (5) - (9) represent all incremental conservation and cumulative load control. These values are projected August values and are based on projections with a 1/2002 starting point.
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1993/94	12,594	278	12,316	0	317	231	342	67	11,935
1994/95	16,563	635	15,928	0	393	265	360	93	15,810
1995/96	18,096	698	17,398	0	459	310	406	143	17,231
1996/97	16,490	626	15,864	0	731	368	418	154	15,341
1997/98	13,060	239	12,821	0	823	403	429	168	11,807
1998/99	16,802	149	16,653	0	1,218	438	417	182	15,167
1999/00	17,057	142	16,915	0	1,296	469	441	193	15,320
2000/01	18,199	150	18,049	0	972	493	448	201	16,779
2001/02	17,597	145	17,452	0	1,081	534	457	242	16,060
2002/03	20,190	246	19,944	0	1,116	581	453	288	18,621
2003/04	20,081	206	19,875	0	932	80	534	15	18,520
2004/05	20,583	208	20,375	0	939	114	540	22	18,968
2005/06	21,100	209	20,891	0	946	149	546	29	19,430
2006/07	21,605	212	21,393	0	952	183	551	37	19,882
2007/08	22,046	137	21,909	0	958	218	556	44	20,270
2008/09	22,539	137	22,402	0	964	252	561	51	20,712
2009/10	23,026	137	22,889	0	968	284	564	57	21,153
2010/11	23,522	137	23,385	0	968	284	564	57	21,649
2011/12	24,024	137	23,887	0	968	284	564	57	22,151
2012/13	24,535	137	24,398	0	968	284	564	57	22,663

Historical Values (1993/94 - 2002/03):

Cols. (2) - (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Cols. (7&9)), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.
Cols. (5) - (9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes GS-LC, CDR and GSD - LC.
Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (6) - Col. (8).

Projected Values (2003/04 - 2012/13):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2002 are incorporated into the forecast.
Cols. (5) - (9) represent all incremental conservation and cumulative load control. These values are projected January values and are based on projections with a 1/2002 starting point.
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH: Base Case

(1) Year	(2) Total	(3) Residential Conservation	(4) C/I Conservation	(5) Retail	(6) Sales for Resale GWH	(7) Utility Use & Losses	(8) Net Energy For Load	(9) Load Factor(%)
1993	76,632	553	303	75,674	958	4,988	75,776	56.7%
1994	81,493	661	456	80,093	1,400	5,367	80,376	60.4%
1995	85,415	777	677	83,978	1,437	6,276	83,961	59.3%
1996	86,708	971	1,039	85,355	1,353	5,984	84,698	60.0%
1997	89,240	1,213	1,174	88,012	1,228	5,770	86,853	59.7%
1998	95,316	1,374	1,279	93,990	1,326	6,205	92,663	59.1%
1999	94,361	1,542	1,362	93,408	953	5,829	91,458	59.3%
2000	99,094	1,674	1,431	98,123	970	7,059	95,989	61.5%
2001	101,736	1,789	1,542	100,765	970	7,222	98,404	59.9%
2002	107,754	1,917	1,637	106,520	1,233	7,443	104,199	61.9%
2003	105,700	53	17	104,278	1,422	7,243	105,630	61.0%
2004	109,525	145	52	108,084	1,441	7,510	109,328	61.6%
2005	112,565	238	88	111,108	1,456	7,711	112,239	61.8%
2006	115,942	334	124	114,468	1,474	7,942	115,484	62.0%
2007	118,430	430	159	116,970	1,459	7,960	117,841	61.9%
2008	120,899	529	193	119,807	1,092	8,126	120,177	61.9%
2009	123,115	629	225	122,023	1,092	8,275	122,261	61.7%
2010	125,811	671	240	124,719	1,092	8,456	124,900	61.7%
2011	128,327	671	240	127,235	1,092	8,625	127,416	61.6%
2012	130,724	671	240	129,631	1,092	8,787	129,813	61.5%

Historical Values (1993 - 2002):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Cols. (2) =(3) + (4) + (8).
Cols. (3) & (4) are DSM values starting in January, 1988 through 2002 which contributed to the values in Cols. (5) - (9).
Cols. (5) & (6) are a breakdown of Net Energy For Load in Col (2) into Retail and Wholesale .
Col. (9) is calculated using Col. (8) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (8)*1000) / ((Col.(2) * 8760)

Projected Values (2003 - 2012):

Col. (2) represents Net Energy for Load w/o DSM values. The values are calculated using the formula: Cols. (2) =(3) + (4) + (8).
Cols. (3) - (4) are forecasted values of the reduction on sales from incremental conservation.
Cols. (5) & (6) are a breakdown of Net Energy For Load in Col (2) , into Wholesale and Retail .
Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760)

Schedule 4
Previous Year Actual and Two-Year Forecast of Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2002 ACTUAL		2003* FORECAST		2004* FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	17,597	7,588	20,190	8,248	20,081	7,959
FEB	13,851	6,524	16,828	6,878	16,737	7,959
MAR	15,459	7,866	15,538	7,735	15,454	8,000
APR	16,862	8,570	16,398	8,125	16,833	8,358
MAY	18,067	9,019	18,128	8,991	18,609	9,221
JUN	18,574	9,262	18,999	9,845	19,503	10,193
JUL	19,084	9,660	19,337	10,310	19,849	10,636
AUG	19,219	10,412	19,773	10,431	20,297	10,825
SEP	19,152	10,330	19,180	10,178	19,689	10,503
OCT	18,172	9,574	17,838	9,004	18,311	9,339
NOV	17,588	8,101	16,928	8,030	16,837	8,351
DEC	14,221	7,294	17,271	7,924	17,178	8,181
TOTALS		104,199		105,700		109,525

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation.

CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990's and has since utilized the process to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of potential new power plants, the primary subjects of this document, are determined as part of the IRP process work. This section discusses how FPL applied this process in its 2002 and early 2003 planning work.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental "steps" to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans;

Step 3: Determine the economics for the total utility system with each of the competing options and resource plans; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process

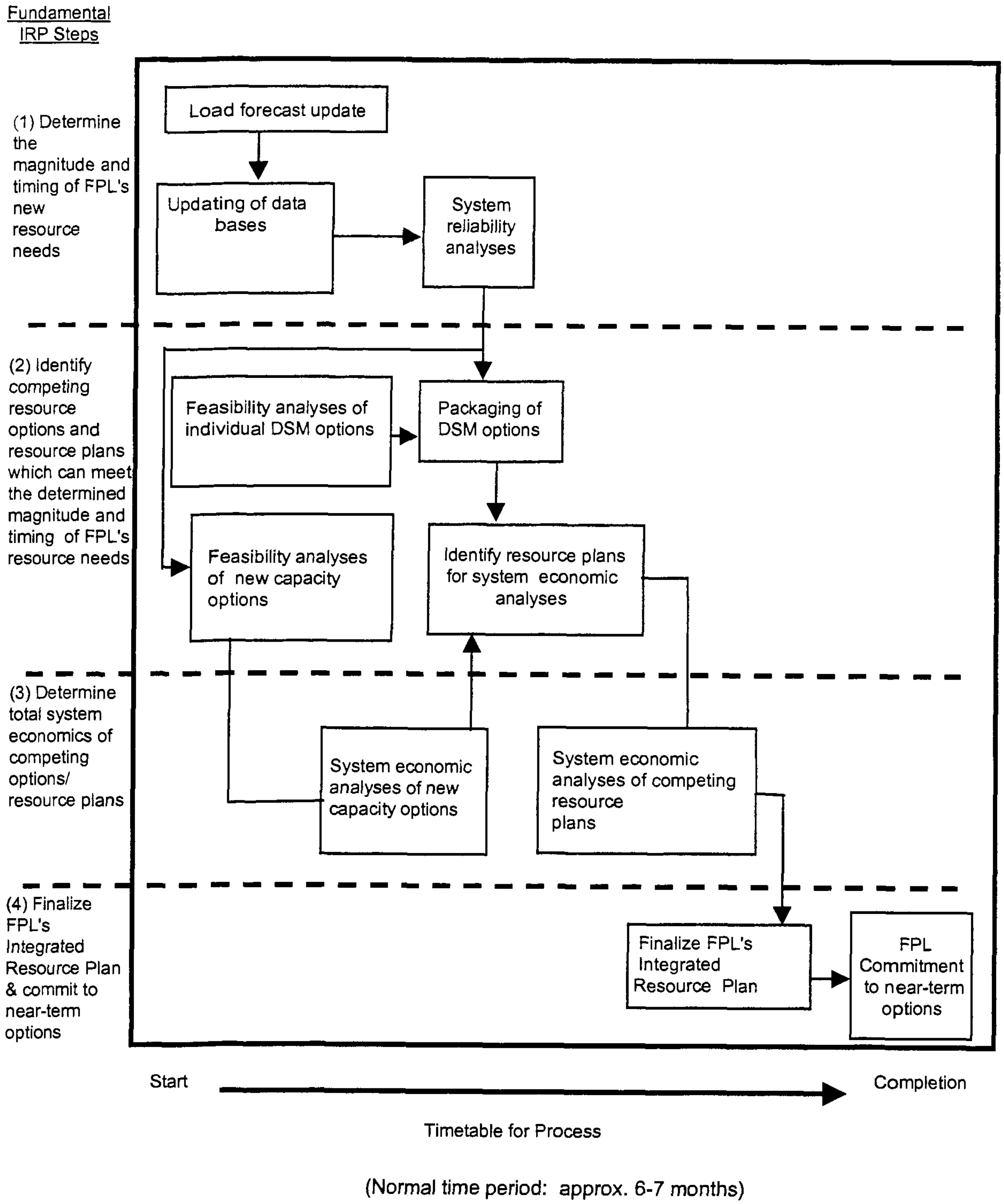

Figure III.A.1

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of these four resource planning steps – determining the magnitude and timing of FPL's resource needs – is essentially a determination of how many megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions are needed. Also determined in this step is when the MW are needed to meet FPL's planning criteria. This step is often referred to as a reliability assessment for the utility system.

Step 1 starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information which is used in many of the fundamental steps in resource planning. Examples of this new information include: delivered fuel price projections, current financial and economic assumptions, and power plant capability and reliability assumptions. During its recent IRP work, FPL utilized four assumptions regarding near-term construction capacity additions, short-term, firm capacity purchase additions, long-term DSM implementation, and the projected extension or renegotiation of the UPS contracts.

The first of these assumptions is based on FPL's announced plans to add near-term capacity through various construction projects. These construction projects include the repowering of an existing unit and the addition of several new units. FPL committed in 1998 to repower both existing steam units at its Fort Myers plant site and two of the three existing steam units at its Sanford plant site. The Fort Myers repowering work is completed, as is the repowering work of one of the Sanford units. The repowering of the other Sanford unit (Unit # 4) will be completed by mid-2003. This Sanford repowering was a "given" in FPL's resource planning work.

Another part of FPL's construction capacity addition assumption was its previously announced decision to add two new CT's during 2003 at FPL's existing Fort Myers site. FPL's resource planning work assumed that this capacity addition would also be a "given".

The final part of FPL's construction capacity addition assumption was the addition of a new combined cycle (CC) unit at Manatee and the conversion of two existing CT's at Martin into a new combined cycle unit. Both additions are scheduled for mid-2005. Both capacity additions were approved by the Florida Public Service Commission in November 2002 after comparing them to 134 competing bids that were received in response to two Requests for Proposals (RFP's) that solicited bids for meeting FPL's 2005/2006 capacity needs.

The second of these assumptions involves short-term, firm capacity purchase additions. FPL decided through its 2000 resource planning work to secure an amount of purchase capacity for the next few years through short-term, firm capacity purchases. These firm capacity purchases are from a combination of utility and independent power producers. The total capacity and duration of these purchases have changed somewhat from what was presented in last year's Site Plan. These changes are due to two factors: new information regarding transmission limitations for several of the new capacity purchases, and a decision to secure additional short-term purchase capacity for 2004 due to the termination of one of the previously signed short-term purchases. The annual total capacity values for these purchases are presented in Table I.D.1. These purchase amounts were also assumed as a "given" in FPL's resource planning work.

The third of these assumptions involves DSM. Since 1994, FPL's resource planning work has used the DSM MW called for in FPL's approved DSM goals as a "given" in its analyses. This was again the case in FPL's most recent planning work, as its approved DSM goals through the year 2009 were taken as a "given".

The fourth of these assumptions is a projected extension or renegotiation of the UPS purchases that are currently scheduled to end in 2010. No final decision has been reached on this matter, but FPL has initiated discussions with Southern Company regarding a possible extension or renegotiation of these purchases. The inclusion, for planning purposes, of the assumption that these coal-by-wire purchases will continue beyond the current expiration date reflects an interest in maintaining/enhancing fuel diversity in FPL's system.

The first place in which these assumptions and much of the other updated information and assumptions are used is the first fundamental step: the determination of the magnitude and the timing of FPL's resource needs. This determination is accomplished by system reliability analyses which are typically based on a dual planning criteria of a minimum peak period reserve margin of 15% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry. The reserve margin criterion increases from 15% to 20% starting in mid-2004 due to a voluntary agreement reached among FPL, FPC, and TECO, and accepted by the FPSC in the FPSC's Docket No. 981890-EU.

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of how well a generating system can meet its native load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as: unit numbers and sizes (i.e., two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time); and the value of being part of an interconnected system.

Therefore, probabilistic methodologies have been used to provide additional information on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss-of-load probability or LOLP. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of the "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using the Tie Line Assistance and Generation Reliability (TIGER) model.

The end result of the first fundamental step of resource planning is a projection of how many new MW of resources are needed to meet both reserve margin and LOLP criteria, and thus maintain system reliability, and of when the MW are needed. This information is used in the second fundamental step: identifying resource options and resource plans that can meet the determined magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans Which can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, feasibility analysis of new capacity options are carried out to determine which new capacity options appear to be the most competitive on FPL's system. These analyses also establish capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs.

The individual new capacity options are then "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new resource needs are met. The creation of these competing resource plans is typically carried out using dynamic programming techniques. For planning purposes, only FPL construction options were included in FPL's most recent planning analyses.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs were identified. These resource plans were then compared on an economic basis.

Step 3: Determining the Total System Economics:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for comparing the system economics of these resource plans. FPL combines the resource options into resource plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI) and Stone & Webster Management Consultants, Inc. The EGEAS model is also used to perform the basic economic analyses of the resource plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the intent of minimizing FPL's leveled system average rate (i.e., a Rate Impact Measure or RIM methodology). However, in cases such as existed for FPL's most recent planning work in which the DSM contribution was taken as a "given" and the only competing options were new generating units, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. Consequently, the competing options and plans were evaluated on a present value system revenue requirement basis.

The basic economic analyses carried out with the EGEAS model focus on the capital and operating costs of new capacity options plus the impact these new capacity options have on FPL's system fuel costs.

At the conclusion of the analyses carried out in Step 3, a determination of FPL's preferred resource plan was made.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps activities were evaluated by FPL management and a decision was made as to what FPL's current resource plan would be. This plan is presented in the following section.

III.B Incremental Resource Additions

FPL's projected incremental generation capacity additions/changes for 2003 through 2012 are depicted in Table III.B.1 (The planned DSM additions are shown separately in Table III.C.1). These capacity additions/changes will result from a variety of actions including: changes to existing units (which are frequently achieved as a result of plant component replacements during major overhauls), changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, repowering of an existing steam unit, projected construction of new units, and conversion of CT's into a CC unit.

As shown in Table III.B.1, the bulk of the capacity additions are made up of the following items: a completion of the repowering of FPL's Sanford Unit # 4 that is projected to be completed by the Summer, 2003; the construction of two new CT's by mid – 2003 at FPL's existing Fort Myers site; the addition of one or more new short-term purchases for 2004 that replaces a previous purchase agreement; the conversion of two CT's into a larger CC unit in 2005 at FPL's Martin site; the addition of a new CC unit, also in 2005, at FPL's Manatee site; and the construction of four additional CC units in the 2007 through 2012 time frame. Sites for these four CC units that are currently projected to be added in the 2007 through 2012 timeframe have not yet been selected.

Projected Capacity Changes and Reserve Margins for FPL [1]			
		Net Capacity Changes (MW)	
		Winter [2]	***Summer*** [3]
2003	Sanford Repowering # 4: Second Phase [4]	---	957
	Combustion Turbines (2) Fort Myers [5]	---	298
	Purchases [6]	1,097	(140)
	Changes to existing Units	31	(32)
2004	Combustion Turbines (2) Fort Myers [5]	366	---
	Purchases [6]	(156)	44
	New Short-Term Purchase [7]	---	213
	Changes to existing Units	72	283
	Sanford Repowering # 4: Second Phase [4]	1,036	---
2005	Changes to existing QF's	(10)	(10)
	Purchases [6]	(6)	(523)
	Manatee Unit #3 Combined Cycle [8]	---	1,107
	New Short-Term Purchase [7]	---	(213)
	Conversion of MR #8 CT's to CC [8]	(363)	783
2006	Manatee Unit #3 Combined Cycle [8]	1,201	---
	Conversion of MR #8 CT's to CC [8]	1,198	---
	Changes to existing QF's	(133)	(133)
	Purchases [6]	(520)	---
2007	Purchases [6]	---	(474)
	Unsited Combined Cycle # 1 [8]	---	1,107
2008	Purchases [6]	(474)	---
	Unsited Combined Cycle # 1 [8]	1,209	---
	Unsited Combined Cycle # 2 [8]	---	1,107
2009	Unsited Combined Cycle # 2 [8]	1,209	---
	Changes to existing QF's	---	(51)
2010	Unsited Combined Cycle # 3 [8]	---	1,107
	Changes to existing QF's	(51)	(44)
2011	Unsited Combined Cycle # 3 [8]	1,209	---
	Changes to existing QF's	(89)	(45)
2012	Unsited Combined Cycle # 4 [8]	---	1,107
	TOTALS =	6,827	6,449

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.

(2) Winter values are values for January of year shown.

(3) Summer values are values for August of year shown.

(4) The second phase of the repowering consists of integrating the combustion turbines, heat recovery steam generators, and steam turbines.

(5) The two CT's at Fort Myers are scheduled to be in-service in the Spring of 2003. Therefore, the CT's are included in the 2003 Summer reserve margin calculation and are included in the 2004 - on reserve margin for Summer and Winter.

(6) These are firm capacity purchases. See Section I.D and III.A. for more details.

(7) Negotiations are currently underway between FPL and several parties to secure this short - term capacity.

(8) All new combined cycle units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

Table III.B.1

III.C Other Results of FPL's Recent Planning Work

In the course of FPL's 2002 and early 2003 planning efforts, two issues were identified that are now receiving attention in FPL's on-going resource planing work. Those two issues are: 1) the need to address the growing imbalance in Southeast Florida between regional load and generating capacity located within this region; and 2) the desire to maintain/enhance fuel diversity in the FPL system.

In regard to the first issue, currently there exists a significant imbalance between the very high peak load in the Southeast Florida region of FPL's service territory and the installed generating capacity in that region. Because of the continuing load growth in this region, the imbalance between generation and load will increase significantly during the next few years unless additional generation is sited in the Southeast Florida region.

If a majority of the generation capacity additions required to meet FPL system needs for 2007 and 2008 are not sited in Southeast Florida, FPL expects that in 2009 and 2010 it will have to either add generating capacity within this region, or add substantial amounts of transmission facilities that are likely to be costly to bring power generated outside the region into Southeast Florida in order to continue to reliably serve this load. At present, FPL believes that adding generation capacity within the region is the preferred approach.

The second issue, the desire to maintain/enhance fuel diversity in the FPL system, is not explicitly reflected in the resource plan presented in this Site Plan. The plan to meet capacity needs beyond 2007, reflected in the Tables and Schedules of this document, consists of the construction of three additional CC units in the 2008 through 2012 time frame at sites yet to be selected. However, these resources additions are subject to change.

FPL intends to identify and evaluate alternatives that would enhance fuel diversity in its capacity resource mix. These alternatives include: extending and/or expanding existing solid fuel-based power purchases such as the UPS contract, building new solid fuel-based generation capacity in FPL's system, obtaining access to non-traditional sources of natural gas, such as through suppliers who deliver natural gas to Florida from international sources of production, and maintaining the ability to utilize fuel oil at FPL's existing units. Therefore, the new gas-fired CC units currently shown as capacity additions for 2008, 2010, and 2012 are subject to change in the future as FPL evaluates the feasibility and cost-effectiveness of various alternatives to enhance fuel diversity.

FPL believes that the earliest that one of these alternatives to enhance fuel diversity, adding new solid fuel-based generating capacity, could be permitted and built in Florida is 2009. In addition, FPL believes it is more likely that such a unit would be sited at some site north of the Southeast Florida region due to permitting and fuel transportation considerations.

As a result, FPL believes that the time and location aspects of these two issues will likely result in an approach in which FPL attempts to address the Southeast Florida imbalance first when it finalizes plans for meeting its 2007 and/or 2008 need. Such an approach would accomplish two things. First, it would address the immediate concern regarding this growing regional imbalance. Second, to the extent the 2007 and/or 2008 capacity additions effectively address the Southeast Florida imbalance concern, solid fuel-based capacity additions north of the Southeast Florida region would be more feasible and cost-effective.

FPL's approach to these two issues will be developed through on-going resource planning work.

III.D Demand Side Management (DSM)

1. FPL's Current DSM Programs

FPL's currently approved DSM programs are summarized as follows:

Residential Conservation Service: This is an energy audit program designed to assist residential customers in understanding how to make their homes more energy-efficient through the installation of conservation measures/practices.

Residential Building Envelope: This program encourages the installation of energy-efficient ceiling insulation in residential dwellings that utilize whole-house electric air conditioning.

Duct System Testing and Repair: This program encourages demand and energy conservation through the identification of air leaks in whole-house air conditioning duct systems and by the repair of these leaks by qualified contractors.

Residential Air Conditioning: This is a program to encourage customers to purchase higher efficiency central cooling and heating equipment.

Residential Load Management (On-Call): This program offers load control of major appliances/household equipment to residential customers in exchange for monthly electric bill credits.

New Construction (BuildSmart): This program encourages the design and construction of energy-efficient homes that cost-effectively reduce coincident peak demand and energy consumption.

Business Energy Evaluation: This program encourages energy efficiency in both new and existing commercial and industrial facilities by identifying DSM opportunities and providing recommendations to the customer.

Commercial/Industrial Heating, Ventilating, and Air Conditioning: This program encourages the use of high-efficiency heating, ventilation, and air conditioning (HVAC) systems in commercial/industrial facilities.

Commercial/Industrial Efficient Lighting: This program encourages the installation of energy-efficient lighting measures in commercial/industrial facilities.

Business Custom Incentive: This program encourages commercial/industrial customers to implement unique energy conservation measures or projects not covered by other FPL programs.

Commercial/Industrial Load Control: This program reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits. (This program was closed to new participants in 2000).

Commercial/Industrial Demand Reduction: This program (which started in 2002) is similar to the Commercial/Industrial Load Control mentioned above by continuing the objective to reduce peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits.

Commercial/Industrial Building Envelope: This program encourages the installation of energy-efficient building envelope measures such as window treatments and roof/ceiling insulation for commercial/industrial facilities.

Business On Call: This program offers load control of central air conditioning units to both small, non-demand-billed and medium, demand-billed commercial/industrial customers in exchange for monthly electric bill credits.

2. Research and Development

FPL's DSM Plan continues to support research and development activities. Historically, FPL has performed extensive DSM research and development. FPL will continue such activities not only through its Conservation Research and Development program, but also through individual research projects. These efforts will examine a wide variety of technologies that build on prior FPL research where applicable and will expand the research to new and promising technologies as they emerge.

Conservative Research and Development Program

FPL's Conservation Research and Development Program is designed to evaluate emerging conservation technologies to determine which are worthy of pursuing for program development and approval. FPL has researched a wide variety of technologies and from that research has been able to develop new programs such as Residential New Construction, Commercial/Industrial Building Envelope, and Business On Call.

Low Income Weatherization Retrofit Project

This R&D project is investigating cost-effective methods of increasing the energy efficiency in the homes of FPL's low-income customers. The research project addresses the needs of low-income housing retrofits by providing monetary incentives to various housing authorities including weatherization agency providers (WAPS), and non-weatherization agency providers (non-WAPS). These incentives are used by the housing authorities to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting. FPL either conducts a home energy survey, trains housing authority employees to perform FPL home energy surveys, accepts the National Energy Audit (NEAT) (as supplemented to capture water heating recommendations not included in the NEAT audit), or approves similar FPL approved audits conducted by weatherization providers to determine the need for energy efficient retrofit measures for each home. FPL has designed the project so as to minimize extra work for the retrofit housing authorities.

Photovoltaic Research, Development and Education Project

Photovotaic (PV) roof-tile systems are a relatively new technology which directly replaces existing roofing materials such as shingles and standing-rib roofing with PV materials. These PV materials have the same waterproofing characteristics as conventional roofing materials. This project is consistent with the Federal Government's Million Solar Roofs Initiative. However, based on FPL's research to-date, a primary hurdle to the physical installation of PV systems, whether roofing materials or flat plate modules, is the lack of awareness, understanding, and acceptance by local building officials. For the most part, these officials are unclear about how these systems work and how to address these systems as part of the building, permitting, and inspection process. This creates barriers toward the use of this technology. As part of this project FPL will be holding workshops to address this issue.

Green Energy Project

Under this project, FPL is examining the feasibility of purchasing electric energy generated from new renewable resources including solar-powered technologies, biomass energy, landfill methane, wind energy, low impact hydroelectric energy, and/or other renewable sources. Customers who participate would then be charged higher premiums for utilizing electric energy derived from these sources.

FPL has determined that there is a level of customer acceptance and desire for a Green Power pricing program. A petition was submitted on May 3, 2002 for a declaratory statement (Docket No.020397 – EQ) asking the FPSC whether FPL may pay higher than avoided costs for energy from renewable sources devoted to a Green Power program. A favorable order was received on August 6, 2002. FPL is continuing its development of this project.

Real-Time Pricing

Although not part of FPL's approved DSM Plan, FPL continues to research new conservation/efficiency options such as real-time pricing. This option is an experimental service offering for large C/I customers that is designed to evaluate customer load response to hourly, marginal cost-based energy prices provided on a day-ahead basis.

On Call Pilot

In March 2003, FPL received FPSC Commission approval to perform a pilot for its On Call program. Under the pilot FPL will offer to new participants a residential load control service similar to the On Call Program at a reduced incentive level. The offering of.this pilot will allow FPL to test its market research data and gauge whether FPL can repackage its current residential load control service, minimize customer attrition, achieve current goals for residential load control, and, ultimately, change On Call incentive levels without damaging system reliability.

FPL will begin implementing the pilot in April 2003 and it will last up to 3 years.

3. FPL's DSM MW Goals

FPL's DSM implementation plan is designed to meet currently approved DSM goals for through 2009. The combined total residential and commercial/industrial Summer MW reduction values from FPL's DSM goals for 2000 – 2009 are presented in Table III. D.1. FPL's DSM efforts through 2002 have resulted in a cumulative Summer peak reduction of approximately 2,923 MW at the meter.

FPL's Summer MW Reduction Goals for DSM
(At the Meter)

Year	Goal Cumulative Summer MW
2000	122
2001	200
2002	269
2003	339
2004	410
2005	484
2006	554
2007	625
2008	697
2009	765

Table III.D.1

III.E Generation Additions From Independent Power Producers

As previously mentioned in Section III.A, FPL recently entered into a number of new short-term, firm capacity purchases that extend through early 2007. The capacity supplied by these purchases are summarized in Table I.D.1. The vast majority of the capacity from these purchases is from independent power producers.

Tables I.B.1 and Table I.B.2 present the previously contracted cogeneration/small power production facilities which are addressed in FPL's resource planning.

III.F Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy for FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV and 500 kV bulk transmission lines irrespective of whether they directly correspond to proposed generating facilities or whether they must be certified under the Transmission Line Siting Act.

List of Proposed Power Lines

(1) LINE OWNERSHIP	(2) TERMINALS (To)	(3) TERMINALS (From)	(4) LINE LENGTH CKT. MILES	(5) COMMERCIAL IN-SERVICE DATE (MO/YR)	(6) NOMINAL VOLTAGE (kV)	(7) CAPACITY (MVA)
FPL	Broward	Delmar	3	Jun-03	230	514
FPL	Charlotte	Whidden #3	29	Jun-03	230	1191
FPL	Cortez	Johnson	11	Jun-03	230	596
FPL/GPC *	Duval-Kingsland	Yulee-Oneil	7	Jun-03	230	478
FPL	Cedar	Lauderdale	1	Oct-03	230	514
FPL	Collier	Orange River	9	Nov-03	230	759
FPL	Coast	Peachland	7	Dec-03	230	596
FPL	Andytown	Pennsuco	2	Jun-04	230	508
FPL	Bridge	Indiantown	10	Dec-04	230	1067
FPL	Broward-Corbett	Rainberry-Clintmoore	6	Jun-04	230	514
FPL	Dade	Overtown	11	Jun-04	230	759
FPL	Delmar	Yamato	2	Jun-04	230	514
FPL	Indiantown	Martin #2	13	Dec-04	230	1067
FPL/PGN *	Whidden	Vandola	27	Jun-04	230	799
FPL	Whidden	Charlotte #2	27	Jun-04	230	1067
FPL	Conservation	Oakland Park	13	Jun-05	230	759
FPL	Collier	Orange River	TBD	Dec-05	230	TBD

* GPC = Georgia Power Corporation
PGN = Progress Energy

Table III.F.1

In addition, there will be transmission facilities needed to connect several of FPL's committed capacity additions to the system transmission grid. These transmission facilities for the projected capacity additions at FPL's existing Fort Myers, Manatee, and Martin sites are described below. (No additional transmission facilities are needed for the repowering of Sanford Unit # 4).

Since the projected capacity additions for 2007 through 2012 are as-yet unsited, no transmission facilities information is provided. This information will be provided in future Site Plan documents once sites are selected.

III.F.1 Transmission Facilities at Fort Myers

The work required for the Fort Myers capacity expansion for two new CT units with the FPL grid is projected to be as follows:

I. Substation:

1. Build one collector bus with 2 breakers for each CT. Add another breaker to the collector bus for the station service transformer.
2. Add the two main step-up transformers (225MVA/each), one for each CT.
3. Add the station service transformer.
4. Connect the new Fort Myers collector bus to the Fort Myers 230kV switchyard.
5. Replace 4 breakers at the existing Fort Myers 230 kV switchyard.
6. Add relay and other protective equipment at Fort Myers switchyard.

II. Transmission:

1. All transmission work at Fort Myers is complete.

III.F.2 Transmission Facilities at Manatee

The work required for the new capacity addition at Manatee with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 6 breakers to connect the four CT's, and one ST.
2. Construct two string busses to connect the collectors and main switchyard.
3. Add five main step-up transformers (4-225MVA, 1- 450MVA) one for each CT, and one for the ST.
4. Add two breakers in bay # 6 to connect the collector bus at the Manatee switchyard.
5. Add two breakers in bay # 5 at the Manatee switchyard to connect the other collector bus.
6. Add relays and other protective equipment.
7. Upgrade 13-230kV circuit breakers to 2 cycle Independent Pole breakers at Manatee switchyard.
8. Upgrade the existing line terminal at Johnson to 3000 Amps.
9. Expand site and relay vault for two new line terminals at Manatee switchyard.

II. Transmission:

1. Upgrade the Calusa-Charlotte 230kV transmission line to 1875 Amps.
2. Upgrade the Johnson- Manatee 230kV transmission line to 2710 Amps.
3. Upgrade the Manatee-Ringling # 3 230kV transmission line to 2710 Amps.
4. Upgrade the Charlotte-Fort Myers # 2 230kV transmission line to 1565 Amps.

III.F.3 Transmission Facilities at Martin

The work required for the incremental capacity planned to be added at Martin (convert the existing two CT's to a new four-on-one combined cycle unit) with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing one collector buss with 4 breakers each to connect the two CT's and one ST.
2. Add one station service transformer in the existing CT yard.
3. Add three main step-up transformers (2-225 MVA, 450MVA) one for each CT, and one for the ST.
4. Add two breakers in bay # 3 to connect the collector bus in the main switchyard.
5. Add relays and other protective equipment.
6. Install phase reactors and string buss in main switchyard to limit fault current.
7. Add breaker in bay # 7 (7WE) for new Indiantown # 2 transmission line. Tap existing 69kV auto-transformer off east 230kV operating bus.
8. Add breaker in Bay # 3 (3WS) at Indiantown Substation for Bridge line.
9. Create new bay 4. Add breakers 4WM, 4WS for Indiantown-Martin #2 line at Indiantown Substation.
10. Create new bay # 1 at Bridge Substation with breakers 1WW and 1WM. Add breakers 2WW and 2WE to convert station configuration from ring buss.
11. Construct one string bus to connect the collector and main switchyard.

II. Transmission:

1. Construct 230kV Martin-Indiantown # 2 transmission line.
2. Construct 230kV Indiantown – Bridge # 2 transmission line.
3. Various OHGW replacements due to increased fault current.
4. Upgrade the Ranch-Homeland 230kV transmission line to 1330 Amps.

III.G. Renewable Resources

FPL has been the leading Florida utility in examining ways to utilize renewable energy technologies to meet its customers' current and future needs. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various technologies.

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970's in demonstrating the first residential solar photovoltiac (PV) system east of the Mississippi. This PV installation at FESC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities on both a daily and annual basis in Florida. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-Kilowatt (KW) system was placed into operation in 1984. (After the testing of this PV installation was completed, the system was removed in 1990 to make room for substation expansion.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. The FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's recent Green Pricing effort (which is discussed on the following page).

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first and only utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was not cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980's, FPL introduced another renewable energy program. FPL's Passive Home Program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for 6 passive homes with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the Florida Public Service Commission to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test may be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, and various customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

More recently, FPL has analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach does not require all of its customers to bear PV's high cost, but allows customers who are interested in facilitating the use of renewable energy the means to do so. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund that FPL used to make PV purchases in bulk quantities. PV modules were then installed and delivered PV-generated electricity directly into the FPL grid. Thus, when sunlight is available, the PV-generated electricity displaces an equivalent amount of fossil fuel-generated electricity.

FPL's basic approach, which has been termed Green Pricing, was initially discussed with the FPSC in 1994. FPL's initial efforts to implement this approach were then formally presented to the FPSC as part of FPL's DSM Plan in 1995 and FPL received approval from the FPSC in 1997 to proceed. FPL initiated the effort in 1998 and received approximately $89,000 in contributions (that significantly exceeded the goal of $70,000). FPL has purchased the PV modules and installed them at FPL's Martin Plant site.

As previously discussed, FPL initiated two new renewable efforts in 2000. FPL's first new initiative in 2000 was the Green Energy Project which is a second, different attempt to implement the basic Green Pricing approach. Under this project FPL would purchase electric energy generated from new renewable sources. The project would offer to supply to FPL's electrical grid the equivalent of all, or part of, a customer's monthly kWh usage with electricity generated from these new renewable resources. Participants would be residential (and possibly commercial) customers who would pay higher ("green" rates) for electricity provided from these renewable sources. FPL issued a Request for Proposals (RFP) in 2001 to solicit proposals to potentially supply energy only (MWH) from new renewable sources.

The second effort initiated in 2000 is FPL's Photovoltaic Research, Development, and Education Project. This demonstration project's objectives are to increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks (as well as the total annual energy capabilities of roof tile PV systems), and assess the homeowner's financial benefits and costs of PV roof tile systems.

Finally, FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy and as-available energy have been purchased by FPL from these developers. (Please refer to Tables I.B.1 and I.B.2).

III.H FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980's, FPL relied primarily on a combination of oil, natural gas, and nuclear energy to generate electricity. In the early 1980's FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix, through FPL's partial ownership and additional purchases from, the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit # 4 in 1989. Starting in 1997, petroleum coke was added to the fuel mix as a blend stock with coal at the St. Johns River Power Park.

The trend in recent years has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective combined cycle generating units. Although this planning document reflects a continuation of this trend, FPL's proposed capacity additions for the years 2008 through 2012 present a plan that is subject to change. FPL's future resource planning work will increasingly focus on identifying and evaluating alternatives that would maintain/enhance FPL's long-term fuel diversity. These fuel diversity-enhancing alternatives may include: extending and/or expanding existing solid/fuel-based power purchases, the construction of, and the purchase of power from, new solid fuel-based (coal and petroleum coke) facilities; obtaining access to diversified sources of natural gas such as from suppliers of natural gas from international production areas; and preserving FPL's ability to utilize fuel oil at is existing units. The feasibility and cost-effectiveness of these, and possibly other, alternatives will be analyzed in future planning cycles.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2012 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2.

2. Fuel Price Forecasts

FPL's long-term oil price forecast assumes that worldwide demand for petroleum products will grow moderately throughout the planning horizon. Non-OPEC crude oil supply is projected to increase as new and improved drilling technology and seismic information will reduce the cost of producing crude oil and increase both recoveries from existing fields and new discoveries. However, the rate of increase in non-OPEC supply is projected to be slower than that of petroleum demand, resulting in an increase in OPEC's market share throughout the planning horizon. As OPEC gains market share, prices for petroleum products are projected to increase.

FPL's natural gas price forecast assumes that domestic demand for natural gas will grow throughout the planning horizon, primarily due to increased requirements for electric generation. Domestic natural gas production will increase as new and improved drilling technology and seismic information will reduce the cost of finding, developing, and producing natural gas fields. The rate of increase in domestic natural gas production is assumed to be slower than that of demand nationally, with the balance being supplied by increased Canadian and liquefied natural gas (LNG) imports. As demand for natural gas in Florida grows, it is anticipated that the Florida Gas Transmission (FGT) pipeline system will be augmented/expanded. This anticipated expansion of FGT's pipeline, combined with the new Gulfstream pipeline and potential sources of non-domestic/international natural gas (such as off-shore suppliers), should result in sufficient gas for FPL's continued needs.

FPL's coal price forecast assumes an ample supply of domestic coal, and the availability of imported coal, to meet a slow, but steady increase in domestic demand in the electric generation sector over the planning horizon. The coal price forecast for FPL's existing coal plant at St. Johns River Power Park (SJRPP) and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts unit expiration, along with the purchase of spot coal, to meet generation requirements. FPL's petroleum coke price forecast assumes that the petroleum industry will continue to cokers in the U.S., as well as in the Caribbean Basin in order to maximize refinery production of light products. This trend will continue to result in sufficient availability of petroleum coke, at delivered prices significantly below delivered coal prices. To support a slow, but steady growth in the use of petroleum coke in the U.S. electric utility industry.

Schedule 5
Fuel Requirements [1/]

	Fuel Requirements	Units	Actual [2/] 2001	2002	Forecasted 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	Nuclear	Trillion BTU	263	276	251	251	255	251	250	255	250	249	254	251
(2)	Coal	1,000 TON	3,078	3,070	3,823	3,717	3,703	3,701	3,701	3,685	3,632	3,631	3,634	3,636
(3)	Residual (FO6)- Total	1,000 BBL	40,995	29,791	28,180	31,431	24,819	22,042	19,464	14,692	10,393	7,823	8,310	6,904
(4)	Steam	1,000 BBL	40,995	29,791	28,180	31,431	24,819	22,042	19,464	14,692	10,393	7,823	8,310	6,904
(5)	Distillate (FO2)- Total	1,000 BBL	381	473	911	103	28	44	22	5	2	0	1	0
(6)	CC	1,000 BBL	75	29	772	10	0	0	0	0	0	0	0	0
(7)	CT	1,000 BBL	306	444	139	93	28	44	22	5	2	0	1	0
(8)	Steam	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Natural Gas -Total	1,000 MCF	212,956	286,112	276,757	292,979	341,174	388,315	417,293	452,382	492,761	528,380	543,930	568,789
(10)	Steam	1,000 MCF	79,157	78,017	33,537	38,373	31,538	27,994	26,358	20,758	16,191	13,015	12,937	11,865
(11)	CC	1,000 MCF	109,778	195,106	240,319	251,320	308,827	359,448	390,419	430,914	476,108	515,042	530,473	556,537
(12)	CT	1,000 MCF	24,022	12,988	2,901	3,285	810	873	516	710	462	323	521	387

1/ Reflects fuel requirements for FPL only.
2/ Source: A Schedules.

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 1/ 2001	Actual 1/ 2002	Forecasted 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	Annual Energy Interchange 2/	GWH	7,701	10,287	10,701	10,590	10,396	10,255	10,208	10,088	9,634	9,601	9,561	9,641
(2)	Nuclear	GWH	24,070	25,295	23,870	23,848	24,280	23,869	23,766	24,331	23,795	23,688	24,173	23,924
(3)	Coal	GWH	6,267	5,977	7,287	7,102	7,073	7,068	7,072	7,044	7,013	7,006	7,016	7,018
(4)	Residual(FO6) -Total	GWH	25,802	18,708	18,133	20,224	16,014	14,221	12,570	9,516	6,734	5,068	5,376	4,469
(5)	Steam	GWH	25,802	18,708	18,133	20,224	16,014	14,221	12,570	9,516	6,734	5,068	5,376	4,469
(6)	Distillate(FO2) -Total	GWH	163	188	664	52	13	20	10	2	1	0	1	0
(7)	CC	GWH	41	18	598	7	0	0	0	0	0	0	0	0
(8)	CT	GWH	122	170	66	45	13	20	10	2	1	0	1	0
(9)	Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(10)	Natural Gas -Total	GWH	24,496	34,541	37,516	39,533	46,912	53,644	57,935	63,242	69,359	74,634	76,921	80,520
(11)	Steam	GWH	7,588	7,549	3,132	3,588	2,949	2,616	2,468	1,943	1,520	1,225	1,214	1,117
(12)	CC	GWH	14,849	25,986	34,117	35,646	43,890	50,952	55,422	61,235	67,796	73,380	75,659	79,367
(13)	CT	GWH	2,060	1,006	267	299	73	76	46	65	42	30	48	35
(14)	Other 3/	GWH	9,905	9,202	7,529	8,176	7,878	6,865	6,869	6,675	6,580	5,814	5,279	5,152
	Net Energy For Load 4/	GWH	98,404	104,199	105,700	109,525	112,565	115,942	118,430	120,899	123,115	125,811	128,327	130,724

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecst of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.
4/ Net Energy For Load is also shown in Column 19 on Schedule 2.3.

Schedule 6.2
Energy % by Fuel Type

	Energy Source	Units	Actual 1/ 2001	2002	Forecasted 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	Annual Energy Interchange 2/	%	7.8	9.9	10.1	9.7	9.2	8.8	8.6	8.3	7.8	7.6	7.5	7.4
(2)	Nuclear	%	24.5	24.3	22.6	21.8	21.6	20.6	20.1	20.1	19.3	18.8	18.8	18.3
(3)	Coal	%	6.4	5.7	6.9	6.5	6.3	6.1	6.0	5.8	5.7	5.6	5.5	5.4
(4)	Residual (FO6) -Total	%	26.2	18.0	17.2	18.5	14.2	12.3	10.6	7.9	5.5	4.0	4.2	3.4
(5)	Steam	%	26.2	18.0	17.2	18.5	14.2	12.3	10.6	7.9	5.5	4.0	4.2	3.4
(6)	Distillate (FO2) -Total	%	0.2	0.2	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	CC	%	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CT	%	0.1	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	24.9	33.1	35.5	36.1	41.7	46.3	48.9	52.3	56.3	59.3	59.9	61.6
(11)	Steam	%	7.7	7.2	3.0	3.3	2.6	2.3	2.1	1.6	1.2	1.0	0.9	0.9
(12)	CC	%	15.1	24.9	32.3	32.5	39.0	43.9	46.8	50.6	55.1	58.3	59.0	60.7
(13)	CT	%	2.1	1.0	0.3	0.3	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0
(14)	Other 3/	%	10.1	8.8	7.1	7.5	7.0	5.9	5.8	5.5	5.3	4.6	4.1	3.9
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules.

2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.

3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed Capacity MW	1/ Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	Reserve Margin Before Maintenance 5/ % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	Reserve Margin After Maintenance 6/ % of Peak
2003	18,864	2,263	0	877	22,004	19,773	1,430	18,343	3,661	20.0	0	3,661	20.0
2004	19,147	2,520	0	877	22,544	20,297	1,510	18,787	3,757	20.0	0	3,757	20.0
2005	21,037	1,784	0	867	23,688	20,799	1,589	19,210	4,478	23.3	0	4,478	23.3
2006	21,037	1,784	0	734	23,555	21,331	1,667	19,664	3,891	19.8	0	3,891	19.8
2007	22,144	1,310	0	734	24,188	21,851	1,744	20,107	4,081	20.3	0	4,081	20.3
2008	23,251	1,310	0	734	25,295	22,289	1,821	20,468	4,827	23.6	0	4,827	23.6
2009	23,251	1,310	0	683	25,244	22,784	1,896	20,888	4,356	20.9	0	4,356	20.9
2010	24,358	1,310	0	640	26,308	23,294	1,922	21,372	4,936	23.1	0	4,936	23.1
2011	24,358	1,310	0	595	26,263	23,783	1,922	21,861	4,402	20.1	0	4,402	20.1
2012	25,465	1,310	0	595	27,370	24,279	1,922	22,357	5,013	22.4	0	5,013	22.4

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. All values are Summer net MW.

2/ Total Capacity Available=Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance =Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	% of Peak
2002/03	18,780	2,475	0	877	22,132	20,190	1,497	18,693	3,439	18.4	0	3,439	18.4
2003/04	20,254	2,319	0	877	23,450	20,081	1,561	18,520	4,930	26.6	0	4,930	26.6
2004/05	19,891	2,313	0	867	23,071	20,583	1,615	18,968	4,103	21.6	0	4,103	21.6
2005/06	22,290	1,793	0	734	24,817	21,100	1,671	19,429	5,388	27.7	0	5,388	27.7
2006/07	22,290	1,793	0	734	24,817	21,605	1,723	19,882	4,935	24.8	0	4,935	24.8
2007/08	23,499	1,319	0	734	25,552	22,046	1776	20,270	5,282	26.1	0	5,282	26.1
2008/09	24,708	1,319	0	734	26,761	22,539	1,828	20,711	6,050	29.2	0	6,050	29.2
2009/10	24,708	1,319	0	683	26,710	23,026	1,873	21,153	5,557	26.3	0	5,557	26.3
2010/11	25,917	1,319	0	595	27,831	23,522	1,873	21,649	6,182	28.6	0	6,182	28.6
2011/12	25,917	1,319	0	595	27,831	24,024	1,873	22,151	5,680	25.6	0	5,680	25.6

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri	Alt.	Start Mo./Yr.	In-Service Mo./Yr	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2003														
Fort Myers GT's		Lee County 35/43S/25E	CT	FO2	No	WA	No	Nov-02	Jan-03	Unknown	744,000	16	---	OT
Fort Myers	2	Lee County 35/43S/25E	CC	NG	No	PL	No	Nov-02	Jan-03	Unknown	402,000	6	---	OT
Sanford	5	Volusia County 16/19S/30E	CC	FO6	No	WA	No	Nov-02	Jan-03	Unknown	436,100	6	---	OT
Martin	3	Martin County 29/29S/38E	CC	NG	No	PL	No	Nov-02	Jan-03	Unknown	612,000	1	(16)	OT
Martin	4	Martin County 29/29S/38E	CC	NG	No	PL	No	Nov-02	Jan-03	Unknown	612,000	1	(16)	OT
Martin	8	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Nov-02	Jan-03	Unknown	362,000	1	---	OT
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-01	Apr-03	Unknown	190,000	---	149	OT
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	May-01	May-03	Unknown	190,000	---	149	OT
Sanford Repowering: Second Phase	4	Volusia County 16/19S/30E	CC	NG	No	PL	No	Aug-02	Jun-03	Unknown	106,600	---	957	RP
									2003 Changes/Additions Total:			**31**	**1,223**	
2004														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-01	Apr-03	Unknown	190,000	183	---	V
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	May-01	May-03	Unknown	190,000	183	---	V
Sanford Repowering: Second Phase	4	Volusia County 16/19S/30E	CC	NG	No	PL	No	Aug-02	Jun-03	Unknown	106,600	1,036	---	RP
Turkey Point	1	Dade County 27/57S/40E	ST	FO6	NG	WA	PL	Feb-04	Apr-04	Unknown	402,500	---	3	OT
Lauderdale	4	Broward County 30/50S/42E	CC	NG	FO2	PL	PL	Nov-03	Jan-04	Unknown	521,250	2	2	OT
Port Everglades	4	City of Hollywood 23/50S/42E	ST	FO6	NG	WA	PL	Nov-03	Jan-04	Unknown	402,050	26	23	OT
Riveria	3	City of Riviera Beach 33/42S/43E	ST	FO6	NG	WA	PL	Nov-03	Jan-04	Unknown	310,420	1	1	OT
Martin	1	Martin County 29/29S/38E	ST	NG	FO6	PL	PL	Nov-03	Jan-04	Unknown	863,000	17	17	OT
Martin	2	Martin County 29/29S/38E	ST	NG	FO6	PL	PL	Nov-03	Jan-04	Unknown	863,000	15	26	OT
Martin	3	Martin County 29/29S/38E	CC	NG	No	PL	No	Apr-04	Jun-04	Unknown	612,000	---	26	OT
Martin	4	Martin County 29/29S/38E	CC	NG	No	PL	No	Apr-04	Jun-04	Unknown	612,000	---	26	OT
Martin	8	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-04	Jun-04	Unknown	362,000	---	26	OT
Sanford	4	Volusia County 16/19S/30E	CC	NG	No	PL	No	Apr-04	Jun-04	Unknown	436,100		(4)	OT
Sanford	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	Nov-03	Jan-04	Unknown	436,100	11	43	OT
Fort Myers	2	Lee County 35/43S/25E	CC	NG	No	WA	No	Apr-04	Jun-04	Unknown	402,000	---	46	OT
Fort Myers CT	3	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-04	Jun-04	Unknown	190,000	---	26	OT
Manatee	1	Manatee County 18/33S/20E	ST	FO6	No	WA	No	Apr-04	Jun-04	Unknown	863,300	---	5	OT
Manatee	2	Manatee County 18/33S/20E	ST	FO6	No	WA	No	Apr-04	Jun-04	Unknown	863,300	---	5	OT
Fort Myers GT's		Lee County 35/43S/25E	CT	FO2	No	WA	No	Apr-04	Jun-04	Unknown	744,000	---	12	OT
									2004 Changes/Additions Total:			**1,474**	**283**	
2005														
Manatee Combined Cycle	3	Manatee County 18/33S/20E	CC	NG	FO2	PL	PL	Jun-03	Jun-05	Unknown	470,000	---	1,107	T
Martin Combined Cycle	8	Martin County 29/29S/38E	CC	NG	No	PL	No	Jun-03	Jun-05	Unknown	470,000	---	1,107	T
Martin Combustion Turbine Conv.	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Jun-99	Jun-01	12/1/04	190,000	(182)	(162)	OT
Martin Combustion Turbine Conv.	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Jun-99	Jun-01	12/1/04	190,000	(182)	(162)	OT
									2005 Changes/Additions Total:			**(363)**	**1,890**	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January The Summer Total MW value consists of all generation additions and changes achieved by June. All other MW will be picked up in the following year

Note 2: Capacity additions/changes shown for 2003 reflect changes/additions from values shown in Schedule 1

Note 3: The values shown for the Sanford repowering project reflect the schedule for the repowering of Sanford Unit # 4 that was used in FPL's 2002 resource planning work.

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2006														
Manatee Combined Cycle	3	Manatee County 18/33S/20E	CC	NG	FO2	PL	PL	Jun-03	Jun-05	Unknown	470,000	1,201	—	T
Martin Combined Cycle	8	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	Jun-03	Jun-05	Unknown	190,000	1,198	—	T
									2006 Changes/Additions Total:			**2,399**	**0**	
2007														
Unsited Combined Cycle Unit	1	Unknown	CC	NG	FO2	PL	PL	Jan-05	Jun-07	Unknown	470,000	—	1,107	P
									2007 Changes/Additions Total:			**0**	**1,107**	
2008														
Unsited Combined Cycle Unit	1		CC	NG	FO2	PL	PL	Jan-05	Jun-07	Unknown	470,000	1,209	—	P
Unsited Combined Cycle Unit	2	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-08	Unknown	470,000	—	1,107	P
									2008 Changes/Additions Total:			**1,209**	**1,107**	
2009														
Unsited Combined Cycle Unit	2	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-08	Unknown	470,000	1,209	—	P
									2009Changes/Additions Total:			**1,209**	**0**	
2010														
Unsited Combined Cycle Unit	3	Unknown	CC	NG	FO2	PL	PL	Jan-08	Jun-10	Unknown	470,000	—	1,107	P
									2010 Changes/Additions Total:			**0**	**1,107**	
2011														
Unsited Combined Cycle Unit	3	Unknown	CC	NG	FO2	PL	PL	Jan-08	Jun-10	Unknown	470,000	1,209	—	P
									2011 Changes/Additions Total:			**1,209**	**0**	
2012														
Unsited Combined Cycle Unit	4	Unknown	CC	NG	FO2	PL	PL	Jan-10	Jun-12	Unknown	470,000	—	1,107	P
									2012 Changes/Additions Total:			**0**	**1,107**	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by August. All other MW will be picked up in the following year. This is done for reserve margin calculation.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Sanford Unit 4 Repowering
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	652	MW Incremental (1036 MW Total After Repowering)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2003	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		None
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	V	(Under Construction > 50% Complete)
(10)	**Certification Status:**	V	(Under Construction > 50% Complete)
(11)	**Status with Federal Agencies:**	V	(Under Construction > 50% Complete)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		3%
	Forced Outage Factor (FOF):		1%
	Equivalent Availability Factor (EAF):		96%
	Resulting Capacity Factor (%):		Approx. 96% (First Year)
	Average Net Operating Heat Rate (ANOHR):		6,918 Btu/kWh (Base Operation)
(13)	**Projected Unit Financial Data *,**,*** **		
	Book Life (Years):		25 years
	Total Installed Cost (In-Service Year $/kW):		656
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr.)		14.41
	Variable O&M ($/MWH): (2001 $/MWH)		0.374
	K Factor:		1.4637

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Fort Myers Combustion Turbines No. 13 and No. 14 *
(2)	**Capacity**		
	a. Summer	149	MW each for a total of 298 MW
	b. Winter	183	MW each for a total of 366 MW
(3)	**Technology Type:**		Combustion Turbine
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2001	
	b. Commercial In-service date:	2003	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NOx Combustors, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Air Coolers
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	V	(Under Construction > 50% Complete)
(10)	**Certification Status:**	V	(Under Construction > 50% Complete)
(11)	**Status with Federal Agencies:**	V	(Under Construction > 50% Complete)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	1%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	98%	
	Resulting Capacity Factor (%):	Approx. 25%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	10,430	Btu/kWh (Base Operation)
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	414	per Combustion Turbine
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr.)	0.69	
	Variable O&M ($/MWH): (2001 $/MWH)	0.87	
	K Factor:	1.5394	

* Values shown are per unit values for the two units being added.
** $/kW values are based on Summer capacity.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Martin Combustion Turbine Conversion to Combined Cycle

(2) **Capacity**
a. Summer 783 MW Incremental (1107 MW Total)
b. Winter 834 MW Incremental (1198 MW Total)

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2003
b. Commercial In-service date: 2005

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Pond/Tower

(8) **Total Site Area:** 11,300 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** T (Regulatory Approval Received But Not Under Construction)

(11) **Status with Federal Agencies:** T (Regulatory Approval Received But Not Under Construction)

(12) **Projected Unit Performance Data ***

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 80%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh (Base Operation)
Base Operation 75F	100%	

(13) **Projected Unit Financial Data **,*****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	586	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001 $kW-Yr.)	9.07	
Variable O&M ($/MWH): (2001 $/MWH)	0.037	
K Factor:	1.5397	

* Values represent an operational combined cycle unit after the conversion is completed.
** $/kW values are based on Summer incremental capacity.
*** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Manatee Combined Cycle

(2) **Capacity**
a. Summer 1,107 MW
b. Winter 1,201 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2003
b. Commercial In-service date: 2005

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: None

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low NO_x Combustors, SCR

(7) **Cooling Method:** Cooling Pond

(8) **Total Site Area:** 9,500 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** T (Regulatory Approval Received But Not Under Construction)

(11) **Status with Federal Agencies:** T (Regulatory Approval Received But Not Under Construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 71%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh (Base Operation)
Base Operation 75F	100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):		25 years
Total Installed Cost (In-Service Year $/kW):		499
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.):	(2001 $kW-Yr.)	12.96
Variable O&M ($/MWH):	(2001 $/MWH)	0.037
K Factor:		1.5397

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Combined Cycle Unit # 1

(2) **Capacity**
a. Summer 1,107 MW
b. Winter 1,209 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2005
b. Commercial In-service date: 2007

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.05% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Unknown

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 70%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh (Base Operation)
Base Operation 75F	100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	571	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2003 $kW-Yr.)	15.29	
Variable O&M ($/MWH): (2003 $/MWH)	0.41	
K Factor:	1.5397	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Combined Cycle # 2

(2) **Capacity**
a. Summer 1,107 MW
b. Winter 1,209 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2006
b. Commercial In-service date: 2008

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.05% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Unknown

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 70%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh (Base Operation)
Base Operation 75F	100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	581	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2003 $kW-Yr.)	15.29	
Variable O&M ($/MWH): (2003 $/MWH)	0.41	
K Factor:	1.5397	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Combined Cycle # 3

(2) **Capacity**
a. Summer 1,107 MW
b. Winter 1,209 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2008
b. Commercial In-service date: 2010

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.05% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Unknown

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 70%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh (Base Operation)
Base Operation 75F	100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	601	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2003 $kW-Yr.)	15.29	
Variable O&M ($/MWH): (2003 $/MWH)	0.41	
K Factor:	1.5397	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle # 4	
(2)	**Capacity**		
	a. Summer	1,107 MW	
	b. Winter	1,209 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2010	
	b. Commercial In-service date:	2012	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low No_x Combustors, SCR 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Unknown
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	
	Resulting Capacity Factor (%):	Approx. 65%	(First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh (Base Operation)
	Base Operation 75F	100%	
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	621	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2003 $kW-Yr.)	15.29	
	Variable O&M ($/MWH): (2003 $/MWH)	0.41	
	K Factor:	1.5397	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sanford Unit # 4 Repowering

The Sanford Unit # 4 transmission work has already been completed.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Fort Myers – Two New CT's

The Fort Myers transmission work is already completed.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Manatee CC

The new Manatee CC unit does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Martin CC Conversion

(1)	Point of Origin and Termination:	Martin – Indiantown #2
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned & New acquisitions
(4)	Line Length:	12.9 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 10/1/03 End date: 12/31/04
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$11,700,000
(8)	Substations:	Martin 230kV and Indiantown
(9)	Participation with Other Utilities:	None

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(1)	Point of Origin and Termination:	Indiantown – Bridge
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	10.0 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 10/1/03 End date: 12/31/04
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$8,900,000
(8)	Substations:	Indiantown and Bridge
(9)	Participation with Other Utilities:	None

CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered plant and animal species. Population growth in our service area is continuing, which heightens competition for air, land, and water resources that are necessary to meet the increased demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

FPL has been recognized for many years as one of the leaders among utilities for our commitment to the environment. Our environmental leadership has been heralded by many outside organizations. For example, FPL was recently ranked first out of 28 major electric utilities surveyed in an environmental assessment conducted by Innovest, an independent advisory group. FPL was also awarded Edison Electric Institute's National Land Management Award for our stewardship of 25,000 acres surrounding our Turkey Point Plant. In addition, FPL won the Council for Sustainable Florida's award for our sea turtle conservation and education programs at our St. Lucie Plant. In 2001, FPL was awarded the 2001 Waste Reduction and Pollution Prevention Award from the Solid Waste Association of North America. We also received the 2001 Program Champion Award from the Environmental Protection Agency's Wastewise Program. The Florida Department of Environmental Protection named FPL a "Partner for Ecosystem Protection" for our emission-reducing "repowering" projects at our Fort Myers and Sanford Plants. In addition, FPL has been recognized by numerous federal and state agencies for our innovative endangered species programs which include such species as manatees, crocodiles, and sea turtles.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Statement in 1992 to clearly define the Company's position. This statement reflects how FPL incorporates environmental values into all aspects of the Company's activities and serves as a framework for new environmental initiatives throughout the Company. The FPL environmental statement further establishes a long-term direction of environmental initiatives throughout the Company. FPL's Environmental Statement is:

> It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:
>
> - Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
> - Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
> - Encourage the wise use of energy to minimize the impact on the environment.
> - Communicate effectively on environmental issues.
> - Conduct periodic self-evaluations, report performance, and take appropriate actions.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an environmental management system to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program that is discussed below. Other components include: executive management support and commitment, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident/emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to evaluate environmental performance, verify compliance with Company policy as well as with legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to: facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and Company policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2002 environmental outreach activities are noted in Table IV.E.1.

Activity	***# of Participants***
Visitors to Energy Encounter	19,000
Visitors to Manatee Park	150,000
Number of "visits" to FPL's Environmental Website	80,000
Number of pieces of Environmental literature distributed	>100,000

Table IV.E.1

(All numbers are approximations.)

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified preferred and potential sites for future generation additions. These preferred and potential sites are discussed in separate sections below.

IV.F.1 Preferred Sites

FPL identifies four preferred sites in this Site Plan: the existing Fort Myers plant site, the existing Sanford plant site, the existing Martin plant site, and the existing Manatee plant site. These four sites are the locations for capacity additions that FPL is committed to make during the 2003-2005 period.

The four preferred sites are discussed below.

Preferred Site # 1: Fort Myers Plant, Lee County

The site is located on the 460-acre Fort Myers property. A repowering project has recently been completed at this facility. Six combustion turbines (CT's) were added that, along with heat recovery steam generating (HRSG) units and the existing steam turbines, comprise the main portion of the repowered facility. These units were completed and began commercial operation on natural gas in May 2002. Approximately 929 MW of incremental Summer capacity and 1,073 MW of incremental Winter capacity was added through the repowering. An existing bank of 12 simple cycle combustion turbine peaking units is also located at the site.

Two additional peaking simple cycle combustion turbines are under construction and are expected to begin commercial service in mid-2003. These peaking combustion turbines have dual fuel capability and are able to operate on either natural gas or distillate oil. These combustion turbines will add an additional 298 MW of Summer capability and 366 MW of Winter capability to the site.

The output capability of the existing bank of 12 CT's and the repowered unit at the site will be unaffected by the addition of the two new CT's.

The site has direct access to a four-lane highway, State Road (SR) 80, and barge access is available. The nearest town is Tice which is approximately 8 miles west of the site. The Fort Myers site has been listed as a potential or preferred site in previous FPL Site Plans.

a and b. U.S. Geological Survey (USGS) Map and Proposed Facilities Layout Map

A USGS map of the Fort Myers plant site, plus a map of the general layout of the proposed generating facilities at the site, is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter. It is pertinent to note that several designations on the current South Florida Water Management District Florida Land Use, Cover, and Forms

Classification System (FLUCCS) appear to be in error or to require some clarification. For example, the freshwater marsh identified toward the western boundary of the site is actually FPL's 50-acre evaporation/percolation pond. Similarly, while there are scattered mangroves along the shore, the "Central Mangrove" area shown is not mangrove but is the FPL switchyard for that site. The "Improved Pasture" shown towards the east of the site is currently the location of a tree nursery.

d. <u>Existing Land Uses of Site and Adjacent Areas</u>

The land on the site is primarily dedicated to industrial use with surrounding grassy and landscaped areas. There is the previously mentioned 50-acre evaporation/percolation pond on the site. Much of the site has been recently used for direct construction activities.

FPL has recently donated an 18-acre island, located north of the plant in the Caloosahatchee River, to the United States Fish & Wildlife Service (USFWS) for the purpose of wildlife conservation. This island has been owned by FPL since the 1950's, but has never been developed. The USFWS has incorporated the island into the Caloosahatchee National Wildlife Refuge.

Lee County operates Manatee Park, (approximately 5 acres) with a manatee viewing area on FPL property to the east side of the discharge canal where it adjoins the Orange River south of SR 80. This manatee viewing area provides public viewing and education about the species.

The adjacent land uses are light commercial and retail to the east of the property and some residential areas located toward the west. Mixed scrub with some hardwoods and wetlands, plus agriculture land, can be found to the east and further to the south. The Caloosahatchee National Wildlife Refuge is located across the Caloosahatchee River, northwest of the power plant.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

The site is adjacent to the south bank of the Caloosahatchee River near the confluence of the Orange River and the Caloosahatchee. Much of the site is no longer in its original natural condition. However, a scattering of mangroves can be found along the river shoreline. Some mixed scrub with some hardwoods and wetlands can be found to the east and further to the south. Other than the occasional congregation of manatees noted below, FPL is not aware of any significant environmental features on the site or in the vicinity.

2. Listed Species

The construction and operation of the new CT's at the site is not expected to affect any rare, endangered, or threatened species. The only known listed species associated with the site are the West Indian Manatees (Trichechus manatees: Federal - and State - listed as endangered) which are attracted to the warmed waters in the vicinity of the site discharge and can be found congregating in the area during cool weather.

The Florida Natural Areas Inventory (FNAI) reports the presence of the Eastern Indigo Snake (Drymarchons corais couperi: Federal - and State - listed as Threatened) and Tricolored Heron (Egretta triccolor: State - listed as a Species of Special Concern) within a two-mile radius of the site.

3. Natural Resources of Regional Significance Status

No Natural Resource of Regional Significance is identified on the plant site in the Southwest Florida Regional Strategic Policy Plan.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option currently being pursued for the Fort Myers site is the addition of two stand-alone CT's. This new generation equipment will be installed on the existing facility property and will make effective use of existing transmission facilities and infrastructure although some substation and transmission line upgrades were required.

Mitigation options that have been incorporated include the use of combustion technology that is inherently low in air pollutant emissions.

g. Local Government Future Land Use Designations

The Local Government Future Land Use Plan designates the major portion of the site as Public Facilities and a small area as Resource Protection. Since there are no significant environmental resources on the site, and the "Resource Protection" designated area appears to be the location of a current tree nursery, FPL believes that this designation is in error.

h. Site Selection Criteria and Process

The Fort Myers plant has been selected as a preferred site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All of these sites are considered ideally suitable for future expansion.

i. Water Resources

The available surface water source is the Caloosahatchee River and the available groundwater source is the sandstone aquifer.

j. Geological Features of Site and Adjacent Areas

The geology underlying the Fort Myers Plant consists of Quaternary Holocene and Pleistocene undifferentiated materials. The upper part of these undifferentiated materials consists of fine-to-medium grained quartz sand with varying percentages of shell and clay. Hardpan frequently occurs at the base of the quartz sands. The lower section consists of shell beds with interbedded limestone. Underlying the undifferentiated materials are the Pliocene Tamiami formations, the Miocene Hawthorn formation, Oligocene Suwanee Limestone, the Eocene Crystal River and Williston formations, the Avon Park Limestone, and the Lake City Limestone.

Several stratigraphic units can be differentiated based upon shallow borings drilled on the plant property. Sand with some heterogeneous fill material related to past site construction activity covers most of the surface. It is underlain by layers of clayey sand and clay to a depth of approximately 23 feet. These units mantle a thicker clay unit with numerous shell fragments that occurs from 15 feet to about 55 feet below the surface. A silty sand with a trace of clay was encountered at 55 feet near the termination depth of one deep boring on the site.

The water table at the site occurs at levels from just under the surface to about 5 feet below grade. Locally, the surficial aquifer and surface water will generally flow toward the Caloosahatchee River. However, at the site, the intake and discharge canal will affect groundwater near the power block area. A drainage canal that borders the plant property on the west will affect groundwater flow along the western portion of the waste treatment area.

k. Projected Water Quantities For Various Uses

Facility water uses may include irrigation, potable use, etc. The total volume of these uses is estimated to be about 65 gallons per minute (gpm).

l. Water Supply Source By Type

For industrial processing, FPL anticipates that groundwater will be available. The new CT's will be air-cooled.

m. Water Conservation Strategies Under Consideration

A plan to treat and recycle equipment wash water, boiler blowdown, and equipment area runoff for use as service water would reduce ground water consumption.

n. Water Discharges and Pollution Control

Heated water discharge for the plant site as a whole will be dissipated using both the existing once-through cooling water system and a multi-cell-helper-cooling tower which will be used during the warmer months. Storm water runoff will be collected and used to recharge the surficial aquifer via a storm water management system. Design elements will be included to capture suspended sediments. Various facility permits mandate various sampling and testing activities which will provide an indication of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasures (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The combustion turbine-based repowering project, plus the addition of the two new CT's, required a natural gas pipeline to be installed. Florida Gas Transmission completed the permitting process and installed and operates the pipeline that serves the Fort Myers Plant. Virtually no solid waste is associated with natural gas firing.

p. Air Emissions and Control Systems

The natural gas-fired facilities at the plant site generally have air pollutant emissions that are substantially lower than emissions from the former oil-fired boilers. While several technologies are available for nitrogen oxide (NO_x) emissions control, FPL is using a dry-low-NO_x combustion turbine design. In these devices, combustion is staged in order to reduce the formation of combustion-derived oxides of nitrogen. FPL has committed to NO_x emission limits for this facility that will be among the lowest in the state. Sulfur dioxide and particulate emissions are intrinsically low due to the lack of sulfur and solids in natural gas fuel. Carbon monoxide and volatile organic compound emissions can each be controlled via the use of efficient combustion rather than through the use of add-on control devices. CT facilities have been permitted at several locations throughout the state of Florida including near Class I areas. Dry-low-NO_x combustor systems have been repeatedly demonstrated to be the Best Available Control Technology (BACT) for the control of NO_x emissions for this technology pursuant to the requirements of the Clean Air Act.

q. **Noise Emissions and Control Systems**

Lee County has a noise ordinance that limits noise at receiving property lines of residential, public space, agricultural, or institutional to 66 decibels in the daytime and 55 decibels at night. FPL will undertake studies to assure that noise level associated with the new CT's comply with the Lee County noise standard.

r. **Status of Applications**

FPL acquired all permits needed to commence construction. Modifications to operating permits were requested in 2002 and will continue to be pursued as necessary through 2003.

Preferred Site # 2: Sanford Plant, Volusia County

The site is located on the 1,718-acre FPL Sanford property just west of Lake Monroe on the north bank of St. Johns River in Volusia County. Current facilities on the site include one steam electric generating unit with a nominal rating of 138 MW and a recently repowered natural gas-fired unit with a nominal rating of 910 MW. One other existing unit, Unit # 4, has been shut down and is in the process of being repowered using combined cycle technology. The site is within the city limits of Debary, and the community of Debary is located approximately 2 miles to the northwest. The town of Deland is approximately 4 miles west of the site. The site has direct access to a four-lane highway, State Road (SR) 17-92, and barge access is available. The Sanford site has been listed as a potential or preferred site in previous FPL Site Plans.

As mentioned above, FPL is in the process of adding new capacity at the Sanford site by replacing one existing oil-and gas-fired unit (i.e., existing Unit # 4) with advanced natural gas fired combustion turbines (CT's) and heat recovery steam generators (HRSG's). This type of steam generation replacement is commonly called repowering.

This repowering will enable FPL to produce significantly more electrical output with nearly the same environmental impact. The repowering of Unit # 4 will produce approximately 567 additional MW during Summer conditions, and approximately 652 additional MW of generation during Winter conditions, beyond the current capabilities of this unit. The existing 138 MW Unit # 3 and the recently repowered Unit # 5 will be unaffected by the repowering of Unit # 4.

a. and b. <u>U.S. Geological Survey (USGS) Map and Proposed Facilities Layout Map</u>

A USGS map of the Sanford plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. <u>Map of Site and Adjacent Areas</u>

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. <u>Existing Land Uses of Site and Adjacent Areas</u>

A large part of the property is covered by the 1,100-acre closed cycle cooling pond that occupies almost the entire northern portion of the site. The remainder of the site is primarily rangeland and the power plant facilities.

The surrounding land use is largely crop land and pasture. To the east of the plant there is a small residential area and some commercial/industrial land use. There are some residential areas mixed in with the agricultural areas located between the site and the St. Johns River to the west. To the south is the St. Johns River. Residential homes and commercial/industrial businesses are located along the south side of the river.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

Small, scattered wooded areas can be found on the site. There are two small areas of wetland marsh on the site and a few acres of wetland forest along the riverbank. There are some wooded areas on the site, primarily upland coniferous forest. Forested and non-forested wetlands can be found to the west, adjacent to the river. River and wetland areas towards the northwest are designated as part of the Wekiwa River Aquatic Preserve and Wekiwa River State Preserve.

2. Listed Species

One inactive bald eagle (Haliaeetus leucocephalus: Federal - and State - listed as Threatened) nest has been found on the site. Bald eagles have also nested in the Lake Monroe area. There are a number of other eagles nests in the vicinity of the site, primarily the St. Johns River. The Florida Natural Areas Inventory (FNAI) reports several Scrub Jay populations (Aphelocoma coerulescens: Federal - and State - listed as Threatened) located in scrub vegetation to the northwest of the site. West Indian Manatees (Trichechus manatus: Federal - and State - listed as Endangered) have also been found in this area.

3. Natural Resources of Regional Significance Status

The Wekiwa River Aquatic Preserve extends along the St. John's River in the vicinity of the plant.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option for the Sanford Site is the repowering of one existing oil - and gas - fired boiler with natural gas fired combustion turbines (CT's) and heat recovery steam generators (HRSG's). Steam produced in the new HRSG's is directed to the existing steam turbine. Natural gas - fired facilities represent one of the cleanest, most efficient technologies currently available for capacity additions to FPL's system.

g. Local Governmental Future Land Use Designations

The site is designated as "Industrial Utilities" in the Local Government land use plan. The city is currently updating its Land Use Plan. It is expected that the name, but not the expected use designation, may change. Land use designation of the surrounding area is primarily Agricultural. There is an area of "Public Institution" around Lake Monroe to the southeast and a small area of "Mixed Use" to the west along Barwick Road.

h. Site Selection Criteria and Process

The Sanford plant has been selected as a preferred site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All are considered permittable.

i. Water Resources

For surface water supply, the available water resource is the St. John's River and/or the on-site cooling pond, which is periodically refilled from the St. John's River. For ground water supply, the available resources are the shallow aquifer or the Floridan Aquifer.

j. Geological Features of Site and Adjacent Areas

The near-surface geology of Volusia County within the St. John's River Valley, like that of most of north central Florida, is represented by late Tertiary and Quaternary geological units. Soils in the vicinity of the plant include unconsolidated Pleistocene to Recent sands, with intervening beds of shells and clay. These deposits from the reservoir for the surficial aquifer in the county. One of the two major structural features in the area is the Peninsula Arch that forms the backbone of the Florida Platform. The arch trends south-southeast and extends from southeast Georgia through Florida into the Great Bahamas. The geological material can be divided into an upper sequence of unconsolidated or poorly consolidated clastic sediments and a lower sequence of limestone rocks. These lower formations are part of the principle hydrologic unit referred to as the Floridan Aquifer. This aquifer, the top of which generally occurs through the region at or below 100 feet, is the major source of potable groundwater in Volusia County. Two faults, one trending north-to-south, the other trending east-to-west, intersect a number of miles north of the site. Downward displacement of the fault is hypothesized as being approximately 60 to 100 feet. The upper clastic region ranges in age from Miocene to Recent and is mostly sand but also contains discontinuous and interfingering lenses and beds of clay and silt.

k. Projected Water Quantities for Various Uses

FPL has estimated that 150 gallons per minute (gpm) is required for industrial processing purposes (boiler makeup, service water, etc.). Note that Unit # 4 currently takes its cooling water directly from an on-site FPL cooling pond and will continue to do so after repowering is completed. The cooling water needs for both of the repowered facilities (i.e., Unit # 4 and Unit # 5) will represent an increase over previous cooling water needs due primarily to the increased heat loading to the cooling pond that results from operating the larger repowered units more than they have been operated in the past and corresponding evaporative losses. Therefore, greater quantities of water will be used. Existing Unit # 3 will continue to use water from the St. John's River in a once-through cooling mode.

FPL evaluated alternative sources of water to meet the expected needs of the site. The existing off-site wells and the existing once - through cooling water system and cooling pond will continue to be used after the repowering project is completed, albeit the use of groundwater will decrease significantly from past usage.

l. Water Supply Sources by Type

The available surface water supply source is the St. John's River. The Floridan Aquifer is an available groundwater source for service water and boiler water.

m. Water Conservation Strategies Under Consideration

In 2000 FPL obtained a revised Consumptive Use permit from the St. John's Water Management District. This permit reduced the quantity of water that FPL has historically been permitted to withdraw from the ground in favor of additional use of surface water.

n. Water Discharges and Pollution Control

Heated water discharges will be dissipated using the existing once - through cooling water system of the existing cooling pond for repowered Unit # 4. Non-point source discharges are collected and reused. Treating and recycling equipment wash water, boiler blow-down, and equipment area runoff helps to minimize industrial discharges. Storm water runoff is collected and used to recharge the surficial aquifer via a stormwater management system. Design elements have been included to capture suspended sediments. Various facility permits mandate sampling and testing activities which provide indications of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The repowered facilities at the Sanford site required a larger natural gas pipeline to be installed. FPL contracted with Florida Gas Transmission Company (FGT) to permit, install, and operate this facility which is now fully operational. Virtually no waste is associated with natural gas firing.

p. Air Emissions and Control Systems

A natural gas-fired facility generally has air pollutant emissions that are substantially lower than emissions from the prior oil-fired boilers. While several technologies are available for nitrogen oxide (NO_x) emissions control, the chosen technology for the Sanford site is a dry low NO_x combustion turbine design type. In these types of devices, combustion is staged in order to reduce the formation of combustion-derived oxides of nitrogen. Sulfur dioxide and particulate emissions are intrinsically low due to the lack of sulfur and solids in natural gas fuel. Carbon monoxide and volatile organic compound emissions can each be controlled via the use of efficient combustion rather than through the use of add-on control devices. CC and CT facilities have been permitted at several locations throughout the state of Florida. Dry-low-NOx combustor systems have been repeatedly demonstrated to be the Best Available Control Technology (BACT) for the control of NO_x emissions for this technology pursuant to the requirements of the Clean Air Act.

q. Noise Emissions and Control Systems

Noise emissions from the project are not significantly different from current levels at the plant prior to repowering. FPL installed appropriate sound attenuation devices including insulation on high energy piping systems in order to ensure that sound levels do not exceed allowable levels. Similar natural gas-fired facilities (the Lauderdale plant in Broward County, the Fort Myers plant in Lee County, and the Martin plant in Martin County) have been constructed and operated without exceeding allowable noise levels.

r. Status of Applications

FPL acquired all permits needed to commence construction. Modifications to operating permits were requested in 2002 and will continue to be pursued as necessary through 2003.

Preferred Site # 3: Manatee Plant, Manatee County

The site is located in unincorporated north central Manatee County approximately 2.5 miles south of the Hillsborough-Manatee County line. It is 5 miles east of Parrish, Florida and is approximately 5 miles east of U.S. Highway 301 and 9.5 miles east of Interstate 75 (I-75). State Road (SR) 62 is about 0.5 miles south of the site. Saffold Road marks the eastern boundary of the site.

FPL's Manatee Plant occupies a portion of the approximately 9,500 acre Manatee Site which is owned wholly by FPL. The site includes a 4,000-acre cooling pond including the dike area. The existing approximately 1,620 MW (Summer) of generating capacity is made up of two steam units (Units # 1 and # 2) which have been in service since 1976 (Unit # 1) and 1977 (Unit # 2). These units burn both fuel oil (residual) with a maximum sulfur content of 1 percent and natural gas. Natural gas may be fired singly or in combination with fuel oil. A recent agreement between FPL and Gulfstream Natural Gas Systems (Gulfstream) will provide two natural gas sources for these units.

Pending final approval by the Governor and Cabinet, additional generating capacity will be added to the site in 2005 to meet projected FPL system capacity needs. Four new combustion turbines (CT's), four new heat recovery steam generators (HRSG's), and a new steam turbine generator are scheduled for in - service operation beginning in June, 2005. The four new CT's, HRSG's and steam turbine will ultimately be operating in combined cycle (CC) configuration. This new CC unit will add 1,107 MW (Summer) and 1,201 MW (Winter) capability to the site. This new CC Unit will be designated as "Manatee Unit # 3".

Unit # 3 will be located west of the existing generating Units # 1 and # 2. The location of the new combined cycle Unit # 3 at the Manatee Plant site and the selection of the highly efficient combined cycle technology (firing clean natural gas) will maximize the beneficial use of the site while minimizing environmental and land use impacts otherwise associated with the development of a new generating plant of this capacity. The Manatee site has been previously listed as a preferred or potential site in previous FPL Site Plans.

a. and b. Map of the Manatee Plant Site and Land Use

A map indicating the Manatee plant site showing the general layout of the facilities and a map indicating the land use of the site are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a 4,000 acre cooling pond. Manatee Units # 1 and # 2 will not be affected by the addition of Unit # 3. The area for Unit # 3 is expected to comprise approximately 73 acres. The site and surrounding land uses are almost exclusively agriculture with the exception of the Willow Shores residential area located northwest of the Manatee Plant site. Individual homes are located in the larger of two out parcels within the Manatee Plant site along SR 62 at the northeast corner of the site. The vast majority of the Manatee Plant site has been redesignated from Agricultural/Rural to Major Public/Semi Public (1) (P/SP) land use category by the Manatee County Commission on November 19, 2002 with the approval of Ordinance 02-13. Electric generating plants are specifically allowed in the P/SP category in accordance with the Manatee County Local Government Comprehensive Plan and Land Development Regulation Act, Chapter 163, Part II, Florida Statutes (FS).

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

There are no incorporated areas within 5 miles of the Manatee Plant site. Unincorporated communities in the area include Willow, located about 2 miles north of the Manatee Plant; Parrish, located about 5 miles southwest of the plant; and, in Hillsborough County, Sundance, located 3 miles northwest of the plant; Sun City Center, located 7 miles north of the plant; and Wimauma, located 8 miles northeast of the plant.

The Manatee Plant site includes areas of improved pasture with forested land southeast of the project area. This forested area is comprised of flat woods and oak habitat. The western side of the Manatee Plant site is currently used for row crops (tomato farm). There are also wetlands to the southeast containing wet pine flat woods mixed with dry pine flat woods. There will not be any disturbance of existing wetlands associated with this project.

2. Listed Species

Construction and operation of the new Unit # 3 at the site is not expected to affect any rare, endangered, or threatened species. The majority of the site is cleared, grassed, and periodically mowed. The project area has been significantly altered by the construction and operation of the existing plant facilities, and, as a result, wildlife utilization of this area is expected to be minimal. Common wading birds utilizing the plant site outside of the project area include the great blue heron, little blue heron, great egret, snowy egret, and the white ibis. Typical mammals found in the habitats surrounding the project area are common bobcat, raccoon, deer, ferel hog, opossum, armadillo, skunk and gray squirrel. Avian species observed in the vicinity of the project include bald eagles, a variety of songbirds, red-shouldered hawks, and marsh hawks.

3. Natural Resources of Regional Significance Status

There are no county, State or Federally designated areas located within one mile of the plant site. The construction and operation of Manatee Unit # 3 is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands that are associated with the Little Manatee River within a 5-mile radius of the project site. These lands include: Little Manatee River State Recreation Area, Little Manatee River State Canoe Trail, Florida Gulf Coast Railroad Museum, Cockroach Bay Aquatic Preserve, Critical

Manatee Habitat, South Hillsborough Wildlife Corridor, Hillsborough County ELAPP Parcels, and SOR-Little Manatee River.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option, Manatee Unit # 3, is the addition of four new combustion turbines and HRSG's and one new steam turbine generator in combined cycle mode in a 4x1 configuration. Manatee Unit # 3 is scheduled to begin operation in mid – 2005. Natural gas, delivered via pipeline, will be the sole fuel for this unit.

Mitigation options being planned for Manatee Unit # 3 include the capture and reuse of plant process water and rainwater. In addition, other mitigating options include the use of combustion technology that is very efficient and low in air pollutant emissions, combined with pollution control technology (dry-low NO_x burners and selected catalytic reduction equipment).

g. Local Government Future Land Use Designations

As mentioned above, the Local Government Future Land Use Plan is consistent with the existing Designated uses of the Manatee Plant Site as major portions of the site are designated as Major Public/Semi Public (1) – P/PS/. Electric generating plants are specifically allowed in this land use category.

h. Site Selection Criteria and Process

The Manatee site has been selected as a preferred site due to consideration of various factors including system load and economics. Also, the at – the – time projected availability of a natural gas pipeline that will be available to Unit # 3 (as well as Units # 1 and # 2) in the near future was also a major factor in the selection of the Manatee site for the new 4x1 CC unit. Environmental issues were not a deciding factor since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All of these sites are considered permittable.

i. Water Resources

The available surface water source is the Little Manatee River which supplies makeup water for the 4,000-acre cooling pond. Plant process and service water requirements are currently supplied by the cooling pond. There are three wells in the Floridan Aquifer that are reserved for standby purposes.

j. Geological Features of Site and Adjacent Areas

Manatee County has three physiographic provinces: the Gulf Coast Lowlands, the DeSoto Plains, and the Polk Upland. The Manatee Plant is situated on the boundary of the DeSoto Plains and the Gulf Coast Lowland provinces. The geology underlying the Manatee Plant consists of unconsolidated sediments comprised of sand, clay silt, marl shell, limestone, and phosphorite (terrace deposits) from the Pleistocene age to recent. Undifferentiated deposits comprised of sand and clay are generally described to be less than 25 feet thick. Underlying the differentiated materials are the Miocene Hawthorn Formation, the Tampa Member, the Suwanee Limestone of the Oligocene age, the Ocala Limestone of the Eocene Age, the Avon Park Formation, the Oldsmar Formation of the Eocene age, and the Cedar Key Formation of the Paleocene age.

The major hydrogeologic units that exist in the vicinity of the site include, in descending order: the surficial aquifer system, the intermediate aquifer system, and the Upper Floridian aquifer. The surficial aquifer system is generally unconfined in Manatee County and consists of Quarternary deposits of predominately marine and nonmarine quartz sand, clayey sand, shell, shelly marl, phosphorite, and occasional stringersmarl and limestone. In the vicinity of the site the surficial sediments are approximately 25 feet thick.

k. Projected Water Quantities for Various Uses

The estimated additional quantity of water for industrial processing is estimated to be 150 gpm (gallons per minute) plant process and service water.

FPL operates on-site water treatment systems for each of these uses. Water quantities for other uses such as irrigation and potable water are estimated to be approximately 5 gpm.

l. Water Supply Sources by Type

Manatee Unit # 3 will utilize the existing on-site cooling pond as its source of cooling water. The cooling pond operates as a “closed cycle” system; any makeup water is provided from the Little Manatee River to replace net evaporation and seepage losses from the pond. These makeup needs are within the existing agreement between FPL and the Southwest Florida Water Management District (SWFWMD). There are three wells currently on reserve (stand-by) that are in the Floridan Aquifer. FPL is currently evaluating alternative water sources for use at the Manatee Plant site.

m. Water Conservation Strategies Under Consideration

Available water including non-contact storm water, treated industrial wastewater, treated sanitary wastewater, and recovered service water are captured and returned to the cooling pond. Storm water from the equipment areas is also treated and returned to the cooling pond.

n. Water Discharges and Pollution Control

The Manatee Plant utilizes a Best Management Practices (BMP) plan, Spill Prevention, Control, and Countermeasure (SPCC) plan to assist in the control of inadvertent release of pollutants. Storm water runoff will be collected and routed to detention ponds. Construction activities will be managed so that equipment maintenance and fueling are performed in designated areas so that, in the event of a spill or release of any contaminant, impacts to any surface water or the cooling pond are minimized.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by fuel delivery services and facilities for residual, low sulfur (1 percent) fuel oil and, most recently, natural gas as an alternate fuel for existing Units # 1 and # 2. The Unit # 3 addition will be solely fueled by natural gas that could be supplied by either Gulfstream or FGT as previously discussed.

p. **Air Emissions and Control Systems**

The addition of natural gas as a permitted fuel for existing Units # 1 and # 2 is expected to lower overall emissions during periods when natural gas, instead of fuel oil, is used. In addition, a NO_x reduction technology, reburn, has been approved for installation on Units # 1 and # 2 within the next several years.

The use of clean fuels and combustion controls will minimize air emissions from Unit # 3 and ensure compliance with applicable emission limiting standards. Using clean fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of carbon monoxide and volatile organic compounds. NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Manatee Unit # 3 will incorporate features that will make it one of the most efficient and cleanest power plants in the State of Florida.

q. **Noise Emissions and Control Systems**

Noise emissions from the project are not anticipated to be significantly different from the current levels at the existing plant. Similar natural gas-fired facilities in Broward and Martin Counties have been constructed and operated without exceeding allowable noise levels.

r. **Status of Applications**

FPL filed the Site Certification Application (SCA) for the Manatee Plant Unit # 3 with the Florida Department of Environmental Protection (FDEP) on February 20, 2002 and received a positive recommendation from the Administrative Law Judge (ALJ) for the project on February 19, 2003.

Preferred Site # 4: Martin Plant, Martin County

The Martin site is located approximately 40 miles northwest of West Palm Beach, 5 miles east of Lake Okeechobee, and 7 miles northwest of Indiantown in Martin County, Florida. The site is bounded on the west by the Florida East Coast Railway (FEC) and the adjacent South Florida Water Management District (SFWMD) L-65 Canal, on the south by the St. Lucie Canal (C-44 or Okeechobee Waterway), and on the northeast by SR 710 and the adjacent CSX Railroad. The Martin site was identified in 1987 as a preferred location for development of coal gasification/combined cycle electric generation facilities and subsequent FPL Site Plans have continued to identify this site as a preferred site.

The existing 2,850 MW (Summer) of generating capacity at FPL's Martin site occupies a portion of the approximately 11,300 acres that are wholly owned by FPL. The generating capacity is made up of two steam units (Units # 1 and # 2), plus two combined cycle units (Units # 3 and # 4), and two combustion turbine units (Units # 8a and # 8b). The site includes a 6,800-acre cooling pond (6,500 acres of water surface and 300 acres of dike area) and approximately 300 acres for the existing power plant units and related facilities.

Additional generating capacity was added to the site in 2001 in the form of two combustion turbines (CT's) that operate in simple cycle mode using natural gas. Pending final project approval by the Governor and Cabinet, these two CT's will be converted into a four-on-one (4X1) combined cycle (CC) unit with the addition of two new CTs, four new Heat Recovery Steam Generators (HRSGs), and a new steam turbine generator. The resulting CC unit will be known as Martin Unit # 8. It is estimated to be in service in mid-2005 adding approximately 800 MW of capacity.

a. and b. U.S. Geological Survey (USGS) Map and Proposed Facilities Layout

A USGS map of the Martin plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a 6,800-acre cooling pond. The existing power plant facilities are located on approximately 300 acres. To the east of the power plant there is an area of mixed pine flat wood with a scattering of small wetlands. To the north of the cooling pond there is a 1,200-acre area which has been set aside as a mitigation area. There is a peninsula of wetland forest on the West Side of the reservoir, that is named the Barley Barber Swamp. The Barley Barber Swap encompasses 400 acres and is preserved as a natural area. There is also a 10-kilowatt (kW) photovoltaic energy facility at the south end of this site.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

As noted above, the Barley Barber Swamp is located on the site. There is also a 1,200-acre mitigation area in the northern area of the site where wetlands and uplands have been restored. Along the south and west sides of the cooling pond is an area where the vegetation has been maintained in its natural state in order to serve as a wildlife corridor. There are pine flat woods and small-scattered wetlands to the east of the plant.

2. Listed Species

Construction and operation of a new unit at the site is not expected to affect any rare, endangered, or threatened species. There are two active Bald Eagle (*Haliaeetus leucocephalus*: Federal - and State - listed as Threatened) nests that have been on the site for many years. The Florida Natural Areas Inventory (FNAI) database notes a record of Eastern Indigo Snakes (*Drymachon coralis coupert*, which are Federal - and State - listed as threatened) in the Barley Barber Swamp. A number of other Bald Eagle nests and sightings of Eastern Indigo Snakes are reported by the FNAI database within a two-mile radius of the site. Infrequent sightings of Florida Panther have been made in the vicinity of the site area.

3. **Natural Resources of Regional Significance Status**

The Treasure Coast Regional Planning Council lists the "FPL Preserve", including the Barley Barber Swamp, as a Significant Regional Facility. Natural communities such as uplands and wetlands are also generically listed as Resources of Regional Significance.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design option is to add two new CT's and four new HRSG's and a new steam turbine that, together with the two existing CT's, will comprise Martin Unit # 8. This unit is scheduled to be in-service in mid-2005. Natural gas delivered via pipeline is the primary fuel type for this unit (with light oil serving as a backup fuel). Natural gas-fired facilities are among the cleanest, most efficient technologies currently available.

Mitigation options being considered include the capture and reuse of plant process water and rainwater, plus the use of cooling towers. The facility already encompasses several preserved areas where wildlife is abundant.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the site is "Public Utilities". Designations for the surrounding area are primarily "Agricultural". There are also limited areas of "Agricultural Ranchette", "Industrial", and a small "Commercial" area designation. To the southeast of the property, fronting on the St. Lucie Canal, is an area designated for "Public Conservation".

h. Site Selection Criteria Process

The Martin plant has been selected as a preferred site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All of these sites are considered permittable.

i. Water Resources

Surface water resources currently used at the Martin facility include the cooling pond which takes its water from the St. Lucie canal. The available ground water resource is the surficial aquifer system which is used as a source of potable water and for service water for Units # 1 and # 2. Both of these sources are available for use with the site expansion.

j. Geological Features of Site and Adjacent Areas

FPL's Martin site is underlain by approximately 13,000 feet of sedimentary rock strata. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine bin origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, or clay. The deepest formation in Martin County on which significant published data are available is the Eocene Age Avon Park. Limited information is available from wells penetrating the underlying Lake City formation. The published information on the sediments comprising the formations below the Avon Park Limestone in western Martin County is based on projections from deep wells in Okeechobee, St. Lucie, and Palm Beach Counties.

k. Projected Water Quantities for Various Uses

The estimated additional quantity of water required for industrial processing is 130 gallons per minute (gpm) for uses such as boiler water and service water.

FPL operates on-site water treatment systems for each of these uses. Cooling water for new Unit # 8 will be supplied by the addition of cooling towers. The two existing CT's that will be converted into combined cycle operation are currently air-cooled. Makeup water for the pond is taken from the St. Lucie canal. The current makeup water quantity to the cooling pond (approximately 4,800 gpm) is expected to be adequate for the proposed expansion. Water quantities needed for other uses such as irrigation and potable water are estimated to be approximately 5 gpm.

l. Water Supply Sources by Type

Martin Unit # 8 will utilize the existing on-site cooling pond as the source of cooling water for the cooling towers and as a heat sink for the dissipation of cooling water heat. The cooling pond operates as a "closed cycle" system in which heated water from the generating unit loses its heat as it is circulated within the pond and back around to the plant intake. Water is also collected in a seepage ditch surrounding the cooling pond and is then pumped back into the cooling pond. Makeup water to the pond is withdrawn from the St. Lucie canal as needed to replace net evaporation and seepage losses from the pond. Such needs will comply with the existing agreement between FPL and the South Florida Water Management District (SFWMD) regarding allocation of cooling water to the pond and with SFWMD's regulations for consumptive water use.

The existing water treatment system at the plant, which provides treated water for use in the Unit # 1 and # 2 boilers, as well as for the HRSG's associated with Units # 3 and # 4, will be used to provide treated water for Unit # 8.

m. Water Conservation Strategies Under Consideration

Impacts on the surficial aquifer will be reduced by changing the source of plant process water to the Floridan Aquifer upon completion of Unit # 8. In addition, the entire plant site captures and reuses process water whenever feasible and manages stormwater in such a manner so as to recharge the surficial aquifer.

n. Water Discharges and Pollution Control

Heated water discharges will be dissipated in the cooling pond. Non-point source discharges are not an issue since there are none at this facility. Industrial discharges will be minimized by treating and recycling equipment wash water, boiler blowdown water, and equipment area runoff. Storm water runoff is collected and used to recharge the surficial aquifer via a storm water management system. Design elements have been included to capture suspended sediments. Facility permits mandate various sampling and testing activities that provide indications of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by multiple fuel delivery facilities. However, the addition of new Unit # 8 will require an enlargement of the existing natural gas pipelines, the installation of a new pipeline, or the addition of another pipeline compressor station. There are currently two natural gas supply lines into the facility, as well as an oil pipeline, which serve the existing steam boilers and combined cycle generating units. Distillate fuel oil is also received by truck and stored in above ground storage tanks. The existing natural gas line also serves CT Units # 8a and # 8b.

p. Air Emissions and Control Systems

FPL's plan for Unit # 8 is subject to "New Source Review" under Federal and State Prevention of Significant Deterioration (PSD) regulations. This review requires these units to meet New Source Performance Standards (NSPS) and that Best Available Control Technology (BACT) be selected to control emissions of those pollutants emitted in excess of applicable PSD significant emission rates. The primary purpose of BACT analysis is to minimize the allowable increases in air pollutants taking into account energy, environmental, and economic impacts. This process provides for the potential for future economic growth without significantly degrading air quality.

q. **Noise Emissions and Control Systems**

A field survey and impact assessment of noise expected to be caused by unit construction at the site indicated that construction noise would be below current noise levels for the residents nearest the site. Noise from the operation of the new unit will also be within allowable levels.

r. **Status of Applications**

A Site Certification Application (SCA) was filed in December, 1989, for the construction and operation of the Martin Coal Gasification/Combined Cycle project under the Florida Electrical Power Plant Siting Act.

On June 15, 1990, the Public Service Commission issued a Determination of Need Order for proposed Martin Units # 3 and # 4. This determination of need applied to the additional 832 MW of combined cycle generation. The Siting Board issued a Land Use Order on June 27, 1990. The Certification Hearing was held on November 5-7, 1990. On February 12, 1991, the Governor and Cabinet, serving as the Siting Board, approved the construction and operation of natural gas-fired combined cycle Units # 3 and # 4 and determined that the Martin Site has capacity to accommodate additional combined cycle units fueled by natural gas or fuel oil.

Since the initial certification in 1991, the certification was modified five times through 1999 to provide authorization for items such as CT testing, increasing the cooling pond elevation, incorporating changes from other permits, and incorporating a custom fuel monitoring program. For the addition of the two simple cycle CT's mentioned above, FPL obtained a sixth modification to the existing site certification in August 2000.

In order to convert these two CT's from simple cycle to (4X1) CC configuration (Unit # 8), a seventh modification to the Site Certification is required. FPL filed the SCA on February 1, 2002 with the Florida Department of Environmental Protection (FDEP). A positive recommendation from the Administrative Law Judge for the project was received in early March of 2003. The certification process is expected to be completed with Governor and Cabinet's final review near the end of May 2003.

IV.F.2 Potential Sites

Five (5) sites are currently identified as potential sites for future generation additions to meet FPL's 2007 – on capacity needs.[2] These sites have been identified as "potential sites" due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies.

Each of these potential sites offers advantages and disadvantages relative to engineering considerations and/or costs associated with the construction and operation of feasible technologies. In addition, each potential site has different characteristics that could require further definition and attention. For purposes of estimating water usage amounts, it is assumed that a natural gas-fired CC unit would be the technology of choice for any capacity additions at the sites.

Permits are presently considered to be obtainable for all of these sites, assuming measures can be taken to mitigate any particular site-specific environmental concerns that may arise. No significant environmental constraints are currently known for any of these five sites. The potential sites briefly discussed below are presented in alphabetical order. At this time FPL considers each site to be equally viable.

Potential Site # 1: Cape Canaveral Plant, Brevard County

This site is located on the FPL Cape Canaveral Plant property in unincorporated Brevard County. The city of Port St. Johns is located less than a mile away. The site has direct access to a four-lane highway (US 1). A rail line is located near the plant. The existing facility consists of two 400 MW (approximate) steam boiler type generating units.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Cape Canaveral property site is found at the end of this chapter.

[2] As has been described in previous FPL Plant Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites.

b. and c. Land Uses and Environmental Features

This site is located on the Indian River. The land is primarily dedicated to industrial use with surrounding grassy areas and a few acres of remnant pine forest. The land adjacent to the site is dedicated to light commercial and residential use. There are no significant environmental features on the site.

d. and e. Water Quantities and Supply Sources

FPL projects that an increase of up to 260 gallons per minute (gpm) would be required for industrial processing use (boiler makeup, service water, etc.) It is expected that industrial cooling water needs could be met using the current 550,000 gpm once-through cooling water quantity. For industrial processing, FPL would use existing on-site wells or local gray water.

Potential Site # 2: Midway Substation Property, St. Lucie County

The site is located on the 122-acre Midway Substation property. Current facilities on the site include an electric substation. The site has direct access to a two-lane highway, State Road (SR) 712 and a nearby entrance to I-95. The City of Port St. Lucie is immediately east and west of the Midway site. The City of Ft. Pierce is approximately 9 miles northeast of the site.

a. U.S. Geological Survey (USGS) Map

A USGS map is provided of the Midway site area is provided at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on the site is currently dedicated to industrial and agricultural use. Much of the site is currently not being used. Developed portions of the adjacent properties are primarily agricultural (orange groves and cattle grazing). Undeveloped portions include mixed scrub with some hardwoods and wetlands.

d. and e. Water Quantities and Supply Sources

No surface water source is available at this site. The water source would either be groundwater from the shallow aquifer or a local source of gray water. It is estimated that 150 gallons per minute (gpm) will be needed for industrial processing water for uses such an inlet air cooling, No_x control during light oil firing and for service water. Other facility water uses may include irrigation, potable use, etc. The total volume of these uses is estimated to be about 5 gpm.

Also, as part of the Everglades Restoration Project, a 500-acre retention pond (Ten Mile Creek Project) is scheduled to be completed near the proposed Midway site in mid-2004. It is possible that some water from this storage facility could be utilized for cooling to supplement ground water usage.

Potential Site # 3: Port Everglades Plant, Broward County

This site is located on the 94-acre FPL Port Everglades plant site in Port Everglades, Broward County. The site has convenient access to State Road (SR) 84 and Interstate 595. A rail line is located near the plant. The existing plant consists of four steam boiler generating units: two 200 MW (approximate) and two 400 MW (approximate) sized units. The four steam boilers are capable of firing residual fuel oil, natural gas, or a combination of both. The site also is home to twelve simple cycle gas turbine (GT) peaking units of 30 MW (approximate) each. The GT's are part of the Gas Turbine Power Park that is made up of 24 GT's at the Lauderdale Plant site and the twelve GTs at the Port Everglades site. The GT's are capable of firing either natural gas or liquid fuel.

a. U.S. Geological Survey (USGS) Map

A map of the Port Everglades plant site is found at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on this site is primarily industrial. The adjacent land uses are port facilities and associated industrial activities, oil storage, cruise ships, and light commercial.

d. and e. Water Resources and Supply Sources

FPL estimates that up to 130 gallons per minute (gpm) of industrial processing water would be required for uses such as boiler makeup, fogger usage, and service water. FPL expects to use the existing municipal water supply for industrial process and makeup water. Cooling water would be drawn from the intercoastal waterway and cooling towers would be constructed.

Potential Site # 4: Riviera Plant, Palm Beach County

This site is located on the FPL Riviera Plant property in Riviera Beach, Palm Beach County. The site has direct access to a four-lane highway, US 1, and barge access is available. A rail line is located near the plant. The facility currently houses two operational 300 MW (approximate) steam boiler generating units and one retired 50 MW generating unit.

a. U.S. Geological Survey

A USGS map of the Riviera plant site is found at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on the site is primarily covered by the existing generation facilities with some open maintained grass areas. There is a small manatee viewing area on the site, which is operated seasonally by FPL. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development. The site is located on the Intracoastal Waterway near the Lake Worth Inlet.

d. and e. Water Quantities and Supply Sources

Additional industrial processing water needs are estimated to be up to 40 gallons per minute (gpm). Industrial cooling water needs are estimated to be up to 54,000 gpm using the existing once-through cooling water system. The existing municipal water supply would be used for industrial processing water if additional generating capacity is placed at Riviera. For once-through cooling water, FPL would continue to use Lake Worth as a source of water.

Potential Site # 5: Turkey Point Plant, Dade County

The Turkey Point Plant site is located on the West Side of Biscayne Bay 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. Access to the plant site is limited due to the nuclear units located there. The land surrounding the site is owned by FPL and acts as a buffer zone. The site is comprised of the nuclear and fossil plants, the cooling canals, an FPL-maintained natural wildlife refuge, and wetlands that have been set aside as an Everglades Mitigation Bank.

Units # 1 and # 2 are fossil fuel generating plants with approximate generating capacity of 400 MW each. Unit 1 was completed in 1967 and Unit # 2 in 1968. Turkey Point also has five diesel peaking units that in total produce approximately 12 MW. These units are primarily used to provide emergency power, but occasionally run during the Summer to provide power during peak load demands.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Turkey Point plant site, is found at the end of this chapter.

b. and c. Land Uses of Site and Environmental Features

A major portion of the site consists of a self-contained cooling canal system that supplies water to condense steam used by the existing units' turbine generators. The canal system consists of 36 interconnected canals each five miles long, 200 feet wide and four feet deep. The remaining developed area of the site is where the two fossil steam generating units and 5 diesel generators are located. Adjacent to the fossil plant are the two nuclear generating units. To the south, wetlands have been set aside as part of the Everglades

Mitigation Bank in an effort to restore these areas to historical plant communities and hydrological function.

d. and e. Water Resources and Supply Sources

The additional quantity of water for industrial processing is estimated to be 150 gpm for plant process and service water. Water for this type of use would be supplied by a county water system. The current plant water treatment system, which provides treated water for use in Units # 1 and # 2 boilers, would likely be expanded.

Water for cooling would likely by supplied by the existing closed loop cooling canal system, although reclaimed water from a nearby publicly owned treatment works could possibly be utilized, if available. Cooling towers may also be used.

Environmental and Land Use Information: Supplemental Information

Preferred Site: Fort Myers

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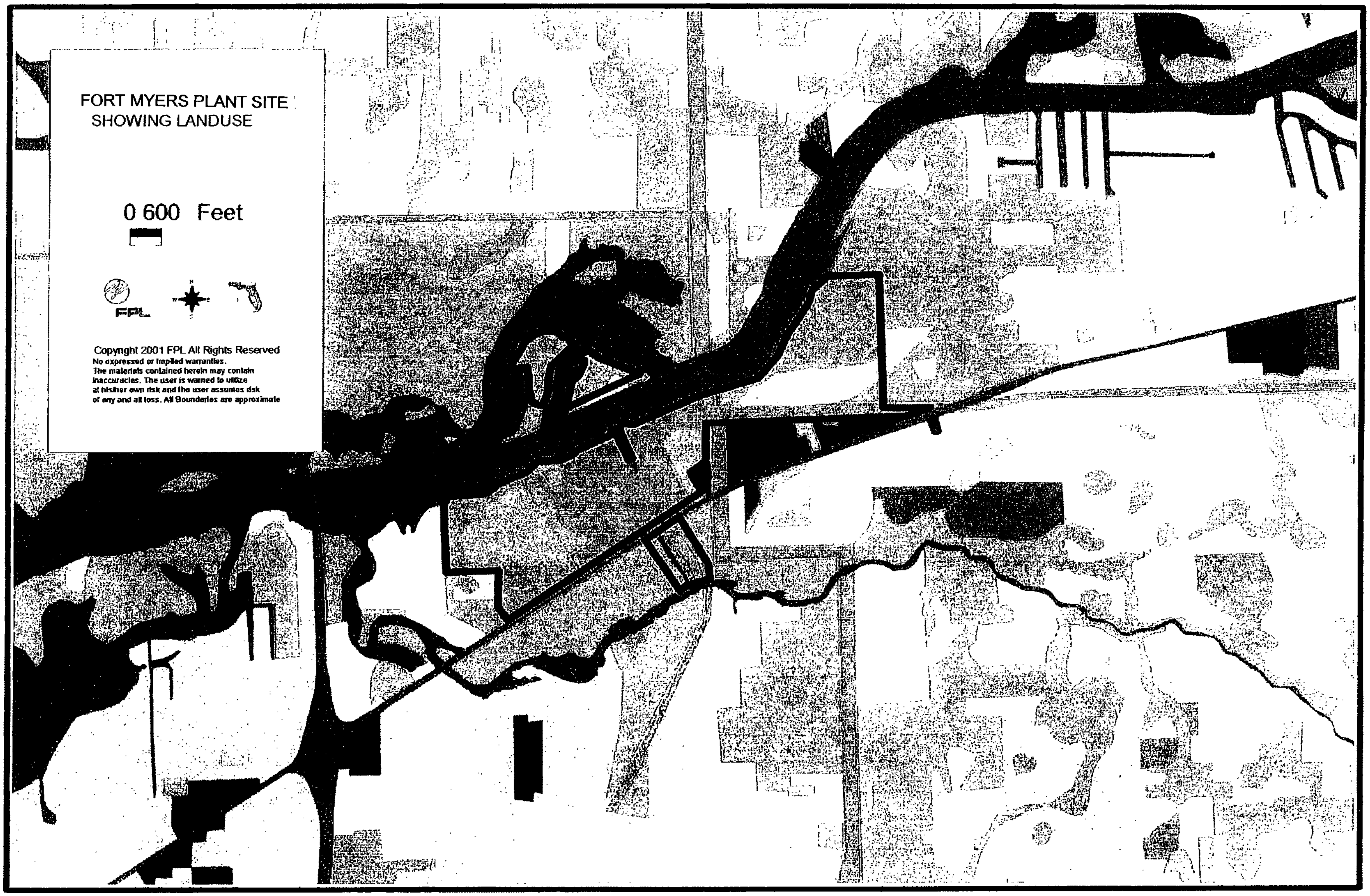
FORT MYERS PLANT SITE
SHOWING LANDUSE
0 600 Feet
FPL
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of any and all loss. All Boundaries are approximate

LEGEND FOR LANDUSE MAPS

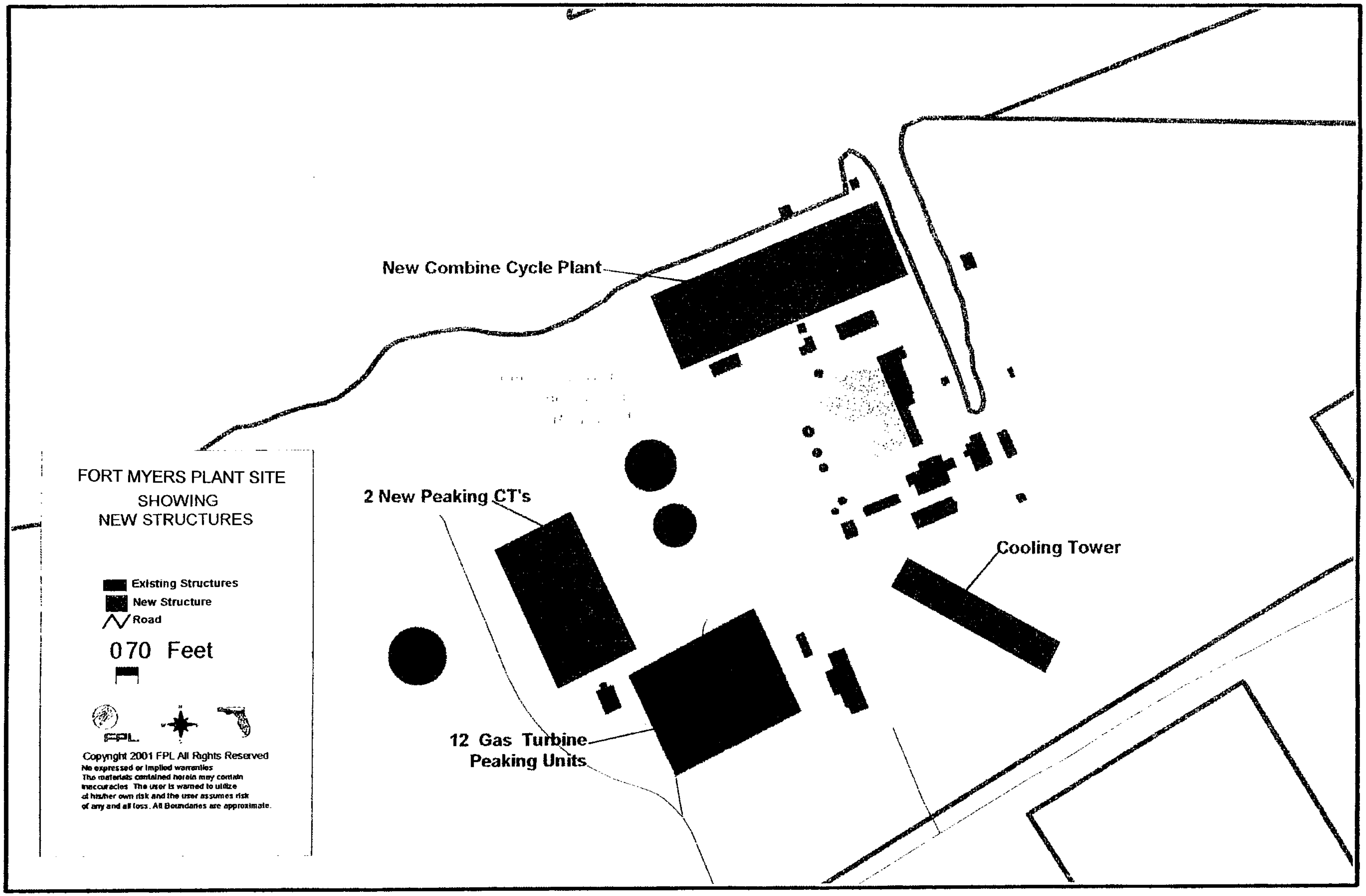
Plant Site Boundary

Level 3 Landuse Categories 1995

Residential Low Density
Residential Medium Density
Residential High Density
Commercial and Services
Industrial
Extractive
Institutional
Recreational
Open Land
Cropland and Pastureland
Tree Crops
Feeding Operations
Nurseries and Vineyards
Specialty Farms
Other Open Lands <Rural>
Herbaceous
Shrub and Brushland
Mixed Rangeland
Upland Coniferous Forests
Upland Hardwood Forests
Tree Plantations

Streams and Waterways
Lakes
Reservoirs
Bays and Estuaries
Major Springs
Slough Waters
Oceans Seas and Gulfs
Wetland Hardwood Forests
Wetland Coniferous Forests
Wetland Forested Mixed
Vegetated Non-Forested Wetlands
Non-Vegetated
Wetland Shrub
Beaches OtherThan Swimming Beaches
Sand Other Than Beaches
Exposed Rock
Disturbed Lands
Riverine Sandbars
Transportation
Communications
Utilities
Vegetation-Sea Grass

FPL


New Combine Cycle Plant
2 New Peaking CT's
Cooling Tower
12 Gas Turbine
Peaking Units
FORT MYERS PLANT SITE
SHOWING
NEW STRUCTURES
Existing Structures
New Structure
Road
0 70 Feet
FPL
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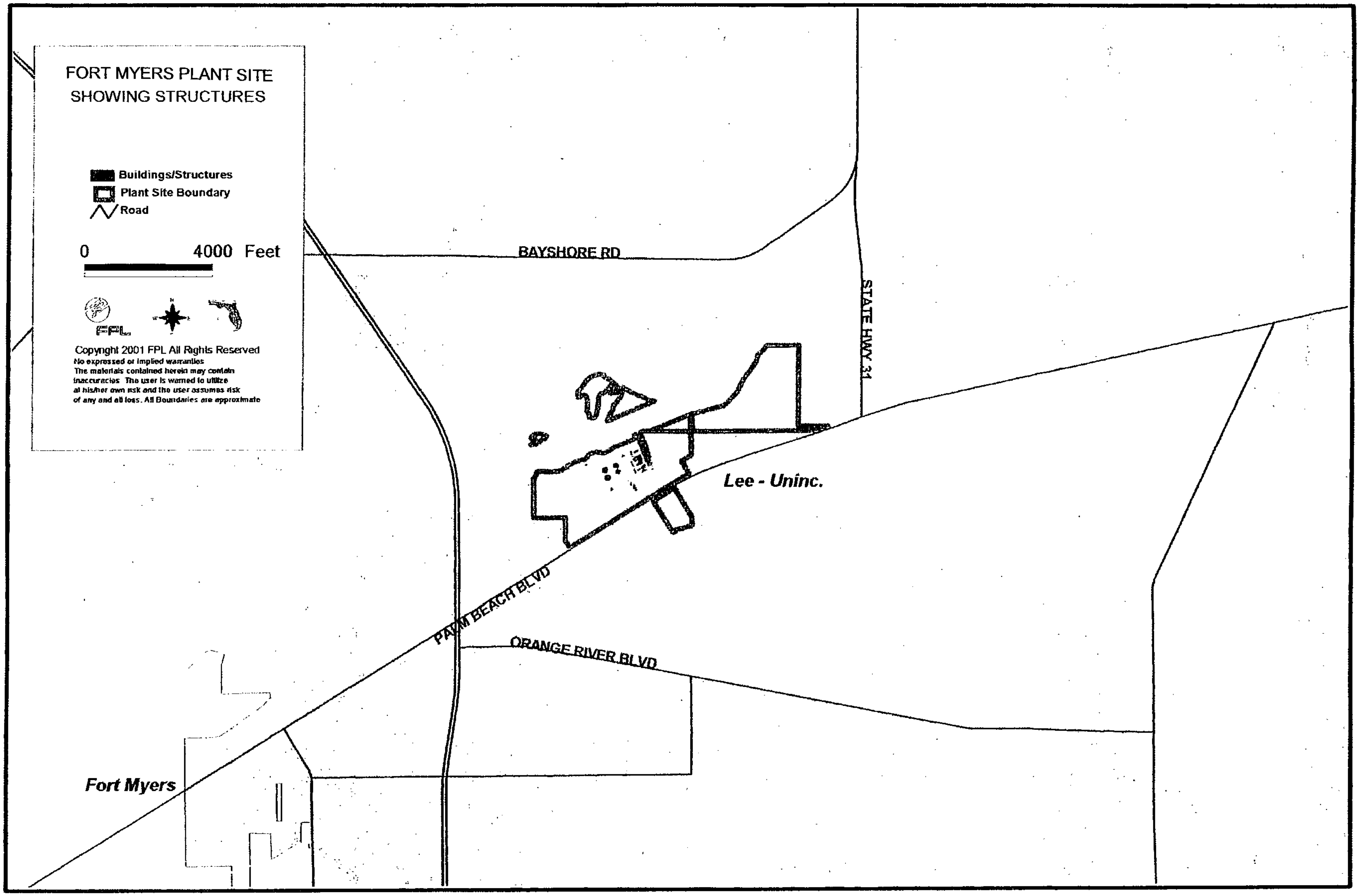
FORT MYERS PLANT SITE
SHOWING STRUCTURES
Buildings/Structures
Plant Site Boundary
Road
0
4000 Feet
FPL
Copyright 2001 FPL All Rights Reserved
No expressed or implied warranties
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BAYSHORE RD
STATE HWY 31
Lee - Uninc.
PALM BEACH BLVD
ORANGE RIVER BLVD
Fort Myers

Environmental and Land Use Information: Supplemental Information

Preferred Site: Sanford

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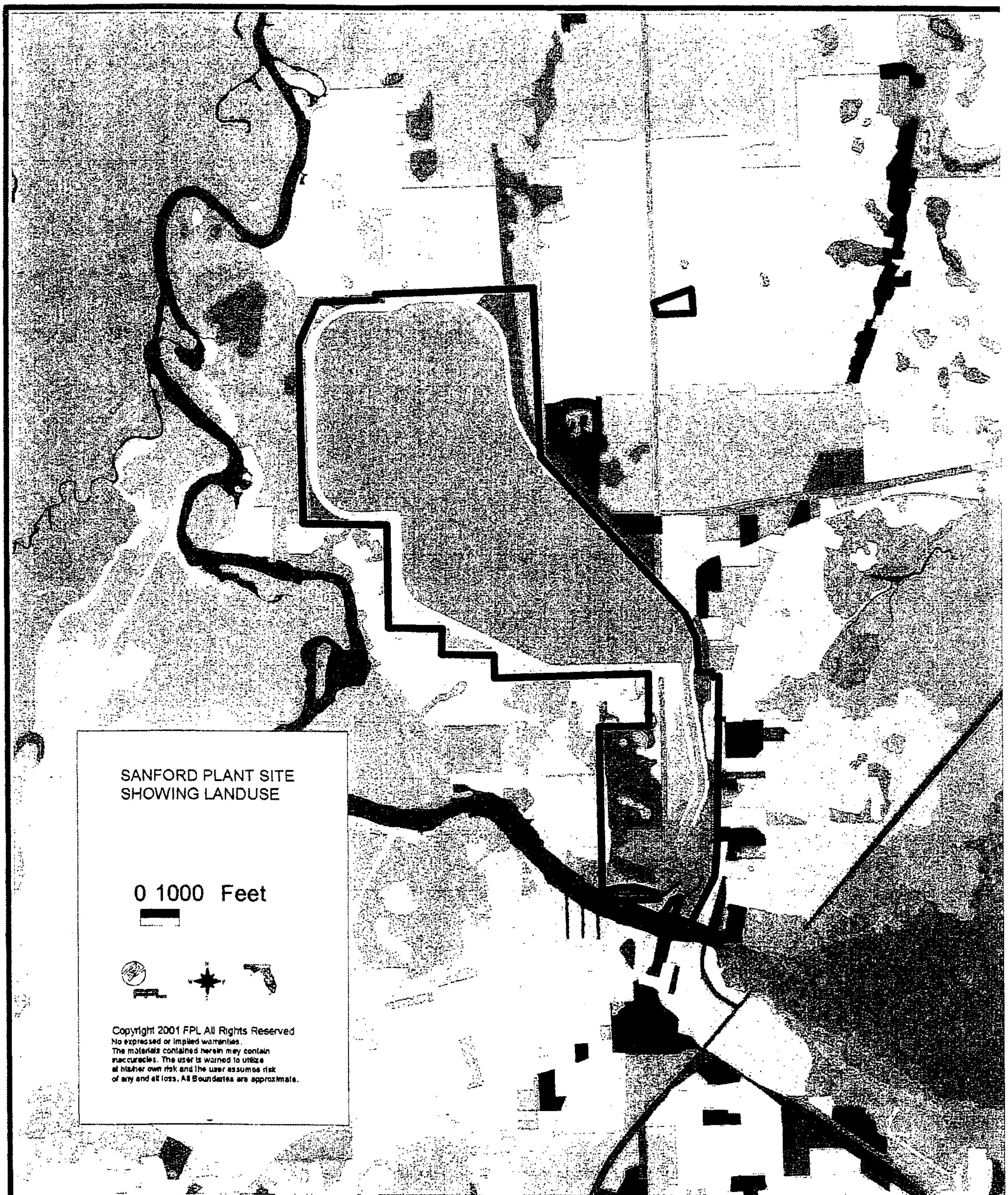
SANFORD PLANT SITE
SHOWING LANDUSE
0 1000 Feet
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LEGEND FOR LANDUSE MAPS

Plant Site Boundary

Level 3 Landuse Categories 1995

- Residential Low Density
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- Extractive
- Institutional
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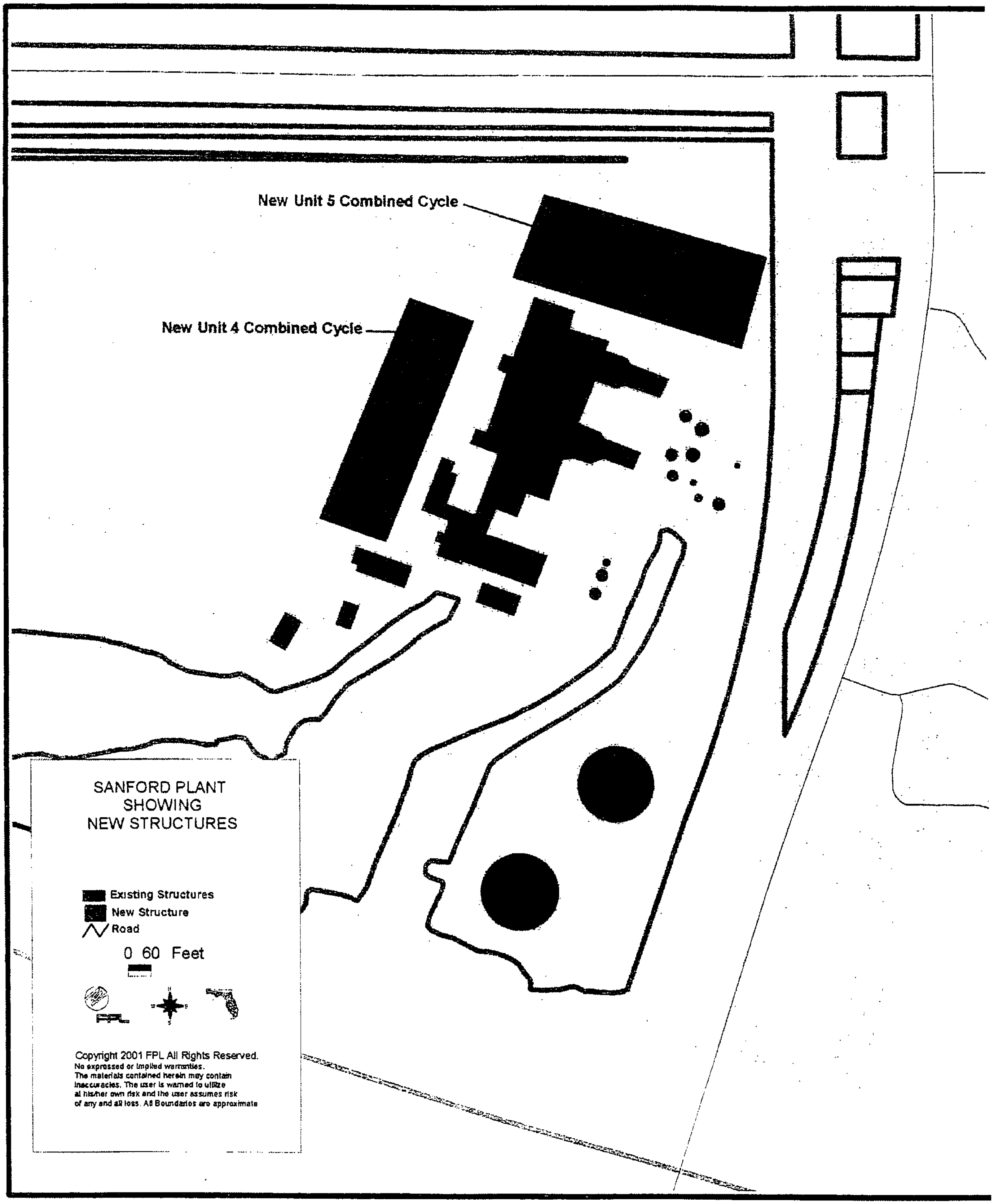
- Cropland and Pastureland
- Tree Crops
- Feeding Operations
- Nurseries and Vineyards
- Specialty Farms
- Other Open Lands <Rural>
- Herbaceous
- Shrub and Brushland
- Mixed Rangeland
- Upland Coniferous Forests
- Upland Hardwood Forests
- Tree Plantations
- Streams and Waterways
- Lakes
- Reservoirs
- Bays and Estuaries
- Major Springs
- Slough Waters
- Oceans Seas and Gulfs
- Wetland Hardwood Forests
- Wetland Coniferous Forests
- Wetland Forested Mixed
- Vegetated Non-Forested Wetlands
- Non-Vegetated
- Wetland Shrub
- Beaches OtherThan Swimming Beaches
- Sand Other Than Beaches
- Exposed Rock
- Disturbed Lands
- Riverine Sandbars
- Transportation
- Communications
- Utilities
- Vegetation-Sea Grass


New Unit 5 Combined Cycle
New Unit 4 Combined Cycle
SANFORD PLANT
SHOWING
NEW STRUCTURES
Existing Structures
New Structure
Road
0 60 Feet
FPL
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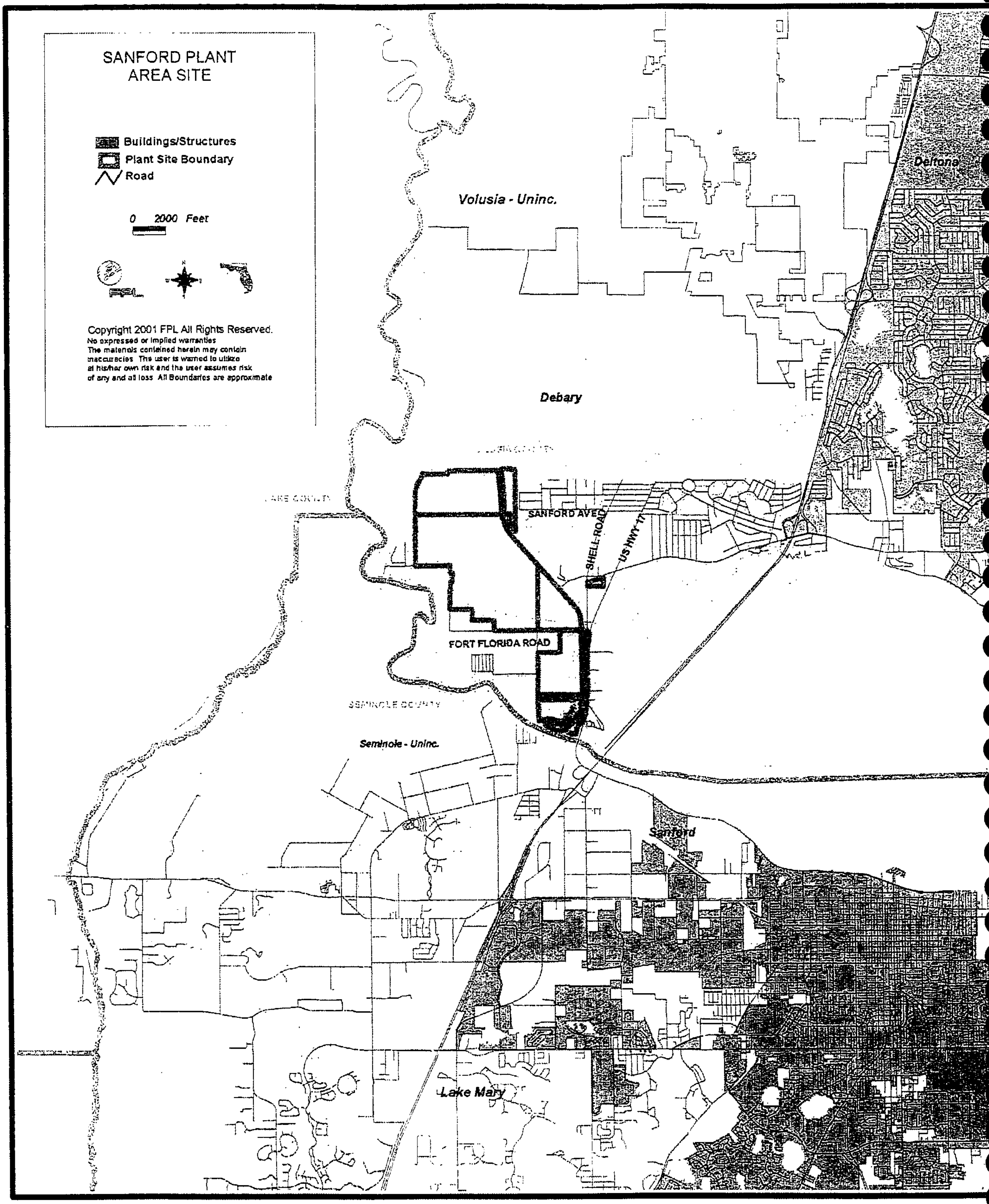
SANFORD PLANT
AREA SITE
Buildings/Structures
Plant Site Boundary
Road
0 2000 Feet
FPL
Copyright 2001 FPL All Rights Reserved.
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The materials contained herein may contain inaccuracies. The user is warned to utilize at his/her own risk and the user assumes risk of any and all loss. All Boundaries are approximate
Volusia - Uninc.
Deltona
Debary
SANFORD AVE
SHELL ROAD
US HWY 17
FORT FLORIDA ROAD
SEMINOLE COUNTY
Seminole - Uninc.
Sanford
Lake Mary

Environmental and Land Use Information: Supplemental Information

Preferred Site: Manatee

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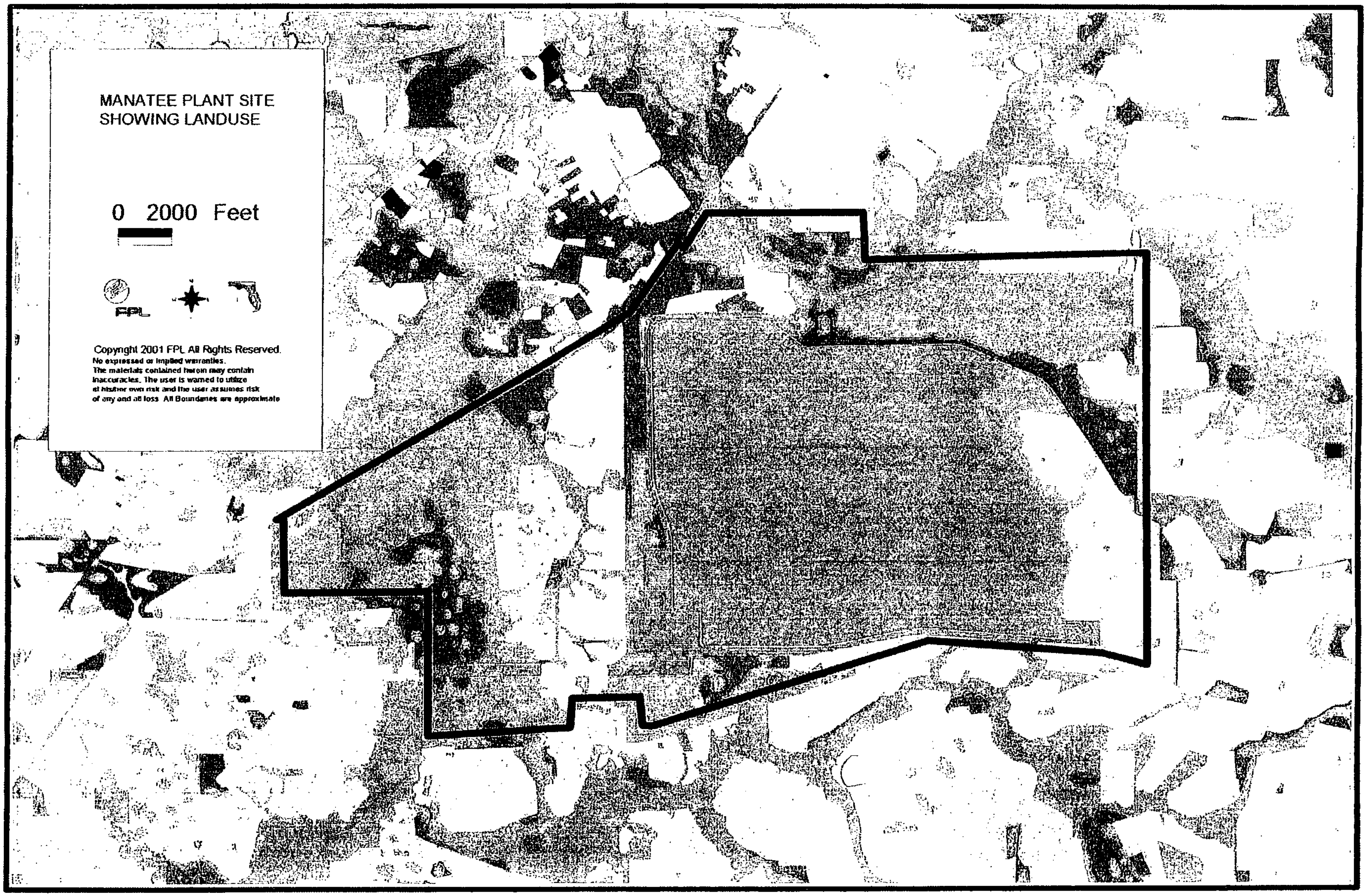
MANATEE PLANT SITE
SHOWING LANDUSE
0 2000 Feet
FPL
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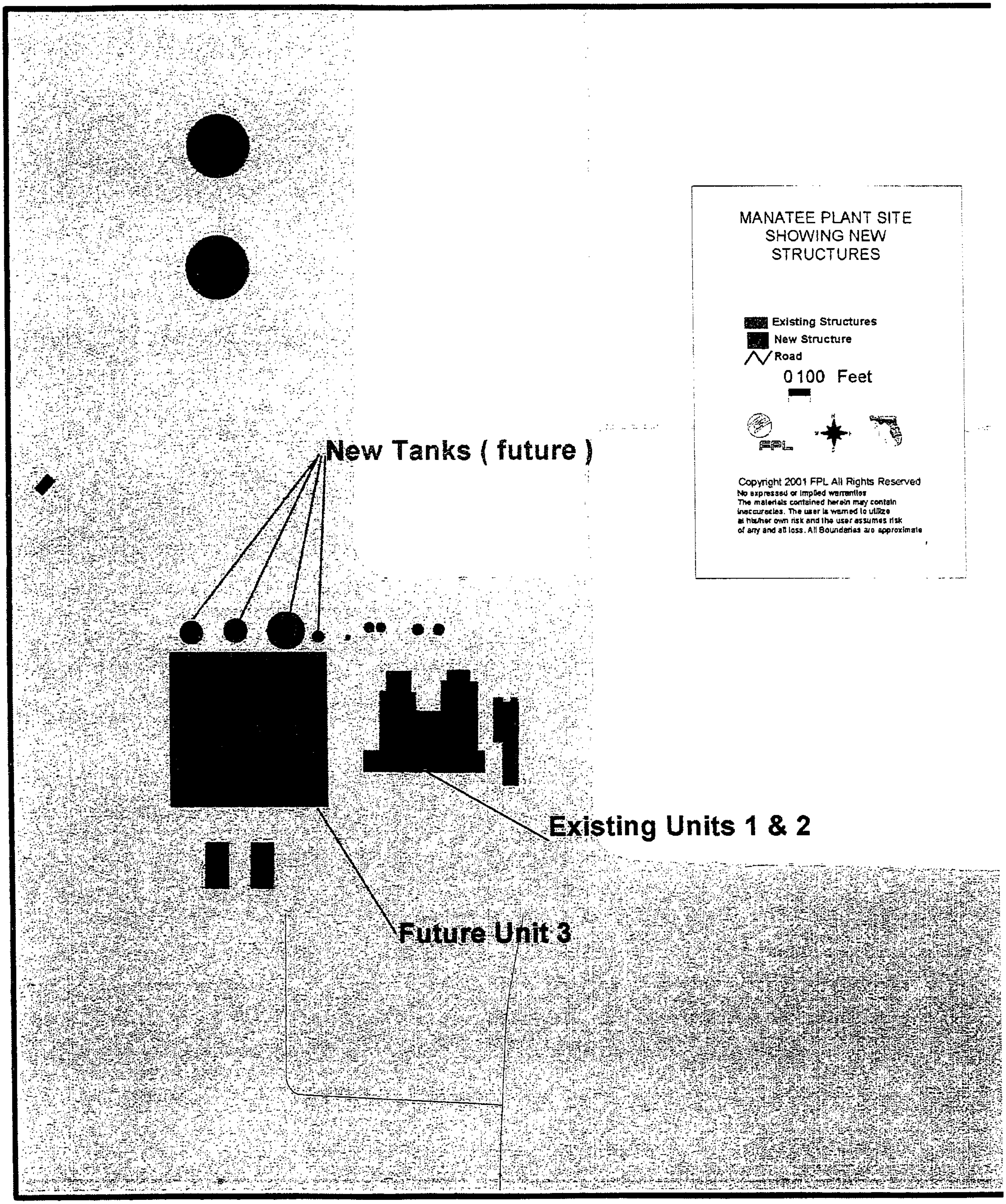
LEGEND FOR LANDUSE MAPS

Plant Site Boundary

Level 3 Landuse Categories 1995

Residential Low Density
Residential Medium Density
Residential High Density
Commercial and Services
Industrial
Extractive
Institutional
Recreational
Open Land
Cropland and Pastureland
Tree Crops
Feeding Operations
Nurseries and Vineyards
Specialty Farms
Other Open Lands <Rural>
Herbaceous
Shrub and Brushland
Mixed Rangeland
Upland Coniferous Forests
Upland Hardwood Forests
Tree Plantations
Streams and Waterways
Lakes
Reservoirs
Bays and Estuaries
Major Springs
Slough Waters
Oceans Seas and Gulfs
Wetland Hardwood Forests
Wetland Coniferous Forests
Wetland Forested Mixed
Vegetated Non-Forested Wetlands
Non-Vegetated
Wetland Shrub
Beaches OtherThan Swimming Beaches
Sand Other Than Beaches
Exposed Rock
Disturbed Lands
Riverine Sandbars
Transportation
Communications
Utilities
Vegetation-Sea Grass


MANATEE PLANT SITE
SHOWING NEW
STRUCTURES
Existing Structures
New Structure
Road
0 100 Feet
FPL
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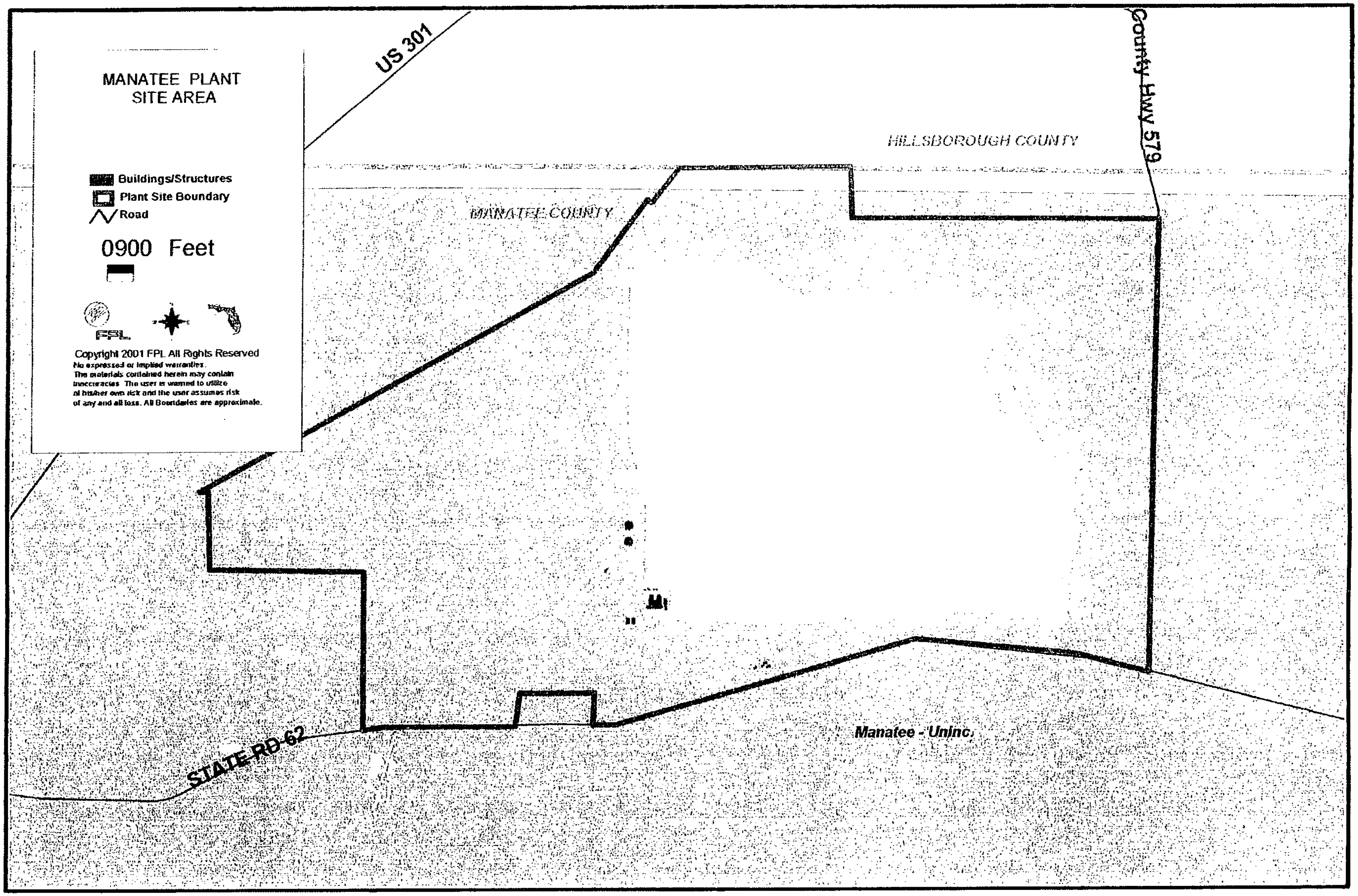
New Tanks (future)
Existing Units 1 & 2
Future Unit 3


MANATEE PLANT
SITE AREA
Buildings/Structures
Plant Site Boundary
Road
0900 Feet
FPL
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US 301
County Hwy 579
HILLSBOROUGH COUNTY
MANATEE COUNTY
STATE RD 62
Manatee - Uninc.

Environmental and Land Use Information: Supplemental Information

Preferred Site: Martin

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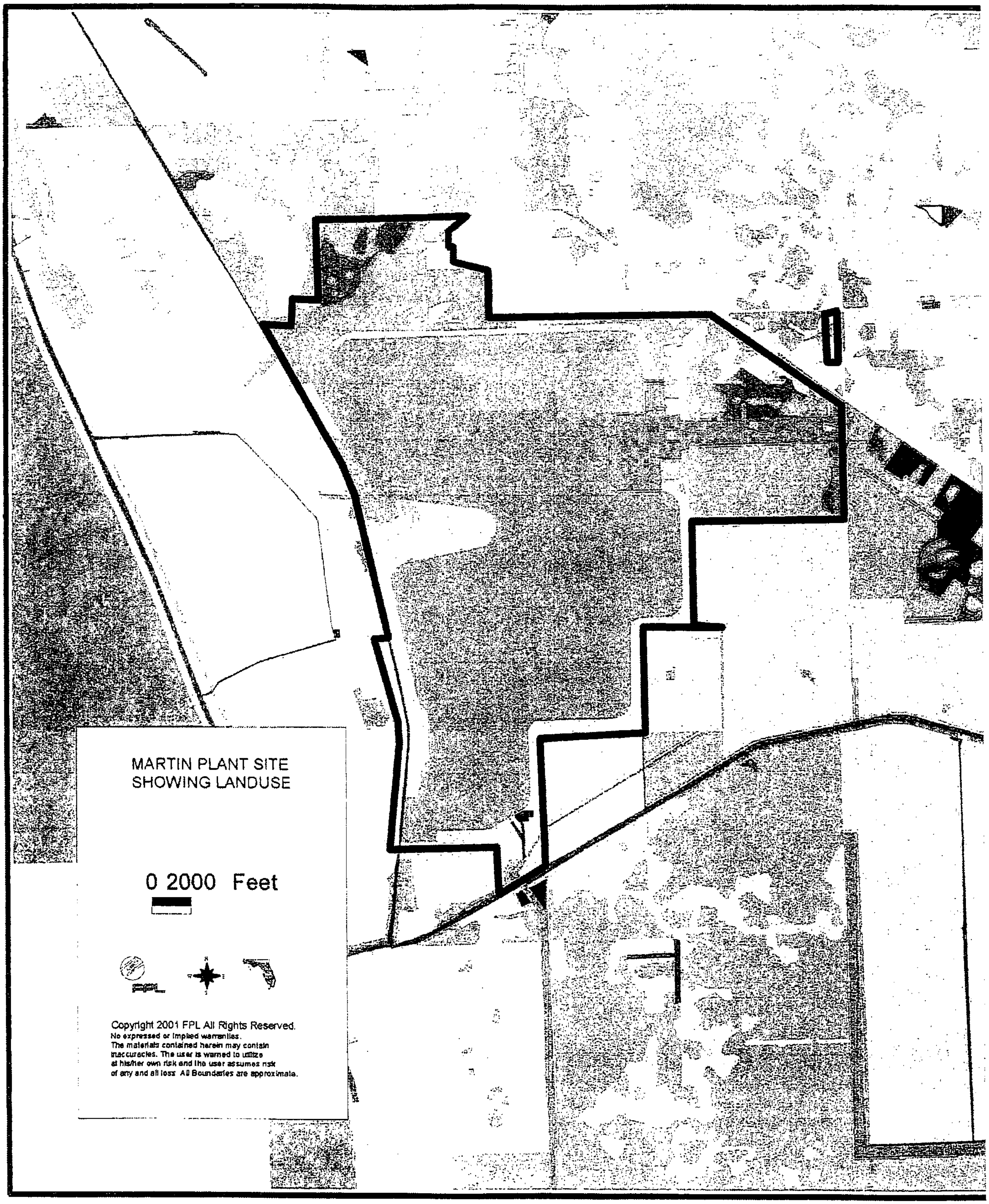
MARTIN PLANT SITE
SHOWING LANDUSE
0 2000 Feet
N
W
E
S
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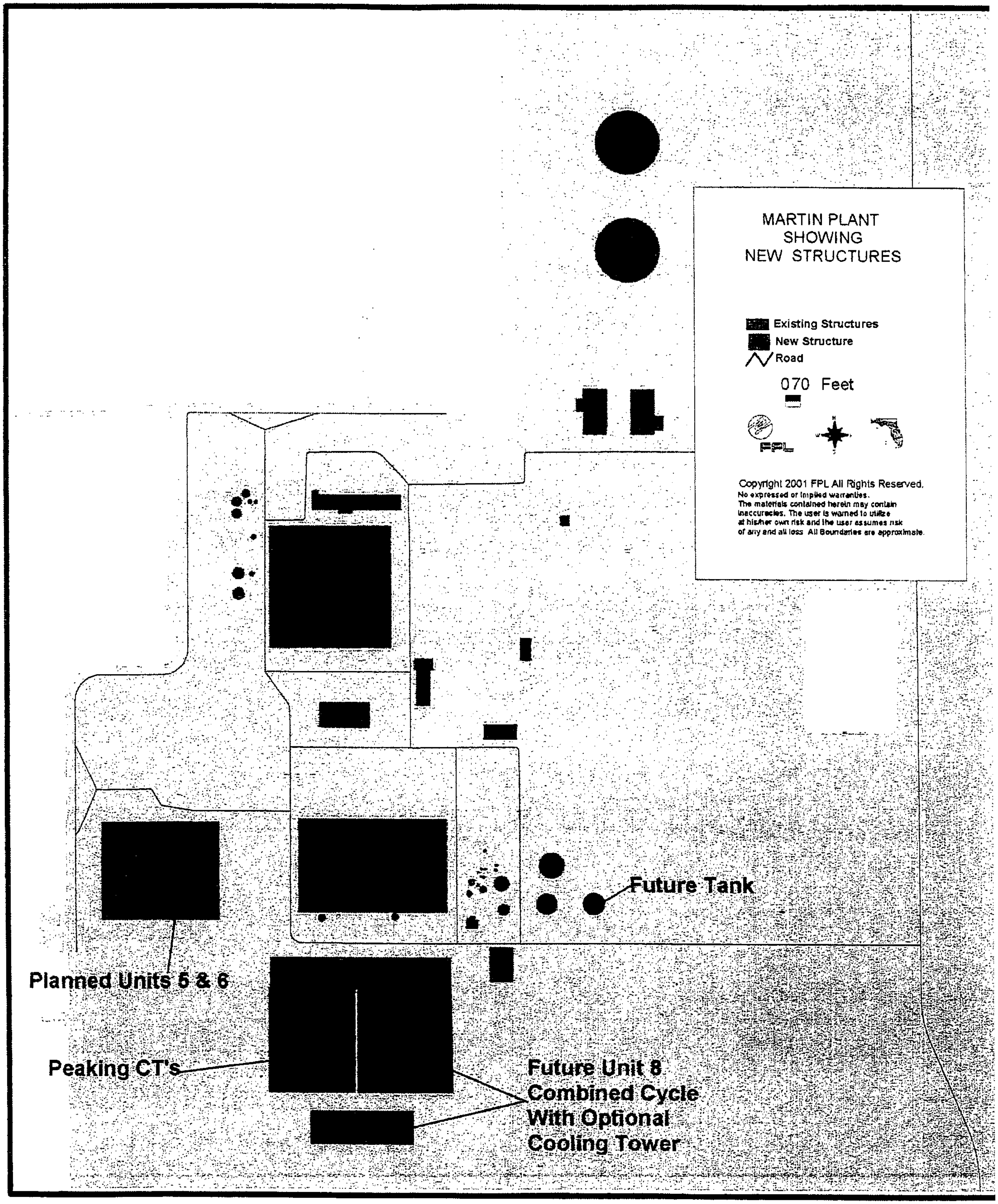
LEGEND FOR LANDUSE MAPS

Plant Site Boundary

Level 3 Landuse Categories 1995

- Residential Low Density
- Residential Medium Density
- Residential High Density
- Commercial and Services
- Industrial
- Extractive
- Institutional
- Recreational
- Open Land
- Cropland and Pastureland
- Tree Crops
- Feeding Operations
- Nurseries and Vineyards
- Specialty Farms
- Other Open Lands <Rural>
- Herbaceous
- Shrub and Brushland
- Mixed Rangeland
- Upland Coniferous Forests
- Upland Hardwood Forests
- Tree Plantations
- Streams and Waterways
- Lakes
- Reservoirs
- Bays and Estuaries
- Major Springs
- Slough Waters
- Oceans Seas and Gulfs
- Wetland Hardwood Forests
- Wetland Coniferous Forests
- Wetland Forested Mixed
- Vegetated Non-Forested Wetlands
- Non-Vegetated
- Wetland Shrub
- Beaches OtherThan Swimming Beaches
- Sand Other Than Beaches
- Exposed Rock
- Disturbed Lands
- Riverine Sandbars
- Transportation
- Communications
- Utilities
- Vegetation-Sea Grass


MARTIN PLANT
SHOWING
NEW STRUCTURES
Existing Structures
New Structure
Road
070 Feet
FPL
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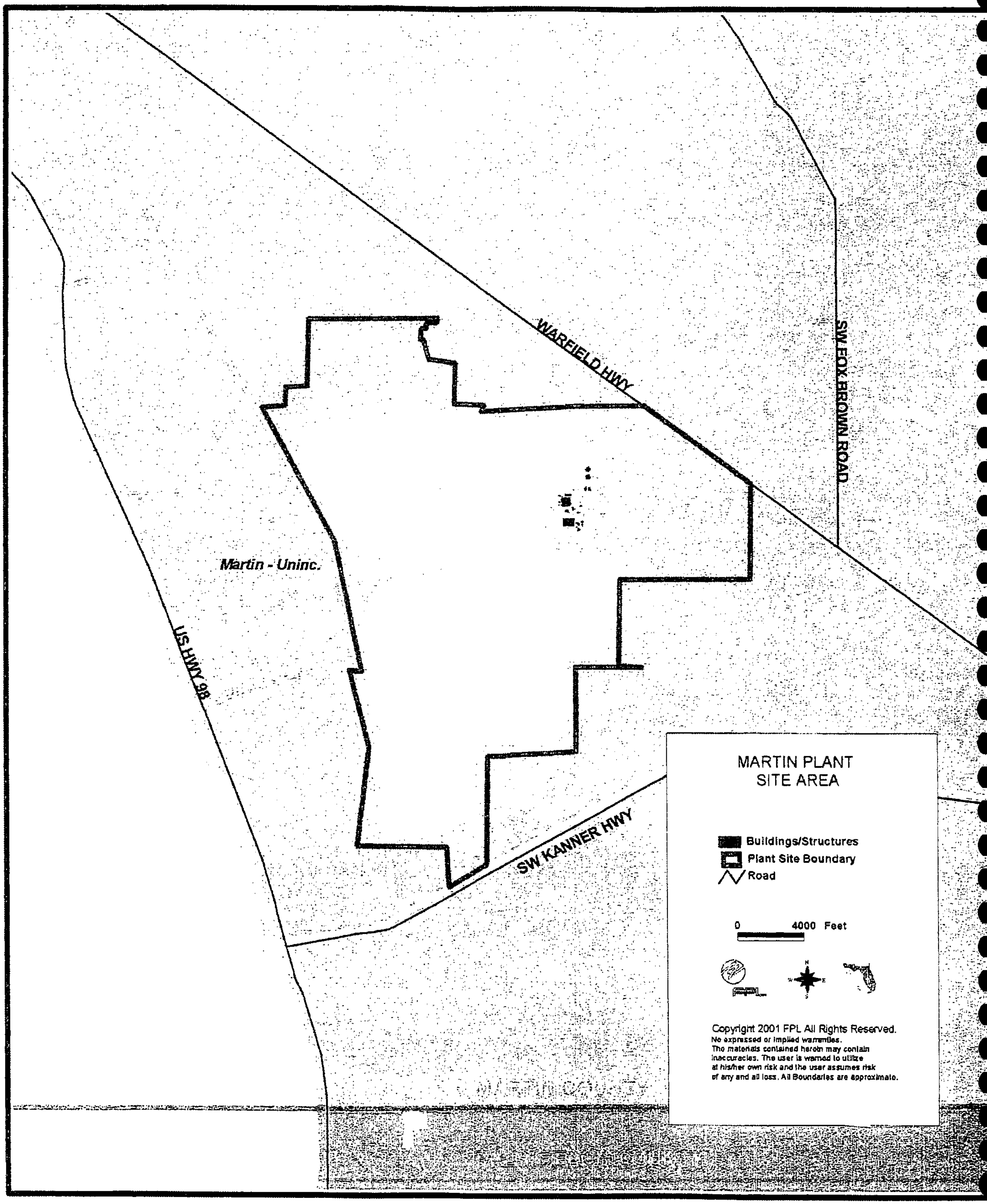
Future Tank
Planned Units 5 & 6
Peaking CT's
Future Unit 8
Combined Cycle
With Optional
Cooling Tower


WARFIELD HWY
SW FOX BROWN ROAD
Martin - Uninc.
US HWY 98
SW KANNER HWY
MARTIN PLANT
SITE AREA
Buildings/Structures
Plant Site Boundary
Road
0 4000 Feet
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Environmental and Land Use Information: Supplemental Information

Potential Site: Cape Canaveral

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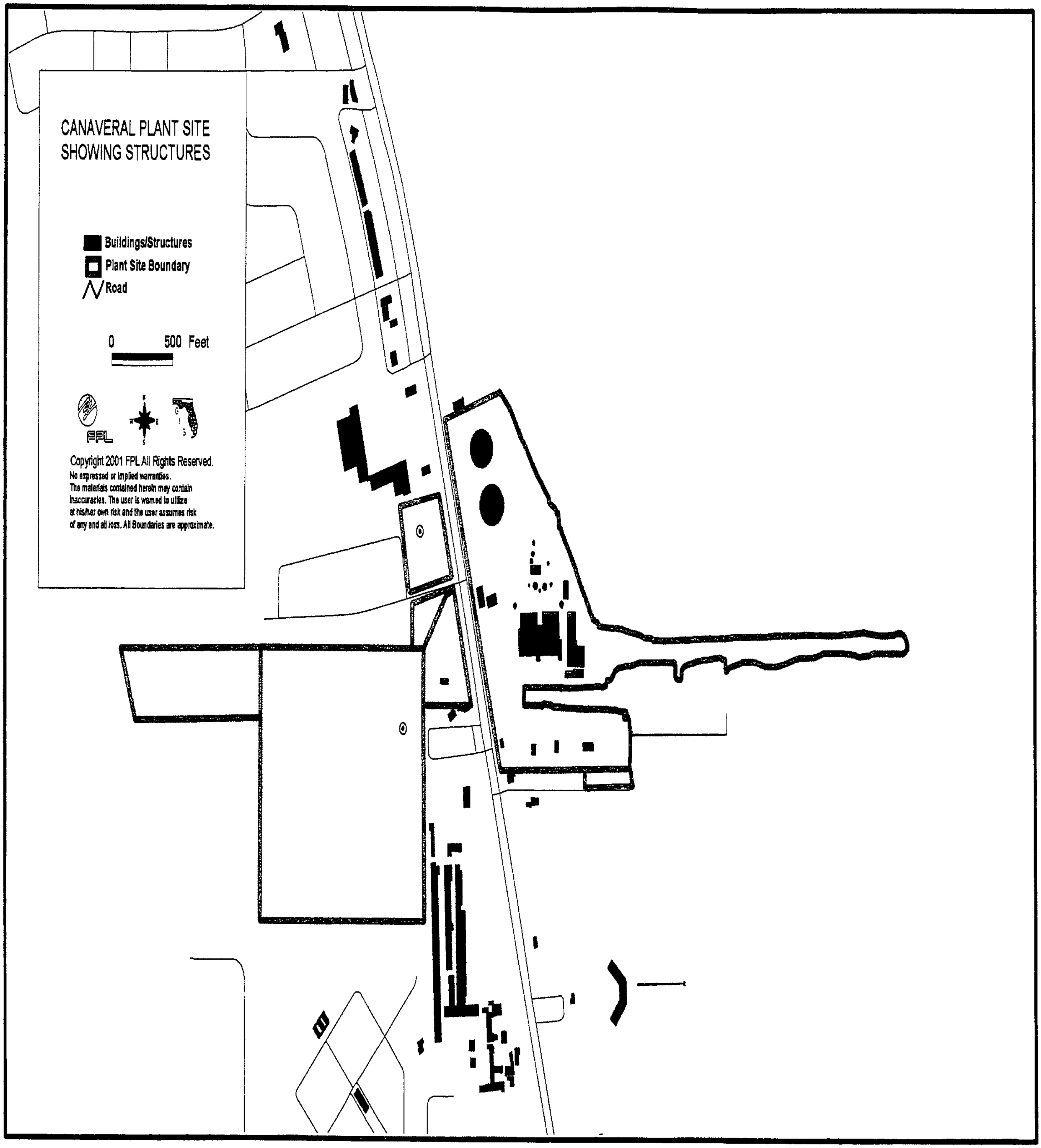
CANAVERAL PLANT SITE
SHOWING STRUCTURES
Buildings/Structures
Plant Site Boundary
Road
0
500 Feet
FPL
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Environmental and Land Use Information: Supplemental Information

Potential Site: Midway

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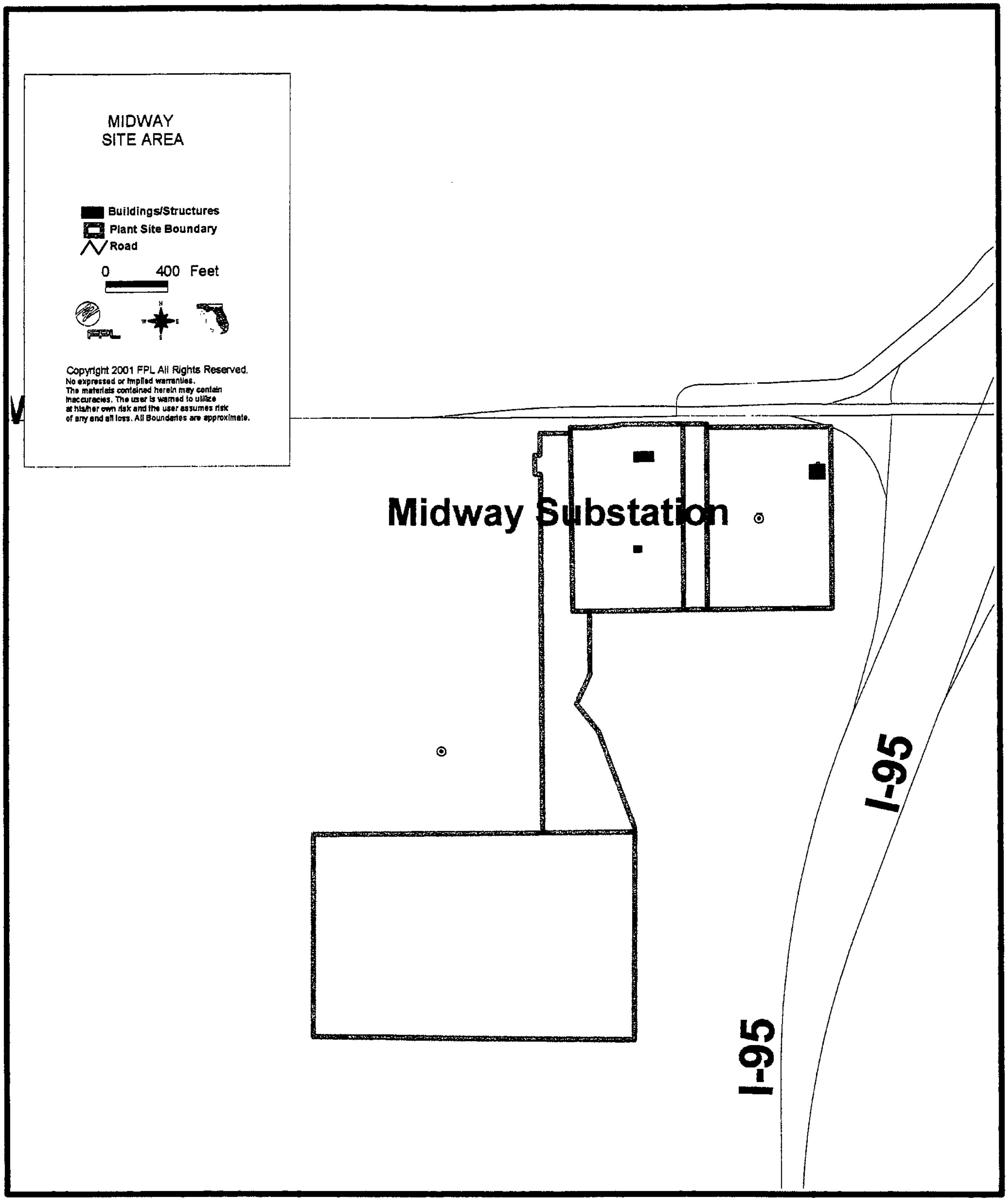
MIDWAY
SITE AREA
Buildings/Structures
Plant Site Boundary
Road
0
400 Feet
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Midway Substation
I-95
I-95

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Environmental and Land Use Information: Supplemental Information

Potential Site: Port Everglades

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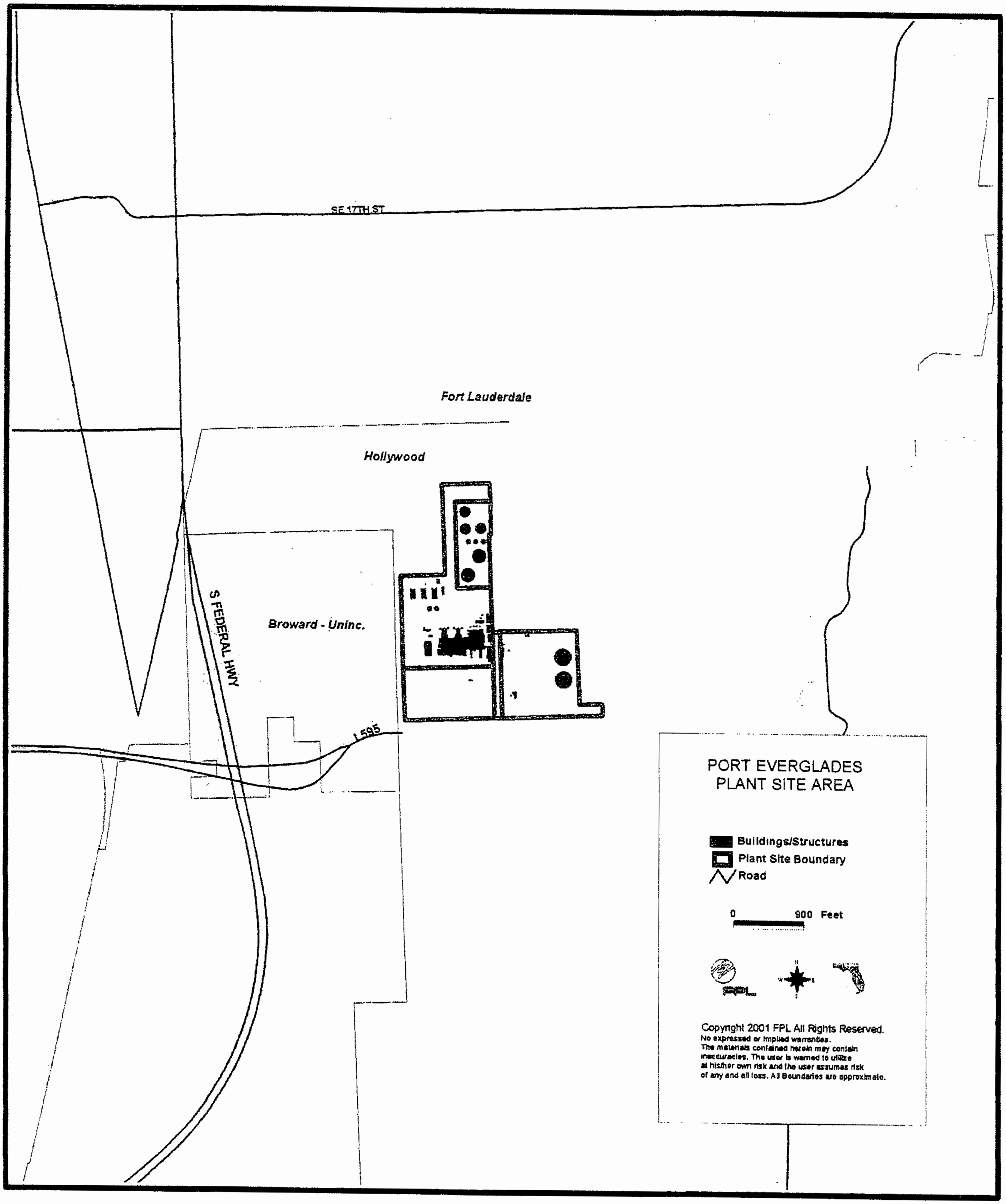
SE 17TH ST
Fort Lauderdale
Hollywood
Broward - Uninc.
S FEDERAL HWY
I 595
PORT EVERGLADES
PLANT SITE AREA
Buildings/Structures
Plant Site Boundary
Road
0
900 Feet
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Environmental and Land Use Information: Supplemental Information

Potential Site: Riviera Plant

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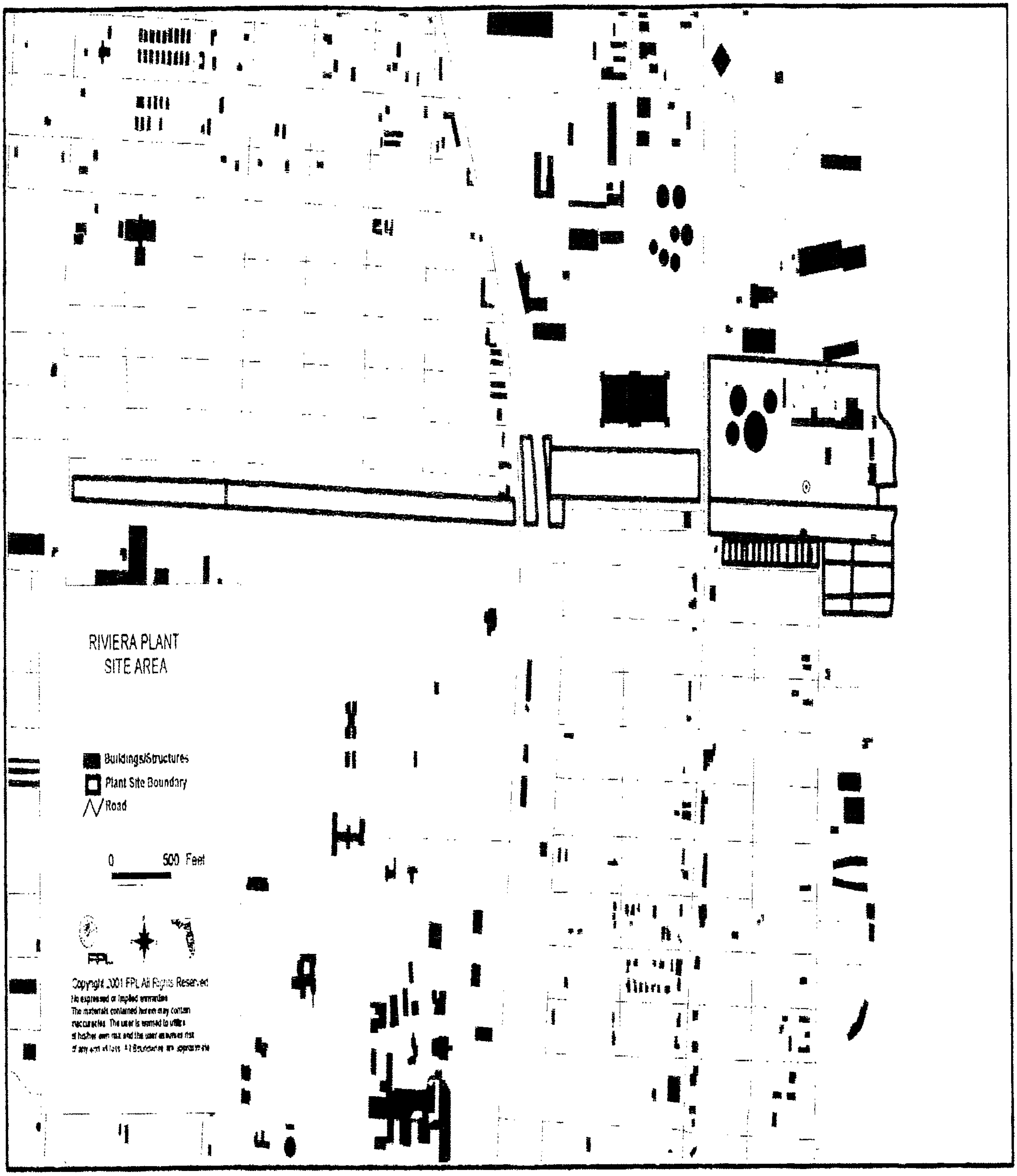
RIVIERA PLANT
SITE AREA
Buildings/Structures
Plant Site Boundary
Road
0
500 Feet
FPL
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Environmental and Land Use Information: Supplemental Information

Potential Site: Turkey Point

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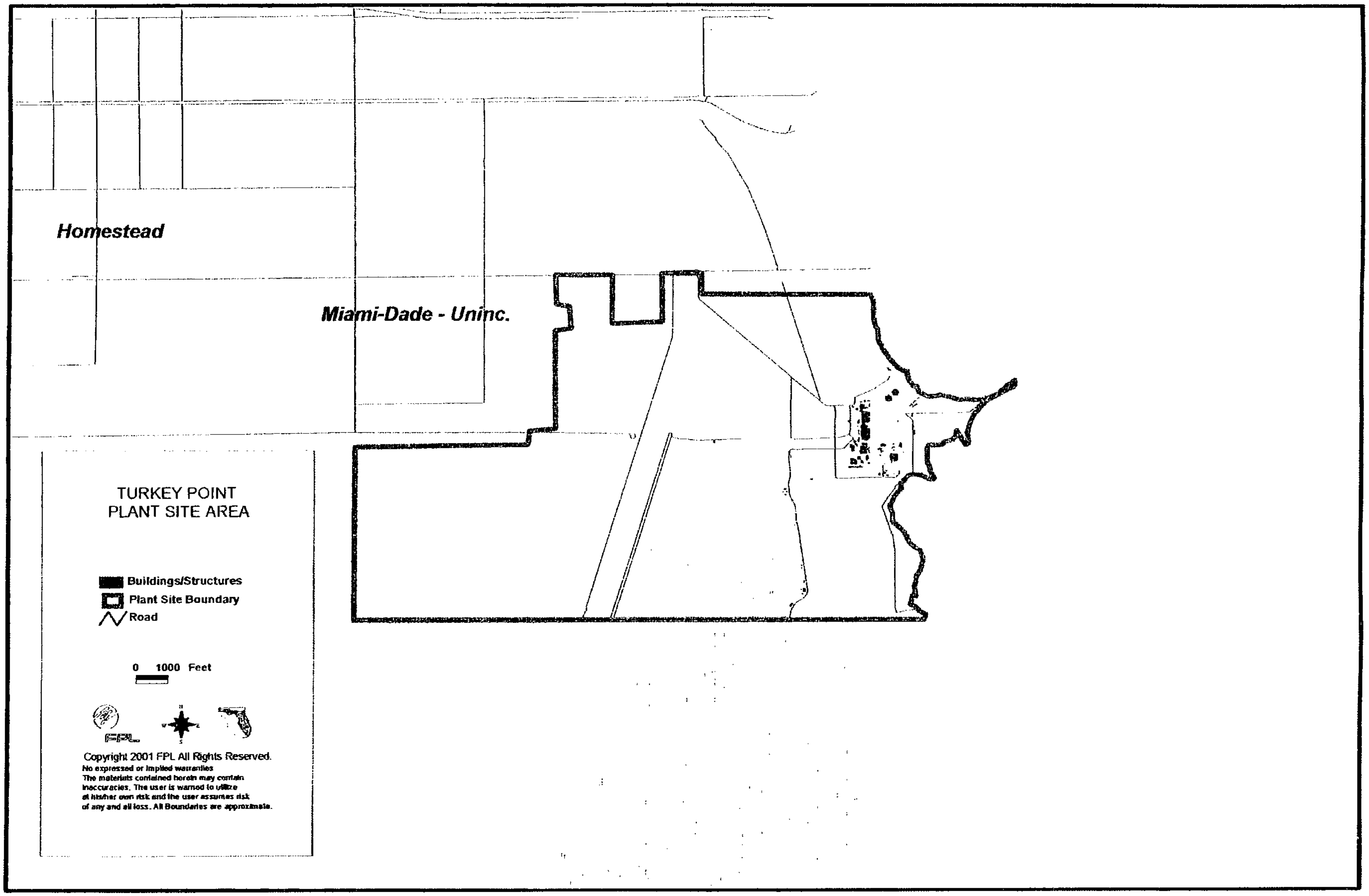
Homestead
Miami-Dade - Uninc.
TURKEY POINT
PLANT SITE AREA
Buildings/Structures
Plant Site Boundary
Road
0 1000 Feet
FPL
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CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten-Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information". These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission constraints. External constraints deal with FPL's ties to its neighboring systems. Internal constraints deal with the flow of electricity within the FPL system.

The external constraints are important since they affect the development of assumptions for the amount of external assistance which is available and the amount and price of economy energy purchases. Therefore, these external constraints are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission constraints or limitations are addressed by identifying potential geographic locations for potential new units that may not adversely impact, or that may even alleviate, such constraints and limitations and in developing the costs for siting new units at different locations. Both site-and system-related transmission costs are developed for each different unit/unit location option or groups of options.

FPL's annual transmission planning work determines transmission additions needed to address constraints and to maintain/enhance system reliability. FPL's transmission plans are presented in Section III.E.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

As discussed in Chapter III of this document, FPL typically performs economic analyses of competing resource plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI) and Stone and Webster Management Consultants, Inc. The resource plan reflected in this document emerged as the resource plan with the least impact on FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach) and on the present value of revenue requirements for the FPL system.[3]

No sensitivity case analyses based on different load forecasts were carried out during FPL 's most recent planning work. This is due to the fact that the most economical options are combined cycle (CC) units. If higher – than – projected loads begin to appear, the combustion turbine components of any of the CC options could be placed in service early in simple cycle mode. FPL believed that this fact qualitatively enabled it to be able to address higher – than – projected loads.

[3] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis, the lowest rate basis and the lowest system revenue requirements basis are identical. In such cases (as in FPL's current resource planning work), FPL evaluates options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its base case or "Most Likely" fuel price forecast are discussed in Chapter III of this document.

In its most recent planning work, FPL did not test the sensitivity of its resource plan to a "Low Price" fuel forecast in conjunction with a "High Load" forecast. All of the options considered in the IRP analysis were gas-fired units, so any change in the fuel costs projections would have affected these options in essentially the same way. Consequently, FPL did not believe that a fuel price sensitivity case was needed.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

For the same reason given in response to Discussion Item #3, FPL did not conduct a "constant fuel differential" sensitivity analysis in its most recent planning work.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, and capacity output ratings and heat rate information. Schedule 1 and Schedule 8 present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options which were considered in the resource planning work. A summary of this information for the new capacity options FPL projects to add over the planing horizon is presented on the Schedule 9 forms.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

The key financial assumptions used in FPL's most recent resource planning work were 45% debt and 55% equity FPL capital structure, projected debt cost of 7.4%, and an equity return of 11.7%. These assumptions resulted in a weighted average cost of capital of 9.8% and an after-tax discount rate of 8.5%. In its recent planning work, FPL did not test the sensitivity of its resource plan to varying financial assumptions. The reason for this is that FPL's planning work focused on FPL construction options only that were generally very similar in design and varied only by site. Consequently, varying financial assumptions would have resulted in little/no change in the analysis results.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM approach). However, in its most recent planning work FPL utilized a net present value of system revenue requirements as the basis for comparing options and plans. (As discussed in response to Discussion Item # 2, both the electricity rate basis and the system revenue requirement basis are identical when DSM levels are unchanged between competing plans. Such was the case in FPL's recent planning work.)

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses two generation reliability criteria in its resource planning work. One of these is a minimum 15% Summer and Winter reserve margin for years up to mid – 2004 that changes to a minimum 20% Summer and Winter reserve margin for the mid – 2004 – on time period. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the planning criteria established by the North American Electric Reliability Council (NERC) in its *Planning Standards*. FPL has applied these planning criteria in a manner consistent with prudent utility practice. The *NERC Planning Standards* are available on the internet (http://www.nerc.com/~filez/pss-psg.html).

In addition, FPL has developed a Facility Connection Requirements (FCR) document as well as a Facility Rating Methodology document that are also available on the internet (http://www.floasis.siemens-asp.com/oasis/fpl/info.htm).

Thermal ratings for specific transmission lines or transformers are found in the load flow cases that are available on the internet (http://www.floasis.siemens- asp.com/oasis/fpl/info.htm).

The normal voltage criteria for FPL stations is given below:

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138, 500	0.95	1.05
230	0.95	1.06

There may have been isolated cases for which FPL may have determined it prudent to deviate from the general criteria stated above. The overall potential impact on customers, the probability of an outage actually occurring, as well as other factors may have influenced the decision in such cases.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The impact of FPL's DSM Programs on demand and energy consumption are revised periodically. Engineering models, calibrated with field-metered data, are updated when significant efficiency changes occur in the marketplace. Participation trends are tracked for all of the FPL programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants.

Survey data is collected from non-participants in order to establish the baseline efficiency. Participant data is compared against non-participant data to establish the demand and energy saving benefits of the utility program versus what would be installed in the absence of the program. Finally, FPL is careful to claim only program savings for the average life of the installed efficiency measure. For these DSM measures which involve the utilization of load management, FPL conducts periodic tests of the load control equipment to ensure that it is functioning correctly.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

Among the strategic or non-price factors FPL typically considers when choosing between resource options are the following: (1) fuel diversity; (2) technology risk; and (3) environmental risk.

Fuel diversity relates to two concepts, the diversity of sources of fuel (e.g., coal vs. oil vs. natural gas), and the diversity of supply for a single fuel source (for example alternative pipeline suppliers for natural gas). All other factors being equal, supply options that increase diversity in fuel source and/or supply would be favored over those that do not.

Technology risk is an assessment of the relative maturity of competing technologies, For example, a prototype technology which has not achieved general commercial acceptance has a higher risk than a technology in wide use and, therefore, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of competing technologies. Technologies which might be regarded as more acceptable from an environmental perspective (e.g., natural gas-fired options) might be considered more favorably.

All of these factors play a part in FPL's planning and decisions, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As has been previously discussed, the near – term elements of FPL's capacity additions include the repowering of one of its Sanford plants, the addition of new combustion turbines (CT's) at Fort Myers, and a number of firm capacity, short-term purchases. The incremental capacity from the repowering project comes from the addition of new CT's and heat recovery steam generators (HRSG's). FPL acquired the repowering-related CT's, plus the other new CT's for Fort Myers, and the HRSG's through a bid process which combined cost and performance considerations. The firm capacity short-term purchases were acquired through negotiations.

The 2005 capacity addition decision was arrived at after evaluating 134 bids received in response to two capacity Request for Proposals (RFP) issued by FPL in mid-2001 and mid-2002. The decision to construct new combined cycle units at FPL's existing Martin and Manatee sites was subsequently approved by the Florida Public Service Commission in late 2002.

The later (2007 – on) capacity additions are likely to be subject to a capacity solicitation process similar to the Request for Proposal (RFP) process that led to the selection of Martin Unit # 8 and Manatee Unit # 3. Identification of these self – build options in FPL's Site Plan is not an indication that FPL has prejudged any capacity solicitation it may conduct. It is merely a recognition of what currently appears to be FPL's best, most cost-effective self – build options at this time. FPL reserves the right to refine its planning analyses and to identify other self – build options. Such refined analyses have the potential to yield a variety of self – build options, some of which might not require an RFP. If an RFP is issued for supply – side resources, FPL reserve the right to choose the best alternative for its customers, even if that option is not an FPL self – build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

FPL's latest Transmission/Substation Expansion Plan for years 2002-2012 published in December, 2002 includes a new transmission line that is planned which would need to be certified under the Transmission Line Siting Act (403.52 – 403.536, F.S.). The new line will connect FPL's Orange River Substation to the Collier Substation. The construction of this line is necessary to serve existing and future customers in the Collier and Lee areas in a reliable and effective manner.

Additionally, contained in FPL's latest Transmission/Substation Expansion Plan for years 2002-2012 published in December, 2002 is a section entitled "Transmission System Long-Range Projects: 2008-2012. These projects are at this time only potential long-range transmission projects and are subject to change. The siting of future generation additions could have an impact on the necessity of such transmission projects. These proposed potential projects are not yet budgeted projects, are in the preliminary stages of consideration, and are based upon current assumptions that will be monitored and adjusted in future planning assessments. No determination has been made with regard to these potential long-range projects as to whether they will need to be certified under the Transmission Line Siting Act (403.52 – 403.536, F.S.).

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ORIGINAL

FPL

Florida Power & Light Company, P.O. Box 029100, Miami, FL 33102

April 1, 2004

VIA HAND DELIVERY

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk and Administrative Services
Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

040000-PU

RECEIVED FPSC
04 APR -1 PM 2:07
COMMISSION CLERK

Re: 2004 – 2013 Ten-Year Site Plan

Dear Ms. Bayó,

In accordance with Chapter 186 (Section 186.801 - Ten Year Plans) of the Florida Statutes, enclosed for filing are twenty-five (25) copies of Florida Power & Light Company's 2004 - 2013 Ten-Year Power Plant Site Plan.

If you have any questions, please do not hesitate to contact me at (305) 552-4332 or John Hepokoski at (305) 552-4159.

Sincerely,

Anne M. Grealy

Anne M. Grealy
Director, Regulatory Affairs

AMG/mg
Enclosures

AUS ___
CAF ___
CMP ___
COM ___
CTR ___
ECR Hoff
GCL ___
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FPSC-BUREAU OF RECORDS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 39
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-D

DOCUMENT NUMBER-DATE
04177 APR-1 04
FPSC-COMMISSION CLERK

Ten Year Power Plant Site Plan
2004 - 2013

FPL

FPL

Ten Year Power Plant Site Plan

2004-2013

Submitted To:

***Florida Public
Service Commission***

***Miami, Florida
April, 2004***

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Table of Contents

List of Figures and Tables

List of Schedules

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Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten - Year Power Plant Site Plan. This plan includes an estimate of the utility's electric power generating needs, a projection of how those needs will be met, and a disclosure of information pertaining to the utility's preferred and potential power plant sites. This information is compiled and presented in accordance with Rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (FAC).

This Ten - Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) planning analyses that were carried out in 2003 and that were completed in the first quarter of 2004. The forecasted information presented in this plan addresses the 2004 – 2013 time frame.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information and is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as needed as part of the Florida site certification process, or through other proceedings and filings.

This document is organized in the following manner:

Executive Summary

The Executive Summary provides a review of the major findings and conclusions presented in the Site Plan.

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

This chapter presents FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, particularly new capacity resources, as determined in FPL's IRP work in 2003 and early 2004.

Chapter IV – Environmental and Land Use Information

This chapter presents environmental information as well as preferred and potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to specific information included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	Abbreviation	Definition
Unit Type	BIT	Bituminous Coal
	CC	Combined Cycle
	CT	Combustion Turbine
	IC	Internal Combustion
	NP	Nuclear Power
	NPGU	Next Planned Generating Unit
	ST	Steam Unit
Fuel Type	UR	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	NO	None
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	P	Planned Unit
	RP	Proposed for repowering
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	P.U.	Per Unit

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Executive Summary

Florida Power & Light Company's (FPL) 2004 Ten - Year Power Plant Site Plan (Site Plan) summarizes FPL's analysis of and plan to address a need for increased electric generation capability. This plan is part of FPL's efforts to meet projected incremental resource needs for the 2004 – 2013 time period.

FPL's integrated resource planning process has identified continued load growth in the FPL service territory in the next ten years. As a result, FPL's total generation capability is expected to significantly increase in response to this need during the 2004 – 2013 time period as shown in Table ES.1. This table also shows the resulting projected Summer and Winter reserve margins for FPL over this ten-year time horizon. Table ES.1 includes FPL's planned changes to existing generation units (due to unit overhauls, etc.), currently scheduled changes in the delivered amounts of purchased power, and the planned additions of new generating units. Although not specifically shown in this table, FPL's approved DSM Goals at the time this Site Plan was filed are assumed to be implemented on schedule.

The amount of new generating capacity that will be added is driven in part by the outcome of the Florida Public Service Commission (FPSC) docket No. 981890-EU. This docket ended with a stipulated agreement that resulted in FPL, along with Tampa Electric Company and Florida Power Corporation, changing its minimum reserve margin planning criterion from 15% to one of 20% beginning with the Summer of 2004. The following summarizes the capacity resources that are a part of FPL's 2004 Site Plan.

Based on previous actions, FPL has obtained the capacity needed over the next several years through a number of short-term, firm capacity purchases from utilities and other entities. Additional short-term, firm purchases for 2004 have been made and the balance will be completed by June 1.

In 2005, FPL will be adding a large (1,107 Summer MW) new combined cycle (CC) unit at its existing Manatee plant site. Also in 2005, the two combustion turbines (CT's) that were added at FPL's existing Martin plant site in mid - 2001 will be converted into a 1,107 Summer MW CC unit by the addition of two additional CT's, heat recovery steam generators, and associated equipment. This conversion will add 785 Summer MW of capability above the present capability of the existing two CT's. The additions for 2005 were selected as the best options among other FPL construction alternatives and numerous proposals received in response to two Request for Proposals (RFP's) FPL issued in August 2001 and April 2002, respectively. These two capacity additions were approved by the FPSC on November 19, 2002, and their applications for certification under the Florida Electric Power Plan Siting Act (PPSA) were granted on April 11, 2003.

In 2007, FPL forecasts a capacity need of 1,066 MW of additional capacity. FPL developed a plan for a 1,144 MW CC unit located at FPL's existing Turkey Point plant site as its next planned generating unit. Following a review of proposals received in response to FPL's 2003 RFP (issued in August, 2003), the FPL next planned generating unit (NPGU) was chosen as the best alternative. FPL filed for FPSC approval of a Determination of Need for this unit on March 8, 2004, and an FPSC decision on this matter is expected in mid-Summer of 2004. FPL filed for PPSA certification for this unit on November 14, 2003 and expects a decision on this application in the 1st Quarter of 2005.

FPL forecasts a continued need for new capacity in the years 2008 through 2013. In response to this continued need, and to facilitate system planning efforts, FPL's current plans include the addition of two combustion turbines (CT's) in 2008 at its Midway site, a CC unit in 2009 at its Corbett site, and two additional CC units: one each year in 2011 and 2012. Sites for these two additional CC units have not yet been selected. These planned increases in electric generation capability will allow FPL to maintain system reliability and integrity at a reasonable cost.

FPL's planning efforts in the past few years have also identified two issues that continue to receive attention in FPL's ongoing resource planning work. These two issues are: 1) the growing imbalance in southeast Florida between load and generating capacity located within this region; and 2) maintaining/enhancing fuel diversity in the FPL system. The selection of the Turkey Point CC unit to meet FPL's 2007 need will help mitigate the southeast Florida imbalance. FPL's approach to these two issues is discussed throughout this document and will continue to influence FPL's on-going resource planning work.

Projected Capacity Changes and Reserve Margins for [illegible]L [1]

		Net Capacity Changes (MW)		FPL Reserve Margin (%)	
		Winter [2]	Summer [3]	Winter	Summer
2004	Purchases [4]	(127)	44	27%	21%
	New Short-Term Purchase [5]	—	360		
	Changes to existing Units	21	74		
2005	Purchases [4]	(16)	(60)	22%	26%
	Manatee Unit #3 Combined Cycle [6]	—	1,107		
	New Short-Term Purchase [5]	—	(360)		
	Conversion of MR #8 CT's to CC [6]	(363)	785		
2006	Manatee Unit #3 Combined Cycle [6]	1,201	—	31%	22%
	Conversion of MR #8 CT's to CC [6]	1,198	—		
	Purchases [4]	(136)	(136)		
	Changes to existing Units	(2)	(1)		
2007	Purchases [4]	—	(945)	28%	20%
	Turkey Point Combined Cycle #5 [6]	—	1,144		
	Changes to existing Units	(1)	(2)		
2008	Purchases [4]	(1,018)	—	26%	20%
	Turkey Point Combined Cycle #5 [6]	1,181	—		
	Combustion Turbines at Midway	—	324		
	Changes to existing Units	(1)	—		
2009	Combustion Turbines at Midway	362	—	26%	23%
	Purchases [4]	—	(51)		
	Combined Cycle at Corbett [6]	—	1,144		
2010	Combined Cycle at Corbett [6]	1,181	—	28%	20%
	Purchases [4]	(51)	(975)		
	New Purchase(s)	—	931		
2011	Unsited Combined Cycle # 1 [6]	—	1,144	25%	22%
	Purchases [4]	(1,020)	(45)		
	New Purchase(s)	931	—		
2012	Unsited Combined Cycle # 1 [6]	1,181	—		
	Unsited Combined Cycle # 2 [6]	—	1,144	27%	25%
2013	Unsited Combined Cycle # 2 [6]	1,181	—	30%	22%
	TOTALS =	5,702	5,627		

1) Additional information about these resulting reserve [illegible]rgins and capacity changes are four[illegible] [illegible]n Schedules 7 & 8 respectively.

2) Winter values are values for January of year shown.

3) Summer values are values for August of year shown.

4) These are firm capacity purchases. See Section I.D and III.A. for more details.

5) Negotiations are currently underway between FPL and several parties to secure this short - term capacity

6) All new combined cycle units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

Table ES.1

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 8,070,000 people. FPL served an average of 4,117,221 customer accounts in thirty-five counties during 2003. These customers were served from a variety of resources including: FPL-owned fossil and nuclear generating units, non-utility owned generation, demand side management, and interchange/purchased power.

I.A. FPL-Owned Resources

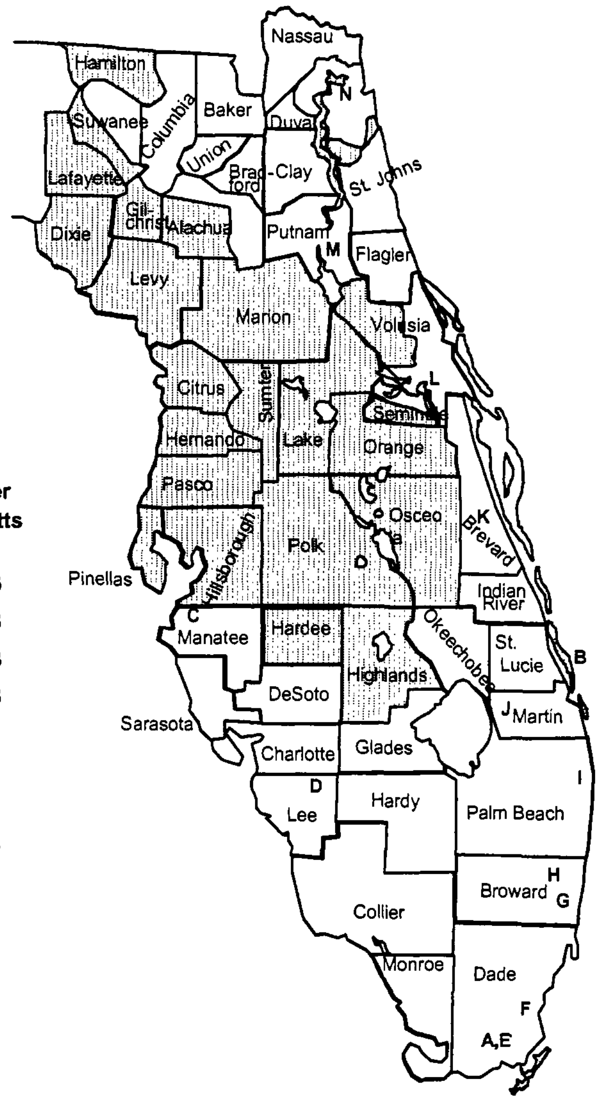
The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory and also include partial ownership of one unit located in Georgia and two units located in Jacksonville. The current generating facilities consist of four nuclear steam units, three coal units, nine combined cycle units, seventeen fossil steam units, fifty-one combustion gas turbines, and five diesel units. The location of these units is shown on Figure I.A.1.

The bulk transmission system is composed of 1,105 circuit miles of 500 Kilovolt (KV) lines (including 75 miles of 500 KV lines [two 37-1/2 mile lines] between Duval Substation and the Florida-Georgia state line, which are jointly owned with Jacksonville Electric Authority) and 2,744 circuit miles of 230 KV lines. The underlying network is composed of 1,634 circuit miles of 138 KV lines, 719 circuit miles of 115 KV lines, and 178 circuit miles of 69 KV transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 526 substations.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3 shows FPL's interconnection ties with other utilities.

Capacity Resources
(as of December 31, 2003)

Non-FPL Territory



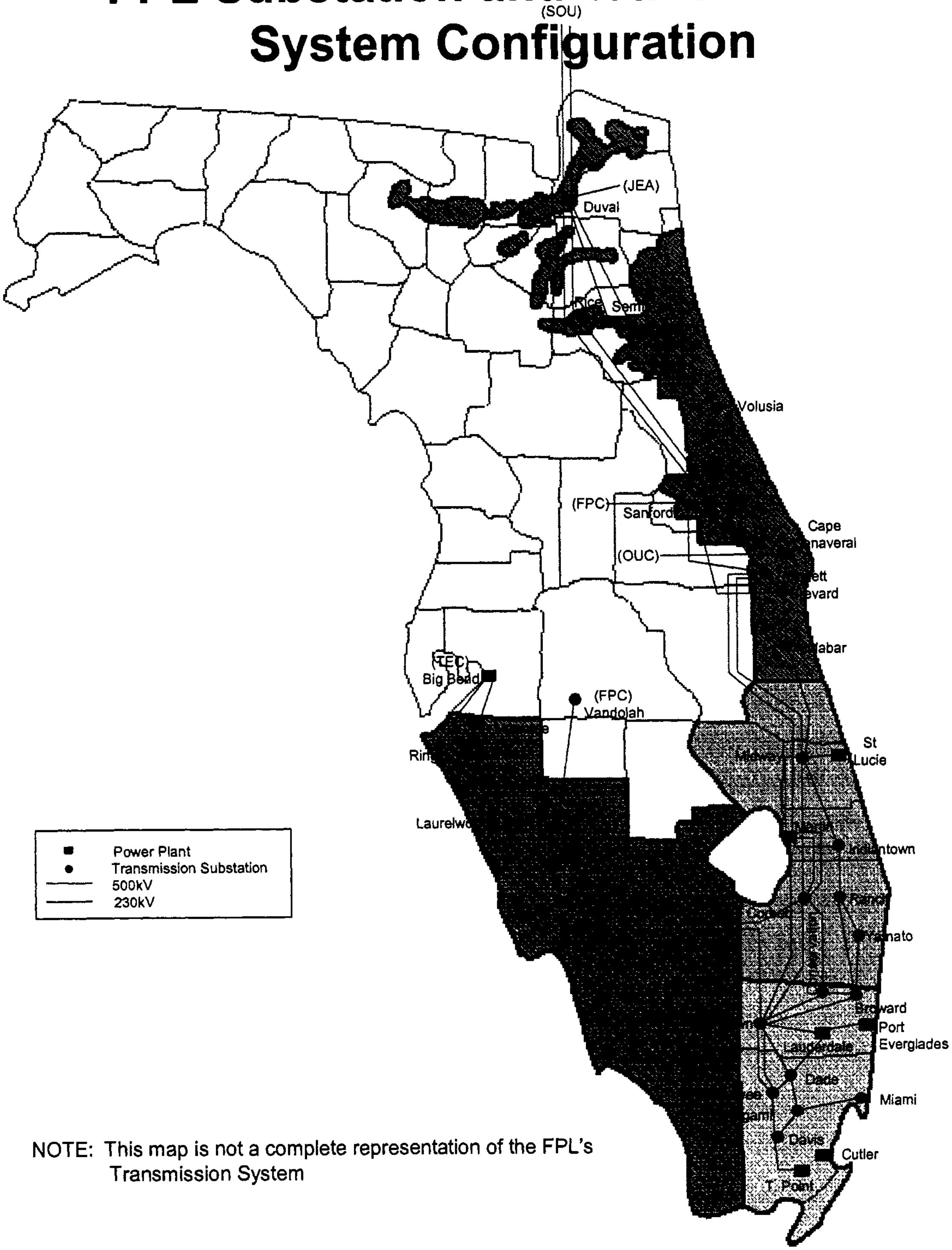
	Unit Name	No. of Units	Fuel Type	Summer Megawatts
A	Turkey Point	2	Nuclear	1,386
B.	St. Lucie *	2	Nuclear	1,553
C.	Manatee	2	Oil/Gas	1,628
D.	Ft. Myers	1	Oil/Gas	1,423
E.	Turkey Point	2	Oil/Gas	807
F.	Cutler	2	Gas	206
G.	Lauderdale	2	Gas/ Oil	859
H.	Port Everglades	4	Oil/Gas	1,233
I.	Riviera	2	Oil/Gas	565
J.	Martin	4	Gas/Oil	2,592
K.	Cape Canaveral	2	Oil/Gas	814
L.	Sanford	3	Gas/ Oil	2,018
M.	Putnam	2	Gas/Oil	498
N.	St. Johns River *	2	Coal/Pet Coke	254
Scherer **		1	Coal	658
Peaking Units				2,562
FPL Generation				19,056

**Represents FPL's ownership share: St. Lucie nuclear: 100% unit 1, 85% unit 2; St. Johns River: 20% of two units.*

*** The Scherer unit is located in Georgia and is not shown on this map.*

Figure I.A.1

FPL Substation and Transmission System Configuration



NOTE: This map is not a complete representation of the FPL's Transmission System

Figure I.A.2

FPL Interconnection Diagram

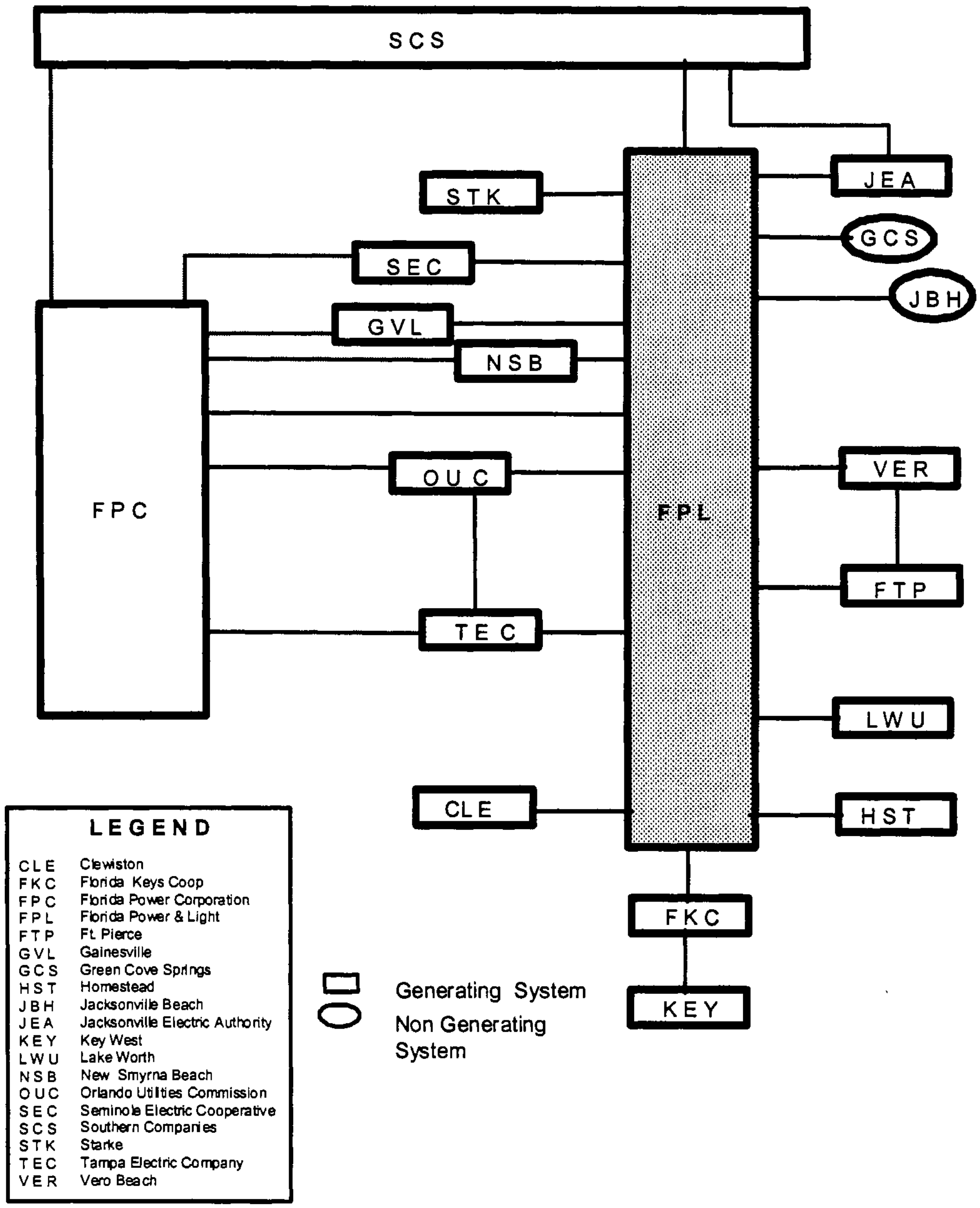


Figure I.A.3

I.B Non-Utility Generation

Non-utility generation is an important part of FPL's resource mix. FPL currently has contracts with seven cogeneration/small power production facilities to purchase firm capacity and energy. A listing of these facilities appears in Table I.B.1. In addition, FPL purchases as-available (non-firm) energy from several cogeneration facilities and small power production facilities as shown in Table I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

Florida Power & Light Company Firm Capacity and Energy Contracts with Cogeneration/Small Power Production Facilities					
Project	**County**	**Fuel**	**Capacity MW**	**In-Service Date**	**End Date**
Bio-Energy	Broward	Landfill Gas	10.0	5/1/1998	01/01/05
Florida Crushed Stone	Hernando	Coal (PC)	110.0	4/1/1992	10/31/05
			11.0	1/1/1994	10/31/05
			12.0	1/1/1995	10/31/05
			3.0	2/1/2003	10/31/05
Broward South	Broward	Solid Waste	50.6	4/1/1991	08/01/09
Palm Beach SWA	Palm Beach	Solid Waste	43.5	4/1/1992	03/31/10
Broward North	Broward	Solid Waste	45.0	4/1/1992	12/31/10
Cedar Bay Generating Co.	Duval	Coal (CFB)	250.0	1/25/1994	12/31/24
Indiantown Cogen., LP	Martin	Coal (PC)	330.0	12/22/1995	12/01/25
Broward South	Broward	Solid Waste	1.4	1/1/1993	12/31/26
			1.5	1/1/1995	12/31/26
			0.6	1/1/1997	12/31/26
Broward North	Broward	Solid Waste	7.0	1/1/1993	12/31/26
			1.5	1/1/1995	12/31/26
			2.5	1/1/1997	12/31/26

Table I.B.1

As Available Energy Purchases From Non-Utility Generators in 2003				
Project	**County**	**Fuel**	**In-Service Date**	**Energy (MWH) Delivered to FPL in 2003**
US Sugar-Bryant	Palm Beach	Bagassee	2/80	3,998
Tropicana	Manatee	Natural Gas	2/90	17,433
Okeelanta	Palm Beach	Bagassee/Wood	11/95	309,523
Tomoka Farms	Volusia	Landfill Gas	7/98	22,869
Georgia Pacific	Putnam	Paper By-Product	2/94	3,050

Table I.B.2

I.C. Demand Side Management (DSM)

FPL's DSM activities continue what has been FPL's practice since 1978 of encouraging cost-effective conservation and load management. FPL's DSM efforts through 2003 have resulted in a cumulative Summer peak reduction of approximately 3,270 MW at the generator and an estimated cumulative energy saving of 25,429 GWH at the generator.

FPL's current DSM Plan was approved by the Florida Public Service Commission in late 1999 and reflects FPL's DSM Goals for the 2000-2009 time frame. FPL's resource plan, and the schedule for new generation additions, presented in this document are based on these approved DSM levels.

I.D. Purchased Power

Purchased power is also an important part of FPL's resource mix. FPL has a Unit Power Sales (UPS) contract to purchase 931 MW, with a minimum of 381 MW, of coal-fired generation from the Southern Company through May, 2010. In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 381 MW (Summer) and 390 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Unit Nos. 1 and 2 (FPL also has ownership interest in these units; that ownership amount is reflected in FPL's installed capacity shown on Schedule 1).

Finally, FPL has additional firm capacity purchase contracts through early 2007. These firm capacity purchase contracts are with a variety of suppliers. Table I.D.1 presents a projection of firm purchased power contracts through the year 2013.

	FPL's Purchased Power MW (1)							
	UPS		***SJRPP***		***Other Firm Capacity Purchases***		***Total***	
Year	***Winter***	***Summer***	***Winter***	***Summer***	***Winter***	***Summer***	***Winter***	***Summer***
2003 (2)	929	929	390	381	1156	953	2475	2263
2004	931	931	390	381	1024	1355	2345	2667
2005	931	931	390	381	1018	945	2339	2257
2006	931	931	390	381	1018	945	2339	2257
2007	931	931	390	381	1018	0	2339	1312
2008	931	931	390	381	0	0	1321	1312
2009	931	931	390	381	0	0	1321	1312
2010	931	0	390	381	0	931	1321	1312
2011	0	0	390	381	931	931	1321	1312
2012	0	0	390	381	931	931	1321	1312
2013	0	0	390	381	931	931	1321	1312

Note:

(1) Total reflects total resource entitlements resulting from existing agreements between FPL, Southern Companies, JEA, and from new firm purchase agreements. In addition, FPL currently projects replacement by purchase(s) of the 2010 - ending UPS contracts.

(2) Values for 2003 are actual.

Table I.D.1

Schedule 1

Existing Generating Facilities
As of December 31, 2003

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport. Pri.	(8) Fuel Transport. Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW
Turkey Point		Miami Dade County 27/57S/40E									2,338,100	2,259	2,205
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	410	407
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	403	400
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	760,000	717	693
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	760,000	717	693
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	14,000	12	12
Cutler		Miami Dade County 27/55S/40E									236,500	212	206
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	74,500	70	68
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	162,000	142	138
Lauderdale		Broward County 30/50S/42E									1,863,972	1,947	1,699
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	521,250	465	430
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	521,250	464	429
	1-12		CT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,736	509	420
	13-24		CT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,736	509	420
Port Everglades		City of Hollywood 23/50S/42E									1,665,086	1,748	1,653
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	225,250	222	221
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	225,000	222	221
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	392	390
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	403	401
	1-12		CT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,736	509	420
Riviera		City of Riviera Beach 33/42S/43E									620,840	569	565
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	283	281
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	286	284

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2003

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW
Martin		Martin County 29/29S/38E									3,312,000	3,012	2,906
	1		ST	NG	FO6	PL	PL	Unknown	Dec-80	Unknown	863,000	830	828
	2		ST	NG	FO6	PL	PL	Unknown	Jun-81	Unknown	863,000	829	821
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	495	471
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	496	472
	8 A & B		CT	NG	No	PL	No	Unknown	Jun-01	Unknown	362,000	362	314
St. Lucie		St. Lucie County 16/36S/41E									1,553,000	1,579	1,553
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	839,000	853	839
	2	2/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	714,000	726	714
Cape Canaveral		Brevard County 19/24S/36F									804,100	820	814
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	410	407
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	410	407
Sanford		Volusia County 16/19S/30E									1,754,350	2,290	2,018
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	150,250	142	138
	4		CC	FO6	NG	WA	PL	Unknown	Oct-03	Unknown	436,100	1,074	940
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,168,000	1,074	940
Putnam		Putnam County 16/10S/27E									580,000	572	498
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,000	286	249
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,000	286	249

1/ These ratings are peak capability.
2/ Total capability is 853/839 MW. Capabilities shown represent the company's share of the unit and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of 14.89551%.

Schedule 1

Existing Generating Facilities
As of December 31, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Fort Myers		Lee County 35/43S/25E									2,483,000	2,759	2,399
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,739,000	1,610	1,423
	3		CT	NG	FO2	PL	PL	Unknown	Jun-01	Unknown		380	328
	1-12		CT	FO2	No	WA	No	Unknown	May-74	Unknown	744,000	769	648
Manatee		Manatee County 18/33S/20E									1,726,600	1,642	1,628
	1		ST	FO6	No	WA	No	Unknown	Oct-76	Unknown	863,300	821	814
	2		ST	FO6	No	WA	No	Unknown	Dec-77	Unknown	863,300	821	814
St. Johns River Power Park 2/		Duval County 12/15/28E (RPC4)									250,000	260	254
	1		BIT	BIT	Pet Coke	RR	WA	Unknown	Mar-87	Unknown	125,000	130	127
	2		BIT	BIT	Pet Coke	RR	WA	Unknown	May-88	Unknown	125,000	130	127
Scherer 3/		Monroe, GA									891,000	666	658
	4		BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	891,000	666	658
								Total System as of December 31, 2002 =				20,335	19,056

1/ These ratings are peak capability.
2/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No. 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80%.
3/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.

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CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are developed on an annual basis for resource planning work at FPL. These forecasts are a key input to the models used to develop the Integrated Resource Plan. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

The primary drivers to develop these forecasts are demographic trends, weather, economic conditions, and prices of electricity. In addition, the resulting forecasts are an integration of economic evaluations, inputs of local economic development boards, weather assessments from the National Oceanic and Atmospheric Administration (NOAA), and inputs from FPL's own customer service planning areas. In the area of demographics, population trends by county, plus housing characteristics such as housing starts, housing size, and vintage of homes are assessed.

Forecasts for electric usage in the residential and commercial classes include end-use information such as appliance saturation studies, efficiencies, and intensity of energy use. In addition to these inputs, residential forecasts also make use of household characteristics such as ages of members in households, number of members in households, and income distributions.

The projections for the national and Florida economy are obtained from Global Insight, formerly know as DRI - WEFA. Population projections for the counties served by FPL are obtained from the Bureau of Economic and Business Research (BEBR) of the University of Florida. In addition, FPL actively participates with local development councils and universities to obtain their assessments of the local economy, specifically in the area of expansion of new businesses and retention of the current business base. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is a key factor that affects the company's sales and peak demand. Weather variables are used in the forecasting models for energy sales and peak demand. There are two sets of weather variables developed and used in forecasting models:

1. Cooling and Heating Degree-Days are used to forecast energy sales.
2. Temperature data is used to forecast Summer and Winter peaks.

The Cooling and Heating Degree-Days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric heaters. A composite temperature is derived using hourly temperatures across FPL's service territory (Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained) weighted by regional energy sales. This composite temperature is used to derive Cooling and Heating Degree-Days which are based on starting point temperatures of 72°F and 66°F, respectively. Similarly, the maximums and minimums of the composite temperature are used for the Summer and Winter peak models.

II.A. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for each revenue class for the forecasting period of 2003-2025 and are adjusted to match the Net Energy for Load (NEL) forecast. The results of these sales forecasts for the years 2004 - 2013 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical tool MetrixND. The methodologies used to develop sales forecasts for each jurisdictional revenue class are outlined below. The first five years of the forecasts were developed using monthly models for Net Energy for Load and energy sales by class.

1. Residential Sales

Residential energy sales are forecast by multiplying the residential use per customer forecast by the number of residential customers forecasted. Residential electric usage per customer is estimated by using a regression model which contains the real residential price of electricity, Florida per capita income, and Cooling and Heating Degree-Days as explanatory variables. The price of electricity plays a role in explaining electric usage since electricity, like all other goods and services, will be used in greater or lesser quantities depending upon its price. The Cooling Degree-Days variable is multiplied by the level of air conditioning saturation and the Heating Degree-Days variable is multiplied by the level of electric heating saturation. To capture economic conditions, the model includes Florida's per capita income. The degree of economic prosperity can, and does, affect residential electricity sales. For the short-term period (first five years), an econometric model is developed using monthly data. The monthly model is a function of the same variables such as Cooling Degree-Days, Heating Degree-Days, price of electricity, Florida's per capita income, and a dummy variable for the months of April, May, and October.

2. Commercial Sales

The commercial sales forecast is also developed using a regression model for the long-and short-term. Commercial sales are a function of the following variables: Florida's commercial employment, commercial real price of electricity, Cooling Degree-Days, and an autoregressive term. Florida's commercial employment is used to capture the economic activity in FPL's service territory. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. Cooling Degree-Days are used to capture weather-sensitive load in the commercial sector. The first five years of the forecast are developed from a monthly model using the same explanatory variables, and for the following years, growth rates from the annual model are applied.

3. Industrial Sales

Industrial sales are forecasted through a linear multiple regression model using Florida manufacturing employment, the price of electricity, and a dummy variable for the economic recessions. Energy sales in this revenue class are primarily due to manufacturers; therefore, employment in this sector is a key variable in capturing the economic activity. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. For the short-term period (first five years), an econometric model is developed using monthly data. The monthly model is a function of the same variables such as Florida manufacturing employment, Cooling Degree-Days, price of electricity, and an autoregressive term. For the following years, growth rates from the annual model are applied.

4. Other Public Authority Sales

At present, this class consists of sports fields and one government account. The forecast for this class is based on historical knowledge of its characteristics.

5. Street & Highway Sales and Railroad & Railways Sales

The forecast for Street and Highway sales is developed by first assuming a constant use per customer and then multiplying that value by the number of projected customers. The forecast of sales to Railroad & Railways is based on historical knowledge of its characteristics. This class consists of Miami-Dade County's Metrorail system.

6. Sales for Resale

Sales for Resale (Wholesale) customers are composed of municipalities and/or electric cooperatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers.

Currently, there are four customers in this class: the Florida Keys Electric Cooperative (Florida Keys), City Electric System of the Utility Board of Key West, Florida (City of Key West), Miami-Dade County, and FMPA. Sales to the Florida Keys are forecasted using a regression model. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor. Miami-Dade County sells 60 MW to Florida Power Corporation. Line losses are billed to Miami-Dade under a wholesale contract. The forecast is calculated based on assumptions about the magnitude of line losses, the sales monthly capacity factor, and the number of hours in a particular month. FMPA has contracted for delivery of 75 MW through October, 2007.

7. Total Sales

Sales forecasts by revenue class are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, an expansion factor is applied to generate a forecast of annual Net Energy for Load (NEL).

II.B. Net Energy for Load

An annual econometric model is developed to produce a Net Energy for Load (NEL) forecast. The key inputs to the model are: the price of electricity, Heating and Cooling Degree-Days, Florida Non-Agricultural Employment, and an autoregressive term. The monthly model is similar, except the economic variable utilized is Florida's per capita income since the model is estimated on a per customer basis. Like the sales forecasts, the first five years are obtained from the short-term model, and forecasts for subsequent years are generated using the growth rates from the annual model.

Once an annual NEL forecast is obtained using the above-mentioned methodology, the results are then compared for reasonableness to the NEL forecast generated using the total sales forecast. The sales by class forecasts previously discussed are then adjusted to match the NEL from the annual NEL model.

The forecasted NEL values for 2004 – 2013 are presented in Schedule 3.3 that appears at the end of this chapter.

II.C. System Peak Forecasts

The rate of absolute growth in FPL system load has been a function of a larger customer base, varying weather conditions, continued economic growth, changing patterns of customer behavior (including an increased stock of electricity-consuming appliances), and more efficient heating and cooling appliances. FPL developed the Peak Forecast models to capture these behavioral relationships.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2004 – 2013 are presented in Schedules 3.1 and 3.2 as well as in Schedules 7.1 and 7.2.

1. System Summer Peak

The Summer peak forecast is developed using an econometric model. The model is a per customer model that includes: the total number of FPL's customers, the price of electricity, Real Florida income as an economic driver, and the maximum temperature as a weather variable. Also included in the model is an autoregressive term.

2. System Winter Peak

Like the system Summer peak model, the Winter peak model is also an econometric model. The Winter peak model is a per customer model which consists of three weather-related variables: (1) the minimum Winter day temperature, (2) a weather term, which is a ratio of heating saturation and minimum Winter day temperature, and (3) Heating Degree-Hours for the prior day until 9:00 a.m. of the peak day. In addition, the model also uses an economic variable, Real Florida Income. A dummy variable, which is used to capture the effects of larger homes, is multiplied by the minimum temperature.

3. Monthly Peak Forecasts

Monthly peaks for the 2003-2025 period are forecasted to provide information for the scheduling of maintenance for power plants and fuel budgeting. The forecasting process is basically the same as for the monthly NEL forecast and consists of the following actions:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to seasonal peak (Summer = April-October, Winter = November-March.)

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.D. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2003-2025 are produced using a System Load Forecasting "shaper" program. This model uses sixteen years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. These daily load shapes are ranked and used with forecasted monthly peaks, NEL, and calendars in developing an hourly forecast. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					Commercial		
Year	Population*	Members per Household	GWH**	Average*** No. of Customers	Average KWH Consumption Per Customer	GWH**	Average*** No. of Customers	Average KWH Consumption Per Customer
1994	6,660,137	2.19	38,716	3,037,629	12,745	29,946	366,409	81,729
1995	6,806,337	2.20	40,556	3,097,192	13,094	30,719	374,005	82,135
1996	6,948,942	2.20	41,302	3,152,625	13,101	31,211	380,860	81,949
1997	7,105,582	2.21	41,849	3,209,298	13,040	32,942	388,906	84,703
1998	7,249,617	2.22	45,482	3,266,011	13,926	34,618	396,749	87,255
1999	7,412,734	2.22	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,603,543	2.23	46,320	3,414,002	13,568	37,001	415,295	89,096
2001	7,754,966	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,896,813	2.21	50,865	3,566,167	14,263	40,029	435,313	91,955
2003	8,070,010	2.21	53,465	3,652,663	14,643	41,425	444,650	93,163
2004	8,184,322	2.21	53,373	3,695,370	14,443	42,574	454,728	93,625
2005	8,328,360	2.22	55,004	3,758,193	14,636	43,701	464,926	93,995
2006	8,471,579	2.22	56,923	3,821,542	14,895	44,852	475,338	94,358
2007	8,614,099	2.22	58,245	3,882,687	15,001	45,983	484,370	94,934
2008	8,756,620	2.22	59,842	3,944,810	15,170	47,024	492,604	95,461
2009	8,898,722	2.22	60,846	4,002,441	15,202	48,065	500,486	96,036
2010	9,041,109	2.23	62,244	4,060,676	15,328	49,157	507,970	96,772
2011	9,184,069	2.23	63,629	4,118,959	15,448	50,092	515,299	97,210
2012	9,328,059	2.23	64,921	4,176,707	15,544	51,010	522,503	97,627
2013	9,472,334	2.24	66,342	4,234,176	15,668	51,945	529,810	98,045

* Population represents only the area served by FPL.
** Actual energy sales include existing conservation. Forecasted energy sales do not include the impact of incremental conservation.
*** Average No. of Customers is the annual average of the twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads & Railways	Street & Highway Lighting	Other Sales to Public Authorities	Total*** Sales to Ultimate Consumers
Year	GWH **	Average* No. of Customers	Average KWH Consumption Per Customer	GWH **	GWH **	GWH **	GWH
1994	3,845	15,588	246,664	85	353	664	73,608
1995	3,883	15,140	256,473	84	358	648	76,248
1996	3,792	14,783	256,511	83	368	577	77,334
1997	3,894	14,761	263,803	85	383	702	79,855
1998	3,951	15,126	261,206	81	373	625	85,130
1999	3,948	16,040	246,135	79	473	465	84,676
2000	3,768	16,410	229,616	81	408	381	87,960
2001	4,091	15,445	264,875	86	419	67	90,212
2002	4,057	15,533	261,186	89	420	63	95,523
2003	4,004	17,029	235,128	93	425	64	99,496
2004	4,036	15,459	261,078	89	440	63	100,574
2005	4,094	15,302	267,547	90	447	63	103,398
2006	4,145	15,185	272,967	90	453	63	106,525
2007	4,165	15,186	274,266	90	463	63	109,010
2008	4,187	15,238	274,774	91	473	63	111,680
2009	4,200	15,275	274,959	91	483	63	113,748
2010	4,214	15,313	275,191	92	493	63	116,262
2011	4,231	15,372	275,241	92	503	63	118,610
2012	4,246	15,377	276,127	93	512	63	120,845
2013	4,260	15,418	276,300	93	521	63	123,224

*Average No.of Customers is the annual average of the twelve month values.
** Actual energy sales include existing conservation. Forecasted energy sales do not include the impact of incremental conservation.
***GWH Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History and Forecast of Energy Consumption And Number of Customers by Customer Class

(1)	(17)	(18)	(19)	(20)	(21)
Year	Sales for Resale GWH	Utility Use & Losses GWH	Net* Energy For Load GWH	Average ** No. of Other Customers	Total Average*** Number of Customers
1994	1,400	5,367	80,376	2,561	3,422,187
1995	1,437	6,276	83,961	2,459	3,488,796
1996	1,353	6,011	84,698	2,480	3,550,748
1997	1,228	5,770	86,853	2,520	3,615,485
1998	1,326	6,205	92,662	2,584	3,680,470
1999	953	5,829	91,458	2,605	3,756,009
2000	970	7,059	95,989	2,694	3,848,401
2001	970	7,222	98,404	2,722	3,935,281
2002	1,233	7,443	104,199	2,792	4,019,805
2003	1,511	7,386	108,393	2,879	4,117,221
2004	1,441	7,510	109,525	2,865	4,168,421
2005	1,456	7,711	112,565	2,905	4,241,326
2006	1,474	7,943	115,942	2,941	4,315,007
2007	1,459	7,961	118,430	3,002	4,385,245
2008	1,092	8,126	120,899	3,061	4,455,713
2009	1,092	8,275	123,115	3,121	4,521,322
2010	1,092	8,456	125,811	3,178	4,587,137
2011	1,092	8,625	128,327	3,234	4,652,864
2012	1,092	8,787	130,724	3,289	4,717,877
2013	1,092	8,958	133,274	3,342	4,782,747

* GWH Col. (19) = Col. (16) + Col. (17) + Col. (18). Actual NEL includes existing conservation and agrees to Col (8) on schedule 3.3.
Forecasted NEL does not include incremental conservation and agrees to Col. (2) on schedule 3.3

** Average Number of Customers is the annual average of the twelve month values.

*** Total Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20)

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
1994	15,179	409	14,770	0	392	220	354	125	14,433
1995	16,172	435	15,737	0	466	259	391	193	15,315
1996	16,064	364	15,700	0	531	339	414	296	15,119
1997	16,613	380	16,233	0	615	440	432	341	15,566
1998	17,897	426	17,471	0	656	480	441	359	16,800
1999	17,615	169	17,446	0	722	565	450	397	16,443
2000	17,808	161	17,647	0	767	626	456	432	16,585
2001	18,754	169	18,585	0	798	673	483	463	17,473
2002	19,219	261	18,958	0	826	733	484	499	17,909
2003	19,668	253	19,415	0	839	775	568	535	18,261
2004	20,297	227	20,070	0	802	84	582	42	18,787
2005	20,799	230	20,569	0	809	126	592	62	19,210
2006	21,331	231	21,100	0	814	170	600	83	19,664
2007	21,851	234	21,617	0	819	214	608	103	20,107
2008	22,289	159	22,130	0	824	259	616	122	20,468
2009	22,784	159	22,625	0	828	306	622	141	20,888
2010	23,294	159	23,135	0	830	321	623	148	21,372
2011	23,783	159	23,624	0	830	321	623	148	21,861
2012	24,279	159	24,120	0	830	321	623	148	22,357
2013	24,784	159	24,625	0	830	321	623	148	22,862

Historical Values (1994 - 2003):

Col. (2) - Col.(4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) -Col. (9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business on Call (BOC) and Commercial Demand Reduction (CDR).

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula:Col. (10) = Col.(2) - Col.(6) - Col.(8).

Projected Values (2004 - 2013):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2003 are incorporated into the forecast.

Col. (5) - Col. (9) represent all incremental conservation and cumulative load control. These values are projected August values and are based on projections with a 1/2003 starting point.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.2
History and Forecast of Winter Peak Demand: Base Case

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
1994/95	16,563	635	15,928	0	393	265	360	93	15,810
1995/96	18,096	698	17,398	0	459	310	406	143	17,231
1996/97	16,490	626	15,864	0	731	368	418	154	15,341
1997/98	13,060	239	12,821	0	823	403	429	168	11,807
1998/99	16,802	149	16,653	0	1,218	438	417	182	15,167
1999/00	17,057	142	16,915	0	1,296	469	441	193	15,320
2000/01	18,199	150	18,049	0	972	493	448	201	16,779
2001/02	17,597	145	17,452	0	1,081	534	457	242	16,060
2002/03	20,190	246	19,944	0	1,116	581	453	288	18,621
2003/04	14,752	211	14,541	0	938	601	534	309	13,280
2004/05	20,583	208	20,375	0	939	114	540	22	18,968
2005/06	21,100	209	20,891	0	946	149	546	29	19,430
2006/07	21,605	212	21,393	0	952	183	551	37	19,882
2007/08	22,046	137	21,909	0	958	218	556	44	20,270
2008/09	22,539	137	22,402	0	964	252	561	51	20,712
2009/10	23,026	137	22,889	0	968	284	564	57	21,153
2010/11	23,522	137	23,385	0	968	284	564	57	21,649
2011/12	24,024	137	23,887	0	968	284	564	57	22,151
2012/13	24,535	137	24,398	0	968	284	564	57	22,663
2013/14	25,057	137	24,920	0	968	284	564	57	23,184

Historical Values (1994/95 - 2003/04):

Col. (2) - Col.(4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col.(9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business on Call (BOC) and Commercial Demand Reduction (CDR).

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (6) - Col. (8).

Projected Values (2004/05- 2013/14):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2003 are incorporated into the forecast.

Col. (5) - Col.(9) represent all incremental conservation and cumulative load control. These values are projected January values and are based on projections with a 1/2003 starting point.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	C/I Conservation	Retail	Sales for Resale GWH	Utility Use & Losses	Net Energy For Load	Load Factor(%)
1994	81,493	661	456	80,093	1,400	5,367	80,376	60.4%
1995	85,415	777	677	83,978	1,437	6,276	83,961	59.3%
1996	86,708	971	1,039	85,355	1,353	5,984	84,698	60.0%
1997	89,240	1,213	1,174	88,012	1,228	5,770	86,853	59.7%
1998	95,316	1,374	1,279	93,990	1,326	6,205	92,663	59.1%
1999	94,361	1,542	1,362	93,408	953	5,829	91,458	59.3%
2000	99,094	1,674	1,431	98,123	970	7,059	95,989	61.5%
2001	101,736	1,789	1,542	100,765	970	7,222	98,404	59.9%
2002	107,754	1,917	1,637	106,520	1,233	7,443	104,199	61.9%
2003	112,158	2,009	1,757	110,646	1,511	7,386	108,393	62.9%
2004	109,525	145	52	108,084	1,441	7,510	109,328	61.4%
2005	112,565	238	88	111,108	1,456	7,711	112,239	61.8%
2006	115,942	334	124	114,468	1,474	7,943	115,484	62.0%
2007	118,430	430	159	116,970	1,459	7,961	117,841	61.9%
2008	120,899	529	193	119,807	1,092	8,126	120,177	61.8%
2009	123,115	629	225	122,023	1,092	8,275	122,261	61.7%
2010	125,811	671	240	124,719	1,092	8,456	124,900	61.7%
2011	128,327	671	240	127,235	1,092	8,625	127,416	61.6%
2012	130,724	671	240	129,631	1,092	8,787	129,813	61.3%
2013	133,274	671	240	132,181	1,092	8,958	132,363	61.4%

Historical Values (1994 - 2003):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) =Col. (3) + Col. (4) + Col. (8).

Col. (3) & Col.(4) are DSM values starting in January, 1988 through 2003 which contributed to the values in Col. (5) -Col. (9).

Col. (5) & Col. (6) are a breakdown of Net Energy For Load in Col (2) into Retail and Wholesale .

Col. (9) is calculated using Col. (8) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (8)*1000) / ((Col.(2) * 8760)

Projected Values (2004 - 2013):

Col. (2) represents Net Energy for Load w/o DSM values. The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (8).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation.

Col. (5) & Col. (6) are a breakdown of Net Energy For Load in Col (2) , into Retail and Wholesale.

Col. (8) NEL projected values shown here do include the impact of conservation in Col. (3) and Col. (4). Therefore, these NEL values do not match those shown on schedule 2.3 because those values do not account for incremental conservation.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of
Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2003 ACTUAL		2004* FORECAST		2005* FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	20,190	8,256	20,081	7,959	20,583	8,230
FEB	14,241	6,832	16,737	7,959	17,156	8,172
MAR	17,816	8,969	15,454	8,000	15,841	8,238
APR	16,505	8,235	16,833	8,358	17,249	8,586
MAY	19,012	9,671	18,609	9,221	19,069	9,467
JUN	18,580	10,011	19,503	10,193	19,985	10,457
JUL	19,668	10,490	19,849	10,636	20,340	10,907
AUG	19,018	10,245	20,297	10,825	20,799	11,100
SEP	18,873	10,392	19,689	10,503	20,175	10,779
OCT	18,311	9,268	18,311	9,339	18,764	9,598
NOV	15,989	8,626	16,837	8,351	17,258	8,599
DEC	15,362	7,399	17,178	8,181	17,608	8,432
TOTALS		108,393		109,525		112,565

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation and are consistent with values shown in Col. (19) of Schedule 2.3 and Col. (2) of Schedule 3.3.

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CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990's and has since utilized the process to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be considered. The projected timing and type of potential new power plants, the primary subject of this document, is determined as part of the IRP process work. This section discusses how FPL applied this process in its 2003 and early 2004 planning work.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental "steps" to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's projected new resource needs;

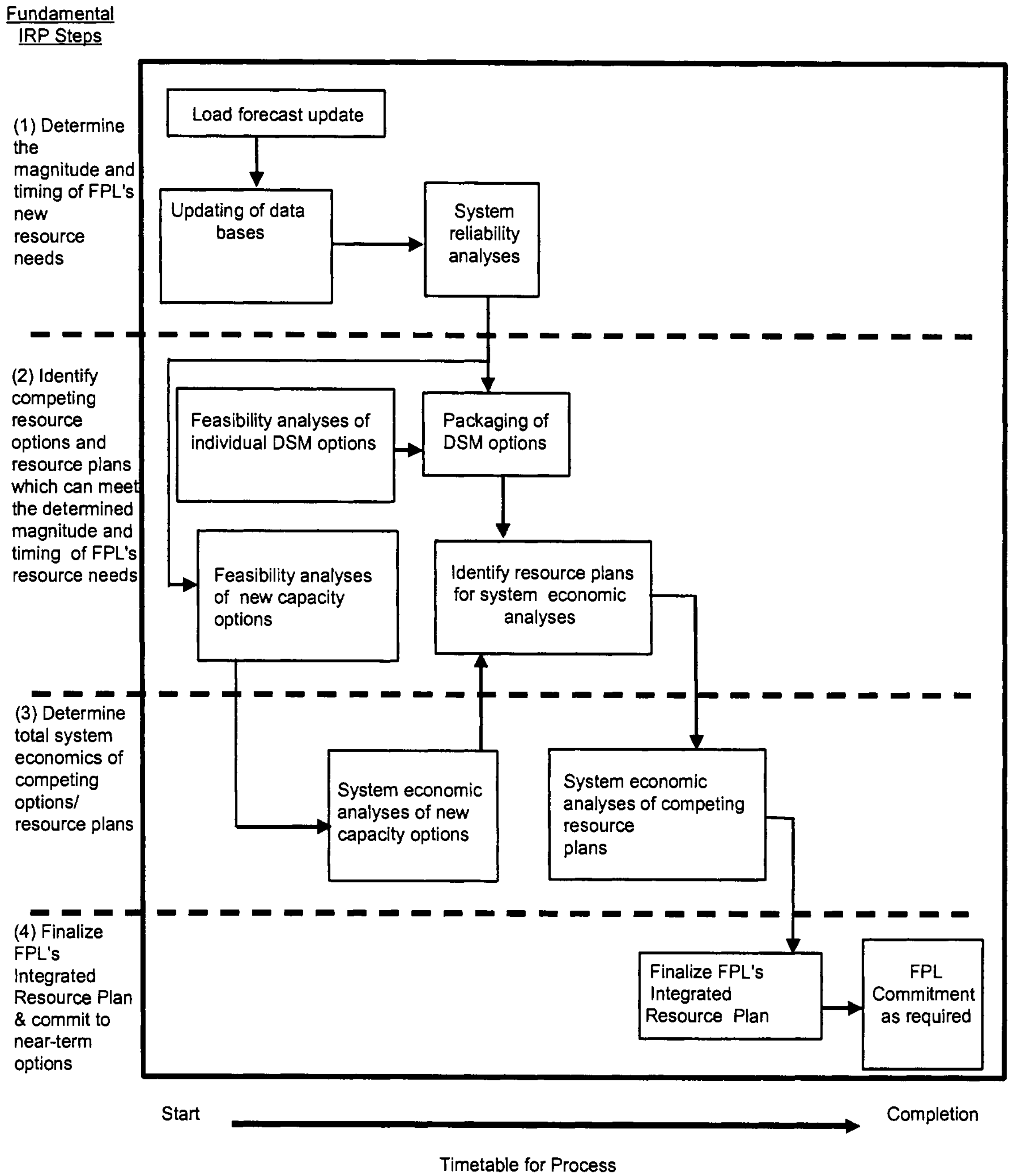
Step 2: Identify which resource options can meet the determined magnitude and timing of the specific resource needs;

Step 3: Determine the economics for the total utility system with each of the competing options and resource plans; and,

Step 4: Select a resource plan and make commitments, as required.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process



(Normal time period: approx. 6-7 months)

Figure III.A.1

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of these four resource planning steps – determining the magnitude and timing of FPL's projected resource needs – is essentially a determination of how many megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions are expected to be needed. Also determined in this step is when the capacity is expected to be needed to meet FPL's planning criteria. This step is often referred to as a reliability assessment for the utility system.

Step 1 generally starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information which is used in many of the fundamental steps in resource planning. Examples of this new information include: delivered fuel price projections, current financial and economic assumptions, as well as power plant capability and reliability assumptions. During its recent IRP work, FPL made four key assumptions. These assumptions include near-term construction capacity additions through the summer of 2007, short-term firm capacity purchase additions through late spring of 2007, long-term DSM implementation through 2009, and the projected replacement of the Southern Company Unit Power Sales (UPS) contracts that end in May, 2010.

The first of these assumptions incorporates FPL's announced plans to add near-term capacity through various construction projects. These construction projects include the addition of a new combined cycle (CC) unit at Manatee, the conversion of two existing CT's at Martin into a new CC unit and a new CC unit at Turkey Point. The Manatee and Martin additions are under construction with a scheduled in-service date of June, 2005. These capacity additions were approved by the FPSC in November 2002 after comparing them to proposals that were received in response to Requests for Proposals (RFP's) that solicited alternatives for meeting FPL's 2005/2006 capacity needs. These capacity additions also received certification under the Florida Electrical Power Plant Siting Act (PPSA) in April, 2003. The new CC unit at FPL's Turkey Point site is scheduled for mid-2007. FPL selected this construction option after evaluating competing proposals provided in response to FPL's 2003 RFP. FPL recently (March 8, 2004) filed for a request for approval of a Determination of Need for this unit with the FPSC and also has pending an application for PPSA certification of this unit with a decision expected in the 1st Quarter of 2005.

The second of these assumptions involves short-term firm capacity purchase additions. These firm capacity purchases are provided by a combination of utility and independent power producers. The total capacity and duration of these purchases have changed somewhat from what was presented in the 2003 Site Plan and the annual total capacity values for these purchases are presented in Table I.D.1 as "Other Firm Capacity Purchases" up to mid-2007. These purchase amounts are included in FPL's resource planning work.

The third of these assumptions involves DSM. Since 1994, FPL's resource planning work has incorporated the DSM MW called for in FPL's approved DSM goals in its analyses. This was again the case in FPL's most recent planning work, as its approved DSM goals at the time this Site Plan was filed were included.

The fourth of these assumptions anticipates a replacement of the UPS purchases that are currently scheduled to end in May, 2010 with other purchases. These purchases are presented in Table I.D.1 as "Other Firm Capacity Purchases" for the years beyond mid-2010.

These assumptions and much of the other updated information are used is the first fundamental step: the determination of the magnitude and the timing of FPL's projected resource needs. This determination is accomplished by system reliability analyses which are typically based on the dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both summer and winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry.

Historically, both deterministic and probabilistic methodologies have been employed in system reliability analysis. The calculation of excess firm capacity at the time of annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. The reserve margin calculation provides an indication of how much extra generation a system has above the forecasted peak load. A value of 20% is used as the reserve margin planning criteria to establish FPL's need. However, deterministic methods do not take into account probabilistic-related elements such as unit reliability and the value of being part of an interconnected system. Therefore, probabilistic methodologies have been used to provide additional information on the reliability of a generating system.

There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss-of-load probability or LOLP. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of the "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year and FPL uses this LOLP standard. LOLP analyses require complex statistical calculations and are carried out using the Tie Line Assistance and Generation Reliability (TIGER) model.

The end result of the first fundamental step of resource planning is a forecast of the amount and timing of capacity resources needed to meet both the reserve margin and LOLP criteria for system reliability. This information is used in the second fundamental step: identifying resource options and resource plans that can meet the projected magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans which can meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, feasibility analyses of new capacity options are carried out to determine which new capacity options appear to be the most economic. These analyses also consider capacity size (MW), estimated development and construction schedules, and operating parameters and costs.

The individual new capacity options are then "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new projected resource needs are met and the planning criteria are satisfied. The creation of these competing resource plans is typically carried out using dynamic programming techniques with the objective of forming alternative resource plans within the constraints applied to the resource planning process. The constraints include recognition of reserve margin criteria, feasible resource option performance characteristics, and construction or DSM implementation lead time. The development of these resource plans has been conducted using the EGEAS (Electric Generation Expansion Analysis System) computer model. When DSM options are being addressed, other computer models using both linear and non-linear programming techniques are used. For planning purposes, only FPL construction options were included in FPL's most recent planning analyses addressing FPL's 2008-2013 forecasted capacity needs.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs were identified.

Step 3: Determining the Total System Economics:

At the completion of fundamental steps 1 & 2, viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for comparing the system economics of these resource plans. The EGEAS model is employed to conduct the basic economic analyses of the resource plans.

The basic economic analysis of the competing resource plans focuses on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM methodology). However, in cases such as those existing for FPL's most recent planning work (wherein the DSM contribution was incorporated and the only competing options were new generating units) comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. This basic economic analysis captures the capital and operating costs of new resource options as well as the impact these new resource options have on FPL's system fuel costs.

In addition, other system costs of these resource plans must be incorporated as needed into the economic analyses. These include transmission-related costs, such as integration and system losses; increased operating costs of existing generating units, and impacts on FPL's capital structure. These costs are evaluated separately and in addition to the system operating cost values developed in the EGEAS analysis to complete the system cost impact of each resource plan. FPL considered the results of all of the economic analyses carried out in Step 3, before a determination of FPL's resource plan was made.

Step 4: Finalizing FPL's Current Resource Plan

The results of the work performed in the previous three fundamental steps are evaluated by FPL management and a decision is made establishing FPL's resource plan. The current resource plan is presented in the following section.

III.B Resource Additions

FPL's preliminary plan for generation capacity additions and changes for the period 2004 through 2013 are depicted in Table III.B.1 (the planned DSM additions are shown separately in Table III.D.1). These capacity additions and changes will result from a variety of actions including: minor changes to existing units (such as plant component wear between maintenance activities or component replacements as part of maintenance activities), changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules, the expiration of contracts, the addition of new purchase contracts, projected construction of new units, and conversion of the CT's at Martin into a CC unit.

As shown in Table III.B.1, the bulk of the capacity additions are made up of the following items:

- the conversion of two CT's into a larger CC unit in 2005 at FPL's Martin site
- the addition of a new CC unit, also in 2005, at FPL's Manatee site
- the projected construction of a new CC unit in 2007 at FPL's Turkey Point site
- the projected construction of 2 new CT units at the Midway site in 2008
- the projected construction of a new CC unit at the Corbett site in 2009
- the projected construction of two additional, unsited CC units, one each in 2011 and 2012.

These projected capacity additions address the forecasted resource needs from FPL's reliability analyses. In 2008, FPL's forecasted resource need is approximately 350 MW. For each year from 2009 through 2013, the projected annual resource need is significantly larger; between 550 MW to 630 MW per year.

In the past several years, FPL has undertaken several plant conversion and new construction activities that will result in the addition of approximately 6,600 MW of high efficiency, low emission combined cycle baseload generating capacity by 2007. Furthermore, as part of these plant conversions, FPL has transformed over 1,600 MW of previously intermediate and peaking generating capacity to high efficiency combined cycle base load capacity. Consequently, FPL currently plans that its relatively small 2008 need will be met by the construction of two CT units. Another factor contributing to this choice is the fact that FPL is in the process of developing proposed DSM Goals for the 2005 – 2014 period. FPL's DSM Goals will be filed with the FPSC in June 2004 and it is expected that the FPSC approval will be obtained no earlier than September 2004. The approved DSM Goals will then be utilized in subsequent analyses to finalize resource plans for 2008 and to evaluate resource plans to meet projected needs in 2009 and beyond. The current choice of new CT's to meet the 2008 need provides the flexibility to adopt the plan consistent with the DSM Goals that will be approved in late 2004 and will allow FPL to also consider meeting this need, in whole or in part, through one or more purchases from existing units.

Projected Capacity Changes and Reserve Margins for FPL (1)					
		Net Capacity Changes (MW)		FPL Reserve Margin (%)	
		Winter (2)	Summer (3)	Winter	Summer
2004	Purchases (4)	(127)	44	27%	21%
	New Short-Term Purchase (5)	---	360		
	Changes to existing Units	21	74		
2005	Purchases (4)	(16)	(60)	22%	26%
	Manatee Unit #3 Combined Cycle (6)	---	1,107		
	New Short-Term Purchase (5)	---	(360)		
	Conversion of MR #8 CT's to CC (6	(363)	785		
2006	Manatee Unit #3 Combined Cycle (6)	1,201	---	31%	22%
	Conversion of MR #8 CT's to CC (6)	1,198	---		
	Purchases (4)	(136)	(136)		
	Changes to existing Units	(2)	(1)		
2007	Purchases (4)	---	(945)	28%	20%
	Turkey Point Combined Cycle #5 (6)	---	1,144		
	Changes to existing Units	(1)	(2)		
2008	Purchases (4)	(1,018)	---	26%	20%
	Turkey Point Combined Cycle #5 (6)	1,181	---		
	Combustion Turbines at Midway	---	324		
	Changes to existing Units	(1)	---		
2009	Combustion Turbines at Midway	362	---	26%	23%
	Purchases (4)	---	(51)		
	Combined Cycle at Corbett (6)	---	1,144		
2010	Combined Cycle at Corbett (6)	1,181	---	28%	20%
	Purchases (4)	(51)	(975)		
	New Purchase(s)	---	931		
2011	Unsited Combined Cycle # 1 (6)	---	1,144	25%	22%
	Purchases (4)	(1,020)	(45)		
	New Purchase(s)	931	---		
2012	Unsited Combined Cycle # 1 (6)	1,181	---		
	Unsited Combined Cycle # 2 (6)	---	1,144	27%	25%
2013	Unsited Combined Cycle # 2 (6)	1,181	---	30%	22%
	TOTALS =	5,702	5,627		

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.

(2) Winter values are values for January of year shown.

(3) Summer values are values for August of year shown.

(4) These are firm capacity purchases. See Section I.D and III.A. for more details.

(5) Negotiations are currently underway between FPL and several parties to secure this short - term capacity.

(6) All new combined cycle units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

Table III.B.1

III.C Additional Issues Impacting FPL's Recent Planning Work

In the course of FPL's 2003 and early 2004 planning efforts, two issues that were identified in FPL's 2003 Site Plan received additional attention in FPL's on-going resource planning work. Those two issues are: 1) the need to address the growing imbalance in southeast Florida between load and generating capacity located within this region; and 2) the desire to maintain/enhance fuel diversity in the FPL system.

Southeast Imbalance

As was identified in previous FPL filings, there exists a significant imbalance between the large peak load in southeast Florida and the installed generating capacity in that region. The imbalance between generation and load is forecast to grow during the next few years because FPL forecasts continued load growth in this area beyond planned generation additions. If this growing imbalance is not addressed this will give rise to additional system costs that result from three transmission-related components: 1) increased transmission integration costs that will be required to deliver power to the load center from units outside the southeast Florida area, 2) the need to dispatch less efficient resources within the southeast Florida area and 3) the transmission losses associated with increased imports of electricity into the area.

Recognizing this load and generation imbalance in southeast Florida and the forecast of continued load growth in this area, FPL concluded it must either add generating capacity within this region or add the needed capacity outside of the southeast Florida area and the necessary transmission facilities to deliver capacity into southeast Florida. FPL's 2003 Request for Proposal (RFP) incorporated these concerns. The evaluation of FPL's Next Planned Generating Unit (NPGU) and proposals received in response to FPL's RFP addressed all system costs, including the three identified transmission-related cost components that are affected by the imbalance issue discussed above. Current and future resource planning processes also recognize these transmission-related costs associated with the geographic location of resource additions.

Fuel Diversity

Fuel diversity was the other key issue that received additional attention. In 2003, FPL began an evaluation of the economic and environmental characteristics of solid fuel-based technologies. Most economic analyses suggest that the forecasted fuel price differential between natural gas and solid fuel options might support the higher capital cost of solid fuel facilities. However, there remain at least three significant uncertainties inherent in the analyses that must be addressed and refined.

The first, and most influential, of these uncertainties is the forecasted behavior of the price differential between natural gas and solid fuels. Recognition of the high volatility exhibited by natural gas prices in recent years has added to the uncertainty of long - term price forecasts. Although continued growth in gas demand may contribute to higher firm gas prices, potential additional supply alternatives in the coming years (such as Liquefied Natural Gas - LNG) may contribute to lower gas prices. The extent to which these factors offset one another is a key influence that must be considered in this process. The second area of uncertainty is related to the type and cost of emissions management opportunities that will be available and the requirements that must be met during the operating life of a solid fuel facility. FPL's analyses of this area will address opportunities to employ evolving technologies to effectively manage the emissions of solid fuel facilities, the likely outcome of several significant legislative proposals that will impact the control level required, and managing the cost of compliance to FPL's customers in the future. Finally, FPL must address the uncertainty surrounding the capital cost and feasibility of developing and constructing a solid fuel facility in Florida. FPL is actively pursuing the refinement of data that will assist characterizing these uncertainties in a quantitative manner and incorporating this information into the resource planning process. FPL will provide to the FPSC, by December 2004, a report on FPL's evaluation regarding the possible addition of a solid fuel generation capacity in the future.

The current plan to meet FPL's projected capacity needs beyond 2007, reflected in the Tables and Schedules of this document, consists of the construction of natural gas - fired units, primarily CC's. The plan identifies this CC technology, in large part, because of its high efficiency and known benign environmental impact, as well as the high-level of development, construction, operational performance and capital cost forecasting confidence that has been accrued over recent years by FPL and the electric industry. Identifying this technology in FPL's current resource plan establishes a basis for which costs and risks are well understood and will allow the relative risks and benefits of competing alternatives to be more efficiently evaluated as detailed information and forecasts for those alternatives are refined. These projected resource additions beyond 2007 are subject to change pending the results of such evaluations.

FPL is actively engaged in identifying and evaluating opportunities that would enhance fuel and resource diversity in its capacity resource mix. These opportunities include:

- the construction of new solid fuel-based (coal and petroleum coke) facilities
- obtaining access to non-traditional sources of natural gas, such as through suppliers who transport and deliver natural gas to Florida in the form of LNG.
- maintaining the ability to utilize fuel oil at FPL's existing units.

Therefore, the new gas-fired CT and CC units currently shown as capacity additions for 2008 through 2013, and in particular for 2011 through 2013, are subject to change in the future as FPL evaluates the feasibility and cost-effectiveness of various alternatives to enhance fuel diversity. Based on current information, FPL believes that the earliest that fuel diversity could be enhanced by adding new solid fuel-based generating capacity would be mid-2011 based on the siting, development, permitting, construction, and commissioning timeline for this technology. In addition, FPL believes it is more likely that such a unit would be sited at some site north of southeast Florida due to permitting and fuel transportation considerations.

FPL's assessment of the fuel and resource diversity alternatives will continue to be developed through its on-going resource planning work and site development activities in 2004.

III.D Demand Side Management (DSM)

1. FPL's currently approved DSM programs are summarized as follows:

Residential Conservation Service: This is an energy audit program designed to assist residential customers in understanding how to make their homes more energy-efficient through the installation of conservation measures/practices.

Residential Building Envelope: This program encourages the installation of energy-efficient ceiling insulation in residential dwellings that utilize whole-house electric air conditioning.

Duct System Testing and Repair: This program encourages demand and energy conservation through the identification of air leaks in whole-house air conditioning duct systems and by the repair of these leaks by qualified contractors.

Residential Air Conditioning: This is a program to encourage customers to purchase higher efficiency central cooling and heating equipment.

Residential Load Management (On-Call): This program offers load control of major appliances/household equipment to residential customers, in exchange for monthly electric bill credits.

Residential New Construction (BuildSmart): This program encourages the design and construction of energy-efficient homes that cost-effectively reduce coincident peak demand and energy consumption.

Business Energy Evaluation: This program encourages energy efficiency in both new and existing commercial and industrial facilities by identifying DSM opportunities and providing recommendations to the customer.

Commercial/Industrial Heating, Ventilating, and Air Conditioning: This program encourages the use of high-efficiency heating, ventilation, and air conditioning (HVAC) systems in commercial/industrial facilities.

Commercial/Industrial Efficient Lighting: This program encourages the installation of energy-efficient lighting measures in commercial/industrial facilities.

Business Custom Incentive: This program encourages commercial/industrial customers to implement unique energy conservation measures or projects not covered by other FPL programs.

Commercial/Industrial Load Control: This program reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortage, in exchange for monthly electric bill credits. (This program was closed to new participants in 2000).

Commercial/Industrial Demand Reduction: This program, which started in 2002, is similar to the Commercial/Industrial Load Control program mentioned above in continuing the objective to reduce peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits.

Commercial/Industrial Building Envelope: This program encourages the installation of energy-efficient building envelope measures, such as window treatments and roof/ceiling insulation, for commercial/industrial facilities.

Business On Call: This program offers load control of central air conditioning units to both small, non-demand-billed and medium, demand-billed commercial/industrial customers, in exchange for monthly electric bill credits.

2. Research and Development

FPL's DSM Plan continues to support research and development activities. Historically, FPL has performed extensive DSM research and development. FPL will continue such activities, not only through its Conservation Research and Development program, but also through individual research projects. These efforts will examine a wide variety of technologies that build on prior FPL research where applicable and will expand the research to new and promising technologies as they emerge.

Conservation Research and Development Program

FPL's Conservation Research and Development Program is designed to evaluate emerging conservation technologies to determine which are worthy of pursuing for program development and approval. FPL has researched a wide variety of technologies and, from that research, has been able to develop new programs such as Residential New Construction, Commercial/Industrial Building Envelope and Business On Call.

Low Income Weatherization Retrofit Project

This R&D project investigated cost-effective methods of increasing the energy efficiency in the homes of FPL's low-income customers. The research project addressed the needs of low-income housing retrofits by providing monetary incentives to various housing authorities, including weatherization agency providers (WAPS), and non-weatherization agency providers (non-WAPS). These incentives were used by the housing authorities to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting.

The final report for this project was filed in November 2003. Of the seven different DSM measures evaluated, it was found that two measures, addressing HVAC maintenance and infiltration, were cost-effective. The Commission recently approved a permanent Low-Income Weatherization Program that includes these cost-effective measures. The research project will be discontinued upon the rollout of the permanent program.

Photovoltaic Research, Development and Education Project

Photovotaic (PV) roof-tile systems are a relatively new technology which directly replaces existing roofing materials such as shingles and standing-rib roofing with PV materials. These PV materials have the same waterproofing characteristics as conventional roofing materials. This project is consistent with the Federal Government's Million Solar Roofs Initiative. Based on FPL's research to-date a primary hurdle to the physical installation of PV systems, whether roofing materials or flat plate modules, is the lack of awareness, understanding and acceptance by local building officials. For the most part, these officials are unclear about how these systems work and how to address these systems as part of the building, permitting, and inspection process. This creates barriers toward the use of this technology. As part of this project, FPL has been holding workshops to address this issue. This project is scheduled to be completed in the first quarter of 2004.

Green Energy Project

Under this project, FPL has examined the feasibility of purchasing tradable renewable energy credits generated from new renewable resources including solar-powered technologies, biomass energy, landfill methane, wind energy, low impact hydroelectric energy and/or other renewable sources. Customers who participate would then be charged higher premiums for purchasing tradable renewable energy credits that are associated with electric energy generated by these sources.

Development of a Green Energy program was completed and FPL filed a petition for program approval with the FPSC in August 2003. As part of this process, a supply contract was put into place that allows FPL to match supply with customer demand for green energy. The FPSC approved the program on December 2, 2003 and program implementation began in the first quarter of 2004.

On Call Incentive Reduction Pilot

In March 2003, FPL received FPSC approval to perform a pilot project for its On Call program. Under the pilot project FPL is offering to new participants a residential load control service similar to the On Call Program at a reduced incentive level. This offering allows FPL to test its market research data and gauge whether FPL can repackage its current residential load control service, minimize customer attrition, achieve current goals for residential load control, and, ultimately, change On Call incentive levels without damaging system reliability.

3. **FPL's approved DSM Goals at the time this Site Plan was filed are listed below in Table III.D.1**

FPL's Summer MW Reduction Goals for DSM
(At the Meter)

Year	Goal Cumulative Summer MW
2000	122
2001	200
2002	269
2003	339
2004	410
2005	484
2006	554
2007	625
2008	697
2009	765

Table III.D.1

III.E Generation Additions from Independent Power Producers

As previously mentioned in Section III.A, FPL has a number of short-term, firm capacity purchases that extend through early 2007. The capacity supplied by these purchases is summarized in Table I.D.1. The vast majority of the capacity from these purchases is from independent power producers.

Tables I.B.1 and Table I.B.2 present the previously contracted cogeneration/small power production facilities which are addressed in FPL's resource planning.

III.F Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy for FPL's retail and wholesale customers. Table III.F.1 presents FPL's proposed future additions of 230 kV and 500 kV bulk transmission lines including those corresponding to proposed generating facilities and those that must be certified under the Transmission Line Siting Act.

List of Proposed Power Lines

(1) LINE OWNERSHIP	(2) TERMINALS (To)	(3) TERMINALS (From)	(4) LINE LENGTH CKT. MILES	(5) COMMERCIAL IN-SERVICE DATE (MO/YR)	(6) NOMINAL VOLTAGE (kV)	(7) CAPACITY (MVA)
FPL	Andytown	Pennsuco	2	6/04	230	508
FPL	Bridge	Indiantown #2	10	12/04	230	759
FPL	Broward-Corbett	Rainberry-Yamato	11	6/04	230	759
FPL	Conservation	Oakland Park	13	6/05	230	759
FPL	Dade	Overtown	11	6/04	230	759
FPL	Indiantown	Martin #2	13	12/04	230	1067
FPL	Whidden	Vandola	27	6/04	230	1067
FPL	Collier	Orange River #3	54	12/05	230	759
FPL	West Palm Coast	St. Johns	23	6/08	230	759

Table III.F.1

In addition, there will be transmission facilities needed to connect a number of FPL's committed and projected capacity additions to the system transmission grid. These transmission facilities for the projected capacity additions at FPL's existing Manatee, Martin, Turkey Point, Midway, and Corbett sites are described below.

Since the projected capacity additions for 2011 and 2012 are as-yet unsited, no transmission facilities information is provided. This information will be provided in future Site Plan documents once sites are selected.

III.F.1 Transmission Facilities at Manatee

The work required for the new capacity addition at Manatee, Manatee Unit No. 3, with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 5 breakers to connect the four CT's, and one ST.
2. Construct two string busses to connect the collectors and main switchyard.
3. Add five main step-up transformers (4-225MVA, 1- 560MVA) one for each CT, and one for the ST.
4. Add two breakers in bay # 6 to connect the collector bus at the Manatee switchyard.
5. Add two breakers in bay # 5 at the Manatee switchyard to connect the other collector bus.
6. Add relays and other protective equipment.
7. Upgrade 13-230kV circuit breakers to 2 cycle Independent Pole breakers at Manatee switchyard.
8. Upgrade the existing line terminal at Johnson to 3000 Amps.
9. Expand site and relay vault for two new line terminals at Manatee switchyard.
10. Upgrade existing breaker at Ringling Sub to 3000 amps

II. Transmission:

1. Upgrade the Calusa-Charlotte 230kV transmission line to 1875 Amps.
2. Upgrade the Johnson- Manatee 230kV transmission line to 3000 Amps.
3. Upgrade the Manatee-Ringling # 3 230kV transmission line to 3000 Amps.
4. Upgrade the Charlotte-Fort Myers # 2 230kV transmission line to 1875 Amps.

III.F.2 Transmission Facilities at Martin

The work required for the incremental capacity planned to be added at Martin (convert the existing two CT's to a new four-on-one combined cycle unit, Martin Unit No. 8) with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing one collector buss with 3 breakers to connect the two CT's and one ST.
2. Add one station service transformer in the existing CT yard.
3. Add three main step-up transformers (2-225 MVA, 560 MVA) one for each CT, and one for the ST.
4. Add two breakers in bay # 3 to connect the collector bus in the main switchyard.
5. Add relays and other protective equipment.
6. Install phase reactors and string buss in main switchyard to limit fault current.
7. Add breaker in bay # 7 (7WE) for new Indiantown # 2 transmission line. Tap existing 69kV auto-transformer off east 230kV operating bus.
8. Add breaker in Bay # 3 (3WS) at Indiantown Substation for Bridge line.
9. Create new bay 4. Add breakers 4WM, 4WS for Indiantown-Martin #2 line at Indiantown Substation.
10. Create new bay # 1 at Bridge Substation with breakers 1WW and 1WM. Add breakers 2WW and 2WE to convert station configuration from ring buss to a breaker and a half scheme.
11. Construct one string bus to connect the collector and main switchyard.

II. Transmission:

1. Construct 230kV Martin-Indiantown # 2 transmission line.
2. Construct 230kV Indiantown – Bridge # 2 transmission line.
3. Various OHGW replacements due to increased fault current.
4. Upgrade the Ranch-Homeland 230kV transmission line to 1600 Amps.

III.F.3 Transmission Facilities at Turkey Point

The work required for the projected new CC unit at Turkey Point, Turkey Point Unit No. 5, with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 5 breakers to connect the four CT's, and one ST.
2. Construct two string busses to connect the collector busses and main switchyard.
3. Add five main step-up transformers (4-225MVA, 1- 560 MVA) one for each CT, and one for the ST.
4. Add a new two breaker bay to connect the collector bus at the Turkey Point switchyard.
5. Add a second two breaker bay at the Turkey Point switchyard to connect the other collector bus.
6. Add relays and other protective equipment.
7. Expand site and relay vault for two new line terminals at Turkey Point switchyard.

II. Transmission:

1. Upgrade the Turkey Point-Galloway Tap 230kV transmission line section to 1418 Amps.
2. Upgrade the Turkey Point-McGregor-Florida City 230kV transmission line section to 1403 Amps.
3. Upgrade the Turkey Point-Miller 230kV transmission line section to 1356 Amps.
4. Upgrade the Miller-Killian 230kV transmission line section to 1315 Amps.

III.F.4 Transmission Facilities at Midway

The work required for the projected new CT units at Midway, Midway Unit Nos. 1A and 1B, with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing one collector buss with 2 breakers to connect the two CT's.
2. Construct one string buss to connect the collector buss and main switchyard.
3. Add two main step-up transformers (2-225 MVA) one for each CT.
4. Build a new 500 kV Bay #3 with two breakers and connect one string buss from the collector yard.
5. Add relays and other protective equipment.
6. Expand site and relay vault for the new line terminal at Midway 500 kV switchyard.

II. Transmission:

No upgrades are expected to be necessary.

III.F.5 Transmission Facilities at Corbett

The work required for the projected new CC unit at Corbett, Corbett Unit No. 1, with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 5 breakers to connect the four CT's, and one ST.
2. Construct two string busses to connect the collector busses and main switchyard.
3. Add five main step-up transformers (4-225 MVA, 1- 560 MVA) one for each CT, and one for the ST.
4. Add a new Bay #4 with 3 breakers at the Corbett 230 kV main switchyard. Connect one string buss from the collector yard and relocate the Alva 230 kV terminal from Bay #3 to new Bay #4.
5. Connect second collector string buss to Bay #3.
6. Add relays and other protective equipment.
7. Expand site and relay vault for two new line terminals at Corbett 230 kV switchyard.

II. Transmission:

No upgrades are expected to be necessary.

III.G. Renewable Resources

FPL has been the leading Florida utility in examining ways to utilize renewable energy technologies to meet its customers' current and future needs. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various technologies.

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970's in demonstrating the first residential solar photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities on both a daily and annual basis in Florida. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-Kilowatt (KW) system was placed into operation in 1984. (After the testing of this PV installation was completed, the system was removed in 1990 to make room for substation expansion.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. The FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's recent Green Pricing effort (which is discussed on the following page).

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first and only large scale utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was not cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980's, FPL introduced another renewable energy program. FPL's Passive Home Program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for 6 passive homes with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the Florida Public Service Commission to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test may be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, and various customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

FPL then analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach did not require all of its customers to bear PV's high cost, but allows customers who are interested in facilitating the use of renewable energy the means to do so. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund that FPL used to make PV purchases in bulk quantities. PV modules were then installed and delivered PV-generated electricity directly into the FPL grid. Thus, when sunlight is available, the PV-generated electricity displaces an equivalent amount of fossil fuel-generated electricity.

FPL's basic approach, which was termed Green Pricing, was initially discussed with the FPSC in 1994. FPL's initial efforts to implement this approach were then formally presented to the FPSC as part of FPL's DSM Plan in 1995, and FPL received approval from the FPSC in 1997 to proceed. FPL initiated the effort in 1998 and received approximately $89,000 in contributions (that significantly exceeded the goal of $70,000). FPL used this money to purchase PV modules and installed them at FPL's Martin Plant site.

FPL initiated two new renewable efforts in 2000. FPL's first new initiative in 2000 was the Green Energy Project, which is a second, different attempt to implement the basic Green Pricing approach. This outcome of this project was discussed in Section III.D.2.

The second effort initiated in 2000 was FPL's Photovoltaic Research, Development, and Education Project. This demonstration project's objectives are to increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks (as well as the total annual energy capabilities of roof tile PV systems), and assess the homeowner's financial benefits and costs of PV roof tile systems. The outcome of this effort is also discussed in section III.D.2.

Finally, FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy and as-available energy have been purchased by FPL from these developers. (Please refer to Tables I.B.1 and I.B.2).

III.H FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980's, FPL relied primarily on a combination of oil and nuclear energy to generate electricity. In the early 1980's FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership and additional purchases from the St. Johns River Power Park (SJRPP). In 1991 FPL significantly expanded its natural gas firm transportation rights. In 1994 FPL re-powered its Lauderdale Units No. 4 and No. 5 to combined cycle and added Martin Units No. 3 and No. 4 to enhance the efficient utilization of natural gas. Additional coal resources were added with the partial acquisition of Scherer Unit No. 4 concluding with FPL owning 76% of the unit by 1995. Beginning in 1997, petroleum coke was added to the fuel mix as a blend stock with coal at SJRPP further diversifying the fuel mix. These steps, among others, allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. In addition, between 1994 and 1998 FPL actively sought certification to convert its Manatee Units No. 1 and No. 2 to utilize Orimulsion. The Governor and cabinet did not grant a certification for this conversion that would have further diversified FPL's fuel mix.

The trend in recent years has been a steady increase in the amount of natural gas that is used by FPL to provide electricity. This is driven by the application of combined cycle generating units that offer significant thermal efficiency, low emissions and low capital costs. Until recently, the price of natural gas was low enough that the economic analysis indicated combined cycle technology as the most cost-effective alternative. Although this planning document reflects a continuation of the trend of natural gas-fired additions, FPL's plan is subject to change as new fuel price forecasts are developed and FPL's knowledge of other cost drivers and uncertainties is refined. FPL's future resource planning work will continue to focus on identifying and evaluating alternatives that will maintain or enhance FPL's long-term fuel diversity. These fuel diversity-enhancing alternatives may include:

- the construction of new solid fuel-based (coal and petroleum coke) facilities
- obtaining access to diverse sources of natural gas, such as from suppliers of natural gas that transport and deliver natural gas to Florida in the form of LNG
- preserving FPL's ability to utilize fuel oil at its existing units.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2013 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2. For purposes of this fuel mix projection, it was conservatively assumed that the projected new purchases to replace the UPS capacity would be delivered from natural gas-fired units.

2. Fuel Price Forecasts

FPL's long-term oil price forecast assumes that worldwide demand for petroleum products will grow moderately throughout the planning horizon. Non-OPEC crude oil supply is projected to increase as new and improved drilling technology and seismic information will reduce the cost of producing crude oil and increase both recoveries from existing fields and new discoveries. However, the rate of increase in non-OPEC supply is projected to be slower than that of petroleum demand, resulting in an increase in OPEC's market share throughout the planning horizon. As OPEC gains market share, prices for petroleum products are projected to increase.

FPL's natural gas price forecast assumes that domestic demand for natural gas will grow throughout the planning horizon, primarily due to increased requirements for electric generation. Domestic natural gas production will increase as new and improved drilling technology and seismic information will reduce the cost of finding, developing, and producing natural gas fields. The rate of increase in domestic natural gas production is assumed to be slower than that of demand nationally, with the balance being supplied by increased Canadian and liquefied natural gas (LNG) imports. As demand for natural gas in Florida grows, it is anticipated that the Florida Gas Transmission (FGT) pipeline system will be augmented/expanded. This anticipated expansion of FGT's pipeline, combined with the new Gulfstream pipeline and potential sources of non-domestic/international natural gas (such as off-shore suppliers), should result in sufficient gas for FPL's continued needs.

FPL's coal price forecast assumes an ample supply of domestic coal, and the availability of imported coal, to meet a slow, but steady increase in domestic demand in the electric generation sector over the planning horizon. The coal price forecast for FPL's existing coal plant at St. Johns River Power Park (SJRPP) and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts, along with the purchase of spot coal, to meet generation requirements. FPL's petroleum coke price forecast assumes that the petroleum industry will continue to utilize cokers in the U.S., as well as in the Caribbean Basin, in order to maximize refinery production of light products. This trend will continue to result in sufficient availability of petroleum coke at delivered prices significantly below delivered coal prices that will support a slow, but steady growth in the use of petroleum coke in the U.S. electric utility industry.

As previously mentioned, FPL's resource planning work will continue to analyze the feasibility of generation alternatives, including solid fuel alternatives, that enhance FPL's long-term fuel diversity. The analyses of gas-fired and solid fuel-fired alternatives will involve the assessment of a number of uncertainties including fuel price uncertainties. Consequently, for these analyses a number of fuel price sensitivities will be used in the analyses that determine the magnitude and likelihood of cost differentials between gas and solid fuel alternatives.

Schedule 5
Fuel Requirements [1]

	Fuel Requirements	Units	Actual [2] 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Nuclear	Trillion BTU	276	257	255	253	263	254	269	264	263	268	265	263
(2)	Coal	1,000 TON	3,070	3,402	3,126	3,243	3,165	3,480	3,288	3,517	3,291	3,296	3,306	3,364
(3)	Residual (FO6)- Total	1,000 BBL	29,791	32,103	28,731	24,627	22,983	20,903	20,261	17,952	18,074	18,049	12,894	13,144
(4)	Steam	1,000 BBL	29,791	32,103	28,731	24,627	22,983	20,903	20,261	17,952	18,074	18,049	12,894	13,144
(5)	Distillate (FO2)- Total	1,000 BBL	473	565	989	1,504	1,627	1,260	1,170	1,683	1,880	1,141	1,247	2,126
(6)	CC	1,000 BBL	29	36	20	26	22	49	24	35	49	39	31	28
(7)	CT	1,000 BBL	444	529	969	1478	1605	1211	1146	1648	1831	1,102	1,216	2,100
(8)	Steam	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Natural Gas -Total	1,000 MCF	286,112	292,993	348,830	383,442	412,181	436,727	447,474	469,581	530,380	573,744	611,334	625,307
(10)	Steam	1,000 MCF	78,017	50,862	65,473	58,658	54,947	53,427	51,715	47,931	44,506	46,881	36,576	36,549
(11)	CC	1,000 MCF	195,106	229,681	262,987	314,409	349,507	381,505	390,821	418,080	483,423	524,881	573,093	586,991
(12)	CT	1,000 MCF	12,988	12,450	20,370	10,375	7,727	1,794	4,938	3,570	2,450	1,983	1,665	1,767

1/ Reflects fuel requirements for FPL only.

2/ Source: A Schedules.

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 1/ 2002	2003	Forecasted 2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Annual Energy Interchange 2/	GWH	10,287	10,387	10,278	10,634	10,663	10,652	10,802	10,641	6,085	2,932	2,937	2,905
(2)	Nuclear	GWH	25,295	23,524	23,262	23,121	24,037	23,198	24,537	24,121	24,042	24,467	24,191	24,043
(3)	Coal	GWH	5,977	6,625	5,962	6,156	6,025	6,568	6,249	6,650	6,265	6,277	6,296	6,389
(4)	Residual(FO6) -Total	GWH	18,708	20,305	18,159	15,587	14,561	13,199	12,780	11,376	11,466	11,421	8,185	8,357
(5)	Steam	GWH	18,708	20,305	18,159	15,587	14,561	13,199	12,780	11,376	11,466	11,421	8,185	8,357
(6)	Distillate(FO2) -Total	GWH	188	248	366	590	633	507	482	656	737	455	492	805
(7)	Steam	GWH	18	0	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	170	21	12	16	13	29	15	21	29	23	19	16
(9)	CT	GWH	0	226	354	575	620	478	467	635	707	432	473	789
(10)	Natural Gas -Total	GWH	34,541	37,707	42,984	49,082	53,465	57,573	58,931	62,521	70,491	76,488	82,324	84,525
(11)	Steam	GWH	7,549	4,905	5,694	5,115	4,800	4,657	4,508	4,170	3,880	4,098	3,180	3,175
(12)	CC	GWH	25,986	31,718	35,661	43,138	48,115	52,787	54,030	58,061	66,409	72,226	78,998	81,208
(13)	CT	GWH	1,006	1,084	1,629	830	550	130	392	290	202	164	146	142
(14)	Other 3/	GWH	9,202	9,597	8,317	7,069	6,100	6,144	6,397	6,297	5,814	5,376	5,389	5,339
	Net Energy For Load 4/	GWH	104,199	108,393	109,328	112,239	115,484	117,841	120,177	122,261	124,900	127,416	129,813	132,363

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecst of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.
4/ Net Energy For Load is also shown in Column 8 on Schedule 3.3.

Schedule 6.2
Energy % by Fuel Type

	Energy Source	Units	Actual 2002	Actual 2003	Forecasted 2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Annual Energy Interchange 2/	%	9.9	9.6	9.4	9.5	9.2	9.0	9.0	8.7	4.9	2.3	2.3	2.2
(2)	Nuclear	%	24.3	21.7	21.3	20.6	20.8	19.7	20.4	19.7	19.2	19.2	18.6	18.2
(3)	Coal	%	5.7	6.1	5.5	5.5	5.2	5.6	5.2	5.4	5.0	4.9	4.9	4.8
(4)	Residual (FO6) -Total	%	18.0	18.7	16.6	13.9	12.6	11.2	10.6	9.3	9.2	9.0	6.3	6.3
(5)	Steam	%	18.0	18.7	16.6	13.9	12.6	11.2	10.6	9.3	9.2	9.0	6.3	6.3
(6)	Distillate (FO2) -Total	%	0.2	0.2	0.3	0.5	0.5	0.4	0.4	0.5	0.6	0.4	0.4	0.6
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CC	%	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	CT	%	0.0	0.2	0.3	0.5	0.5	0.4	0.4	0.5	0.6	0.3	0.4	0.6
(10)	Natural Gas -Total	%	33.1	34.8	39.3	43.7	46.3	48.9	49.0	51.1	56.4	60.0	63.4	63.9
(11)	Steam	%	7.2	4.5	5.2	4.6	4.2	4.0	3.8	3.4	3.1	3.2	2.4	2.4
(12)	CC	%	24.9	29.3	32.6	38.4	41.7	44.8	45.0	47.5	53.2	56.7	60.9	61.4
(13)	CT	%	1.0	1.0	1.5	0.7	0.5	0.1	0.3	0.2	0.2	0.1	0.1	0.1
(14)	Other 3/	%	8.8	8.9	7.6	6.3	5.3	5.2	5.3	5.2	4.7	4.2	4.2	4.0
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules.
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	% of Peak
2004	19,130	2,667	0	880	22,677	20,297	1,510	18,787	3,890	20.7	0	3,890	20.7
2005	21,021	2,257	0	870	24,148	20,799	1,589	19,210	4,938	25.7	0	4,938	25.7
2006	21,020	2,257	0	734	24,011	21,331	1,667	19,664	4,347	22.1	0	4,347	22.1
2007	22,162	1,312	0	734	24,208	21,851	1,744	20,107	4,101	20.4	0	4,101	20.4
2008	22,486	1,312	0	734	24,532	22,289	1,822	20,467	4,065	19.9	0	4,065	19.9
2009	23,630	1,312	0	683	25,625	22,784	1,897	20,887	4,738	22.7	0	4,738	22.7
2010	23,630	1,312	0	640	25,582	23,294	1,922	21,372	4,210	19.7	0	4,210	19.7
2011	24,774	1,312	0	595	26,681	23,783	1,922	21,861	4,820	22.0	0	4,820	22.0
2012	25,918	1,312	0	595	27,825	24,279	1,922	22,357	5,468	24.5	0	5,468	24.5
2013	25,918	1,312	0	595	27,825	24,784	1,922	22,862	4,963	21.7	0	4,963	21.7

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. All values are Summer net MW.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	% of Peak
2003/04	20,356	2,345	0	880	23,581	20,081	1,561	18,520	5,061	27.3	0	5,061	27.3
2004/05	19,993	2,339	0	870	23,202	20,583	1,615	18,968	4,234	22.3	0	4,234	22.3
2005/06	22,390	2,339	0	734	25,463	21,100	1,670	19,430	6,033	31.0	0	6,033	31.0
2006/07	22,389	2,339	0	734	25,462	21,605	1,723	19,882	5,580	28.1	0	5,580	28.1
2007/08	23,569	1,321	0	734	25,624	22,046	1776	20,270	5,354	26.4	0	5,354	26.4
2008/09	23,931	1,321	0	734	25,986	22,539	1,828	20,711	5,275	25.5	0	5,275	25.5
2009/10	25,112	1,321	0	683	27,116	23,026	1,873	21,153	5,963	28.2	0	5,963	28.2
2010/11	25,112	1,321	0	595	27,028	23,522	1,873	21,649	5,379	24.8	0	5,379	24.8
2011/12	26,293	1,321	0	595	28,209	24,024	1,873	22,151	6,058	27.3	0	6,058	27.3
2012/13	27,474	1,321	0	595	29,390	24,535	1,873	22,662	6,728	29.7	0	6,728	29.7

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2004														
Turkey Point	1	Dade County 27/57S/40E	ST	FO6	NG	WA	PL	Unknown	Jun-04	Unknown	402,050	(4)	(4)	OT
Lauderdale	4	Broward County 30/50S/42E	CC	NG	FO2	PL	PL	Unknown	Jun-04	Unknown	521,250	(3)	(3)	OT
Port Everglades	4	City of Hollywood 23/50S/42E	ST	FO6	NG	WA	PL	Nov-03	Jun-04	Unknown	402,050	3	2	OT
Riviera	3	City of Riviera Beach 33/42S/43E	ST	FO6	NG	WA	PL	Unknown	Jun-04	Unknown	310,420	1	1	OT
Martin	1	Martin County 29/29S/38E	ST	NG	FO6	PL	PL	Unknown	Jun-04	Unknown	863,000	—	4	OT
Martin	2	Martin County 29/29S/38E	ST	NG	FO6	PL	PL	Unknown	Jun-04	Unknown	863,000	(17)	(4)	OT
Martin	3	Martin County 29/29S/38E	CC	NG	No	PL	No	Unknown	Jun-04	Unknown	612,000	1	6	OT
Martin	4	Martin County 29/29S/38E	CC	NG	No	PL	No	Unknown	Jun-04	Unknown	612,000	1	6	OT
Martin	8	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Unknown	Jun-04	Unknown	362,000	1	8	OT
Cape Canaveral	1	Brevard County 19/24S/36F	ST	FO6	NG	WA	PL	Unknown	Jun-04	Unknown	402,050	(4)	(4)	OT
Cape Canaveral	2	Brevard County 19/24S/36F	ST	FO6	NG	WA	PL	Unknown	Jun-04	Unknown	402,050	(4)	(4)	OT
Sanford	4	Volusia County 16/19S/30E	CC	NG	No	PL	No	Apr-04	Jun-04	Unknown	436,100	14	13	OT
Sanford	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	Nov-03	Jun-04	Unknown	436,100	14	13	OT
Manatee	1	Manatee County 18/33S/20E	ST	FO6	No	WA	No	Unknown	Jun-04	Unknown	863,300	(4)	—	OT
Manatee	2	Manatee County 18/33S/20E	ST	FO6	No	WA	No	Unknown	Jun-04	Unknown	863,300	(4)	—	OT
Fort Myers	2	Lee County 35/43S/25E	CC	NG	No	WA	No	Apr-04	Jun-04	Unknown	402,000	15	46	OT
Fort Myers	3	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-04	Jun-04	Unknown	362,000	(5)	6	OT
• Fort Myers CT		Lee County 35/43S/25E	CT	FO2	No	WA	No	Unknown	Jun-04	Unknown	744,000	16	(12)	OT
										2004 Changes/Additions Total:		**21**	**74**	
2005														
Pt Everglades	2	City of Hollywood 23/50S/42E	ST	FO6	NG	WA	PL	Unknown	Mar-05	Unknown	225,000	—	(1)	OT
Manatee Combined Cycle	3	Manatee County 18/33S/20E	CC	NG	FO2	PL	PL	Jun-03	Jun-05	Unknown	470,000	—	1,107	T
Martin Combined Cycle	8	Martin County 29/29S/38E	CC	NG	No	PL	No	Jun-03	Jun-05	Unknown	470,000	—	1,107	T
Martin Combustion Turbine Conv.	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Jun-99	Jun-01	12/1/2004	190,000	(182)	(161)	OT
Martin Combustion Turbine Conv.	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Jun-99	Jun-01	12/1/2004	190,000	(182)	(161)	OT
										2005 Changes/Additions Total:		**(363)**	**1,891**	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All other MW will be picked up in the following year.

Note 2: Capacity additions/changes shown for 2004 reflect changes/additions from values shown in Schedule 1.

Schedule 8

Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter	Summer	
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt.	Mo./Yr.	Mo./Yr	Mo./Yr.	KW	MW	MW	Status
ADDITIONS/ CHANGES														
2006														
Pt Everglades	2	City of Hollywood 23/50S/42E	ST	FO6	NG	WA	PL	Unknown	Mar-05	Unknown	225,000	(1)	—	OT
Pt Everglades	1	City of Hollywood 23/50S/42E	ST	FO6	NG	WA	PL	Unknown	Sep-05	Unknown	225,250	(1)	(1)	OT
Manatee Combined Cycle	3	Manatee County 18/33S/20E	CC	NG	FO2	PL	PL	Jun-03	Jun-05	Unknown	470,000	1,201	—	T
Martin Combined Cycle	8	Martin County 29/29S/38E	CC	NG	FO2	PL	PL	Jun-03	Jun-05	Unknown	190,000	1,198	—	T
											2006 Changes/Additions Total:	2,397	(1)	
2007														
Pt Everglades	3	City of Hollywood 23/50S/42E	ST	FO6	NG	WA	PL	Unknown	Mar-07	Unknown	402,050		(1)	OT
Pt Everglades	4	City of Hollywood 23/50S/42E	ST	FO6	NG	WA	PL	Unknown	Sep-06	Unknown	402,050	(1)	(1)	OT
Turkey Point CC	5	Dade County 27/57S/40E	CC	NG	FO2	PL	PL	Jan-05	Jun-07	Unknown	470,000	—	1,144	P
											2007 Changes/Additions Total:	(1)	1,142	
2008														
Pt Everglades	3	City of Hollywood 23/50S/42E	ST	FO6	NG	WA	PL	Unknown	Mar-07	Unknown	402,050	(1)	—	OT
Turkey Point CC	5	Dade County 27/57S/40E	CC	NG	FO2	PL	PL	Jan-05	Jun-07	Unknown	470,000	1,181	—	P
Combustion Turbines at Midway	1&2	St. Lucie 36S/39E/10	CT	NG	FO2	PL	PL	Jan-06	Jun-08	Unknown	190,000	—	324	P
											2008 Changes/Additions Total:	1,180	324	
2009														
Combustion Turbines at Midway	1&2	St. Lucie 36S/39E/10	CT	NG	FO2	PL	PL	Jan-06	Jun-08	Unknown	190,000	362	—	P
Combined Cycle at Corbett	1	Palm Beach 43S/40E/29	CC	NG	FO2	PL	PL	Jan-07	Jun-09	Unknown	470,000	—	1,144	P
											2009Changes/Additions Total:	362	1,144	
2010														
Combined Cycle at Corbett	1	Palm Beach 43S/40E/29	CC	NG	FO2	PL	PL	Jan-07	Jun-09	Unknown	470,000	1,181	—	P
											2010 Changes/Additions Total:	1,181	0	
2011														
Unsited Combined Cycle Unit	1	Unknown	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	470,000	—	1,144	P
											2011 Changes/Additions Total:	0	1,144	
2012														
Unsited Combined Cycle Unit	1	Unknown	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	470,000	1,181	—	P
Unsited Combined Cycle Unit	2	Unknown	CC	NG	FO3	PL	PL	Jan-10	Jun-12	Unknown	470,001	—	1,144	P
											2012 Changes/Additions Total:	1,181	1,144	
2013														
Unsited Combined Cycle Unit	2	Unknown	CC	NG	FO2	PL	PL	Jan-10	Jun-12	Unknown	470,000	1,181	—	P
											2013 Changes/Additions Total:	1,181	0	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by August. All other MW will be picked up in the following year. This is done for reserve margin calculation.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Martin Combustion Turbine Conversion to Combined Cycle
(2)	**Capacity**		
	a. Summer	785	MW Incremental (1107 MW Total)
	b. Winter	835	MW Incremental (1198 MW Total)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Tower
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	U	(Under Construction <= 50% Complete)
(10)	**Certification Status:**	U	(Under Construction <= 50% Complete)
(11)	**Status with Federal Agencies:**	U	(Under Construction <= 50% Complete)
(12)	**Projected Unit Performance Data** *		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	(Base & Duct Firing Operation)
	Resulting Capacity Factor (%):	Approx. 80%	(First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh (Base Operation)
	Base Operation 75F,100%		
(13)	**Projected Unit Financial Data** **,***		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	589	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	9.11	
	Variable O&M ($/MWH): (2001 $/MWH)	0.037	
	K Factor:	1.5397	

* Values represent an operational combined cycle unit after the conversion is completed.
** $/kW values are based on Summer incremental capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Manatee Combined Cycle	
(2)	**Capacity**			
	a. Summer	1,107	MW	
	b. Winter	1,201	MW	
(3)	**Technology Type:**		Combined Cycle	
(4)	**Anticipated Construction Timing**			
	a. Field construction start-date:	2003		
	b. Commercial In-service date:	2005		
(5)	**Fuel**			
	a. Primary Fuel		Natural Gas	
	b. Alternate Fuel		None	
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR	
(7)	**Cooling Method:**		Cooling Pond	
(8)	**Total Site Area:**	9,500	Acres	
(9)	**Construction Status:**	U	(Under Construction <= 50% Complete)	
(10)	**Certification Status:**	U	(Under Construction <= 50% Complete)	
(11)	**Status with Federal Agencies:**	U	(Under Construction <= 50% Complete)	
(12)	**Projected Unit Performance Data:**			
	Planned Outage Factor (POF):		2%	
	Forced Outage Factor (FOF):		1%	
	Equivalent Availability Factor (EAF):		97%	(Base & Duct Firing Operation)
	Resulting Capacity Factor (%):		Approx. 71%	(First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):		6,850	Btu/kWh (Base Operation)
	Base Operation 75F,100%			
(13)	**Projected Unit Financial Data *,****			
	Book Life (Years):		25	years
	Total Installed Cost (In-Service Year $/kW):		499	
	Direct Construction Cost ($/kW):			
	AFUDC Amount ($/kW):			
	Escalation ($/kW):			
	Fixed O&M ($/kW -Yr.):	(2001 $kW-Yr)	12.96	
	Variable O&M ($/MWH):	(2001 $/MWH)	0.037	
	K Factor:		1.5397	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point Combined Cycle

(2) **Capacity**
a. Summer 1,144 MW
b. Winter 1,181 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2005
b. Commercial In-service date: 2007

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low NO_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 11000 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** L (Regulatory Approval Pending)

(11) **Status with Federal Agencies:** L (Regulatory Approval Pending)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 80%	(First Year)
Average Net Operating Heat Rate (ANOHR):	6,835 Btu/kWh	(Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25 years
Total Installed Cost (In-Service Year $/kW):	507
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2007 $kW-Yr)	10.06
Variable O&M ($/MWH): (2007 $/MWH)	0.13
K Factor:	1.5699

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Midway SC No. 1	
(2)	**Capacity**		
	a. Summer	324 MW	
	b. Winter	362 MW	
(3)	**Technology Type:**	Simple Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2006	
	b. Commercial In-service date:	2008	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low No_x Combustors, SCR 0.0015% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Unknown
(8)	**Total Site Area:**	75	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		2%
	Forced Outage Factor (FOF):		1%
	Equivalent Availability Factor (EAF):		97% (Base Operation)
	Resulting Capacity Factor (%):		Approx. 15% (First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):		10,400 Btu/kWh (Base Operation)
	Base Operation 75F,100%		
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):		25 years
	Total Installed Cost (In-Service Year $/kW):		448
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2008 $kW-Yr)		12.78
	Variable O&M ($/MWH): (2008 $/MWH)		0.18
	K Factor:		Approx. 1.6

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement. (Firm gas transportation cost are applicable for this option.)

NOTE: Total installed cost includes escalation and AFUDC only.
Transmission interconnection, transmission integration and gas expansion costs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Corbett Combined Cycle No. 1

(2) **Capacity**
a. Summer 1,144 MW
b. Winter 1,181 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2007
b. Commercial In-service date: 2009

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low NO_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 70%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,835	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):		25 years
Total Installed Cost (In-Service Year $/kW):		538
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.):	(2009 $kW-Yr)	13.44
Variable O&M ($/MWH):	(2009 $/MWH)	0.20
K Factor:		Approx. 1.6

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes escalation and AFUDC only.
Transmission interconnection, transmission integration and gas expansion costs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 1	
(2)	**Capacity**		
	a. Summer	1,144 MW	
	b. Winter	1,181 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2009	
	b. Commercial In-service date:	2011	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low No_x Combustors, SCR 0.0015% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Unknown
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		2%
	Forced Outage Factor (FOF):		1%
	Equivalent Availability Factor (EAF):		97% (Base & Duct Firing Operation)
	Resulting Capacity Factor (%):		Approx. 65% (First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):		6,835 Btu/kWh (Base Operation)
	Base Operation 75F,100%		
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):		25 years
	Total Installed Cost (In-Service Year $/kW):		577
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2011 $kW-Yr)		14.26
	Variable O&M ($/MWH): (2011$/MWH)		0.21
	K Factor:		Approx. 1.6

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes escalation and AFUDC only.
Transmission interconnection, transmission integration and gas expansion costs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Combined Cycle No. 2

(2) **Capacity**
a. Summer 1,144 MW
b. Winter 1,181 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2010
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Unknown

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 65%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,835	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	594	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2012 $kW-Yr)	14.69	
Variable O&M ($/MWH): (2012 $/MWH)	0.21	
K Factor:	Approx. 1.6	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes escalation and AFUDC only.
Transmission interconnection, transmission integration and gas expansion costs are not included.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Manatee CC

The new Manatee CC unit does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Martin CC Conversion

(1)	Point of Origin and Termination:	Martin – Indiantown #2
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned & New acquisitions
(4)	Line Length:	12.9 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 1/5/04 End date: 12/31/04
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$11,700,000
(8)	Substations:	Martin 230kV and Indiantown
(9)	Participation with Other Utilities:	None

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(1)	Point of Origin and Termination:	Indiantown – Bridge
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	10.0 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 3/15/04 End date: 12/31/04
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$8,900,000
(8)	Substations:	Indiantown and Bridge
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point 5 CC

The new Turkey Point CC unit does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Midway CT 1a and 1b

The new Midway CTs do not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Corbett CC

The new Corbett CC unit does not require any "new" transmission lines.

CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered plant and animal species. Population growth in FPL's service area is continuing, which increases competition for air, land, and water resources that are necessary to meet the increased demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

FPL has been recognized for many years as one of the leaders among utilities for its commitment to the environment. FPL's environmental leadership has been heralded by many outside organizations. For example, FPL was recently ranked first out of 28 major electric utilities surveyed in an environmental assessment conducted by Innovest, an independent advisory group. In recognition of its success in executing a strategy to become a clean energy provider harnessing primarily clean and renewable fuels while also boosting shareholder value, FPL Group, Inc. was named in June 2003 as the winner of the Edison Award, the electric power industry's highest honor by the Edison Electric Institute. FPL was also awarded Edison Electric Institute's National Land Management Award for its stewardship of 25,000 acres surrounding the Turkey Point Plant. In addition, FPL won the Council for Sustainable Florida's award for its sea turtle conservation and education programs at the St. Lucie Plant. In 2001, FPL was awarded the 2001 Waste Reduction and Pollution Prevention Award from the Solid Waste Association of North America. FPL also received the 2001 Program Champion Award from the Environmental Protection Agency's Wastewise Program. The Florida Department of Environmental Protection named FPL a "Partner for Ecosystem

Protection" for its emission-reducing "repowering" projects at the Fort Myers and Sanford Plants. In addition, FPL has been recognized by numerous federal and state agencies for its innovative endangered species programs which include such species as manatees, crocodiles, and sea turtles.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Statement in 1992 to clearly define the Company's position. This statement reflects how FPL incorporates environmental values into all aspects of the Company's activities and serves as a framework for new environmental initiatives throughout the Company. The FPL environmental statement further establishes a long-term direction of environmental initiatives throughout the Company. FPL's Environmental Statement is:

> It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:
>
> - Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
> - Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
> - Encourage the wise use of energy to minimize the impact on the environment.
> - Communicate effectively on environmental issues.
> - Conduct periodic self-evaluations, report performance, and take appropriate actions.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an environmental management system to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program that is discussed below. Other components include: executive management support and commitment, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident/emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

In February 2004 FPL Group voluntarily committed to join the World Wildlife Fund PowerSwitch Challenge in support of binding limits on national CO2 emissions. This commitment was made to support initiatives to better manage utility impacts on global warming through use of greenhouse gas emission reductions and improvements in energy efficiency.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to evaluate environmental performance, verify compliance with Company policy as well as with legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to: facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and Company policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2003 environmental outreach activities are noted in Table IV.E.1.

Activity	# of Participants
Visitors to Energy Encounter	19,000
Visitors to Manatee Park	150,000
Number of "visits" to FPL's Environmental Website	185,000
Number of pieces of Environmental literature distributed	>100,000

Table IV.E.1

(All numbers are approximations.)

IV.F. Preferred Sites

FPL identifies three preferred sites in this Site Plan: the existing Manatee plant site, the existing Martin plant site, and the existing Turkey Point plant site. The Manatee and Martin sites are the locations for capacity additions that FPL is committed to bring in-service in 2005. The Turkey Point site is the location for FPL's planned new Turkey Point Unit No. 5 which is projected to come in-service in 2007.

The three preferred sites are discussed below.

Preferred Site # 1: Manatee Plant, Manatee County

The site is located in unincorporated north central Manatee County approximately 2.5 miles south of the Hillsborough-Manatee County line. It is 5 miles east of Parrish, Florida and is approximately 5 miles east of U.S. Highway 301 and 9.5 miles east of Interstate 75 (I-75). State Road (SR) 62 is about 0.5 miles south of the site. Saffold Road marks the eastern boundary of the site.

FPL's Manatee Plant occupies a portion of the approximately 9,500 acre Manatee Site which is owned wholly by FPL. The site includes a 4,000-acre cooling pond including the dike area. The existing approximately 1,630 MW (Summer) of generating capacity is made up of two steam units (Units No. 1 and No. 2) which have been in service since 1976 (Unit No. 1) and 1977 (Unit No. 2). These units burn both fuel oil (residual) with a maximum sulfur content of 1 percent and natural gas. Natural gas may be fired singly or in combination with fuel oil. A recent agreement between FPL and Gulfstream Natural Gas Systems (Gulfstream) will provide natural gas for these units.

Additional generating capacity will be added to the site in 2005 to meet projected FPL system capacity needs. One unit consisting of four new combustion turbines (CT's), four new heat recovery steam generators (HRSG's), and a new steam turbine generator are scheduled for in -service operation beginning in June, 2005. The four new CT's, HRSG's and steam turbine will ultimately be operating in combined cycle (CC) configuration. This new CC unit will add 1,107 MW (Summer) and 1,201 MW (Winter) capability to the site. This new CC Unit will be designated as "Manatee Unit No. 3".

Unit No. 3 will be located west of the existing generating Units No. 1 and No. 2. The location of the new combined cycle Unit No. 3 at the Manatee Plant site and the selection of the highly efficient combined cycle technology (firing clean natural gas) will maximize the beneficial use of the site while minimizing environmental and land use impacts otherwise associated with the development of a new generating plant of this capacity. The Manatee site has been listed as a preferred or potential site in previous FPL Site Plans.

a. and b. U.S. Geological Survey (USGS) Map and Proposed Facilities Layout

A USGS map of the Manatee plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a 4,000 acre cooling pond. Manatee Units No. 1 and No. 2 will not be affected by the addition of Unit No. 3. The area for Unit No. 3 is expected to comprise approximately 73 acres. The site and surrounding land uses are almost exclusively agriculture with the exception of the Willow Shores residential area located northwest of the Manatee Plant site. Individual homes are located in the larger of two out parcels within the Manatee Plant site along SR 62 at the northeast corner of the site. The vast majority of the Manatee Plant site has been redesignated from Agricultural/Rural to Major Public/Semi Public (1) (P/SP) land use category by the Manatee County Commission on November 19, 2002 with the approval of Ordinance 02-13. Electric generating plants are specifically allowed in the P/SP category in accordance with the Manatee County Local Government Comprehensive Plan and Land Development Regulation Act, Chapter 163, Part II, Florida Statutes (FS).

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

There are no incorporated areas within 5 miles of the Manatee Plant site. Unincorporated communities in the area include Willow, located about 2 miles north of the Manatee Plant; Parrish, located about 5 miles southwest of the plant; and, in Hillsborough County, Sundance, located 3 miles northwest of the plant; Sun City Center, located 7 miles north of the plant; and Wimauma, located 8 miles northeast of the plant.

The Manatee Plant site includes areas of improved pasture with forested land southeast of the project area. This forested area is comprised of flat woods and oak habitat. The western side of the Manatee Plant site is currently used for row crops (tomato farm). There are also wetlands to the southeast containing wet pine flat woods mixed with dry pine flat woods. There will not be any disturbance of existing wetlands associated with this project.

2. Listed Species

Construction and operation of the new Unit No. 3 at the site is not expected to affect any rare, endangered, or threatened species. The majority of the site is cleared, grassed, and periodically mowed. The project area has been significantly altered by the construction and operation of the existing plant facilities, and, as a result, wildlife utilization of this area is expected to be minimal. Common wading birds utilizing the plant site outside of the project area include the great blue heron, little blue heron, great egret, snowy egret, and the white ibis. Typical mammals found in the habitats surrounding the project area are common bobcat, raccoon, deer, feral hog, opossum, armadillo, skunk and gray squirrel. Avian species observed in the vicinity of the project include bald eagles, a variety of songbirds, red-shouldered hawks, and marsh hawks.

3. Natural Resources of Regional Significance Status

There are no county, state or federally designated areas located within one mile of the plant site. The construction and operation of Manatee Unit No. 3 is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands that are associated with the Little Manatee River within a 5-mile radius of the project site. These lands include: Little Manatee River State Recreation Area, Little Manatee River State Canoe Trail, Florida Gulf Coast Railroad Museum, Cockroach Bay Aquatic Preserve, Critical Manatee Habitat, South Hillsborough Wildlife Corridor, Hillsborough County ELAPP Parcels, and SOR-Little Manatee River.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option, Manatee Unit No. 3, is the addition of four new combustion turbines and HRSG's and one new steam turbine generator in combined cycle mode in a 4x1 configuration. Manatee Unit No. 3 is scheduled to begin operation in mid – 2005. Natural gas, delivered via pipeline, will be the sole fuel for this unit.

Mitigation options being planned for Manatee Unit No. 3 include the capture and reuse of plant process water and rainwater. In addition, other mitigating options include the use of combustion technology that is very efficient and low in air pollutant emissions, combined with pollution control technology (dry-low NO_x burners and selected catalytic reduction equipment).

g. Local Government Future Land Use Designations

As mentioned above, the Local Government Future Land Use Plan is consistent with the existing Designated uses of the Manatee Plant Site as major portions of the site are designated as Major Public/Semi Public (1) – P/PS/. Electric generating plants are specifically allowed in this land use category.

h. Site Selection Criteria and Process

The Manatee site has been selected as a preferred site due to consideration of various factors including system load and economics. Also, the at–the–time projected availability of a natural gas pipeline that will be available to Unit No. 3 (as well as Units No. 1 and No. 2) was also a major factor in the selection of the Manatee site for the new 4x1 CC unit. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues and the site is permitted.

i. Water Resources

The available surface water source is the Little Manatee River that supplies makeup water for the 4,000-acre cooling pond. Plant process and service water requirements are currently supplied by the cooling pond. There are three wells in the Floridan Aquifer that are reserved for standby purposes.

j. Geological Features of Site and Adjacent Areas

Manatee County has three physiographic provinces: the Gulf Coast Lowlands, the DeSoto Plains, and the Polk Upland. The Manatee Plant is situated on the boundary of the DeSoto Plains and the Gulf Coast Lowland provinces. The geology underlying the Manatee Plant consists of unconsolidated sediments comprised of sand, clay silt, marl shell, limestone, and phosphorite (terrace deposits) from the Pleistocene age to recent. Undifferentiated deposits comprised of sand and clay are generally described to be less than 25 feet thick. Underlying the differentiated materials are the Miocene Hawthorn Formation, the Tampa Member, the Suwanee Limestone of the Oligocene age, the Ocala Limestone of the Eocene Age, the Avon Park Formation, the Oldsmar Formation of the Eocene age, and the Cedar Key Formation of the Paleocene age.

The major hydro-geologic units that exist in the vicinity of the site include, in descending order: the surficial aquifer system, the intermediate aquifer system, and the Upper Floridian aquifer. The surficial aquifer system is generally unconfined in Manatee County and consists of Quaternary deposits of predominately marine and non-marine quartz sand, clayey sand, shell, shelly marl, phosphorite, and occasional marl stringers and limestone. In the vicinity of the site the surficial sediments are approximately 25 feet thick.

k. <u>Projected Water Quantities for Various Uses</u>

The estimated additional quantity for process water is estimated to be 150 gpm (gallons per minute). FPL operates on-site water treatment systems for this use. Water quantities for other uses such as irrigation and potable water are estimated to be approximately 5 gpm.

l. <u>Water Supply Sources by Type</u>

Manatee Unit No. 3 will utilize the existing on-site cooling pond as its source of cooling water. The cooling pond operates as a "closed cycle" system; any makeup water is provided from the Little Manatee River to replace net evaporation and seepage losses from the pond. These makeup needs are within an agreement between FPL and the Southwest Florida Water Management District (SWFWMD). There are three wells currently on reserve (stand-by) that are in the Floridan Aquifer.

FPL is currently evaluating alternative water sources for use at the Manatee Plant site.

m. Water Conservation Strategies Under Consideration

Available water including non-contact storm water, treated industrial wastewater, treated sanitary wastewater, and recovered service water are captured and returned to the cooling pond. Storm water from the equipment areas is also treated and returned to the cooling pond.

n. Water Discharges and Pollution Control

The Manatee Plant utilizes a Best Management Practices (BMP) plan, Spill Prevention, Control, and Countermeasure (SPCC) plan to assist in the control of inadvertent release of pollutants. Storm water runoff will be collected and routed to detention ponds. Construction activities are managed so that equipment maintenance and fueling are performed in designated areas so that, in the event of a spill or release of any contaminant, impacts to any surface water or the cooling pond are minimized.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by fuel delivery services and facilities for residual, low sulfur (1 percent) fuel oil and, most recently, natural gas as an alternate fuel for existing Units No. 1 and No. 2. The Unit No. 3 addition will be solely fueled by natural gas that will be supplied by Gulfstream.

p. Air Emissions and Control Systems

The addition of natural gas as a permitted fuel for existing Units No. 1 and No. 2 is expected to lower overall emissions during periods when natural gas, instead of fuel oil, is used. In addition, a NO_x reduction technology, re-burn, has been approved for installation on Units No. 1 and No. 2 within the next several years.

The use of clean fuels and combustion controls will minimize air emissions from Unit No. 3 and ensure compliance with applicable emission limiting standards. Using clean fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of carbon monoxide and volatile organic compounds. NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). These design alternatives constitute the Best Available Control Technology (BACT) for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Manatee Unit # 3 will incorporate features that will make it one of the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

A field survey and impact assessment of noise expected to be caused by unit construction at the site indicated that construction noise would be below current noise levels for the residents nearest the site. Noise from the operation of the new unit will also be within allowable levels.

r. Status of Applications

FPL filed the Site Certification Application (SCA) for the Manatee Plant Unit No. 3 with the Florida Department of Environmental Protection (FDEP) on February 20, 2002, and received approval and Site Certification by the Governor and Cabinet in April, 2003. FPL acquired all permits needed and commenced construction in May, 2003. Modifications to operating permits will be pursued as necessary through 2004.

Preferred Site # 2: Martin Plant, Martin County

The Martin site is located approximately 40 miles northwest of West Palm Beach, 5 miles east of Lake Okeechobee, and 7 miles northwest of Indiantown in Martin County, Florida. The site is bounded on the west by the Florida East Coast Railway (FEC) and the adjacent South Florida Water Management District (SFWMD) L-65 Canal, on the south by the St. Lucie Canal (C-44 or Okeechobee Waterway), and on the northeast by SR 710 and the adjacent CSX Railroad. The Martin site was identified in 1987 as a preferred location for development of coal gasification/combined cycle electric generation facilities and subsequent FPL Site Plans have continued to identify this site as a preferred site.

The existing 2,906 MW (Summer) of generating capacity at FPL's Martin site occupies a portion of the approximately 11,300 acres that are wholly owned by FPL. The generating capacity is made up of two steam units (Units No. 1 and No. 2), plus two combined cycle units (Units No. 3 and No. 4), and two combustion turbine units (Units No. 8a and No. 8b). The site includes a 6,800-acre cooling pond (6,500 acres of water surface and 300 acres of dike area) and approximately 300 acres for the existing power plant units and related facilities.

Additional generating capacity was added to the site in 2001 in the form of two combustion turbines (CT's) that operate in simple cycle mode using natural gas. These two CT's will be converted into one four-on-one (4X1) combined cycle (CC) unit with the addition of two new CTs, four new Heat Recovery Steam Generators (HRSGs), and a new steam turbine generator. The resulting CC unit will be known as Martin Unit No. 8. It is estimated to be in service in mid-2005 adding approximately 785 MW of capacity.

a. and b. U.S. Geological Survey (USGS) Map and Proposed Facilities Layout

A USGS map of the Martin plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a 6,800-acre cooling pond. The existing power plant facilities are located on approximately 300 acres. To the east of the power plant there is an area of mixed pine flat wood with a scattering of small wetlands. To the north of the cooling pond there is a 1,200-acre area which has been set aside as a mitigation area. There is a peninsula of wetland forest on the West Side of the reservoir that is named the Barley Barber Swamp. The Barley Barber Swap encompasses 400 acres and is preserved as a natural area. There is also a 10-kilowatt (kW) photovoltaic energy facility at the south end of this site.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

As noted above, the Barley Barber Swamp is located on the site. There is also a 1,200-acre mitigation area in the northern area of the site where wetlands and uplands have been preserved. Along the south and west sides of the cooling pond is an area where the vegetation has been maintained in its natural state in order to serve as a wildlife corridor. There are pine flat woods and small-scattered wetlands to the east of the plant.

2. Listed Species

Construction and operation of a new unit at the site is not expected to affect any rare, endangered, or threatened species. There are two active Bald Eagle (*Haliaeetus leucocephalus*: Federal-and State-listed as Threatened) nests that have been on the site for many years. The Florida Natural Areas Inventory (FNAI) database notes a record of Eastern Indigo Snakes (*Drymachon coralis coupert*, which are Federal-and State listed as threatened) in the Barley Barber Swamp. A number of other Bald Eagle nests and sightings of Eastern Indigo Snakes are reported by the FNAI database within a two-mile radius of the site. Infrequent sightings of Florida Panther have been made in the vicinity of the site area.

3. Natural Resources of Regional Significance Status

The Treasure Coast Regional Planning Council lists the "FPL Preserve", including the Barley Barber Swamp, as a Significant Regional Facility.

Natural communities such as uplands and wetlands are also generically listed as Resources of Regional Significance.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option is to add two new CT's and four new HRSG's and a new steam turbine that, together with the two existing CT's, will comprise Martin Unit No. 8. This unit is scheduled to be in-service in mid-2005. Natural gas delivered via pipeline is the primary fuel type for this unit (with light oil serving as a backup fuel). Natural gas-fired facilities are among the cleanest, most efficient technologies currently available. Mitigation options include the capture and reuse of plant process water and rainwater, plus the use of a cooling tower. The facility already encompasses several preserved areas where wildlife is abundant.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is "Public Utilities". Designations for the surrounding area are primarily "Agricultural". There are also limited areas of "Agricultural Ranchette", "Industrial", and a small "Commercial" area designation. To the southeast of the property, fronting on the St. Lucie Canal, is an area designated for "Public Conservation".

h. Site Selection Criteria and Process

The Martin plant has been selected as a preferred site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. This site is considered permittable.

i. Water Resources

Surface water resources currently used at the Martin facility include the cooling pond which takes its water from the St. Lucie canal. The available ground water resource is the surficial aquifer system which is used as a source of potable water and for service water for Units No. 1 and No. 2. Both of these sources are available for use with the site expansion.

j. Geological Features of Site and Adjacent Areas

FPL's Martin site is underlain by approximately 13,000 feet of sedimentary rock strata. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks, about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine bin origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, or clay. The deepest formation in Martin County on which significant published data are available is the Eocene Age Avon Park. Limited information is available from wells penetrating the underlying Lake City formation. The published information on the sediments comprising the formations below the

Avon Park Limestone in western Martin County is based on projections from deep wells in Okeechobee, St. Lucie, and Palm Beach Counties.

k. **Projected Water Quantities for Various Uses**

The estimated additional quantity of water required for process water is 150 gallons per minute (gpm). FPL operates on-site water treatment systems for this use. Cooling water for new Unit No. 8 will be cycled through new cooling towers and approximately 7 million gallons per day for makeup water to the cooling tower will be needed. (The two existing CT's that will be converted into combined cycle operation are currently air-cooled.) Makeup water for the cooling pond is taken from the St. Lucie canal. The current makeup water quantity to the cooling pond is adequate for Unit No. 8.

l. **Water Supply Sources by Type**

Martin Unit No. 8 will utilize the existing on-site cooling pond as the source of makeup water for the cooling towers. Makeup water to the pond is withdrawn from the St. Lucie canal as needed to replace net evaporation and seepage losses from the pond. Such needs will comply with the existing agreement between FPL and the SFWMD regarding allocation of cooling water to the pond and with SFWMD's regulations for consumptive water use.

The existing water treatment system at the plant, which provides treated water for use in the Unit No. 1 and No. 2 boilers, as well as for the HRSG's associated with Units No. 3 and No. 4, will be used to provide treated water for Unit No. 8.

m. **Water Conservation Strategies Under Consideration**

The entire plant site captures and reuses process water whenever feasible and manages storm-water in such a manner so as to recharge the surficial aquifer.

n. **Water Discharges and Pollution Control**

Water discharges from the facility are minimized by collecting and treating most point sources into the existing cooling pond. Discharges from the cooling pond are infrequent and only occur for the protection of the cooling pond embankment. Collected sources of water include equipment wash water, boiler blowdown water, and equipment area runoff. Non-contact storm water runoff is collected and treated via a storm water management system. Design elements have been included to capture suspended sediments. Facility permits mandate various sampling and testing activities that provide indications of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

The site is already serviced by multiple fuel delivery facilities. Three pipelines will serve the site. One pipeline is the FPL-owned north lateral from Florida Gas Transmission (FGT). A second pipeline is the FPL-owned south lateral dual purpose (oil and gas) pipeline which supplies oil to the steam boilers from the oil terminal on 45th Street and is interconnected with FGT. The third pipeline is a Gulfstream-owned lateral that will be constructed as part of the Unit No. 8 Conversion Project. Distillate fuel oil is received by truck and stored in above ground storage tanks. An additional above ground storage tank is being constructed to serve Unit No. 8.

p. **Air Emissions and Control Systems**

The use of clean fuels and combustion controls will minimize air emissions from Unit No. 8 and ensure compliance with applicable emission limiting standards. Using clean fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of carbon monoxide and volatile organic compounds. NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). These design alternatives constitute the BACT for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Martin Unit # 8 will incorporate features that will make it one of the most efficient and cleanest power plants in the State of Florida.

q. **Noise Emissions and Control Systems**

A field survey and impact assessment of noise expected to be caused by unit construction at the site indicated that construction noise would be within allowable levels. Noise from the operation of the new unit will also be within allowable levels.

r. **Status of Applications**

A Site Certification Application (SCA) was filed in December, 1989 for the construction and operation of the Martin Coal Gasification/Combined Cycle project under the Florida Electrical Power Plant Siting Act. In 2000, FPL added two CT's operating in simple cycle mode via an amendment to the initial certification to the site. Now, in order to convert the two CT's from simple cycle to 4X1 CC configuration (Unit No. 8), a modification to the Site Certification was required. FPL filed the modification on February 1, 2002 with the Florida Department of Environmental Protection

(FDEP). Approval and Site Certification was issued by the Governor and Cabinet in April, 2003. FPL acquired all construction permits and commenced construction in May, 2003. Modifications to operating permits will be pursued as necessary. Unit No. 8 will be in-service by June, 2005.

Preferred Site # 3: Turkey Point Plant, Miami-Dade County

The Turkey Point Plant site is located on the west side of Biscayne Bay, 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. Public access to the plant site is limited due to the nuclear units located there. The land surrounding the site is owned by FPL and acts as a buffer zone. The site is comprised of two nuclear and two conventional fossil fuel boiler units and the cooling canals. Adjacent to the plant site is an FPL-owned and operated mitigation bank known as the Everglades Mitigation Bank (EMB) covering approximately 13,000 acres.

Existing Units No. 1 and No. 2 are fossil fuel generating plants with approximate generating capacity of 400 MW each. Unit No. 1 was completed in 1967 and Unit No. 2 in 1968. Existing Units No. 3 and No. 4 are nuclear generating units with approximate generating capacity of 690 MW each. Unit No. 3 was completed in 1972 and Unit No. 4 in 1973. Turkey Point also has five diesel peaking units that in total produce approximately 12 MW. These units are primarily used to provide emergency power, but occasionally run during the summer to provide power during peak load demands.

The proposed Expansion Site for the location of new Turkey Point Unit No. 5, a 4x1 CC unit, is within the existing FPL Turkey Point facility property. The Expansion Site is adjacent to the existing fossil Units No. 1 and No. 2, and includes the existing parking lot and storage areas immediately northwest of Units No. 1 and No. 2 as well as wetlands north of the facility.

a. and b. U.S. Geological Survey (USGS) Map and Proposed Facilities Layout

A USGS map of the Turkey Point plant site, plus a map of the general layout of the proposed generating facilities at the site, is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a self-contained cooling canal system that supplies water to condense steam used by the existing units' turbine generators. The canal system consists of 36 interconnected canals each five miles long, 200 feet wide and four feet deep. The remaining developed area of the site is where the two fossil steam generating units and 5 diesel generators are located. South of and adjacent to the fossil plant are the two nuclear generating units. Further to the south exists the EMB previously discussed.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the proposed Expansion Site is undeveloped dwarf red mangrove swamp, tidally inundated with waters from Biscayne Bay. Along with the dominant red mangroves, buttonwood is a common canopy component, along with occasional white mangrove. Only a few individual black mangroves were observed within the Site. Biscayne Bay is a shallow, subtropical bay supporting sea grasses, sponges, coral reefs, and a variety of marine life.

2. Listed Species

The construction and operation of Unit No.5 is not expected to adversely affect any rare, endangered, or threatened species. One species listed by the FFWCC as a species of special concern was observed on the Expansion Site, the white ibis (Eudocimus albus). Listed species known to occur in the nearby Biscayne National Park that could potentially utilize the Expansion Site include the peregrine falcon (Falco peregrinus), wood stork (Mycteria americana), American crocodile (Crocodylus acutus), mangrove rivulus (Rivulus marmoratus), roseate spoonbill (Ajaja ajaja), limpkin (Aramus guarauna), little blue heron (Egretta caerulea), snowy egret (Egretta thula), American oystercatcher (Haematopus palliates), least tern (Sterna antillarum), brown pelican (Pelicanus occidentalis), and bald eagle (Haliaeetus leucocephalus). The FFWCC's bald eagle nest locator database was queried and resulted in no known nests in the vicinity of the Expansion Site. The federally listed, endangered American Crocodile thrives at the Turkey Point site, primarily in and around the southern end of the cooling canals which lie south of the proposed Expansion Site. The entire site is considered crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American crocodile. A Project-specific crocodile management plan has been developed for construction of Unit No. 5.

3. Natural Resources of Regional Significance Status

Significant features in the vicinity of the proposed Expansion Site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park. Biscayne National Park contains 180,000 acres, approximately 95% of which is open water interspersed with over 40 keys. The Biscayne National Park headquarters is located approximately 2 miles north of the Turkey Point plant, adjacent to the Miami-Dade County Homestead Bayfront Park, which contains a marina and day use recreational facilities.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option is to add one new unit consisting of four new CT's and four new HRSG's and a new steam turbine that will comprise Turkey Point Unit No. 5. This unit is scheduled to be in-service in mid-2007. Natural gas delivered via pipeline is the primary fuel type for this unit (with ultra low sulfur light oil serving as a backup fuel). Natural gas-fired facilities are among the cleanest, most efficient technologies currently available.

Mitigation options for unavoidable wetland impacts related to construction of Unit No. 5 that are being considered include on site hydrologic improvements to enhance existing wetlands, restoration and preservation of areas overgrown with exotic plant species, the purchase of mitigation credits from the EMB which is in the same drainage basin, and land preservation. Additional mitigating options include the capture and reuse of plant process water and rainwater, plus the use of cooling towers. The facility already encompasses several preserved areas where wildlife is abundant.

g. Local Government Future Land Use Designations

Local government future land use plan designates most of the site as IU-3 "Industrial, Unlimited Manufacturing District." There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. Site Selection Criteria and Process

For the past several years, a number of FPL's existing power plant sites have been considered as potentially suitable sites for new or re-powered generation. The Turkey Point plant has been selected as a preferred site due to consideration of various factors including system load, imbalances between load and generation in Southeast Florida, and economics. Recognizing that this site represents valued and sensitive environmental resources. FPL will give significant attention to minimizing environmental impacts and mitigating where impacts are unavoidable. This site is considered permittable.

i. Water Resources

Unique to Turkey Point Plant is the cooling canal system that supplies water to condense steam used by the plant's turbine generators. The canal system consists of 36 interconnected canals each five miles long, 200 feet wide and four feet deep. Water circulates through the 153-mile maze of canals in a two-day cycle, ending at the plant's intake pumps and cooling by as much as 15 degrees F.

However, FPL anticipates using a closed cooling system (cooling tower) for the new Unit No. 5 that uses forced air to cool the warm water coming off the generating equipment.

j. Geological Features of Site and Adjacent Areas

FPL's Turkey Point site is underlain by approximately 13,000 feet of sedimentary rock strata that forms the Biscayne aquifer. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily of marine origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, or clay. The Tamiami formation is named for deposits composed principally of white cream-colored calcareous sandstone, sandy limestone, and beds and pockets of quartz sand. Key Largo limestone is present in the Turkey Point area.

The Floridan aquifer, located approximately 1,200 feet below the land surface, is a confined aquifer. The Floridan aquifer system is composed entirely of carbonate rocks, except for minor evaporates. The water in the carbonate rock aquifer is more highly mineralized.

k. Projected Water Quantities for Various Uses

The additional quantity of process water is estimated to average 150 gpm. Water for this use would be supplied by a county water system. Cooling water for new Unit No. 5 will be cycled through a new cooling tower and approximately 12 million gallons per day for makeup water to the cooling tower will be needed. FPL proposes to use water from the Floridan Aquifer as the source of make-up water used by the cooling towers.

l. Water Supply Sources by Type

Turkey Point Unit No. 5 will utilize the cooling towers for the dissipation of heat from the cooling water. A new water treatment plant, separate from the existing water treatment system that provides treated water for use in the boilers of Unit No. 1 and No. 2, will be constructed for Unit No. 5.

m. Water Conservation Strategies Under Consideration

A plan to treat and recycle equipment wash water, boiler blowdown, and equipment area runoff for use as service water would reduce ground water consumption.

n. **Water Discharges and Pollution Control**

Water discharges from the new unit will be minimized by collecting and treating most point sources, with the water eventually entering the existing cooling canal system. There are no surface water discharges from the cooling canal system. Collected sources of water include equipment wash water, boiler blowdown water, equipment area runoff, and storm water runoff.

Design elements have been included to capture suspended sediments. Various facility permits mandate various sampling and testing activities, which provide indication of any pollutant discharges.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

The site is already serviced by multiple fuel delivery facilities. There is currently a pipeline that supplies natural gas to the facility. The facility also has oil capabilities through on-site storage tanks and accessibility to barge deliveries. The additional capacity will utilize the existing pipeline with the possible addition of compression system(s). An above ground storage tank for the ultra-low sulfur back-up fuel will be added.

p. Air Emissions and Control Systems

The use of clean fuels and combustion controls will minimize air emissions from the new unit and ensure compliance with applicable emission-limiting standards. Using clean fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter and other fuel bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x), and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during CC operations when firing ultra-low sulfur backup fuel. These design alternatives constitute the BACT for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of Turkey Point Unit No. 5 will incorporate features that will make it one of the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by unit construction at the site is expected to be within allowable limits. Noise from the operation of the new unit will also be within allowable levels.

r. Status of Applications

FPL filed the SCA for the Turkey Point Plant Unit No. 5 with the Florida Department of Environmental Protection (FDEP) on November 14, 2003. A federal Dredge and Fill application was submitted to the U.S. Army Corps of Engineers on November 14, 2003. The certification process and the dredge and fill permit process is expected to be completed with final review by the Governor and Cabinet in January, 2005.

Construction would commence in spring 2005 with an anticipated, in-service date of mid-2007.

IV.G. Potential Sites for Gas-Fired Generating Options

Six (6) sites are currently identified as potential sites for near-term (primarily 2008-2010) future gas-fired generation additions to meet FPL's capacity needs.[2] These sites have been identified as "potential sites" due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies.

Each of these potential sites offers advantages and disadvantages relative to engineering considerations and/or costs associated with the construction and operation of feasible technologies. In addition, each potential site has different characteristics that could require further definition and attention. For purposes of estimating water usage amounts, it is assumed that a natural gas-fired CC unit would be the technology of choice for any capacity additions at the sites.

Permits are presently considered to be obtainable for all of these sites, assuming measures can be taken to mitigate any particular site-specific environmental concerns that may arise. No significant environmental constraints are currently known for any of these six sites. The potential sites briefly discussed below are presented in alphabetical order. At this time FPL considers each site to be equally viable.

[2] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites.

Potential Site # 1: Andytown Substation , Broward County

FPL has identified the Andytown Substation Property in western Broward County as a potential site for the addition of new generating capacity. Current facilities on-site include an electric substation. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Andytown site is provided at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land uses for the potential site are designated as industrial or agricultural use. The site identification process included screening of potential sites to determine potential wetland impacts and impacts to endangered or threatened species. Extensive low-quality wetlands are adjacent to the site. FPL would expect to mitigate any impacts from construction of a power plant at this site. Construction and operation of a new facility on this site is not expected to adversely affect any rare, endangered, or threatened species.

d. and e. Water Quantities and Supply Sources

Surface water sources are not available at the site identified for the new plant. Groundwater from the shallow aquifer, or a local source of gray water, has been identified as potential water sources. FPL estimates that up to 12 million gallons per day of industrial processing water would be required for uses such as boiler makeup,

cooling water makeup, pollution control device usage, inlet air-cooling and service water.

Potential Site # 2: Cape Canaveral Plant, Brevard County

This site is located on the FPL Cape Canaveral Plant property in unincorporated Brevard County. The city of Port St. Johns is located less than a mile away. The site has direct access to a four-lane highway (US 1). A rail line is located near the plant. The existing facility consists of two 400 MW (approximate) steam boiler type generating units.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Cape Canaveral property site is provided at the end of this chapter.

b. and c. Land Uses and Environmental Features

This site is located on the Indian River. The land is primarily dedicated to industrial use with surrounding grassy areas and a few acres of remnant pine forest. The land adjacent to the site is dedicated to light commercial and residential use. There are no significant environmental features on the site.

d. and e. Water Quantities and Supply Sources

Water sources available at the site include surface water and groundwater. Groundwater from the shallow aquifer, or surface water, has been identified as potential water sources. FPL estimates that up to 12 million gallons per day of industrial processing water would be required for uses such as boiler makeup,

cooling water makeup, pollution control device usage, inlet air-cooling and service water.

Potential Site # 3: Corbett Substation Property, Palm Beach County

FPL has identified the Corbett Substation Property in Western Palm Beach County as a potential site for the addition of new generating capacity. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections.

a. U.S. Geological Survey (USGS) Map

A USGS map Corbett site is provided at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land uses for the potential sites are designated as industrial or agricultural use. The site identification process included screening of potential sites to determine potential wetland impacts and impacts to endangered or threatened species. Construction and operation of a new facility on these sites is not expected to adversely affect any rare, endangered, or threatened species.

d. and e. Water Quantities and Supply Sources

Water sources available at the site include surface water and groundwater. Groundwater from the Floridan aquifer, or surface water, has been identified as potential water sources. FPL estimates that up to 12 million gallons per day of industrial processing water would be required for uses such as boiler makeup,

cooling water makeup, pollution control device usage, inlet air-cooling and service water.

Potential Site # 4: Midway Substation Property, St. Lucie County

The site is located on the 122-acre Midway Substation property. Current facilities on the site include an electric substation. The site has direct access to a two-lane highway, State Road (SR) 712 and a nearby entrance to I-95. The City of Port St. Lucie is immediately east and west of the Midway site. The City of Ft. Pierce is approximately 9 miles northeast of the site.

a. U.S. Geological Survey (USGS) Map

A USGS map is provided of the Midway site area is provided at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on the site is currently dedicated to industrial and agricultural use. Much of the site is currently not being used. Developed portions of the adjacent properties are primarily agricultural (orange groves and cattle grazing). Undeveloped portions include mixed scrub with some hardwoods and wetlands.

d. and e. Water Quantities and Supply Sources

Water sources available at the site include surface water and groundwater. Groundwater from the Floridan aquifer, or surface water, has been identified as potential water sources. FPL estimates that up to 12 million gallons per day of industrial processing water would be required for uses such as boiler makeup,

cooling water makeup, pollution control device usage, inlet air-cooling and service water.

Potential Site # 5: Port Everglades Plant, Broward County

This site is located on the 94-acre FPL Port Everglades plant site in Port Everglades, Broward County. The site has convenient access to State Road (SR) 84 and Interstate 595. A rail line is located near the plant. The existing plant consists of four steam boiler generating units: two 200 MW (approximate) and two 400 MW (approximate) sized units. The four steam boilers are capable of firing residual fuel oil, natural gas, or a combination of both. The site also is home to twelve simple cycle gas turbine (GT) peaking units of 30 MW (approximate) each. The GT's are part of the Gas Turbine Power Park that is made up of 24 GT's at the Lauderdale Plant site and the twelve GTs at the Port Everglades site. The GT's are capable of firing either natural gas or liquid fuel.

a. U.S. Geological Survey (USGS) Map

A map of the Port Everglades plant site is provided at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on this site is primarily industrial. The adjacent land uses are port facilities and associated industrial activities, oil storage, cruise ships, and light commercial.

d. and e. Water Resources and Supply Sources

Water sources available at the site include surface water and groundwater. Groundwater from the Floridan aquifer, or surface water, has been identified as potential water sources. FPL estimates that up to 12 million gallons per day of industrial processing water would be required for uses such as boiler makeup, cooling water makeup, pollution control device usage, inlet air-cooling and service water.

Potential Site # 6: Riviera Plant, Palm Beach County

This site is located on the FPL Riviera Plant property in Riviera Beach, Palm Beach County. The site has direct access to a four-lane highway, US 1, and barge access is available. A rail line is located near the plant. The facility currently houses two operational 300 MW (approximate) steam boiler generating units and two retired generating units.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Riviera plant site is provided at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on the site is primarily covered by the existing generation facilities with some open maintained grass areas. There is a small manatee viewing area on the site which is operated seasonally by FPL. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development. The site is located on the Inter-coastal Waterway near the Lake Worth Inlet.

d. and e. Water Quantities and Supply Sources

Water sources available at the site include surface water and groundwater. Groundwater from the Floridan aquifer, or surface water, has been identified as potential water sources. FPL estimates that up to 12 million gallons per day of industrial processing water would be required for uses such as boiler makeup, cooling water makeup, pollution control device usage, inlet air-cooling and service water.

IV.H. Potential Sites for Solid Fuel-Fired Generating Options

As previously discussed, FPL is currently in the process of analyzing the feasibility of solid fuel-based generating options. FPL believes that the earliest a solid fuel generating option could be permitted and constructed is 2011. At the time this document was being prepared, FPL had made no decision regarding these options for 2011 – and is continuing to analyze these options.

These analyses include on-going investigations of potential sites for solid fuel options. A number of potential sites for solid fuel-based generation are being studied including sites both in and outside of Florida. The potential Florida sites are generally outside of the southeast Florida region previously discussed due to permitting and fuel transportation considerations. FPL will provide specific information regarding sites in future Site Plans if solid fuel generation options are determined to be viable options.

Environmental and Land Use Information: Supplemental Information

Preferred Site: Manatee

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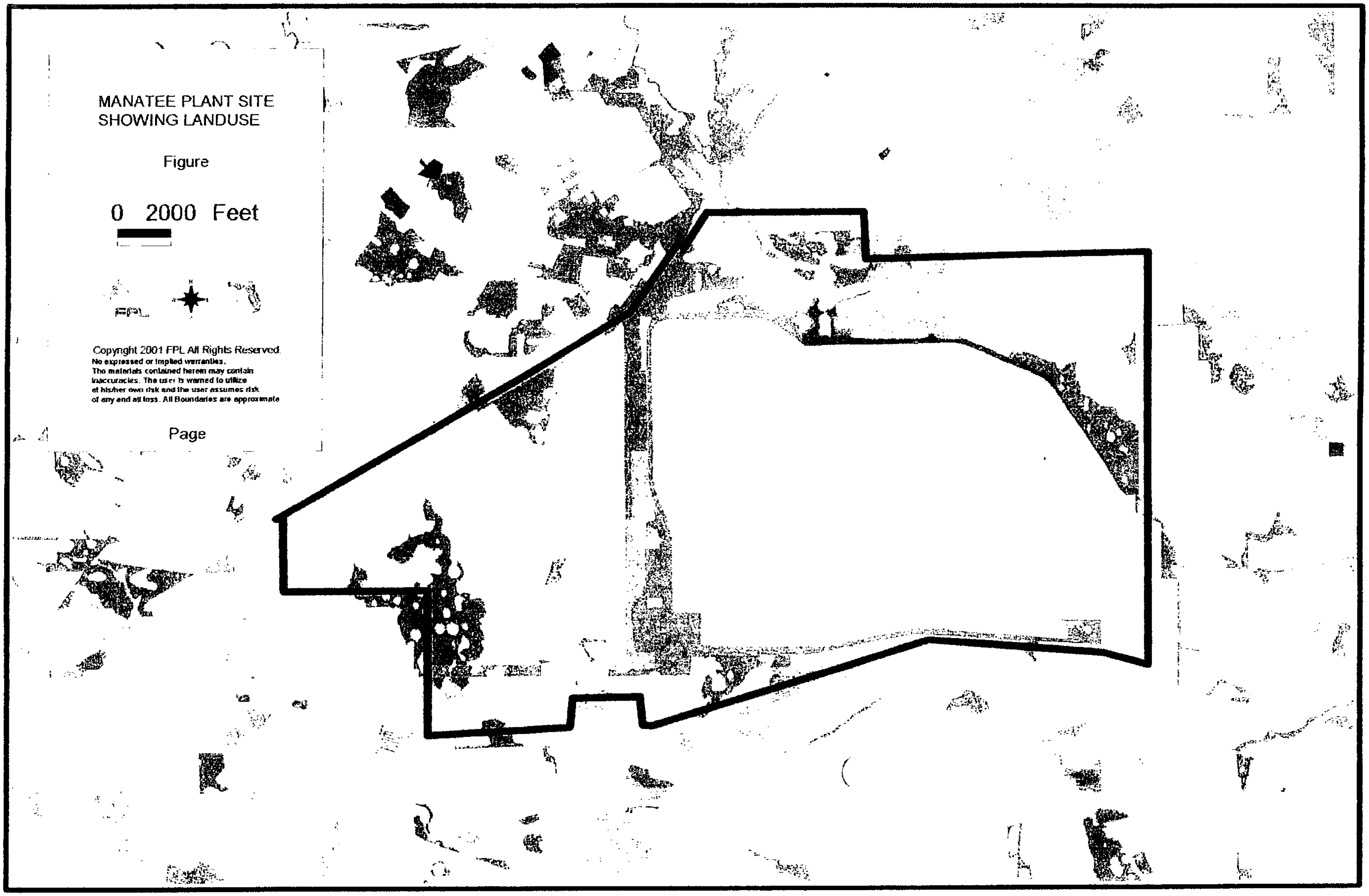
MANATEE PLANT SITE
SHOWING LANDUSE
Figure
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FPL
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Page

LEGEND FOR LANDUSE MAPS

Plant Site Boundary

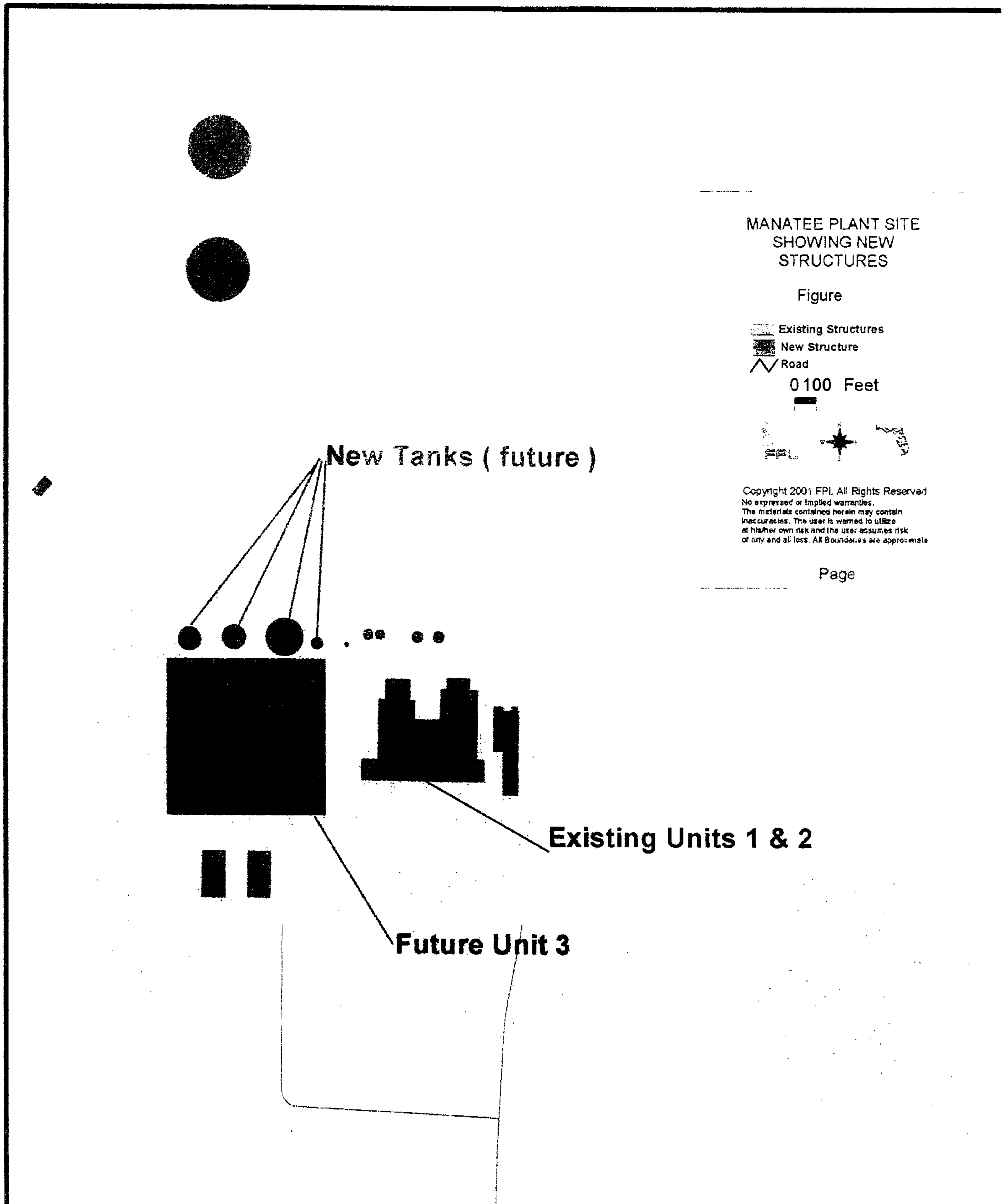
Level 3 Landuse Categories 1995

Residential Low Density
Residential Medium Density
Residential High Density
Commercial and Services
Industrial
Extractive
Institutional
Recreational
Open Land
Cropland and Pastureland
Tree Crops
Feeding Operations
Nurseries and Vineyards
Specialty Farms
Other Open Lands <Rural>
Herbaceous
Shrub and Brushland
Mixed Rangeland
Upland Coniferous Forests
Upland Hardwood Forests
Tree Plantations

Streams and Waterways
Lakes
Reservoirs
Bays and Estuaries
Major Springs
Slough Waters
Oceans Seas and Gulfs
Wetland Hardwood Forests
Wetland Coniferous Forests
Wetland Forested Mixed
Vegetated Non-Forested Wetlands
Non-Vegetated
Wetland Shrub
Beaches OtherThan Swimming Beaches
Sand Other Than Beaches
Exposed Rock
Disturbed Lands
Riverine Sandbars
Transportation
Communications
Utilities
Vegetation-Sea Grass

Figure

Page


MANATEE PLANT SITE
SHOWING NEW
STRUCTURES
Figure
Existing Structures
New Structure
Road
0 100 Feet
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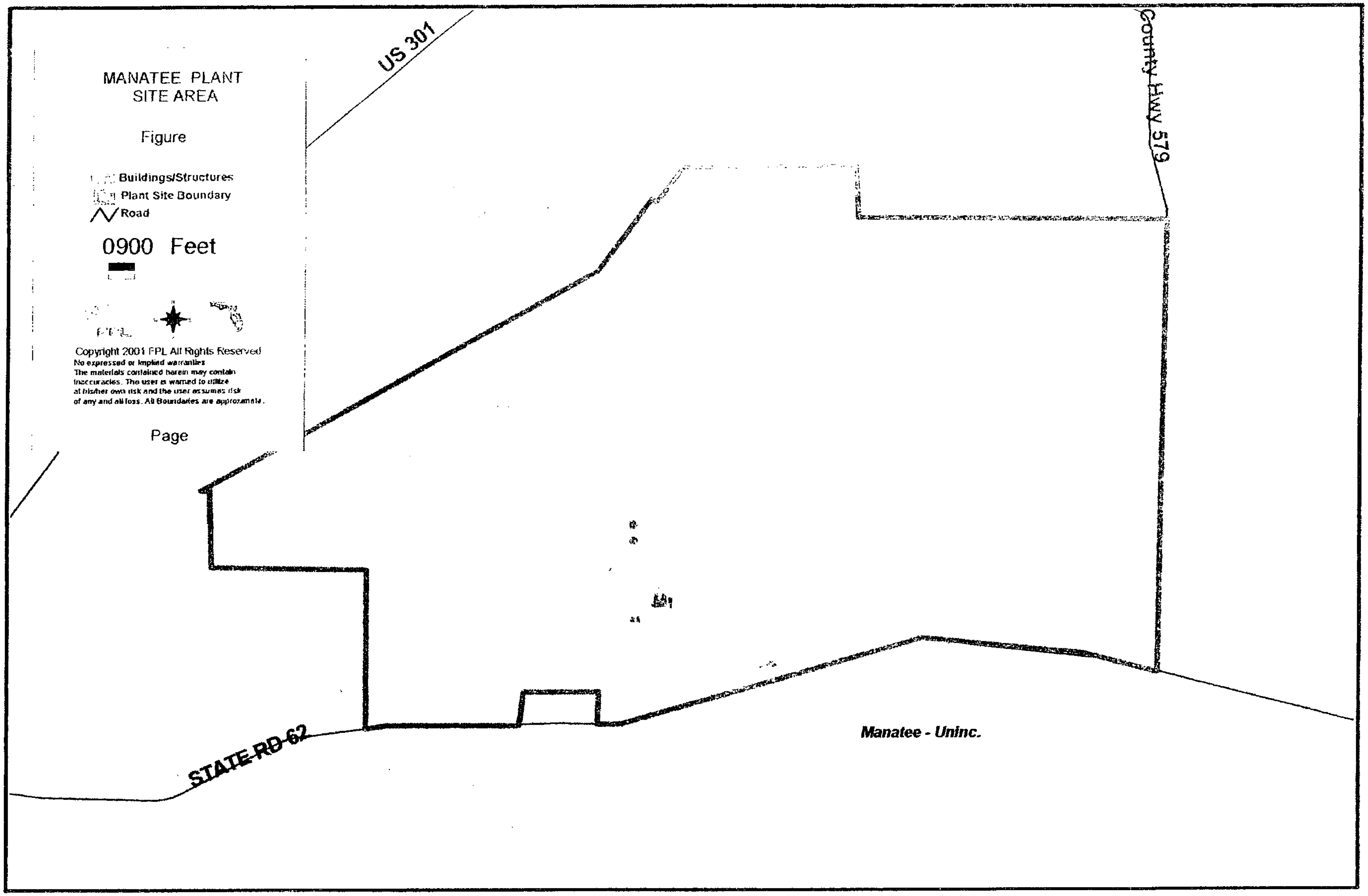
Page
New Tanks (future)
Existing Units 1 & 2
Future Unit 3

Florida Power & Light Company



Environmental and Land Use Information: Supplemental Information

Preferred Site: Martin

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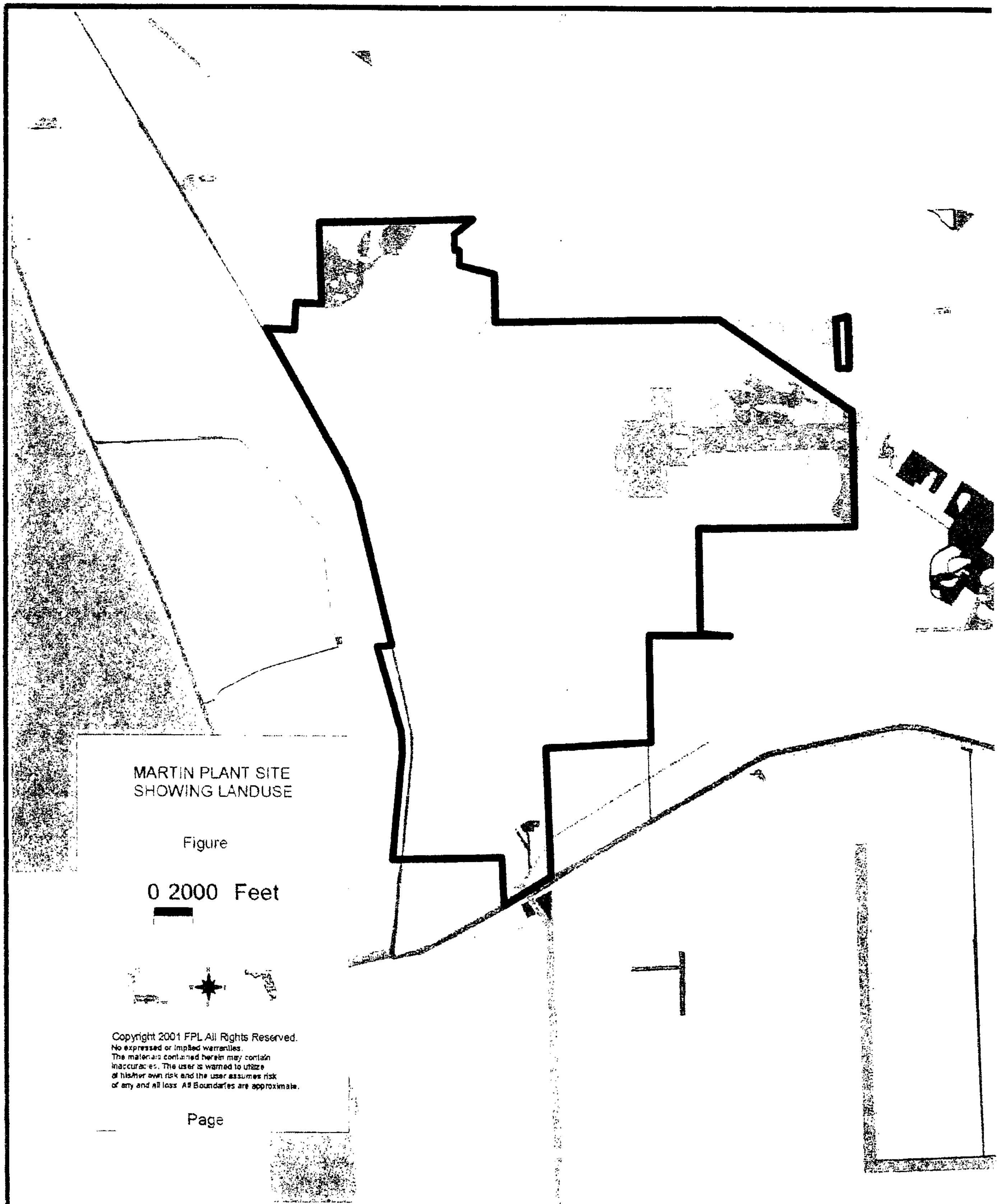
MARTIN PLANT SITE
SHOWING LANDUSE
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Page

LEGEND FOR LANDUSE MAPS

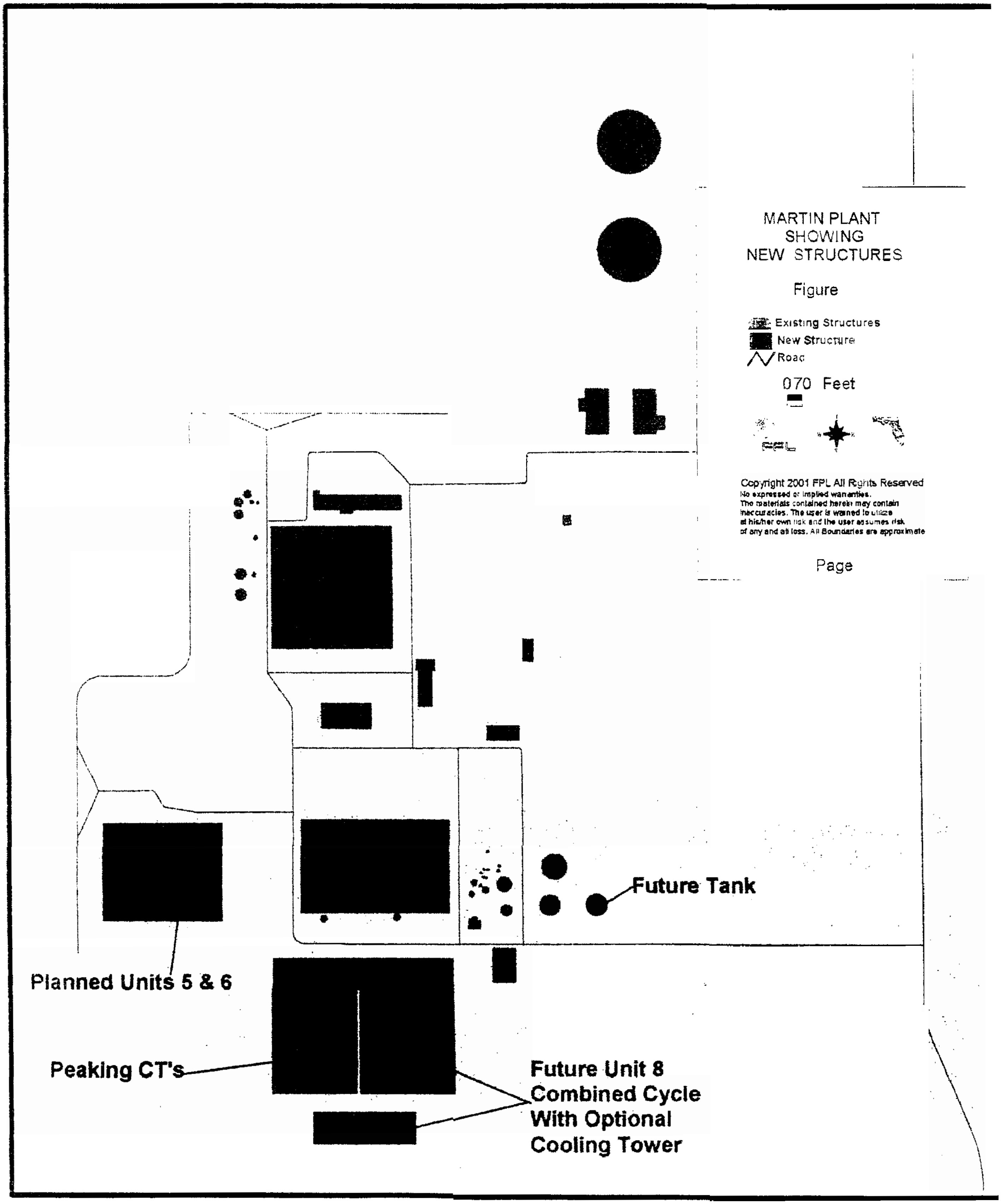
Plant Site Boundary

Level 3 Landuse Categories 1995

- Residential Low Density
- Residential Medium Density
- Residential High Density
- Commercial and Services
- Industrial
- Extractive
- Institutional
- Recreational
- Open Land
- Cropland and Pastureland
- Tree Crops
- Feeding Operations
- Nurseries and Vineyards
- Specialty Farms
- Other Open Lands <Rural>
- Herbaceous
- Shrub and Brushland
- Mixed Rangeland
- Upland Coniferous Forests
- Upland Hardwood Forests
- Tree Plantations
- Streams and Waterways
- Lakes
- Reservoirs
- Bays and Estuaries
- Major Springs
- Slough Waters
- Oceans Seas and Gulfs
- Wetland Hardwood Forests
- Wetland Coniferous Forests
- Wetland Forested Mixed
- Vegetated Non-Forested Wetlands
- Non-Vegetated
- Wetland Shrub
- Beaches OtherThan Swimming Beaches
- Sand Other Than Beaches
- Exposed Rock
- Disturbed Lands
- Riverine Sandbars
- Transportation
- Communications
- Utilities
- Vegetation-Sea Grass

Figure

Page


MARTIN PLANT
SHOWING
NEW STRUCTURES
Figure
Existing Structures
New Structure
Road
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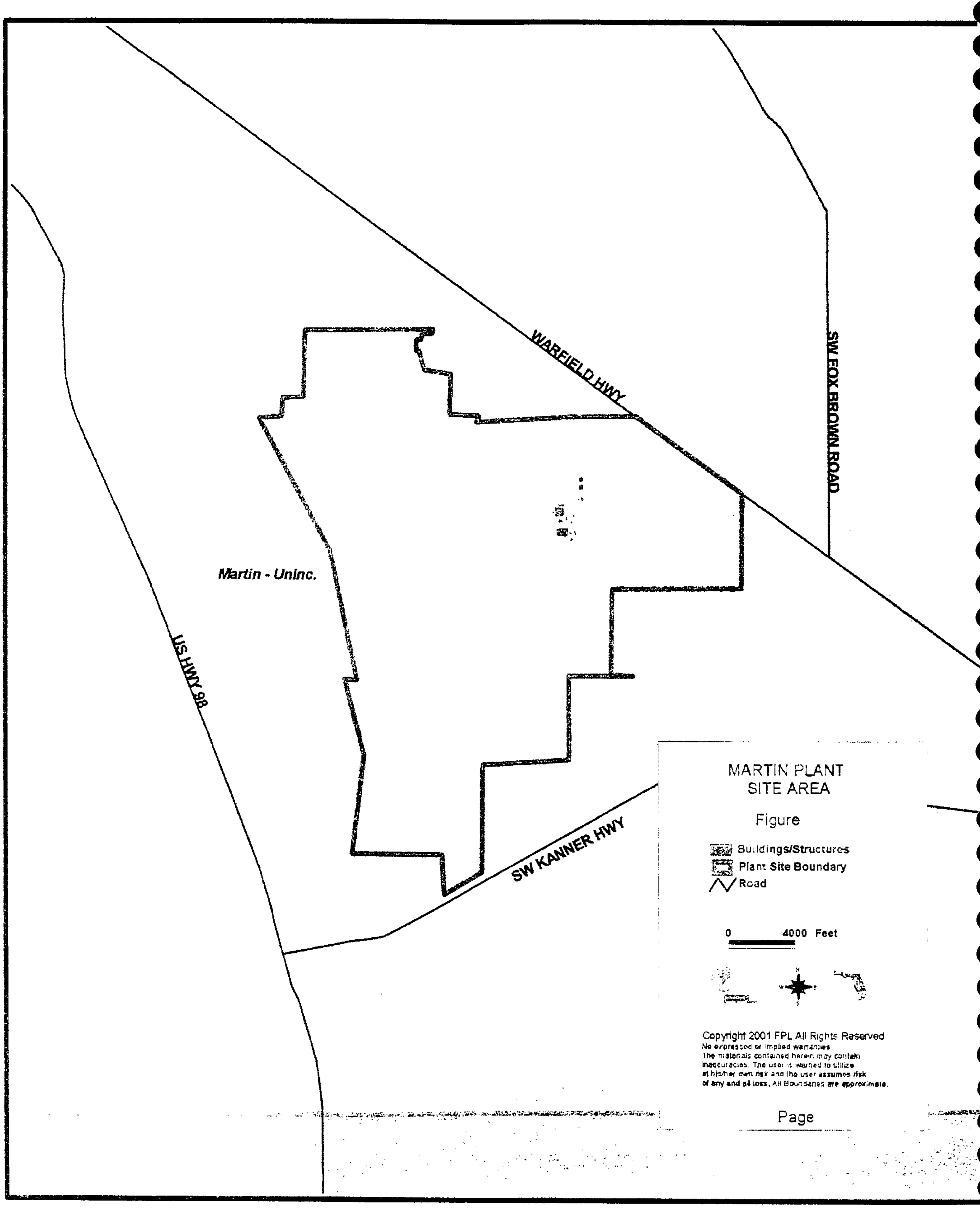
Future Tank
Planned Units 5 & 6
Peaking CT's
Future Unit 8
Combined Cycle
With Optional
Cooling Tower


WARFIELD HWY
SW FOX BROWN ROAD
Martin - Uninc.
US HWY 98
SW KANNER HWY
MARTIN PLANT
SITE AREA
Figure
Buildings/Structures
Plant Site Boundary
Road
0 4000 Feet
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Environmental and Land Use Information: Supplemental Information

Preferred Site: Turkey Point

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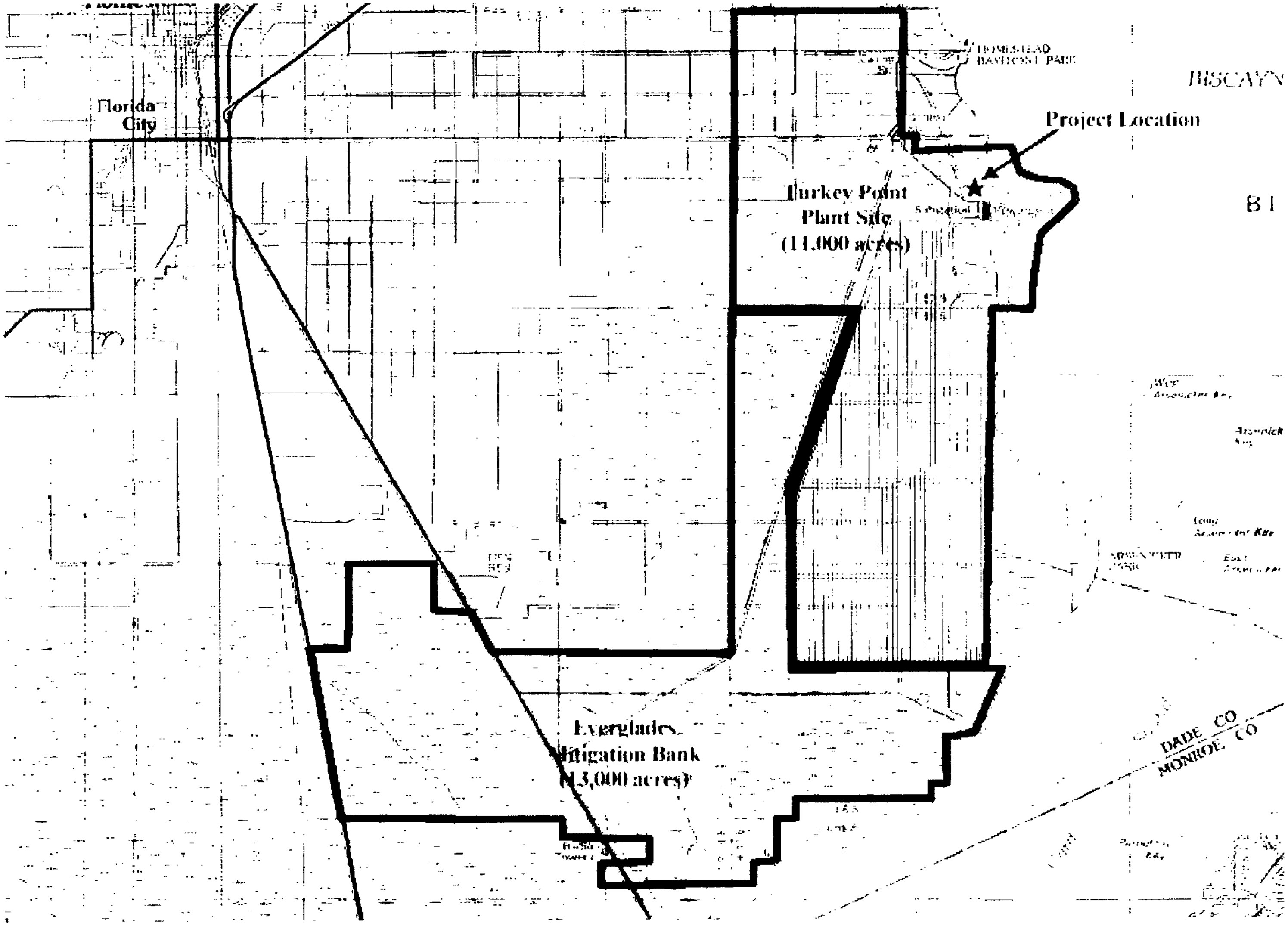
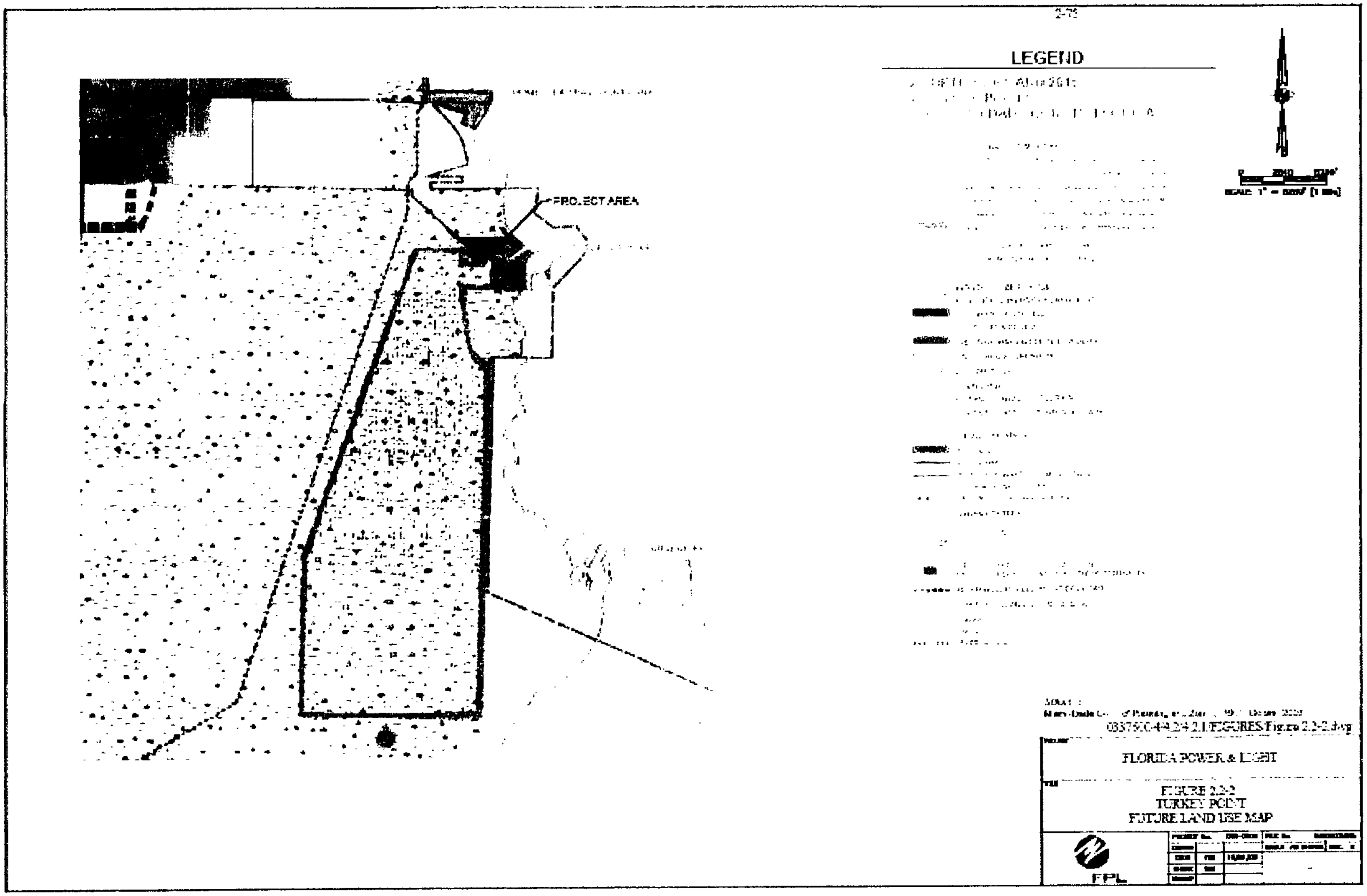
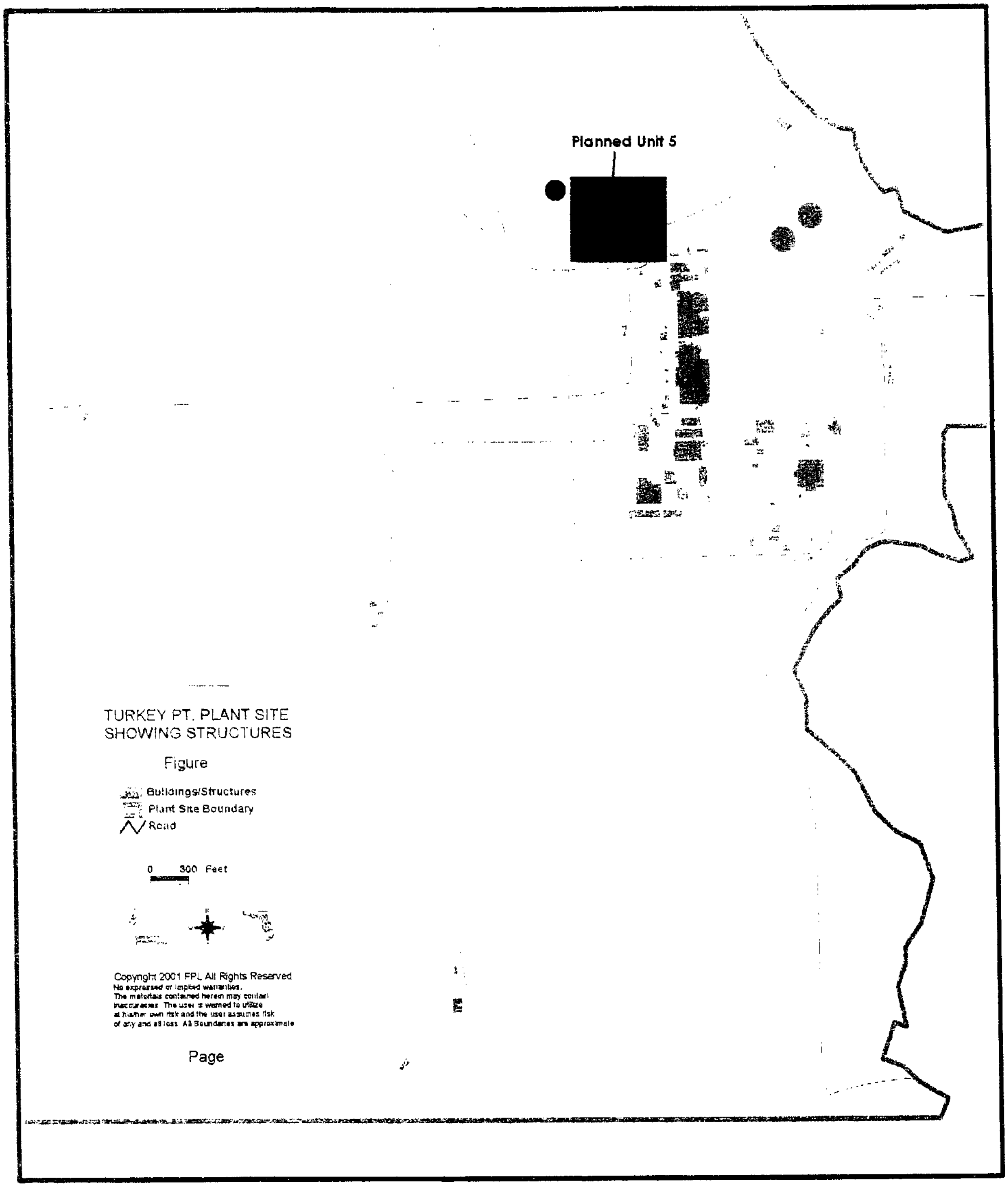

Florida City
Project Location
HOMESTEAD BAYFRONT PARK
BISCAYN
Turkey Point Plant Site (11,000 acres)
Everglades Mitigation Bank (13,000 acres)
DADE CO
MONROE CO


LEGEND
PROJECT AREA
FLORIDA POWER & LIGHT
FIGURE 2.2-2
TURKEY POINT
FUTURE LAND USE MAP
FPL


Planned Unit 5
TURKEY PT. PLANT SITE
SHOWING STRUCTURES
Figure
Buildings/Structures
Plant Site Boundary
Road
0 300 Feet
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Environmental and Land Use Information: Supplemental Information

Potential Site: Andytown

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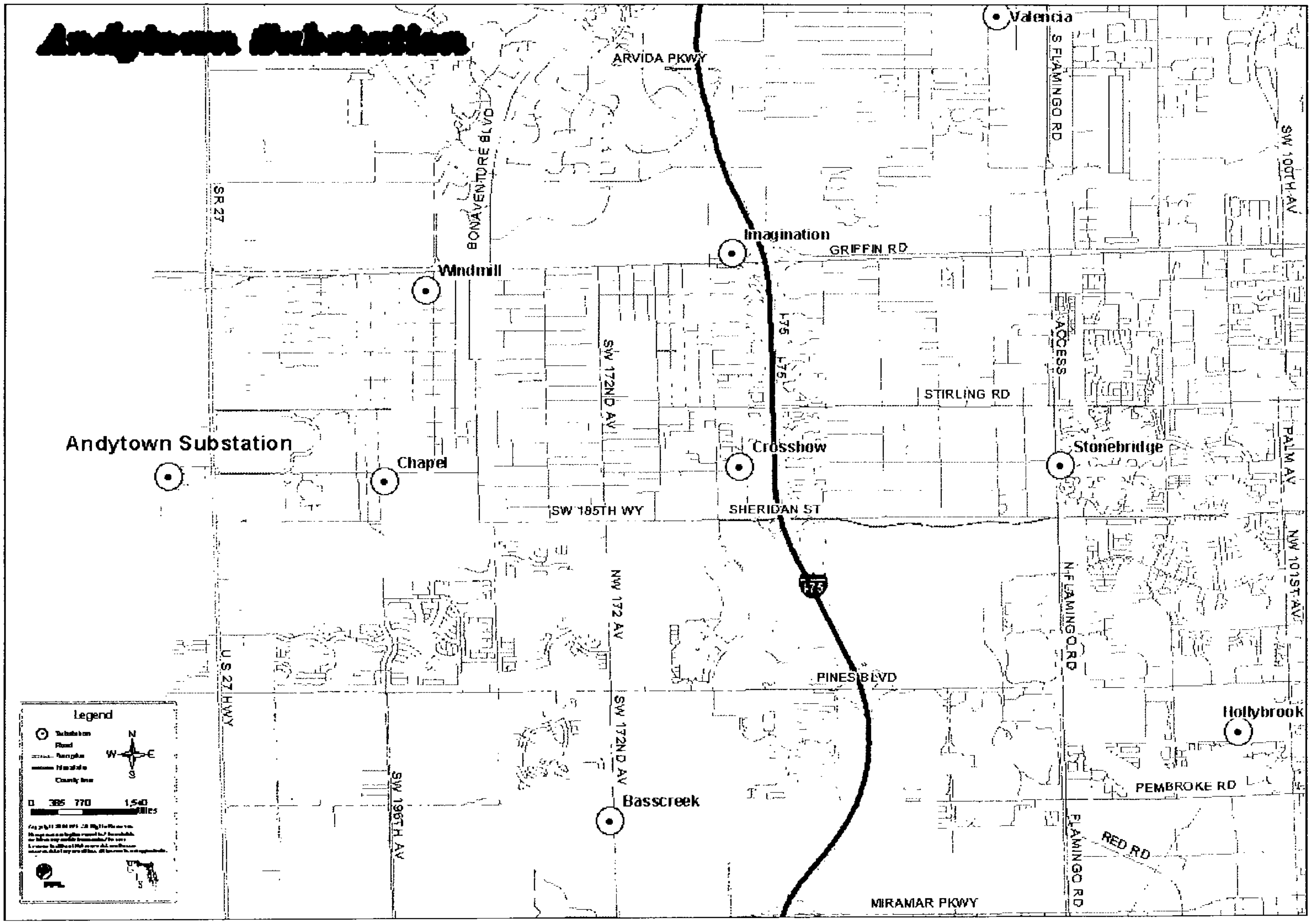
Andytown Substation
Andytown Substation
Valencia
Imagination
Windmill
Chapel
Crosshow
Stonebridge
Hollybrook
Basscreek
ARVIDA PKWY
S FLAMINGO RD
SW 100TH AV
BONAVENTURE BLVD
SR 27
GRIFFIN RD
ACCESS
STIRLING RD
SW 172ND AV
PALM AV
SW 185TH WY
SHERIDAN ST
NW 172 AV
N FLAMINGO RD
NW 101ST AV
PINES BLVD
U S 27 HWY
SW 172ND AV
SW 196TH AV
PEMBROKE RD
RED RD
FLAMINGO RD
MIRAMAR PKWY
75
Legend
N
W
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Miles
FPL

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Environmental and Land Use Information: Supplemental Information

Potential Site: Cape Canaveral

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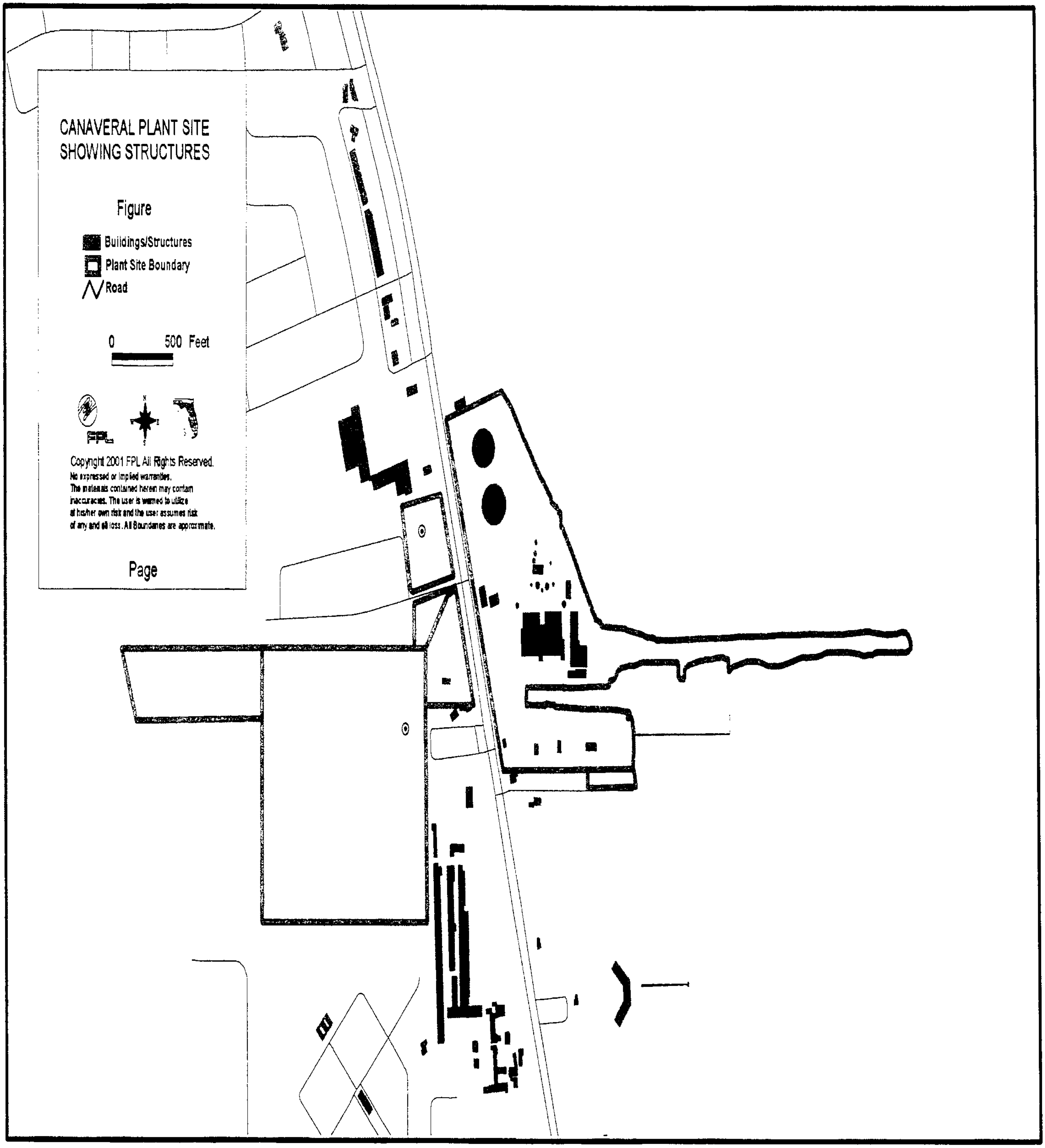
CANAVERAL PLANT SITE
SHOWING STRUCTURES
Figure
Buildings/Structures
Plant Site Boundary
Road
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Page

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Environmental and Land Use Information: Supplemental Information

Potential Site: Corbett

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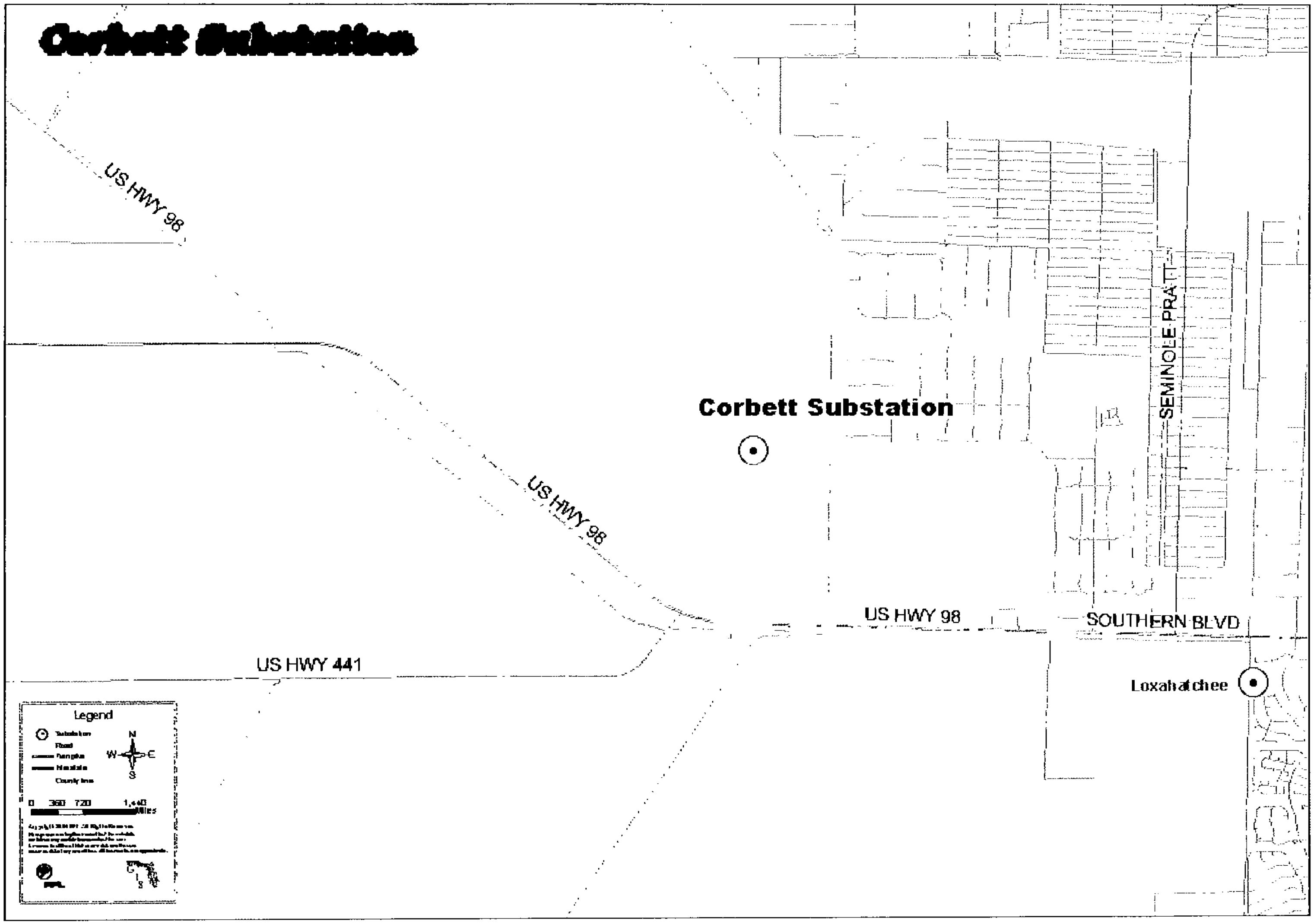
Corbett Substation
US HWY 98
US HWY 98
Corbett Substation
SEMINOLE PRATT
US HWY 98
SOUTHERN BLVD
US HWY 441
Loxahatchee
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Miles

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Environmental and Land Use Information:
Supplemental Information

Potential Site: Midway

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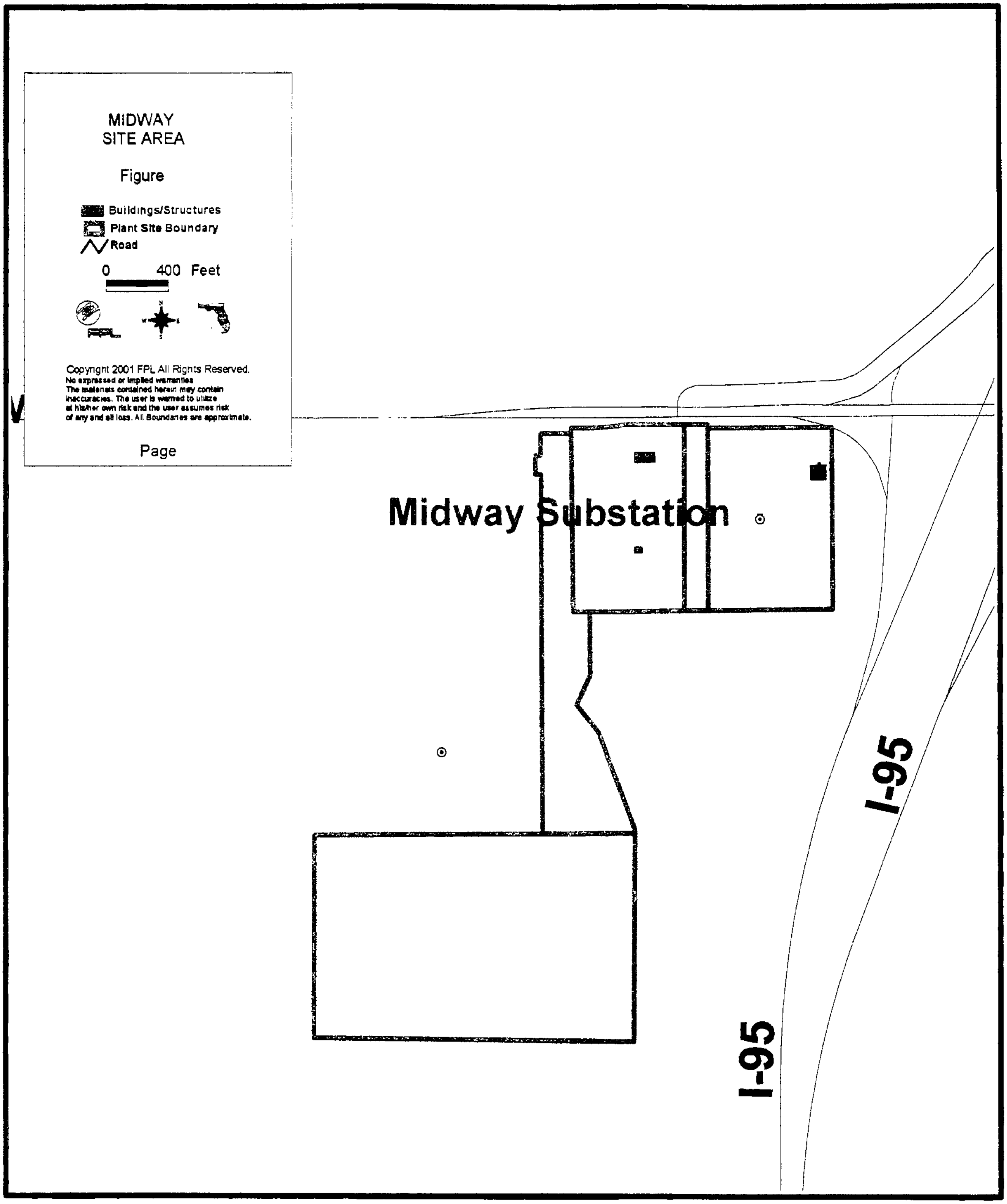
MIDWAY
SITE AREA
Figure
Buildings/Structures
Plant Site Boundary
Road
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Page
Midway Substation
I-95
I-95

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Environmental and Land Use Information: Supplemental Information

Potential Site: Port Everglades

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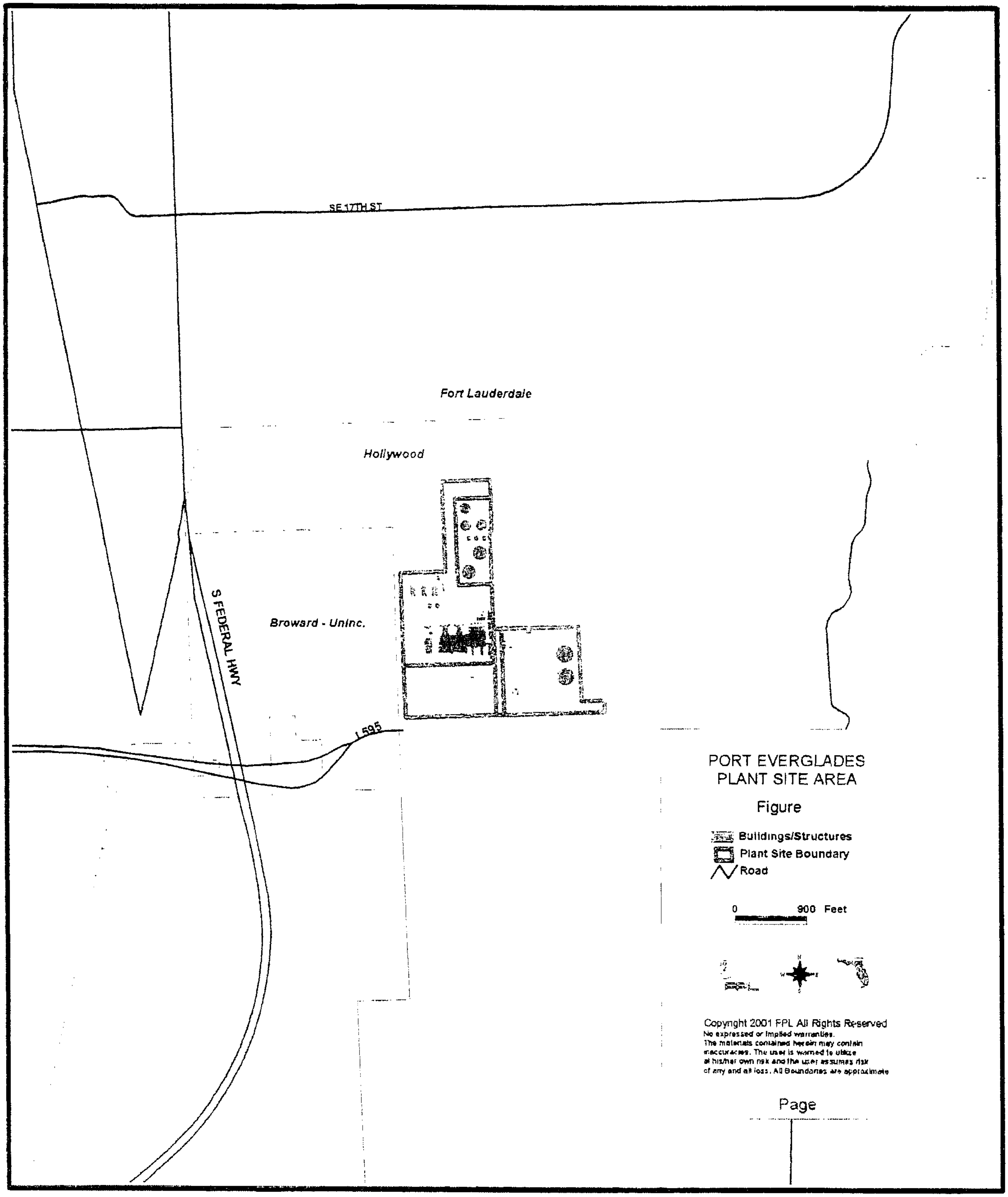
SE 17TH ST
Fort Lauderdale
Hollywood
S FEDERAL HWY
Broward - Uninc.
I 595
PORT EVERGLADES
PLANT SITE AREA
Figure
Buildings/Structures
Plant Site Boundary
Road
0 900 Feet
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Page

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Environmental and Land Use Information: Supplemental Information

Potential Site: Riviera Plant

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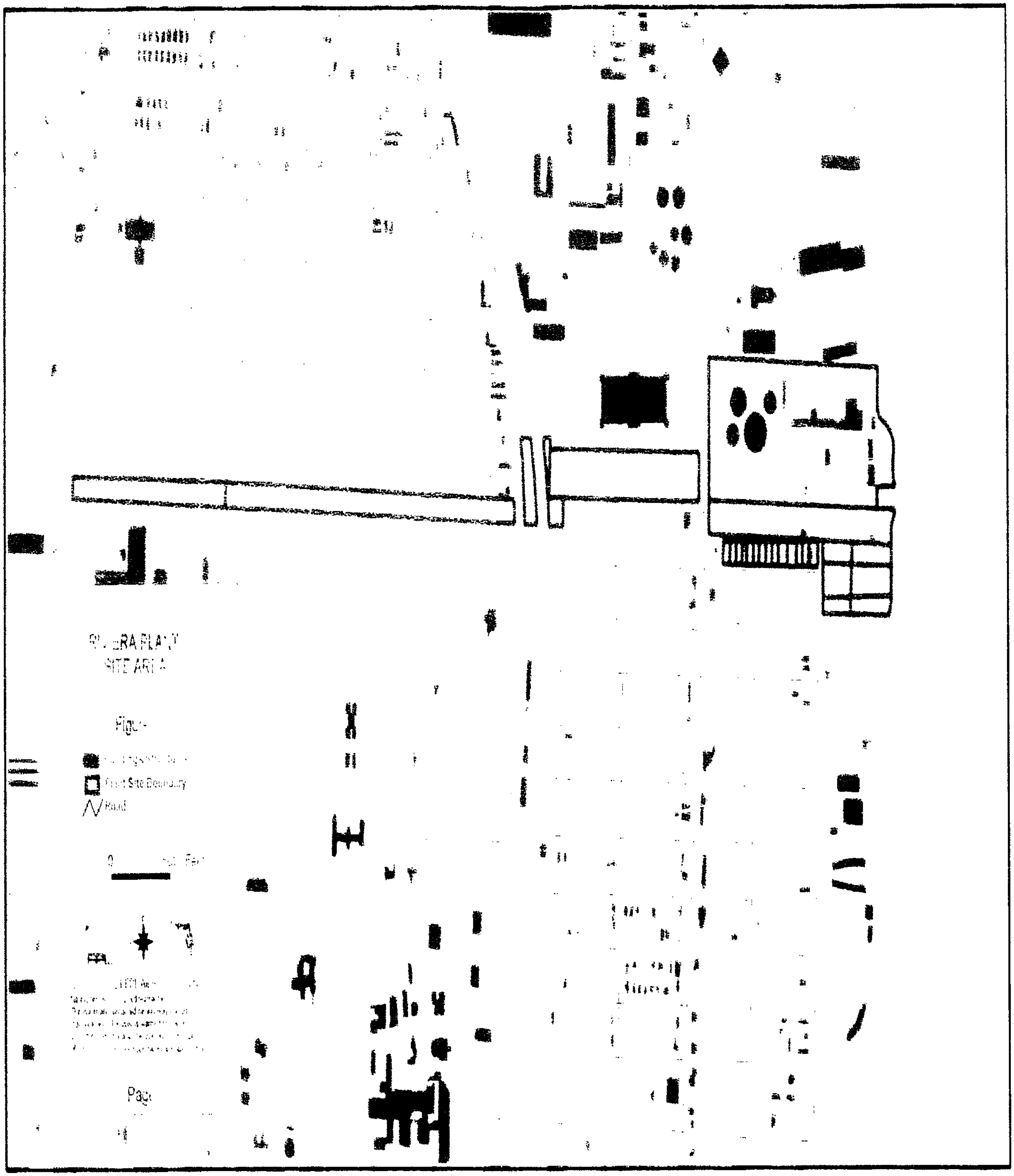

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CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten-Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information". These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission constraints. External constraints deal with FPL's ties to its neighboring systems. Internal constraints deal with the flow of electricity within the FPL system.

The external constraints influence the development of assumptions regarding the amount of external assistance which is available and the amount and price of economy energy purchases. Therefore, these external constraints are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission constraints or limitations are addressed by identifying potential geographic locations for potential new units that may not adversely impact, or that may even alleviate, such constraints and limitations and in developing the costs for siting new units, or delivering power from existing units, at different locations. Both site- and system-related transmission costs are developed for each different unit/unit location option or groups of options.

FPL's annual transmission planning work determines transmission additions needed to address constraints and to maintain/enhance system reliability. FPL's transmission plans are presented in Section III.E.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

As discussed in Chapter III of this document, FPL typically performs economic analyses of competing resource plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI) and Stone and Webster Management Consultants, Inc. The resource plan reflected in this document emerged as the resource plan with the least impact on FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach) and on the present value of revenue requirements for the FPL system.[3]

No sensitivity case analyses based on different load forecasts were carried out during FPL's most recent planning work. This is due to the fact that the near-term options projected to be added are combustion turbines can be added to the system on relatively short notice. If higher–than–projected loads begin to appear, combustion turbines can be placed in service in simple cycle mode in response to this unexpected occurrence. FPL believes that this fact qualitatively enables it to be able to address higher–than–projected loads.

[3] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis, the lowest rate basis and the lowest system revenue requirements basis are identical. In such cases (as in FPL's current resource planning work), FPL evaluates options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its base case or "Most Likely" fuel price forecast are discussed in Chapter III of this document.

In its most recent planning work, FPL did not test the sensitivity of its resource plan to fuel price forecasts different than its "Most Likely" fuel price forecast. All of the options considered in the IRP analysis for possible near-term implementation (i.e., through at least 2010) were natural gas-fired units, so any change in the fuel costs projections would have affected these near-term options in essentially the same way. Consequently, FPL concluded that a fuel price sensitivity case would not have provided information that would affect the selection of resources in the plan.

This approach is unique to the specific resources identified in this plan. FPL's on-going resource planning work will analyze the potential for solid fuel alternatives for the 2011-on time period. Support of these analyses will likely include fuel price sensitivity considerations to identify both the magnitude and likelihood of fuel cost reductions or the ability of fuel diversification to reduce the volatility of FPL's system fuel costs.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

For the same reason given in response to Discussion Item #3, FPL did not conduct a "constant fuel differential" sensitivity analysis in its most recent planning work.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, and capacity output ratings and heat rate information. Schedule 1 and Schedule 8 present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options which were considered in the resource planning work. A summary of this information for the new capacity options FPL projects to add over the planning horizon is presented on the Schedule 9 forms.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

The key financial assumptions used in FPL's most recent resource planning work were 45% debt and 55% equity FPL capital structure, projected debt cost of 6.4%, and an equity return of 11.0%. These assumptions resulted in a weighted average cost of capital of 8.9% and an after-tax discount rate of 7.8%. In its recent planning work, FPL did not test the sensitivity of its resource plan to varying financial assumptions. The reason for this is that FPL's planning work focused on near-term FPL construction options only that were generally very similar in design and varied only by site. Consequently, FPL concluded that varying financial assumptions would have resulted in no significant change in the results of the analysis.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM approach). However, in its most recent planning work FPL utilized a net present value of system revenue requirements as the basis for comparing resource plans. (As discussed in response to Discussion Item # 2, both the electricity rate basis and the system revenue requirement basis are identical when DSM levels are unchanged between competing plans. Such was the case in FPL's recent planning work.)

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses two generation reliability criteria in its resource planning work. One of these is a minimum 20% Summer and Winter reserve margin for the mid – 2004 – on time period. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the planning criteria established by the North American Electric Reliability Council (NERC) in its *Planning Standards*. FPL has applied these planning criteria in a manner consistent with prudent utility practice. The *NERC Planning Standards* are available on the internet (http://www.nerc.com/~filez/pss-psg.html).

In addition, FPL has developed a Facility Connection Requirements (FCR) document as well as a Facility Rating Methodology document that are also available on the internet (http://www.floasis.siemens-asp.com/oasis/fpl/info.htm). Thermal ratings for specific transmission lines or transformers are found in load flow cases.

Generally, the normal voltage criteria for FPL stations is given below:

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95	1.05
230	0.95	1.06
500	0.95	1.07

There may have been isolated cases for which FPL may have determined it prudent to deviate from the general criteria stated above. The overall potential impact on customers, the probability of an outage actually occurring, as well as other factors, may have influenced the decision in such cases.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The impact of FPL's DSM Programs on demand and energy consumption is revised periodically. Engineering models, calibrated with field-metered data, are updated when significant efficiency changes occur in the marketplace. Participation trends are tracked for all of the FPL programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants.

Survey data is collected from non-participants in order to establish the baseline efficiency. Participant data is compared against non-participant data to establish the demand and energy saving benefits of the utility program versus what would be installed in the absence of the program. Finally, FPL is careful to claim only program savings for the average life of the installed efficiency measure. For these DSM measures which involve the utilization of load management, FPL conducts periodic tests of the load control equipment to ensure that it is functioning correctly.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

Among the strategic or non-price factors FPL typically considers when choosing between resource options are the following: (1) fuel diversity; (2) technology risk; and (3) environmental risk.

Fuel diversity relates to two concepts, the diversity of sources of fuel (e.g., coal vs. oil vs. natural gas), and the diversity of supply for a single fuel source (for example alternative pipeline suppliers for natural gas). All other factors being equal, supply options that increase diversity in fuel source and/or supply would be favored over those that do not.

Technology risk is an assessment of the relative maturity of competing technologies, For example, a prototype technology which has not achieved general commercial acceptance has a higher risk than a technology in wide use and, therefore, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of competing technologies. Technologies which might be regarded as more acceptable from an environmental perspective (e.g., natural gas-fired options) might be considered more favorably.

All of these factors play a part in FPL's planning and decisions, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As has been previously discussed, the very near–term elements of FPL's capacity additions include a number of firm capacity short-term purchases and the construction (or proposed construction) of three new generating units; one each at FPL's existing Martin, Manatee and Turkey Point sites. The firm capacity short-term purchases were acquired through negotiations and the three generation construction projects were selected after evaluating competing proposals received in response to Request for Proposals (RFP's) issued by FPL in mid-2002 and mid-2003 respectively. The decision to construct new combined cycle units at FPL's existing Martin and Manatee sites was subsequently approved by the Florida Public Service Commission (FPSC) in late 2002. FPL has recently filed for FPSC approval of the Turkey Point combined cycle unit and expects a decision later this year.

FPL's current plan reflects the addition of two CT's to meet the 2008 need. This part of the plan will be refined after DSM goals are approved in the 3rd or 4th Quarter of 2004. FPL will also continue to evaluate purchases from existing units to meet all or part of the 2008 need.

To the extent that the capacity additions for 2009 and beyond require approval under the Power Plant Siting Act, FPL would conduct a capacity solicitation process similar to these Request for Proposal (RFP) processes.

FPL's current plan includes purchases to replace the UPS contracts that expire 2010. At present FPL is evaluating various purchase strategies for filing this need.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new line.

FPL plans to construct a new transmission line (by December 2005) that is presently being certified under the Transmission Line Siting Act (403.52 – 403.536, F.S.). The new line will connect FPL's Orange River Substation to FPL's Collier Substation (as shown on Table III.F.1). The certification process for this new line should be completed by the summer of 2004. The construction of this line is necessary to serve existing and future customers in the Collier and Lee areas in a reliable and effective manner. Additionally, FPL has identified the need for a new 230kV transmission line (by June 2008) that requires certification under the Transmission Line Siting Act (403.52 – 403.536, F.S.). The new line will connect FPL's St. Johns Substation to FPL's proposed West Palm Coast Substation (as shown on Table III.F.1). The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

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ORIGINAL

FPL

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05 APR -1 PM 3:45
COMMISSION CLERK

April 1, 2005

VIA HAND DELIVERY

M. Blanca S. Bayo, Director
Division of the Commission Clerk and Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: 2005 – 2014 Ten Year Site Plan

Dear Ms. Bayo,

In accordance with Chapter 186 (Section 186.801 – Ten Year Plans) of the Florida Statues, enclosed for filing are twenty-five (25) copies of Florida Power & Light Company's 2005 – 2014 Ten Year Power Plant Site Plan.

If you have any questions, please do not hesitate to contact me.

Sincerely,

John A. Hepokoski
Regulatory Issues Manager
(305) 552-4159

CMP ____
COM ____
CTR ____
ECR Haff
GCL ____
OPC ____
MMS ____
RCA ____
SCR ____
SEC 1
OTH 2 (Pena)

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Enclosures

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 40
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-E

DOCUMENT NUMBER-DATE
03234 APR-1 05
FPSC-COMMISSION CLERK

Ten Year Power Plant Site Plan

2005 - 2014

FPL®

FPL

Ten Year Power Plant Site Plan

2005-2014

Submitted To:

Florida Public
Service Commission

Miami, Florida
April, 2005

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Table of Contents

List of Figures and Tables

List of Schedules

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Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the state of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten-Year Power Plant Site Plan. This plan includes an estimate of the utility's electric power generating needs, a projection of how those needs will be met, and a disclosure of information pertaining to the utility's preferred and potential power plant sites. This information is compiled and presented in accordance with Rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (FAC).

This Ten-Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) planning analyses that were carried out in 2004 and that were completed in the first quarter of 2005. The forecasted information presented in this plan addresses the 2005–2014 time period.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information, especially for the latter years of the ten year time horizon, and is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as needed in the future as part of the Florida site certification process or other proceedings and filings.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is current information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, particularly new power plants, as determined by FPL's IRP work in 2004 and early 2005.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as preferred and potential site locations for additional electric generation facilities under consideration.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional specific information which is to be included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	***Abbreviation***	***Definition***
Unit Type	BIT	Bituminous Coal
	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	IC	Internal Combustion
	NP	Nuclear Power
	NPGU	Next Planned Generating Unit
	ST	Steam Unit
Fuel Type	UR	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	LNG	Liquified Natural Gas
	NG	Natural Gas
	NO	None
	Pet	Petroleum Coke
Fuel Transportation	NO	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	P	Planned Unit
	RP	Proposed for repowering
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	CKT.	Circuit
	P.U.	Per Unit

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Executive Summary

Florida Power & Light Company's (FPL) 2005 Ten Year Power Plant Site Plan (Site Plan) addresses FPL's plans to meet its projected incremental resource needs for the 2005–2014 time period.

FPL's total generation capability is projected to significantly increase during the 2005–2014 time period as shown in Table ES.1. This table also shows the resulting projected Summer and Winter reserve margins for FPL over this ten-year time horizon.

Table ES.1 reflects FPL's planned changes to existing generation units (due to unit overhauls, etc.), scheduled changes in the delivered amount of purchased power, and the planned additions of new generating units. Although not specifically shown in this table, FPL's approved DSM Goals are assumed to be implemented on schedule.

The amount of new generating capacity that will be added is driven in part by the outcome of the Florida Public Service Commission docket No. 981890-EU. This docket ended with a stipulated agreement that resulted in FPL, along with Tampa Electric Company and Florida Power Corporation, switching from a minimum reserve margin planning criterion of 15% to one of 20% beginning with the Summer of 2004.

FPL has previously sought to partially secure needed capacity through a number of short-term and long-term firm capacity purchases from utilities and other entities. Included in the capacity additions for the 2005 through 2014 time frame are a new four-year firm purchase from Reliant's Indian River facility starting in 2006 and a five and a half-year firm purchase from Southern Company starting in 2010.

In 2005, FPL will be adding a large (1,107 Summer MW) new combined cycle (CC) unit at its existing Manatee plant site. Also in 2005, the two combustion turbines (CT's) that were added at FPL's existing Martin plant site in mid-2001 will be converted into a 1,107 Summer MW CC unit by the addition of two additional CT's, heat recovery steam generators, and associated equipment. This conversion will add another 787 Summer MW of capability above the present capability of the existing two CT's. The additions for 2005 were selected as the best options among other FPL construction alternatives and numerous proposals received in response to two Requests for Proposals (RFP's) FPL issued in August 2001 and April 2002, respectively. These two capacity additions were approved by the Florida Public Service Commission (FPSC) on November 19, 2002, and their applications for certification under the Florida Electric Power Plant Siting Act (Siting

Act) were approved by the Governor and Siting Board on April 11, 2003.

In 2007, FPL will be adding a large (1,144 Summer MW) new CC unit at its existing Turkey Point plant site. This unit was selected as the best option after comparison to other FPL construction alternatives and proposals received in response to an RFP that FPL issued in August 2003. This capacity addition was approved by the FPSC on June 18, 2004. On February 7, 2005, the Governor of Florida and Cabinet, acting as the Siting Board, approved the certification of the location, construction, and operation of the Turkey Point CC capacity addition.

FPL's 2008 capacity requirement will be met by a four-year purchase of varying capacity from Reliant's Indian River facility that starts in 2006 and continues through 2009. This purchase also has an option that would allow FPL to extend the purchase by one-year, through 2010.

FPL currently projects to meet its 2009 capacity need with the addition of a new self–build CC unit at its West County Energy Center site. FPL's 2010 capacity requirements will be met, in part, by the previously mentioned five and a half-year purchase from Southern Company. This 930 MW purchase begins in mid-2010 and continues through the end of 2015. In addition, FPL projects to meet the remainder of its 2010 capacity need and its 2011 capacity need with the addition of a second new self–build CC unit at its West County Energy Center site. These capacity addition selections will be conducted in a manner consistent with the Commission's Bid Rule through a Request for Proposal (RFP) process. Specifically, FPL intends to publish an RFP in the Summer of 2005 to solicit competitive proposals for comparison to its Next Planned Generating Unit(s) for the capacity need required in the years 2009 – 2011.

As noted on Table ES.1, the projected reserve margin for 2011 with these capacity additions is 19.7%, 75 MW under the 20% reserve margin planning standard. Should the need remain as currently forecast, FPL anticipates that it will make short-term purchases or other capacity adjustments as required to satisfy the reserve margin requirement. This situation presents itself again, to a lesser degree, in 2014.

Based on FPL's current forecast, there will be additional capacity needs of approximately 550 MW per year in the 2012 through 2014 time frame. Given the issue of fuel diversity, FPL proposes to meet that need with two supercritical pulverized coal (SCPC) units. These units will combine highly efficient and reliable supercritical pulverized coal combustion technology with advanced emissions control technology and plant design allowing for recycling of generation byproducts into useful commercial products, bringing a new generation of clean coal facilities to Florida. Current need projections for the in-service dates of the first and second units are June 2012 and June 2013, respectively. These planned increases in electric generation capability will allow FPL to continue to maintain system reliability and integrity at a reasonable cost and maintain the economic and reliability benefits of a diverse fuel mix. The clean coal units are discussed in detail in FPL's recent *Report on Clean Coal Generation*, provided to the Commission in March of 2005. FPL plans to publish a Clean Coal RFP on or before August 2006 for the capacity need required in the years 2012-2014. Because the objective of the Clean Coal RFP is to enhance fuel diversity, the Clean Coal RFP will be restricted to proposals for clean coal generation, or other proposals that enhance fuel diversity as effectively as clean coal generation. The Clean Coal RFP is being initiated with a lead time that will support the longer construction schedule of a clean coal plant.

FPL's 2004 planning efforts have continued to address two significant issues that can affect the reliability and cost of electricity in the FPL service territory. Those two issues are: 1) the economic impact of the imbalance in southeast Florida between regional load and generating capacity located within this region and, 2) addressing fuel diversity in the FPL system. The selection of the Turkey Point CC unit to meet FPL's 2007 resource need has helped mitigate the immediate imbalance in southeast Florida through the year 2010. The purchase of additional coal-fired generation through a purchase agreement, the development of a potential clean coal generation facility, and efforts to evaluate bringing Liquefied Natural Gas (LNG) supplies to Florida, are the steps FPL is pursuing to address fuel diversity concerns. FPL's approach to these two issues will continue to be incorporated into FPL's resource planning work and other related initiatives.

Projected Capacity Changes and Reserve Margins for FPL [1]					
		Net Capacity Changes (MW)		FPL Reserve Margin (%)	
		Winter [2]	Summer [3]	Winter	Summer
2005	Changes to Existing Purchases [4]	(166)	(566)	20.9%	25.4%
	Manatee Unit #3 Combined Cycle [6]	---	1,107		
	Conversion of Martin #8 CT's to CC [6]	0	787		
	Changes to existing Units	---	12		
2006	Changes to Existing Purchases [4]	(132)	(136)	29.3%	23.1%
	New Purchases [5]	130	130		
	Manatee Unit #3 Combined Cycle [6]	1,197	---		
	Conversion of Martin #8 CT's to CC [6]	835	---		
	Changes to existing Units	240	167		
2007	Changes to Existing Purchases [4]	---	(935)	27.1%	22.1%
	Changes to New Purchases [5]	224	224		
	Turkey Point Combined Cycle #5 [6]	---	1,144		
	Changes to existing Units	(1)	(1)		
2008	Changes to Existing Purchases [4]	(1,008)	---	26.4%	20.5%
	Changes to New Purchases [5]	222	222		
	Turkey Point Combined Cycle #5 [6]	1,181	---		
2009	Changes to Existing Purchases [4]	---	(51)	21.9%	21.1%
	Changes to New Purchases [5]	(326)	(326)		
	West County Energy Center #1 Combined Cycle [6]	---	1,107		
2010	Changes to Existing Purchases [4]	(51)	(979)	23.1%	22.4%
	Changes to New Purchases [5]	(250)	680		
	West County Energy Center #1 Combined Cycle [6]	1,181	---		
	West County Energy Center #2 Combined Cycle [6]	---	1,107		
2011	Changes to Existing Purchases [4]	(94)	(45)	25.2%	19.7%
	Changes to New Purchases [5]	930	---		
	West County Energy Center #2 Combined Cycle [6]	1,181	---		
2012	Unsited Clean Coal Unit # 1 (6)	---	850	22.4%	21.0%
2013	Unsited Clean Coal Unit # 1 (6)	855	---	23.3%	22.4%
	Unsited Clean Coal Unit # 2 (6)	---	850		
2014	Unsited Clean Coal Unit # 2 (6)	855	---	24.1%	19.9%
	TOTALS =	7,003	5,348		

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.

(2) Winter values are values for January of year shown.

(3) Summer values are values for August of year shown.

(4) These are firm capacity purchases with contract that existed on 12/31/03. See Section I.B, I.D and III.A. for more details.

(5) These are firm capacity purchases with contracts executed on/after 1/01/04.

(6) All new units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

Table ES.1

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 8 million people. FPL served an average of 4,224,509 customer accounts in thirty-five counties during 2004. These customers were served from a variety of resources including: FPL-owned fossil and nuclear generating units, non-utility owned generation, demand side management, and interchange/purchased power.

I.A. FPL-Owned Resources

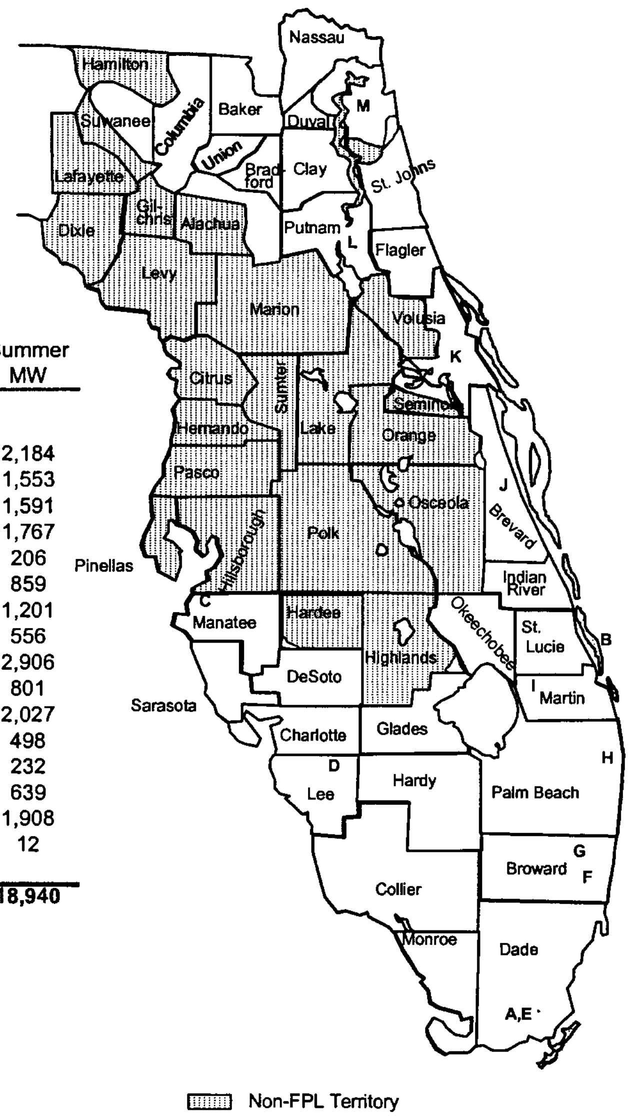
The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory and also include partial ownership of one unit located in Georgia and two units located in Jacksonville, FL. The current generating facilities consist of four nuclear steam units, three coal units, nine combined cycle units, seventeen fossil steam units, forty-eight combustion gas turbines, two simple cycle combustion turbines, and five diesel units. The location of these units is shown on Figure I.A.1 and in Table 1.A.1.

The bulk transmission system is composed of 1,104 circuit miles of 500 Kilovolt (KV) lines (including 75 miles of 500 KV lines [two 37-1/2 mile lines] between Duval Substation and the Florida-Georgia state line, which are jointly owned with Jacksonville Electric Authority) and 2,753 circuit miles of 230 KV lines. The underlying network is composed of 1,584 circuit miles of 138 KV lines, 717 circuit miles of 115 KV lines, and 164 circuit miles of 69 KV transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 537 substations.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3 shows FPL's interconnection ties with other utilities.

Capacity Resources by Location
(as of December 31, 2004)

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	4	2,184
B	St. Lucie *	2	1,553
C	Manatee	2	1,591
D	Fort Myers	2	1,767
E	Cutler	2	206
F	Lauderdale	2	859
G	Port Everglades	4	1,201
H	Riviera	2	556
I	Martin	5	2,906
J	Cape Canaveral	2	801
K	Sanford	3	2,027
L	Putnam	2	498
M	SJRPP **	2	232
	Scherer ***	1	639
	Gas Turbines	48	1,908
	Internal Combustion Turbines	5	12
	FPL Generation =	**88**	**18,940**



* Represents FPL's ownership share: St Lucie nuclear: 100% unit 1, 85% unit 2: St. Johns River: 20% of two units.

** SJRPP = St. John's River Power Park

*** The Scherer unit is located in Georgia and is not shown on this map.

Figure I.A.1

Capacity Resource by Unit Type
As of December 31, 2004

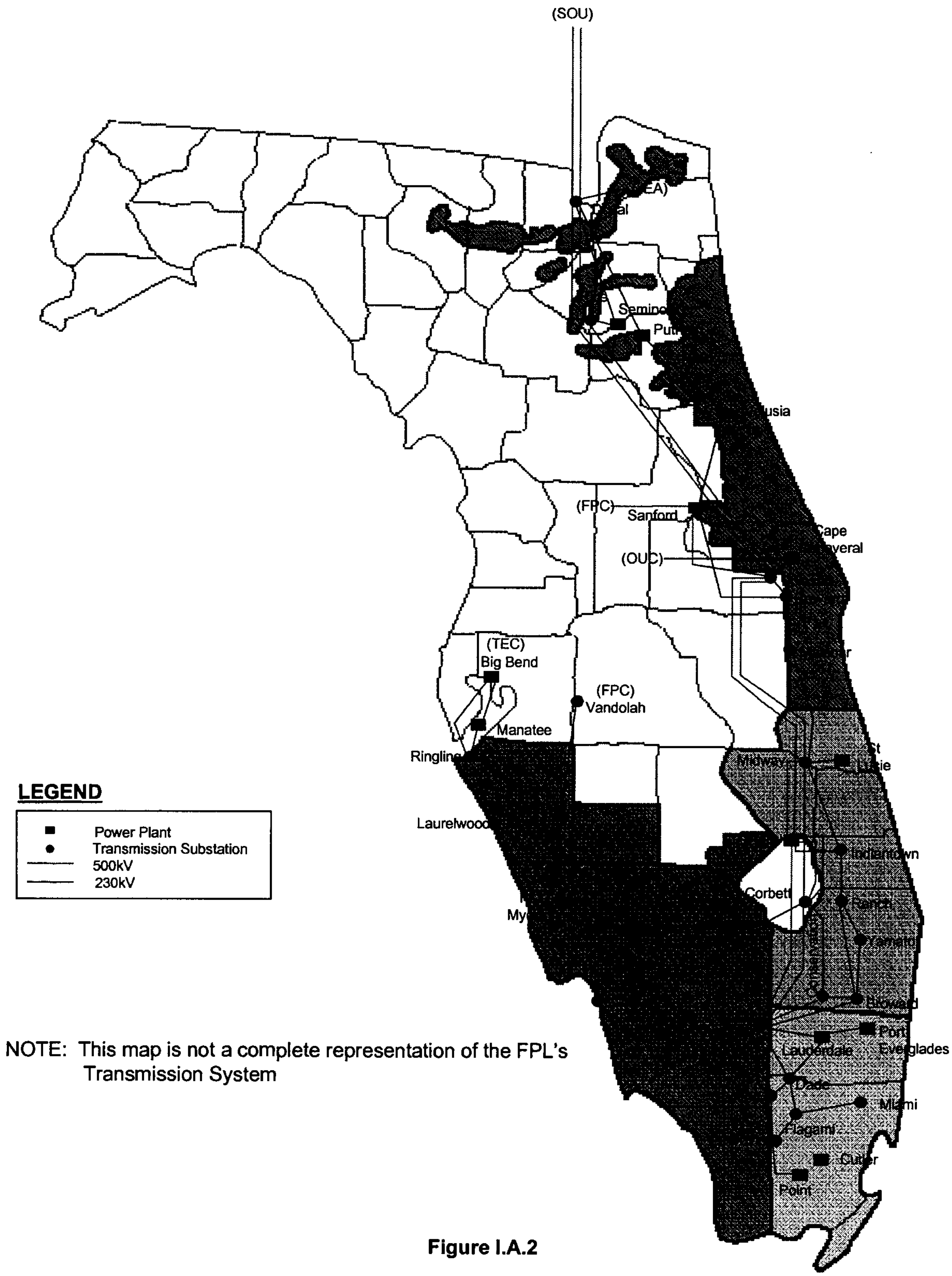
Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Combined-Cycle				
Lauderdale	Dania, FL	2	Gas/Oil	859
Martin	Indiantown,FL	2	Gas	943
Sanford	Lake Monroe, FL	2	Gas	1,889
Putnam	Palatka, FL	2	Gas/Oil	498
Fort Myers	Fort Myers, FL	1	Gas	1,441
Total Combined Cycle		9		5,630
Combustion Turbines				
Martin *	Indiantown,FL	1	Gas/Oil	320
Fort Myers *	Fort Myers, FL	1	Gas/Oil	326
Total Combustion Turbines		2		646
Nuclear				
Turkey Point	Florida City, FL	2	Nuclear	1,386
St. Lucie **	Hutchinson Island, FL	2	Nuclear	1,553
Total Nuclear		4		2,939
Coal Steam				
SJRPP **	Jacksonville, FL	2	Coal	232
Scherer	Monroe County, Ga	1	Coal	639
Total Coal Steam		3		871
Oil/Gas Steam				
Cape Canaveral	Cocoa, FL	2	Oil/Gas	801
Cutler	Miami, FL	2	Gas	206
Manatee	Parrish, FL	2	Oil/Gas	1,591
Martin	Indiantown,FL	2	Oil/Gas	1,643
Port Everglades	Port Everglades, FL	4	Oil/Gas	1,201
Riviera	Riviera Beach, FL	2	Oil/Gas	556
Sanford	Lake Monroe, FL	1	Oil/Gas	138
Turkey Point	Florida City, FL	2	Oil/Gas	798
Total Oil/Gas Steam		17		6,934
Gas Turbines(GT)/Diesels(IC)				
Lauderdale (GT)	Dania, FL	24	Oil/Gas	840
Port Everglades (GT)	Port Everglades, FL	12	Oil/Gas	420
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Turkey Point (IC)	Florida City, FL	5	Oil	12
Total Gas Turbines/Diesels		53		1,920
Total Units:		88		
Total Net Generating Capability:				18,940

* Each unit consists of two combustion turbines totaling approximately 300 MW.

** Represents FPL's ownership share: St. Lucie nuclear: 100% unit 1, 85% unit 2; SJRPP coal: 20% of two units.

Table I.A.1

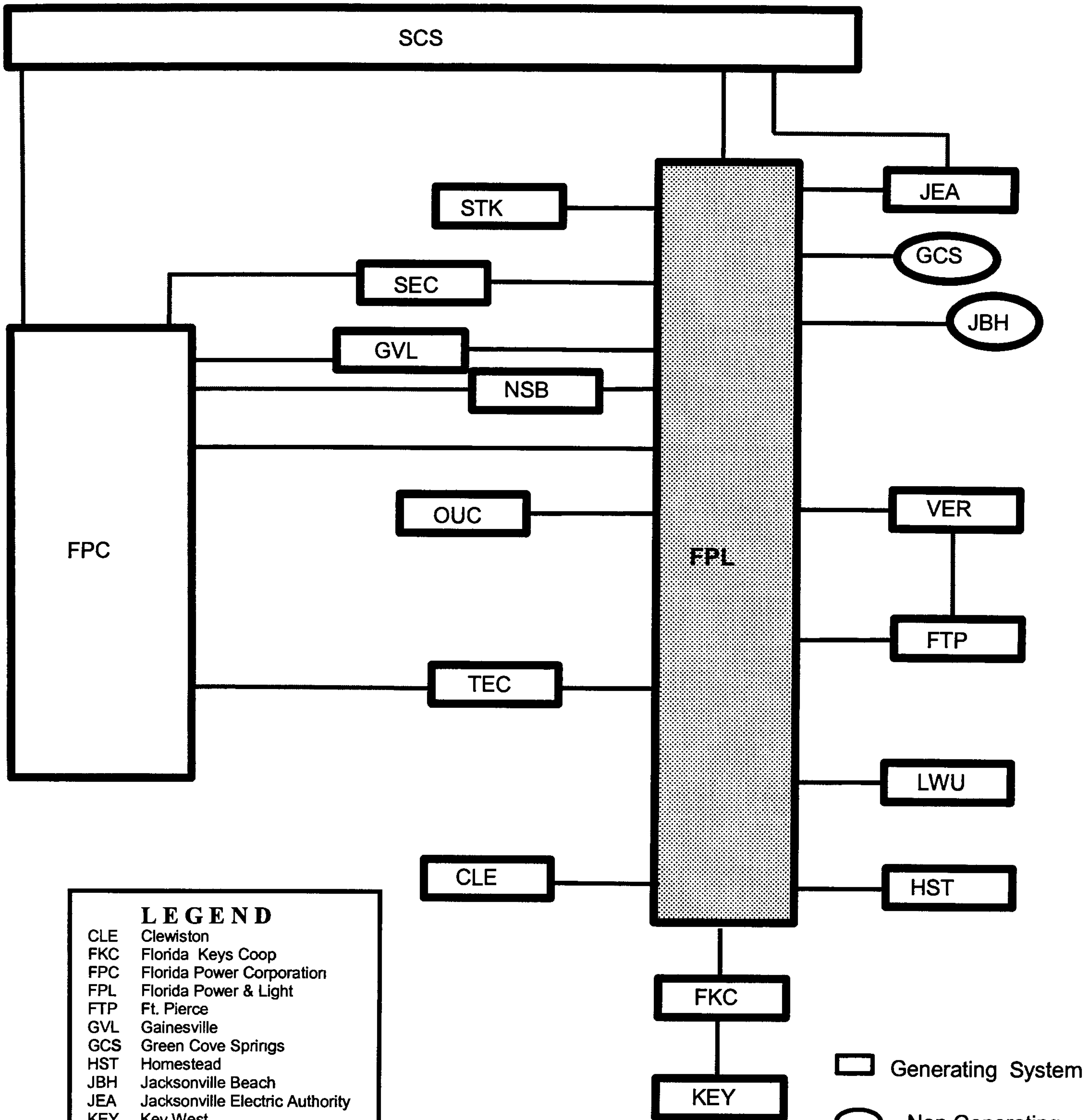
FPL Substation and Transmission System Configuration



NOTE: This map is not a complete representation of the FPL's Transmission System

Figure I.A.2

FPL Interconnection Diagram



LEGEND

CLE	Clewiston
FKC	Florida Keys Coop
FPC	Florida Power Corporation
FPL	Florida Power & Light
FTP	Ft. Pierce
GVL	Gainesville
GCS	Green Cove Springs
HST	Homestead
JBH	Jacksonville Beach
JEA	Jacksonville Electric Authority
KEY	Key West
LWU	Lake Worth
NSB	New Smyrna Beach
OUC	Orlando Utilities Commission
SEC	Seminole Electric Cooperative
SCS	Southern Companies
STK	Starke
TEC	Tampa Electric Company
VER	Vero Beach

Figure I.A.3

I.B Non-Utility Generation

Non-utility generation is an important part of FPL's resource mix. FPL currently has contracts with seven cogeneration/small power production facilities to purchase firm capacity and energy. A listing of these facilities appears in Table I.B.1. In addition, FPL purchases as-available (non-firm) energy from several cogeneration facilities and small power production facilities as shown in Table I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

Florida Power & Light Company Firm Capacity and Energy Contracts with Cogeneration/Small Power Production Facilities					
Project	**County**	**Fuel**	**Capacity MW**	**In-Service Date**	**End Date**
Bio-Energy	Broward	Landfill Gas	10.0	5/1/1998	1/1/2005
Florida Crushed Stone	Hernando	Coal (PC)	110.0	4/1/1992	10/31/2005
			11.0	1/1/1994	10/31/2005
			12.0	1/1/1995	10/31/2005
			3.0	2/1/2003	10/31/2005
Broward South	Broward	Solid Waste	50.6	4/1/1991	8/1/2009
Palm Beach SWA	Palm Beach	Solid Waste	43.5	4/1/1992	3/31/2010
			4.0	6/1/2005	3/31/2010
Broward North	Broward	Solid Waste	45.0	4/1/1992	12/31/2010
Cedar Bay Generating Co.	Duval	Coal (CFB)	250.0	1/25/1994	12/31/2024
Indiantown Cogen., LP	Martin	Coal (PC)	330.0	12/22/1995	12/1/2025
Broward South	Broward	Solid Waste	1.4	1/1/1993	12/31/2026
			1.5	1/1/1995	12/31/2026
			0.6	1/1/1997	12/31/2026
Broward North	Broward	Solid Waste	7.0	1/1/1993	12/31/2026
			1.5	1/1/1995	12/31/2026
			2.5	1/1/1997	12/31/2026

Table I.B.1

As Available Energy Purchases From Non-Utility Generators in 2004				
Project	**County**	**Fuel**	**In-Service Date**	**Energy (MWH) Delivered to FPL in 2004**
US Sugar-Bryant	Palm Beach	Bagassee	2/80	3,159
Tropicana	Manatee	Natural Gas	2/90	10,072
Okeelanta	Palm Beach	Bagassee/Wood	11/95	355,734
Tomoka Farms	Volusia	Landfill Gas	7/98	20,097
Georgia Pacific	Putnam	Paper By-Product	2/94	5,134

Table I.B.2

I.C. Demand Side Management (DSM)

FPL's DSM activities continue what has been FPL's practice since 1978 of encouraging cost-effective conservation and load management. FPL's DSM efforts through 2004 have resulted in a cumulative Summer peak reduction of approximately 3,418 MW at the generator and an estimated cumulative energy saving of 29,050 GWH at the generator.

FPL's new DSM Goals for the 2005-2014 time frame were approved by the Florida Public Service Commission (Commission) on August 9, 2004. FPL's 2004 resource planning work, and the schedule for new generation additions presented in this document, are based on these approved DSM levels. FPL filed its DSM Plan (with which FPL will meet the approved DSM Goals) on November 30, 2004 with the Commission. The Commission approved FPL's DSM Plan in March 2005.

I.D. Purchased Power

Purchased power remains an important part of FPL's resource mix. FPL has a Unit Power Sales (UPS) contract to purchase 931 MW, with a minimum of 381 MW, of coal-fired generation from the Southern Company (Southern) through May, 2010. In January 2005, the Commission approved a new firm purchase contract with Southern that will result in FPL receiving 930 MW from June 2010 through the end of 2015. This capacity will be supplied by Southern from a mix of gas-fired and coal-fired units.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) through mid-2021 for the purchase of 381 MW (Summer) and 390 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2 (FPL also has ownership interest in these units; that ownership amount is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1).

Finally, FPL has additional firm capacity purchase contracts through 2009. These firm capacity purchase contracts are with a variety of suppliers. Table I.D.1 presents the Summer and Winter MW resulting from all firm purchased power contracts through the year 2014.

	FPL's Purchased Power MW (1)							
	UPS		SJRPP		Other Firm Capacity Purchases		Total	
Year	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
2004 (2)	931	931	390	381	1,164	1,495	2,485	2,807
2005	931	931	390	381	1,008	935	2,329	2,247
2006	931	931	390	381	1,138	1,065	2,459	2,377
2007	931	931	390	381	1,362	354	2,683	1,666
2008	931	931	390	381	576	576	1,897	1,888
2009	931	931	390	381	250	250	1,571	1,562
2010	931	0	390	381	0	930	1,321	1,311
2011	0	0	390	381	930	930	1,320	1,311
2012	0	0	390	381	930	930	1,320	1,311
2013	0	0	390	381	930	930	1,320	1,311
2014	0	0	390	381	930	930	1,320	1,311

Note:

(1) Total reflects total resource entitlements resulting from existing agreements between FPL, Southern Companies, JEA, and from new firm purchase agreements.

(2) Values for 2004 are actual.

Table I.D.1

Schedule 1

Existing Generating Facilities
As of December 31, 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport.		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Turkey Point		Miami Dade County 27/57S/40E									2,336,475	2,259	2,196
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	410	398
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	403	400
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	760,000	717	693
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	760,000	717	693
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	12,375	12	12
Cutler		Miami Dade County 27/55S/40E									236,000	212	206
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	74,500	70	68
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	161,500	142	138
Lauderdale		Broward County 30/50S/42E									1,873,968	1,947	1,699
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	465	430
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	464	429
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	509	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,734	509	420
Port Everglades		City of Hollywood 23/50S/42E									1,710,384	1,729	1,621
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	247,775	220	212
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	247,775	220	219
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	390	385
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	390	385
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	509	420
Riviera		City of Riviera Beach 33/42S/43E									620,840	560	556
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	274	272
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	286	284

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2004

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW
Martin		Martin County 29/29S/38E									3,468,700	3,012	2,906
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	830	828
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	829	815
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	495	471
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	496	472
	8 A & B		CT	NG	FO2	PL	PL	Unknown	Jun-01	Unknown	375,700	362	320
St. Lucie		St. Lucie County 16/36S/41E									1,573,775	1,579	1,553
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	850,000	853	839
	2	2/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	723,775	726	714
Cape Canaveral		Brevard County 19/24S/36F									804,100	808	801
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	398	394
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	410	407
Sanford		Volusia County 16/19S/30E									2,534,050	2,232	2,027
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	156,250	142	138
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,900	1,045	949
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,900	1,045	940
Putnam		Putnam County 16/10S/27E									580,008	572	498
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,004	286	249
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,004	286	249

1/ These ratings are peak capability.
2/ Total capability is 853/839 MW. Capabilities shown represent FPL's share of the unit and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of 14.89551%.

Schedule 1

Existing Generating Facilities
As of December 31, 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
Plant Name	Unit No.	Location	Unit Type	Fuel Pri.	Fuel Alt.	Transport Pri.	Transport Alt.	Days Use	In-Service Month/Year	Retirement Month/Year	Nameplate KW	Winter MW	Summer MW
Fort Myers		Lee County 35/43S/25E									2,895,210	2,759	2,415
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,775,390	1,610	1,441
	3A & B		CT	NG	FO2	PL	PL	Unknown	Jun-01	Unknown	375,700	380	326
	1-12		GT	FO2	No	WA	No	Unknown	May-74	Unknown	744,120	769	648
Manatee		Manatee County 18/33S/20E									1,726,600	1,605	1,591
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	795	788
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	810	803
St. Johns River Power Park 2/		Duval County 12/15/28E (RPC4)									271,836	242	232
	1		BIT	et Col	BIT	WA	RR	Unknown	Mar-87	Unknown	135,918	130	127
	2		BIT	et Col	BIT	WA	RR	Unknown	May-88	Unknown	135,918	112	105
Scherer 3/		Monroe, GA									680,368	642	639
	4		BIT	BIT	FO2	RR	PL	Unknown	Jul-89	Unknown	680,368	642	639
								Total System as of December 31, 2004 =				20,158	18,940

1/ These ratings are peak capability.
2/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No. 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80%.
3/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.

CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are developed on an annual basis for resource planning work at FPL. These forecasts are a key input to the models used to develop the Integrated Resource Plan. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

The primary drivers to develop these forecasts are demographic trends, weather, economic conditions, and prices of electricity. In addition, the resulting forecasts are an integration of economic evaluations, inputs of local economic development boards, weather assessments from the National Oceanic and Atmospheric Administration (NOAA), and inputs from FPL's own customer service planning areas. In the area of demographics, population trends by county, plus housing characteristics such as housing starts, housing size, and vintage of homes, are assessed.

Forecasts for electric usage in the residential and commercial classes include end-use information such as appliance saturation studies, efficiencies, and intensity of energy use. In addition to these inputs, residential forecasts also make use of household characteristics such as ages of members in households, number of members in households, and income distributions.

The projections for the national and Florida economy are obtained from Global Insight, an international economic consulting firm. Population projections for the counties served by FPL are obtained from the Bureau of Economic and Business Research (BEBR) of the University of Florida. In addition, FPL actively participates with local development councils and universities to obtain their assessments of the local economy, specifically in the area of expansion of new businesses and retention of the current business base. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects the company's sales and peak demand. Weather variables are used in the forecasting models for energy sales and peak demand. There are two sets of weather variables developed and used in forecasting models:

1. Cooling and Heating Degree-Days are used to forecast energy sales.
2. Temperature data is used to forecast Summer and Winter peaks.

The Cooling and Heating Degree-Days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. A composite temperature hourly profile is derived using hourly temperatures across FPL's service territory (Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained) weighted by regional energy sales. This composite temperature is used to derive Cooling and Heating Degree-Days which are based on starting point temperatures of 72°F and 66°F, respectively. Similarly, the maximums and minimums of the composite temperature hourly profile are used for the Summer and Winter peak models.

1. Impact of 2004 Hurricanes

FPL has estimated the impact of the 2004 hurricanes on its projected customer growth and resulting demand forecasts. These estimates were based, in part, on FPL's experience following Hurricane Andrew. After Hurricane Andrew, population growth declined to a level of approximately 65,000 customers per year and remained at that level for approximately six years before returning to a more robust growth rate. FPL's customer growth reached a peak in August 2004, with 120,000 customers having been added for the preceding 12 months. However, as a consequence of the three South Florida hurricanes (Charley, Frances, and Jeanne), growth significantly declined.

Before the hurricanes hit Florida in 2004, FPL was projecting an annual increase of 80,000 new customers in 2005, 82,000 new customers in 2006, and 81,000 new customers in 2007. When the impact of the 2004 hurricanes is taken into account, the resulting projections are 72,000 new customers in 2005, 75,000 in 2006, and a return to trend of 80,000 in 2007. FPL is assuming that the impact of the 2004 hurricanes will be short-lived and customer growth will return to a more normal level in a couple of years, versus the six year impact of Hurricane Andrew. This difference is primarily due to the assumption that the population growth in Florida will be fueled by larger numbers of baby-boomers retiring and moving to Florida, as well as an increasing availability of jobs.

II.A. Long-Term Sales Forecasts

Long-term forecasts of electricity sales are developed for each revenue class for the forecasting period of 2004-2023 and are adjusted to match the Net Energy for Load (NEL) forecast. The results of these sales forecasts for the years 2005-2014 are presented in

Schedules 2.1-2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical tool MetrixND. The methodologies used to develop sales forecasts for each jurisdictional revenue class are outlined below. The first five years of the forecasts are developed using monthly models for Net Energy for Load and energy sales by class.

1. Residential Sales

Residential electric usage per customer is estimated by using a regression model which contains the real residential price of electricity, real Florida personal income, and Cooling and Heating Degree-Days as explanatory variables as well as a dummy variable for shoulder months. The price of electricity plays a role in explaining electric usage since electricity, like all other goods and services, will be used in greater or lesser quantities depending upon its price. To capture economic conditions, the model includes Florida's real personal income. The degree of economic prosperity can, and does, affect residential electricity sales. The impact of weather is captured by the Cooling and Heating Degree-Days; in addition, a one month lagged Cooling Degree-Day is also included as an explanatory variable. Residential energy sales are forecast by multiplying the residential use per customer forecast by the number of residential customers forecasted

2. Commercial Sales

The commercial sales forecast is also developed using a regression model. Commercial sales are a function of the following variables: Florida's non-agricultural employment, commercial real price of electricity, Cooling Degree-Days, and an autoregressive term. Florida's non-agricultural employment is used to capture the economic activity in FPL's service territory. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. Cooling Degree-Days are used to capture weather-sensitive load in the commercial sector.

3. Industrial Sales

The industrial sales forecast is also developed using a regression model. Industrial sales are a function of industrial customers, the price of electricity, Cooling Degree-Days, a dummy variable for outliers, and an autoregressive term. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. The Cooling Degree-Day term is included to capture the weather-sensitive load in the industrial class.

4. Other Public Authority Sales

At present, this class consists of sports fields and one government account. The forecast for this class is based on historical knowledge of its characteristics.

5. Street & Highway Sales and Railroad & Railways Sales

The forecast for street and highway sales is developed by first assuming a constant use per customer and then multiplying that value by the number of projected customers. The forecast of sales to railroad & railways is based on historical knowledge of its characteristics. This class consists of Miami-Dade County's Metrorail system.

6. Sales for Resale

Sales for resale (wholesale) customers are composed of municipalities and/or electric cooperatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers.

Currently, there are four customers in this class: the Florida Keys Electric Cooperative (Florida Keys), City Electric System of the Utility Board of Key West, Florida (City of Key West), Miami-Dade County, and the Florida Municipal Power Agency (FMPA). Sales to the Florida Keys are forecasted using a regression model. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor. Miami-Dade County sells 60 MW to Progress Energy. Line losses are billed to Miami-Dade under a wholesale contract. FMPA has contracted for delivery of 75 MW from FPL through October, 2007.

7. Total Sales

Sales forecasts by revenue class are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, an expansion factor is applied to generate a forecast of annual Net Energy for Load (NEL).

II.B. Net Energy for Load

An annual econometric model is developed to produce a net energy for load (NEL) forecast. The key inputs to the model are: the price of electricity, Heating and Cooling Degree-Days, Florida Non-Agricultural Employment, and an autoregressive term. The monthly model is similar, except the economic variables utilized are Florida's real personal income and a dummy variable for February. The first five years are obtained from the short-term model. Forecasts for subsequent years are generated using the growth rates from the annual model.

Once an annual NEL forecast is obtained using the above-mentioned methodology, the results are then compared for reasonableness to the NEL forecast generated using the total sales forecast. The sales by class forecasts previously discussed are then adjusted to match the annual NEL Forecast.

The forecasted NEL values for 2005–2014 are presented in Schedule 3.3 that appears at the end of this chapter.

II.C. System Peak Forecasts

The rate of absolute growth in FPL system load has been a function of an increase in the customer base, varying weather conditions, continued economic growth, changing patterns of customer behavior (including an increased stock of electricity-consuming appliances), and more efficient heating and cooling appliances. FPL developed the peak forecast models to capture these behavioral relationships.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2005–2014 are presented in Schedules 3.1 and 3.2 that appear at the end of this chapter, and again in Schedules 7.1 and 7.2 that appear near the end of Chapter 3.

System Summer Peak

The Summer peak forecast is developed using an econometric model. The variables included in the model are the price of electricity, Florida real personal income, and maximum peak day temperature. The econometric model uses these variables to develop the Summer peak load per customer. The Summer peak load per customer value is multiplied by total customers to derive FPL's system Summer peak.

System Winter Peak

Like the system Summer peak model, this model is also an econometric model. The model consists of two weather-related variables: the minimum temperature on the peak day and Heating Degree-Hours for the prior day as well as for the morning of the Winter peak day. In addition, Florida real personal income is a variable used in the model. The model generates the Winter peak load per customer. The Winter peak load per customer value is multiplied by total customers to derive FPL's system Winter peak.

Monthly Peak Forecasts

Monthly peaks for the 2004-2023 period are forecasted to provide information for the scheduling of maintenance for power plants and fuel budgeting. The forecasting process is basically the same as for the monthly NEL forecast and consists of the following actions:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to seasonal peaks (Summer = April-October, Winter = November-March.)

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.D. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2004-2023 are produced using a System Load Forecasting "shaper" program. This model uses sixteen years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. These daily load shapes are ranked and used with forecasted monthly peaks, NEL, and calendars in developing an hourly forecast. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load–to-peak ratio is maintained.

Schedule 2.1
History and Forecast of Energy Consumption And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population*	Members per Household	GWH**	Average*** No. of Customers	Average KWH Consumption Per Customer	GWH**	Average*** No. of Customers	Average KWH Consumption Per Customer
1995	6,806,351	2.20	40,556	3,097,192	13,094	30,719	374,005	82,135
1996	6,948,951	2.20	41,302	3,152,625	13,101	31,211	380,860	81,949
1997	7,105,592	2.21	41,849	3,209,298	13,040	32,942	388,906	84,703
1998	7,249,627	2.22	45,482	3,266,011	13,926	34,618	396,749	87,255
1999	7,412,744	2.22	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,603,964	2.23	46,320	3,414,002	13,568	37,001	415,295	89,096
2001	7,754,846	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,898,628	2.21	50,865	3,566,167	14,263	40,029	435,313	91,955
2003	8,079,316	2.21	53,485	3,652,663	14,643	41,425	444,650	93,163
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,406,324	2.21	55,713	3,809,120	14,626	42,151	468,211	90,025
2006	8,565,263	2.21	57,848	3,875,162	14,928	43,668	477,484	91,455
2007	8,721,735	2.21	59,969	3,945,994	15,197	45,326	486,673	93,134
2008	8,876,279	2.21	62,602	4,016,456	15,586	46,854	495,521	94,556
2009	9,029,214	2.21	65,131	4,086,068	15,940	48,092	504,304	95,363
2010	9,181,121	2.21	67,221	4,155,016	16,178	49,227	513,104	95,939
2011	9,333,931	2.21	68,899	4,223,741	16,312	50,092	521,935	95,974
2012	9,486,208	2.21	70,624	4,292,229	16,454	50,937	530,740	95,973
2013	9,638,031	2.21	72,491	4,360,482	16,625	51,935	539,608	96,246
2014	9,789,447	2.21	74,460	4,429,329	16,811	53,032	548,242	96,731

* Population represents only the area served by FPL.
** Actual energy sales include the impacts of existing conservation. Forecasted energy sales do not include the impact of incremental conservation.
*** Average No. of Customers is the annual average of the twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads & Railways	Street & Highway Lighting	Other Sales to Public Authorities	Total**** Sales to Ultimate Consumers
Year	GWH **	Average*** No. of Customers	Average KWH Consumption Per Customer	GWH	GWH **	GWH	GWH **
1995	3,883	15,140	256,473	84	358	648	76,248
1996	3,792	14,783	256,511	83	368	577	77,334
1997	3,894	14,761	263,803	85	383	702	79,855
1998	3,951	15,126	261,206	81	373	625	85,130
1999	3,948	16,040	246,135	79	473	465	84,676
2000	3,768	16,410	229,616	81	408	381	87,960
2001	4,091	15,445	264,875	86	419	67	90,212
2002	4,057	15,533	261,186	89	420	63	95,523
2003	4,004	17,029	235,128	93	425	64	99,496
2004	3,964	18,512	214,139	93	413	58	99,095
2005	3,982	16,590	240,050	100	418	63	102,427
2006	3,958	16,239	243,733	103	423	63	106,064
2007	3,957	16,169	244,698	106	431	63	109,852
2008	3,969	15,831	250,713	110	438	63	114,036
2009	3,968	15,442	256,973	113	446	63	117,813
2010	3,961	15,317	258,564	113	453	63	121,038
2011	3,923	15,187	258,295	113	461	63	123,550
2012	3,875	14,959	259,027	113	469	63	126,080
2013	3,838	14,826	258,880	113	476	63	128,917
2014	3,808	14,678	259,417	113	484	63	131,959

** Actual energy sales include existing conservation. Forecasted energy sales do not include the impact of incremental conservation.

*** Average No.of Customers is the annual average of the twelve month values.

**** GWH Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWH	(18) Utility Use & Losses GWH	(19) Net* Energy For Load GWH **	(20) Average *** No. of Other Customers	(21) Total Average***,****** Number of Customers
1995	1,437	6,276	83,961	2,459	3,488,796
1996	1,353	6,306	84,993	2,480	3,550,748
1997	1,228	5,771	86,853	2,520	3,615,485
1998	1,326	6,206	92,662	2,584	3,680,470
1999	953	5,829	91,458	2,605	3,756,009
2000	970	7,059	95,989	2,694	3,848,401
2001	970	7,222	98,404	2,722	3,935,281
2002	1,233	7,443	104,199	2,792	4,019,805
2003	1,511	7,386	108,393	2,879	4,117,221
2004	1,531	7,464	108,091	3,029	4,224,509
2005	1,568	7,700	111,695	3,036	4,296,957
2006	1,586	7,813	115,463	3,072	4,371,957
2007	1,558	8,068	119,477	3,121	4,451,957
2008	1,092	8,331	123,459	3,170	4,530,979
2009	1,092	8,616	127,521	3,221	4,609,035
2010	1,092	8,849	130,980	3,271	4,686,707
2011	1,092	9,031	133,674	3,321	4,764,184
2012	1,092	9,215	136,387	3,371	4,841,299
2013	1,092	9,420	139,429	3,421	4,918,337
2014	1,092	9,641	142,692	3,471	4,995,720

** Actual energy sales include existing conservation. Forecasted energy sales do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

*** Average No.of Customers is the annual average of the twelve month values.

***** GWH Col. (19) = Col. (16) + Col. (17) + Col. (18). Actual NEL include the impacts of existing conservation and agrees to Col. (8) on schedule 3.3.

****** Total Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20)

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1995	16,172	435	15,737	0	465	260	406	195	15,301
1996	16,064	364	15,700	0	525	339	422	297	15,117
1997	16,613	380	16,233	0	582	440	435	343	15,596
1998	17,897	426	17,471	0	628	526	458	385	16,811
1999	17,615	169	17,446	0	673	592	452	420	16,490
2000	17,808	161	17,647	0	719	645	467	451	16,622
2001	18,754	169	18,585	0	737	697	488	481	17,529
2002	19,219	261	18,958	0	770	755	489	517	17,960
2003	19,668	253	19,415	0	781	799	577	554	18,310
2004	20,545	258	20,287	0	782	828	580	569	19,183
2005	20,614	264	20,351	0	788	87	592	40	19,108
2006	21,178	266	20,912	0	796	128	603	55	19,596
2007	21,769	269	21,500	0	807	170	615	67	20,111
2008	22,306	197	22,109	0	820	214	627	79	20,566
2009	22,884	197	22,687	0	836	261	639	90	21,058
2010	23,424	197	23,227	0	853	310	650	102	21,510
2011	23,964	197	23,767	0	871	361	662	112	21,958
2012	24,516	197	24,319	0	891	413	674	123	22,416
2013	25,059	197	24,862	0	912	467	686	133	22,861
2014	25,633	197	25,436	0	936	523	698	143	23,333

Historical Values (1995 - 2004):

Col. (2) - Col. (4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) for 1995 through 2003 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC) and Commercial /Industrial Demand Reduction (CDR). Col.(5) - Col.(9) for year 2004 are "estimated actuals" and are August values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula:Col. (10) = Col.(2) - Col.(6) - Col.(8).

Projected Values (2005 - 2014):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2004 are incorporated into the load forecast.

Col. (5) - Col. (9) represent all incremental conservation and cumulative load control. These values are projected August values and the conservation values are based on projections with a 1/2004 starting point for use with the 2004 load forecast.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
1995/96	18,096	698	17,398	0	512	266	406	89	17,178
1996/97	16,490	626	15,864	0	578	311	417	139	15,495
1997/98	13,060	239	12,821	0	641	369	426	151	11,993
1998/99	16,802	149	16,653	0	692	404	446	164	15,664
1999/00	17,057	142	16,915	0	741	434	438	176	15,878
2000/01	18,199	150	18,049	0	791	459	448	183	16,960
2001/02	17,597	145	17,452	0	811	500	457	196	16,329
2002/03	20,190	246	19,944	0	847	546	453	206	18,890
2003/04	14,752	211	14,541	0	857	570	532	230	13,363
2004/05	18,108	225	17,884	0	864	38	539	28	16,705
2005/06	21,336	252	21,083	0	871	60	545	35	19,825
2006/07	21,898	255	21,644	0	881	82	552	40	20,344
2007/08	22,369	182	22,187	0	894	105	559	44	20,768
2008/09	22,916	182	22,734	0	910	130	566	48	21,262
2009/10	23,466	182	23,284	0	928	156	573	52	21,758
2010/11	24,035	182	23,853	0	947	183	579	57	22,270
2011/12	24,608	182	24,426	0	968	210	586	61	22,783
2012/13	25,197	182	25,015	0	990	238	593	66	23,309
2013/14	25,798	182	25,616	0	1,014	266	600	72	23,846

Historical Values (1995/96 - 2004/05):

Col. (2) - Col. (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col.(9) for 1995/96 through 2003/04 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC) and Commercial/Industrial Demand Reduction (CDR).Col.(5) - Col.(9) for year 2004/05 are "estimated actuals" and are January values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (6) - Col. (8).

Projected Values (2005/06- 2013/14):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2004 are incorporated into the load forecast.

Col. (5) - Col.(9) represent all incremental conservation and cumulative load control. These values are projected January values and the conservation values are based on projections with a 1/2004 starting point for use with the 2004 load forecast.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	C/I Conservation	Retail	Sales for Resale GWH	Utility Use & Losses	Net Energy For Load	Load Factor(%)
1995	85,418	777	680	83,981	1,437	6,276	83,961	59.3%
1996	87,007	971	1,043	85,654	1,353	6,306	84,993	60.2%
1997	89,243	1,213	1,177	88,015	1,228	5,771	86,853	59.7%
1998	95,318	1,374	1,282	93,992	1,326	6,206	92,662	59.1%
1999	94,365	1,542	1,365	93,412	953	5,829	91,458	59.3%
2000	99,097	1,674	1,434	98,127	970	7,059	95,989	61.4%
2001	101,739	1,789	1,545	100,768	970	7,222	98,404	59.9%
2002	107,755	1,917	1,639	106,522	1,233	7,443	104,199	61.9%
2003	112,160	2,008	1,759	110,648	1,511	7,386	108,393	62.9%
2004	112,036	2,109	1,836	110,504	1,531	7,464	108,091	59.9%
2005	111,695	59	17	110,127	1,568	7,700	111,619	61.9%
2006	115,463	148	45	113,876	1,586	7,813	115,270	62.2%
2007	119,477	235	61	117,919	1,558	8,068	119,181	62.7%
2008	123,459	327	70	122,366	1,092	8,331	123,062	63.0%
2009	127,521	425	80	126,429	1,092	8,616	127,016	63.6%
2010	130,980	528	90	129,887	1,092	8,849	130,362	63.8%
2011	133,674	635	101	132,582	1,092	9,031	132,938	63.7%
2012	136,387	745	111	135,295	1,092	9,215	135,531	63.3%
2013	139,429	858	123	138,337	1,092	9,420	138,448	63.5%
2014	142,692	974	134	141,600	1,092	9,641	141,584	63.5%

Historical Values (1995 - 2004):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (8).

Col.(3) & Col.(4) for 1995 through 2003 are DSM values starting in January 1988 and are annual (12-month) values.Col. (3) and Col. (4) for 2004 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWH reductions actually experienced each year .

Col. (5) & Col. (6) are a breakdown of Net Energy For Load in Col (2) into Retail and Wholesale .

Col. (9) is calculated using Col. (8) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (8)*1000) / ((Col.(2) * 8760)

Projected Values (2005 - 2014):

Col. (2) represents Net Energy for Load w/o DSM values. The values are extracted from Schedule 2.3, Col. (19).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation and are mid-year (6-month) values. The effects of conservation implemented prior to 2004 are incorporated into the load forecast.

Col. (5) & Col. (6) are a breakdown of Net Energy For Load in Col (2) , into Retail and Wholesale.

Col. (8) NEL projected values shown here do include the impact of conservation in Col. (3) and Col. (4). Therefore, these NEL values do not match those shown on schedule 2.3 because those values do not account for incremental conservation.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2004 ACTUAL		2005* FORECAST		2006* FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	13,857	7,646	20,791	8,221	21,336	8,483
FEB	14,752	7,365	17,138	7,591	17,588	7,835
MAR	14,618	7,855	16,170	8,230	16,594	8,530
APR	16,529	8,063	17,161	8,572	17,631	8,878
MAY	18,936	9,138	19,039	9,454	19,560	9,771
JUN	20,250	10,991	19,814	10,401	20,356	10,736
JUL	20,545	10,634	20,193	10,833	20,746	11,183
AUG	19,836	10,594	20,614	11,010	21,178	11,364
SEP	20,531	10,049	20,010	10,717	20,557	11,065
OCT	18,635	9,369	18,618	9,601	19,127	9,931
NOV	17,358	8,495	17,678	8,617	18,144	8,928
DEC	15,871	7,893	18,047	8,447	18,522	8,760
TOTALS		108,091		111,695		115,463

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation and are consistent with values shown in Col. (19) of Schedule 2.3 and Col (2) of Schedule 3.3.

CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990's and has since utilized the process to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of potential new power plants, the primary subjects of this document, are determined as part of the IRP process work. This section discusses how FPL applied this process in its 2004 and early 2005 resource planning work.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental "steps" to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Determine the economics for the total utility system with each of the competing options and resource plans; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process

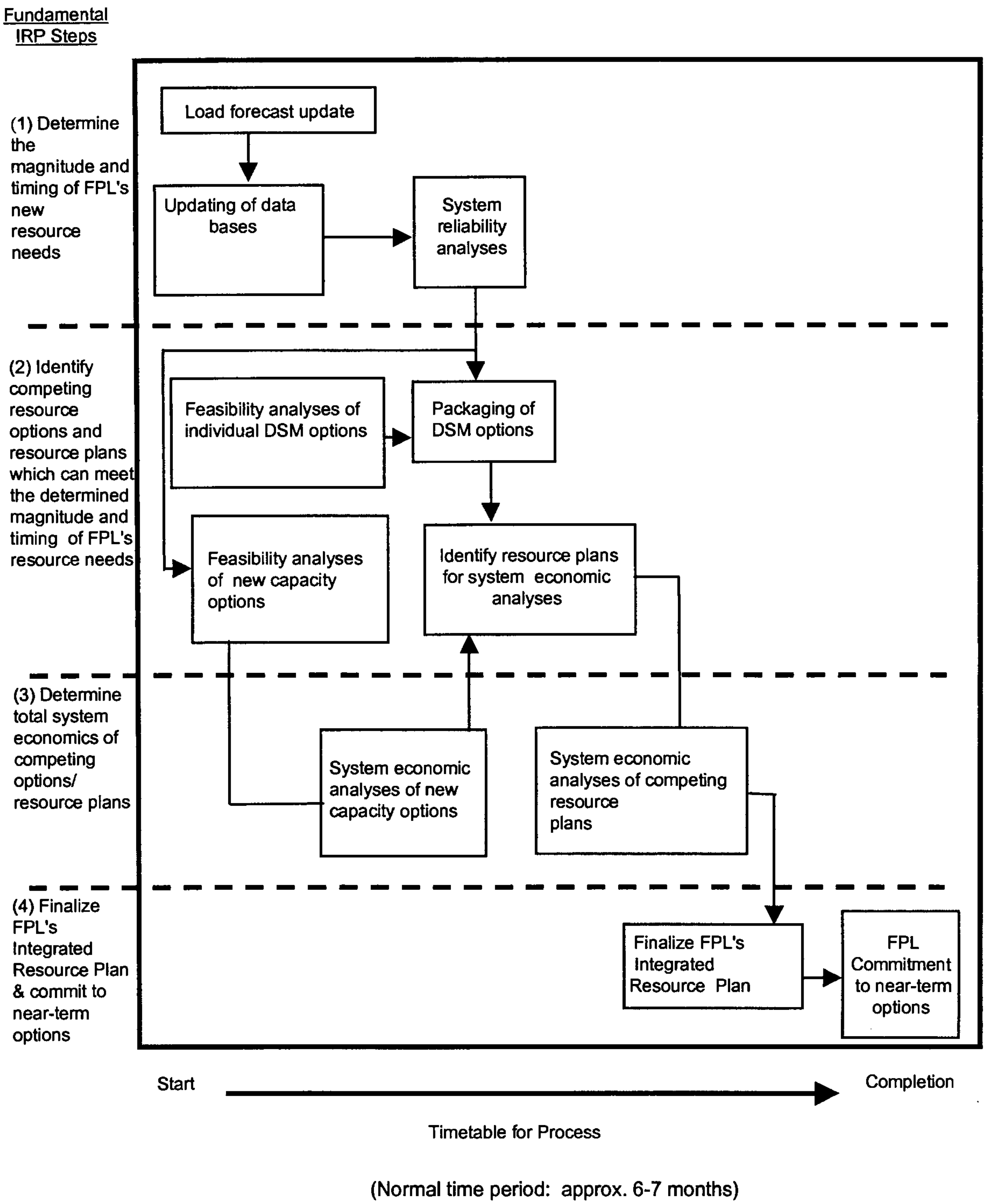

Figure III.A.1

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of these four resource planning steps–determining the magnitude and timing of FPL's resource needs–is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed. Also determined in this step is when the MW are needed to meet FPL's planning criteria. This step is often referred to as a resource adequacy or reliability assessment for the utility system.

Step 1 starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information which is used in many of the fundamental steps in resource planning. Examples of this new information include: delivered fuel price projections, current financial and economic assumptions, and power plant capability and reliability assumptions. FPL also includes key assumptions regarding three specific resource areas: (1) near-term construction capacity additions, (2) short-term, firm capacity purchase additions, and (3) long-term DSM implementation.

The first of these assumptions is based on FPL's ongoing engineering and construction activities to add near-term capacity through various projects. These construction projects include the addition of a new combined cycle (CC) unit at Manatee and the conversion of two existing CT's at Martin into a new CC unit. Both additions are scheduled to come in-service in mid-2005. The additions were approved by the Florida Public Service Commission (FPSC) in November 2002 after comparing them to 134 competing bids that were received in response to two Requests for Proposals (RFP's) that solicited bids for meeting FPL's 2005/2006 capacity needs. In addition, a new CC unit at FPL's Turkey Point site is planned to come in-service in mid-2007. FPL selected this capacity option after conducting an RFP during the last part of 2003. The addition was approved by the FPSC in June of 2004 and the Governor and Siting Board approved certification of the plant location, construction, and operation of the new CC unit in February, 2005.

The second of these assumptions involves short-term, firm capacity purchase additions. These firm capacity purchases are from a combination of utility and independent power producers. The total capacity and duration of these purchases have changed somewhat from what was presented in last year's Site Plan. These changes include a new firm purchase from Reliant's Indian River facility of up to 576 MW from 2006 through 2009, with an option to extend the purchase through 2010. In addition, in January 2005 the

FPSC approved a five and one half-year firm purchase of 930 MW from the Southern Company that was identified as a projected purchase in FPL's prior Site Plan. The annual total capacity values for these purchases are presented in Table I.D.1. These purchased capacity amounts were incorporated in FPL's recent resource planning work.

The third of these assumptions involves DSM. Since 1994, FPL's resource planning work has used the DSM MW called for in FPL's approved DSM Goals as a "given" in its analyses. This was again the case in FPL's most recent planning work, as its new DSM Goals that address the years 2005 through 2014, and that were approved by the FPSC in August 2004, were taken as a "given".

The assumptions and much of the other updated information and assumptions are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's resource needs. This determination is accomplished by system reliability analyses which are typically based on a dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss–of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry. (FPL's reserve margin criterion increased from 15% to 20% starting in mid-2004 due to a voluntary agreement reached among FPL, FPC, and TECO, and accepted by the FPSC in FPSC Docket No. 981890-EU.)

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its native load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the generation resource adequacy of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss–of-load probability or LOLP. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of the "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program currently used by FPL.

The result of the first fundamental step of resource planning is a projection of how many new MW of resources are needed to meet both reserve margin and LOLP criteria, and thus maintain system reliability, and of when the MW are needed. This information is used in the second fundamental step: identifying resource options and resource plans that can meet the determined magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, feasibility analysis of new capacity options are carried out to determine which new capacity options appear to be the most competitive on FPL's system. These analyses also establish capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs.

The individual new capacity options are then "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new resource needs are met. The creation of these competing resource plans is typically carried out using dynamic programming techniques. For planning purposes, only FPL construction options are typically included in these analyses.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs were identified. These resource plans were then compared on an economic basis.

Step 3: Determining the Total System Economics:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for comparing the system economics of these resource plans. In its 2004 resource planning work, FPL performed much of this work of combining resource options into resource plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI). The EGEAS model was also used to perform much of the basic economic analyses of the resource plans. For various analyses, FPL applied the P-MArea (P-Month) production cost model to develop an additional perspective of the production costs for the various resource plans developed in the EGEAS model. The P-MArea model is the model used by FPL to develop the Fuel Cost Budget and to conduct other production cost-related analyses.

In 2004, FPL also utilized several other models in its resource planning work. For the work carried out for the DSM Goals and DSM Plan dockets, FPL used its CPF model–an FPL spreadsheet model utilizing the FPSC's approved cost-effectiveness methodology-for analyzing the cost-effectiveness of individual DSM measures/programs and its linear programming model for creating and analyzing combinations of DSM options that constitute multi-year DSM implementation plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the intent of minimizing FPL's leveled system average rate (i.e., a Rate Impact Measure or RIM methodology). However, in cases such as existed for FPL's most recent planning work in which the DSM contribution was assumed as planned and the only competing options were new generating units, and purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. Consequently, the competing options and plans were evaluated on a present value system revenue requirement basis that includes the system capital and operating costs of the new capacity options.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps were used to develop the future generation plan. This plan is presented in the following section.

III.B Incremental Resource Additions

FPL's projected incremental generation capacity additions/changes for 2005 through 2014 are depicted in Table III.B.1 (the planned DSM additions are shown separately in Table III.C.1). These capacity additions/changes result from a variety of actions including: changes to existing units (which are frequently achieved as a result of plant component replacements during major overhauls or by unit conversion from one type of unit to another), changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, and by projected construction of new generating units.

As shown in Table III.B.1, the capacity additions are largely made up of new construction, new purchases, and proposed self-build alternatives. The new construction contribution is made up of three projects: the conversion of two CT's into a larger CC unit in 2005 at FPL's Martin site; the addition of a new CC unit in 2005 at FPL's Manatee site, and the addition of a new CC unit in 2007 at FPL's Turkey Point site. FPL has negotiated the addition of firm capacity of varying amounts through a purchase power contract with Reliant's Indian River facility during the years 2006 through 2009 and with the Southern Company during the time period from mid-2010 through 2015. FPL projects the construction of two new CC units at the proposed West County Energy Center site in Palm Beach County, one in 2009 and one in 2010, and the proposed addition of two new clean coal technology units, one each in 2012 and 2013. The issues surrounding clean coal units are discussed in more detail in FPL's recent *Report on Clean Coal Generation*, provided to the Commission in March of 2005.

The above capacity additions address the projected resource needs from FPL's reliability analyses. For 2008, FPL's projected resource need is relatively small, approximately 470 MW. For each year from 2009 through 2013, the projected annual resource need is significantly larger; in the range of approximately 550 MW to 850 MW each year.

Projected Capacity Changes and Reserve Margins for FPL (1)			
		Net Capacity Changes (MW)	
		Winter (2)	***Summer*** (3)
2005	Changes to Existing Purchases (4)	(166)	(566)
	Manatee Unit #3 Combined Cycle (6)	---	1,107
	Conversion of Martin #8 CT's to CC (6)	0	787
	Changes to existing Units	---	12
2006	Changes to Existing Purchases (4)	(132)	(136)
	New Purchases (5)	130	130
	Manatee Unit #3 Combined Cycle (6)	1,197	---
	Conversion of Martin #8 CT's to CC (6)	835	---
	Changes to existing Units	240	167
2007	Changes to Existing Purchases (4)	---	(935)
	Changes to New Purchases (5)	224	224
	Turkey Point Combined Cycle #5 (6)	---	1,144
	Changes to existing Units	(1)	(1)
2008	Changes to Existing Purchases (4)	(1,008)	---
	Changes to New Purchases (5)	222	222
	Turkey Point Combined Cycle #5 (6)	1,181	---
2009	Changes to Existing Purchases (4)	---	(51)
	Changes to New Purchases (5)	(326)	(326)
	West County Energy Center #1 Combined Cycle (6)	---	1,107
2010	Changes to Existing Purchases (4)	(51)	(979)
	Changes to New Purchases (5)	(250)	680
	West County Energy Center #1 Combined Cycle (6)	1,181	---
	West County Energy Center #2 Combined Cycle (6)	---	1,107
2011	Changes to Existing Purchases (4)	(94)	(45)
	Changes to New Purchases (5)	930	---
	West County Energy Center #2 Combined Cycle (6)	1,181	---
2012	Unsited Clean Coal Unit # 1 (6)	---	850
2013	Unsited Clean Coal Unit # 1 (6)	855	---
	Unsited Clean Coal Unit # 2 (6)	---	850
2014	Unsited Clean Coal Unit # 2 (6)	855	---
	TOTALS =	**7,003**	**5,348**

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.

(2) Winter values are values for January of year shown.

(3) Summer values are values for August of year shown.

(4) These are firm capacity purchases with contract that existed on 12/31/03. See Section I.B, I.D and III.A. for more details.

(5) These are firm capacity purchases with contracts executed on/after 1/01/04.

(6) All new units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

Table III.B.1

III.C Other Results of FPL's Recent Planning Work

FPL's 2004 and early 2005 planning efforts have continued to address two issues that were identified in FPL's 2003 Site Plan. Those two issues are: (1) the need to address the imbalance between regional load and generating capacity located in southeast Florida, and (2) the desire to maintain and enhance fuel diversity in the FPL system.

1. Southeast Imbalance

There continues to be an imbalance between regionally installed generation and peak load in southeast Florida. A significant amount of energy required in the southeast region during peak periods is provided through the transmission system from plants located outside the region. Based on the forecast for continued load growth in this region, the imbalance between generation and load will increase unless additional generation capacity is periodically located within this region or additional transmission delivery capability is constructed.

FPL's prior planning work had concluded that either additional installed capacity in this region or transmission capacity capable of delivering additional electricity from outside the region would be required to address this imbalance. Delivering additional electricity from outside the region increases transmission-related costs and incurs the cost of the additional capacity.

The evaluation conducted as part of FPL's 2003 Request for Proposal (RFP) process met FPL's 2007 need by considering all cost components of FPL's next planned generating unit (NPGU) and alternative options, including transmission-related costs. The location of the NPGU and the locations of proposed units included in the alternative option combinations contributed to the transmission-related costs determined in the evaluation. The results of the RFP evaluation confirmed that because of the existing imbalance, generating units located in the southeast region contribute significantly lower transmission-related costs than do those located outside the region.

Partly because of the lower transmission-related costs resulting from its location, Turkey Point Unit # 5, was evaluated as the most cost-effective option to meet FPL's 2007 capacity need. Adding Turkey Point Unit # 5 will significantly reduce the imbalance between generation and load in southeast Florida. However, assuming no other resources are added, the imbalance will re-develop to the pre-Turkey Point Unit # 5 levels within 3 to 4 years because of the continued load growth of approximately 250-300 MW per year in this region. Therefore, the re-emergence of the southeast imbalance is expected to remain a factor in the calculation of transmission-related costs which are an integral part of the evaluation of new capacity additions. This factor has contributed to the identification in the Site Plan of two new CC units to be added in 2009 and 2010 at the proposed West County Energy Center site in Palm Beach County. The location of these proposed capacity additions would continue to mitigate this regional imbalance issue.

2. Fuel Diversity

FPL has also taken positive steps in 2004 to address the issue of fuel diversity in the FPL system. This has been accomplished in three key ways: through purchased power, proposed generation capacity additions, and pursuit of long-term Liquefied Natural Gas (LNG) supplies delivered to Florida.

First, FPL successfully negotiated and gained approval for a new purchased power agreement with Southern Company for the period 2010 to 2015. This new purchase adds 930 MW of capacity, of which 165 MW is coal-fired capacity that adds to system diversity. This purchase agreement also has strategic benefits for FPL's customers from a resource perspective in that it allows FPL to maintain access to the generation capabilities of the SERC region, which currently has a surplus of generation. This access allows FPL to purchase generation during certain periods at prices that may be lower than those of the generation assets FPL has under contract. Additionally, the time period of this purchase provides a bridge to a period where technological enhancements may offer cleaner, more efficient, and more diverse capacity alternatives than would be available in 2010.

Second, during 2004 FPL undertook a significant investigation and analysis of the benefits and risks of adding clean coal generation to the FPL system. A *Report on Clean Coal Generation* was presented to the Commission summarizing FPL's findings. These findings showed that, while there are uncertainties surrounding the costs of clean coal generation, significant cost and reliability benefits may be obtained by adding clean coal generation. The result is the proposed addition of two new supercritical pulverized coal units with advanced emission control technology, one each in 2012 and 2013. These clean coal capacity additions will help enhance FPL's fuel diversity by adding 1,700 MW of coal-based generation to the FPL system that would otherwise likely be provided by natural gas-fired units. FPL has initiated the process necessary to pursue the addition of these units.

Finally, FPL is evaluating proposals submitted in response to FPL's RFP requesting proposals to bring LNG to the Florida natural gas system under a long-term agreement. If cost-effective, LNG supply would add an additional source of natural gas to further support FPL's recent combined cycle unit additions.

In the future FPL will continue to identify and evaluate alternatives that may maintain or enhance fuel diversity in its capacity resource mix, including purchasing power from coal-fired facilities when such power becomes available. FPL also plans to maintain the ability to utilize fuel oil at those existing units that have that capability. FPL will continue to conduct reviews of technologies that may provide substantial fuel diversity in the future, such as nuclear power. Feasible opportunities to develop projects utilizing these technologies are currently beyond the planning horizon of this Site Plan.

III.D Demand Side Management (DSM)

1. FPL's currently approved DSM programs are summarized as follows:

Residential Conservation Service: This is an energy audit program designed to assist residential customers in understanding how to make their homes more energy-efficient through the installation of conservation measures/practices.

Residential Building Envelope: This program encourages the installation of energy-efficient ceiling insulation and reflective roofs in residential dwellings that utilize whole-house electric air conditioning.

Duct System Testing and Repair: This program encourages demand and energy conservation through the identification of air leaks in whole-house air conditioning duct systems and by the repair of these leaks by qualified contractors.

Residential Air Conditioning: This is a program to encourage customers to purchase higher efficiency central cooling and heating equipment.

Residential Load Management (On-Call): This program offers load control of major appliances/household equipment to residential customers, in exchange for monthly electric bill credits.

New Construction (BuildSmart): This program encourages the design and construction of energy-efficient homes that cost-effectively reduce coincident peak demand and energy consumption.

Residential Low Income Weatherization: This program addresses the needs of low-income housing retrofits by providing monetary incentives to various housing authorities, including weatherization agency providers (WAPS), and non-weatherization agency providers (non-WAPS). These incentives are used by the housing authorities to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting.

Business Energy Evaluation: This program encourages energy efficiency in both new and existing commercial/industrial facilities by identifying DSM opportunities and providing recommendations to the customer.

Commercial/Industrial Heating, Ventilating, and Air Conditioning: This program encourages the use of high-efficiency heating, ventilation, and air conditioning (HVAC) systems in commercial/industrial facilities.

Commercial/Industrial Efficient Lighting: This program encourages the installation of energy-efficient lighting measures in commercial/industrial facilities.

Business Custom Incentive: This program encourages commercial/industrial customers to implement unique energy conservation measures or projects not covered by other FPL programs.

Commercial/Industrial Load Control: This program reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages, in exchange for monthly electric bill credits. (This program was closed to new participants in 2000).

Commercial/Industrial Demand Reduction: This program, which started in 2002, is similar to the Commercial/Industrial Load Control program mentioned above in continuing the objective to reduce peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits.

Commercial/Industrial Building Envelope: This program encourages the installation of energy-efficient building envelope measures, such as roof/ceiling insulation and reflective roof coatings for commercial/industrial facilities.

Business On Call: This program offers load control of central air conditioning units to both small non–demand-billed and medium demand-billed commercial/industrial customers in exchange for monthly electric bill credits.

2. Research and Development

FPL continues to support research and development activities. Historically, FPL has performed extensive DSM research and development. FPL will continue such activities, not only through its Conservation Research and Development program, but also through individual research projects. These efforts will examine a wide variety of technologies that build on prior FPL research where applicable and will expand the research to new and promising technologies as they emerge.

Conservation Research and Development Program

FPL's Conservation Research and Development Program is designed to evaluate emerging conservation technologies to determine which are worthy of pursuing for program development and approval. FPL has researched a wide variety of technologies such as condenser coil cleaner and coating, ultraviolet lights for evaporator coils, Energy Recovery Ventilators (ERV), fuel cell demonstrations, CO_2 ventilation control, two-speed air handlers, and duct plenum repair. Many of the technologies examined have resulted in enhancements to existing programs or the development of new programs such as Residential New Construction, Commercial/Industrial Building Envelope, and Business On Call.

Green Power Pricing Research Project

Under this project, FPL is examining the feasibility of purchasing tradable renewable energy credits generated from new renewable resources including solar-powered technologies, biomass energy, landfill methane, wind energy, low impact hydroelectric energy, and/or other renewable sources. Residential customers who participate are charged higher premiums for purchasing the tradable renewable energy credits associated with electric energy generated by these sources.

Development of the Green Pricing program was completed and filed with the FPSC in August 2003. As part of this process, a supply contract was put into place that allows FPL to match supply with demand for green energy. Tradable renewable energy credits are used to supply the renewable benefits required of this project. The FPSC approved the program on December 2, 2003 with program implementation the first quarter of 2004. As of year-end 2004, FPL had over 10,000 project participants.

On Call Incentive Reduction Pilot

In March 2003, FPL received FPSC approval to perform a pilot for its On Call Program. Under the pilot FPL is offering to new participants a residential load control service similar to the On Call Program at a reduced incentive level. The offering of this pilot is allowing FPL to test its market research data and gauge whether FPL can repackage its current residential load control service, minimize customer attrition, achieve current goals for residential load control, and, ultimately, change On Call incentive levels without damaging FPL system reliability.

Business Green Energy Research Project

As mentioned above, FPL currently has a R&D project addressing residential customer acceptance of green energy. In an attempt to determine business customer acceptance of green pricing rates, FPL is investigating if it is feasible to design and implement a Green Energy Program that addresses these customer segments.

FPL's Summer MW Reduction Goals for DSM *

(At the Meter)

Year	Goal Cumulative Summer MW
2005	74.0
2006	141.7
2007	211.9
2008	287.2
2009	365.9
2010	447.9
2011	532.1
2012	618.8
2013	707.9
2014	801.7

Table III.D.1

* Table III.D.1 reflects FPL's new DSM Goals for 2005–2014 as approved by the Florida Public Service Commission in June, 2004. These annual cumulative values assume a 1/1/05 starting point.

III.E Generation Additions From Independent Power Producers

As previously mentioned in Section III.A, FPL has a number of new short-term, firm capacity purchases that extend through 2009. The capacity additions supplied by these purchases are summarized in Table I.D.1. Many of these purchases are from independent power producers.

Tables I.B.1 and Table I.B.2 present the capacity contributions from cogeneration/small power production facilities which are also included in FPL's resource planning work.

III.F Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy for FPL's retail and wholesale customers. The following table presents FPL's proposed future additions to proposed transmission facilities and those that must be certified under the Transmission Line Siting Act.

List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (kV)	(7) Capacity (MVA)
FPL	Collier	Orange River #3	54	12/05	230	759
FPL	St. Johns	Pringle	23	12/08	230	759

Table III.F.1

In addition, there will be transmission facilities needed to connect several of FPL's committed and projected capacity additions to the system transmission grid. These transmission facilities for the capacity additions at FPL's existing Manatee, Martin, Turkey Point, and West County Energy Center sites are described below.

Since the projected capacity additions for 2011 through 2013 are as-yet unsited, no transmission facilities information is provided. This information will be provided in future Site Plan documents once sites are selected.

III.F.1 Transmission Facilities at Manatee Unit # 3

The work required for the new capacity addition at Manatee with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 5 breakers to connect the four CT's and one steam turbine.
2. Construct two string busses to connect the collectors and main switchyard.
3. Add five main step-up transformers (4-225MVA, 1-560MVA), one for each CT and one for the steam turbine.
4. Add two breakers in Bay # 6 to connect the collector bus at the Manatee switchyard.
5. Add two breakers in Bay # 5 at the Manatee switchyard to connect the other collector bus.
6. Add relays and other protective equipment.
7. Upgrade 13-230kV circuit breakers to 2 cycle Independent Pole breakers at Manatee switchyard.
8. Upgrade the existing line terminal at Johnson to 3000 Amps.
9. Expand site and relay vault for two new line terminals at Manatee switchyard.
10. Upgrade existing breaker at Ringling Sub to 3000 amps

II. Transmission:

1. Upgrade the Calusa-Charlotte 230kV transmission line to 1875 Amps.
2. Upgrade the Johnson-Manatee 230kV transmission line to 3000 Amps.
3. Upgrade the Manatee-Ringling # 3 230kV transmission line to 3000 Amps.
4. Upgrade the Charlotte-Fort Myers # 2 230kV transmission line to 1875 Amps.

III.F.2 Transmission Facilities at Martin Unit # 8

The work required for the new capacity addition at Martin (convert the existing two CT's to a new four-on-one combined cycle unit) with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing one collector buss with 3 breakers to connect the two CT's and one steam turbine.
2. Add one station service transformer in the existing CT yard.
3. Add three main step-up transformers (2-225 MVA, 560 MVA), one for each CT and one for the steam turbine.
4. Add two breakers in Bay # 3 to connect the collector bus in the main switchyard.
5. Add relays and other protective equipment.
6. Install phase reactors and string buss in main switchyard to limit fault current.
7. Add breaker in Bay # 7 for new Indiantown # 2 transmission line. Tap existing 69kV auto-transformer off east 230kV operating bus.
8. Add breaker in Bay # 3 at Indiantown Substation for Bridge line.
9. Create new Bay 4. Add 2 breakers for Indiantown-Martin #2 line at Indiantown Substation.
10. Create new Bay # 1 at Bridge Substation with 2 breakers. Add 2 breakers to convert station configuration from ring buss to a breaker and a half scheme.
11. Construct one string bus to connect the collector and main switchyard.

II. Transmission:

1. Construct 230kV Martin-Indiantown # 2 transmission line (Completed).
2. Construct 230kV Indiantown–Bridge # 2 transmission line (Completed).
3. Various OHGW replacements due to increased fault current.
4. Upgrade the Ranch-Homeland 230kV transmission line to 1600 Amps.

III.F.3 Transmission Facilities at Turkey Point Unit # 5

The work required for the new capacity addition at Turkey Point with the FPL grid is projected to be as follows:

II. Substation:

1. Build new collector yard containing two collector busses with 5 breakers to connect the four CT's and one steam turbine.
2. Construct two string busses to connect the collector busses and main switchyard.
3. Add five main step-up transformers (4-225MVA, 1-560 MVA), one for each CT and one for the steam turbine.
4. Add a new two breaker bay to connect the collector bus at the Turkey Point switchyard.
5. Add a second two breaker bay at the Turkey Point switchyard to connect the other collector bus.
6. Add relays and other protective equipment.
7. Expand site and relay vault for two new line terminals at Turkey Point switchyard.

II. Transmission:

1. Upgrade the Turkey Point-Galloway Tap 230kV transmission line section to 1418 Amps.
2. Upgrade the Turkey Point–McGregor-Florida City 230kV transmission line section to 1403 Amps.
3. Upgrade the Turkey Point-Miller 230kV transmission line section to 1356 Amps.
4. Upgrade the Miller-Killian 230kV transmission line section to 1315 Amps.

III.F.4 Transmission Facilities at West County Energy Center Unit # 1

The work required for the first new capacity addition projected to be added in 2009 at the West County Energy Center with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 5 breakers to connect the four CT's and one steam turbine.
2. Construct two string busses to connect the collector busses and main switchyard.
3. Add five main step-up transformers (4-225 MVA, 1-560 MVA), one for each CT and one for the steam turbine.
4. Add a new Bay #4 with 3 breakers at the Corbett 230 kV main switchyard. Connect one string buss from the collector yard and relocate the Alva 230 kV terminal from Bay #3 to new Bay #4.
5. Connect second collector string buss to Bay #3.
6. Add relays and other protective equipment.
7. Expand substation and relay vault for two new line terminals at Corbett 230 kV switchyard.

II. Transmission:

1. No upgrades expected to be necessary at this time.

III.F.5 Transmission Facilities at West County Energy Center Unit # 2

The work required for the second new capacity addition projected to be added in 2010 at West County Energy Center with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 5 breakers to connect the four CT's and one steam turbine.
2. Construct two string busses to connect the collector busses and main switchyard.
3. Add five main step-up transformers (4-225 MVA, 1-560 MVA), one for each CT and one for the steam turbine.
4. Add a new bay with 3 breakers at the Corbett 500 kV main switchyard. Connect both string busses from the collector yard.
5. Add relays and other protective equipment.
6. Expand substation and relay vault for two new line terminals at Corbett 500 kV switchyard.

II. Transmission:

1. No upgrades expected to be necessary at this time.

III.G. Renewable Resources

FPL has been the leading Florida utility in examining ways to utilize renewable energy technologies to meet its customers' current and future needs. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various technologies.

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970's in demonstrating the first residential solar photovoltaic (PV) system east of the Mississippi. This PV installation at FESC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities on both a daily and annual basis in Florida. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-Kilowatt (KW) system was placed into operation in 1984. (The system was removed in 1990 to make room for substation expansion after the testing of this PV installation was completed.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. The FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's recent Green Pricing effort (which is discussed on the following page).

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first and only utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was not cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980's, FPL introduced another renewable energy program. FPL's Passive Home Program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for 6 passive homes with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the Florida Public Service Commission to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test may be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, and various customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

More recently, FPL has analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach does not require all of its customers to bear PV's high cost, but allows customers who are interested in facilitating the use of renewable energy the means to do so. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund that FPL used to make PV purchases in bulk quantities. PV modules were then installed and delivered PV-generated electricity directly into the FPL grid. Thus, when sunlight is available, the PV-generated electricity displaces an equivalent amount of fossil fuel-generated electricity.

FPL's basic approach, which has been termed Green Pricing, was initially discussed with the FPSC in 1994. FPL's efforts to implement this approach were then formally presented to the FPSC as part of FPL's DSM Plan in 1995 and FPL received approval from the FPSC in 1997 to proceed. FPL began the effort in 1998 and received approximately $89,000 in contributions (that significantly exceeded the goal of $70,000). FPL purchased the PV modules and installed them at FPL's Martin Plant site.

FPL initiated two new renewable efforts in 2000. FPL's first new initiative in 2000 was the Green Energy Project. The objectives of this Project were to: determine customer interest in an on–going renewable energy program, determine their price responsiveness and views on the different renewable technologies, and identify potential renewable energy supply sources that would meet the forecasted customer demand for this type of product. FPL both conducted customer research and issued a Request for Proposals (RFP) in 2001 to solicit proposals to potentially supply energy only (MWH) from new renewable sources. This Project formed the basis for FPL's existing Green Power Pricing Research Project , and then led to FPL's Business Green Energy Research Project, that are discussed in Section III.D.2.

The second effort initiated in 2000 was FPL's Photovoltaic Research, Development, and Education Project. This demonstration project's objectives were to: increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks (as well as the total annual energy capabilities of roof tile PV systems), and assess the homeowner's financial benefits and costs of PV roof tile systems. This project was completed in 2003.

Finally, FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy and as-available energy have been purchased by FPL from these developers. (Please refer to Tables I.B.1 and I.B.2).

III.H FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980's, FPL relied primarily on a combination of oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fired generation. In the early 1980's FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership and additional purchases from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit # 4 in 1989. Starting in 1997, petroleum coke was added to the fuel mix as a blend stock with coal at SJRPP.

The trend in recent years has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective combined cycle generating units. This planning document shows a slowing of that trend as FPL recognizes that adding natural gas-fired additions exclusively would, in the long term, create an unbalanced generation portfolio. FPL does project the addition of new gas-fired units in 2009 and 2010, which is a necessity given the longer lead times associated with the addition of coal-fired generation.

FPL's future resource planning work will remain focused on identifying and evaluating alternatives that would maintain or enhance FPL's long-term fuel diversity. These fuel diversity-enhancing alternatives may include: the purchase of power from new coal-based facilities, obtaining access to diversified sources of natural gas such as LNG, and preserving FPL's ability to utilize fuel oil at its existing units. The evaluation of the feasibility and cost-effectiveness of these, and other possible alternatives, will be an ongoing part of future planning cycles.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2014 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

2. Fuel Price Forecasts

FPL's long-term oil price forecast assumes that worldwide demand for petroleum products will grow moderately throughout the planning horizon. Non-OPEC crude oil supply is projected to increase as new and improved drilling technology and seismic information will reduce the cost of producing crude oil and increase both recoveries from existing fields and new discoveries. However, the rate of increase in non-OPEC supply is projected to be slower than that of petroleum demand, resulting in an increase in OPEC's market share throughout the planning horizon. As OPEC gains market share, prices for crude oil and petroleum products are projected to increase.

FPL's natural gas price forecast assumes that domestic demand for natural gas will grow throughout the planning horizon, primarily due to increased requirements for electric generation. Domestic natural gas production will slowly decline as new and improved drilling technology and seismic information and resulting new finds will only reduce the projected rate of decline in the overall domestic resource base. The rate of decline in domestic natural gas production is projected to be more than offset by the anticipated increase in U.S. imports from Canada during the next decade, with the development of the MacKenzie Delta region, and the continued increase in re-gasified Liquefied Natural Gas (LNG) imports over the planning horizon. Further enhancement in domestic supply is assumed with the development and delivery of the proven natural gas reserves on the North Slope of Alaska sometime in the next decade.

As demand for natural gas in Florida grows, it is anticipated that the Gulfstream pipeline will fill existing capacity, and along with the Florida Gas Transmission (FGT) pipeline system, expand beyond current capacity to meet the growing requirements of the State of Florida. When coupled with the potential for re-gasified LNG (natural gas) imports directly into Florida, there should be sufficient natural gas deliverability for FPL's customers and the State of Florida's continued needs.

FPL issued an RFP in August 2004 for between 400,000 and 600,000 MMBTU/day of re-gasified LNG supplies, for a minimum term of fifteen (15) years and a maximum term of twenty-five (25) years, with a start date between January 1, 2007 through December 31, 2010. FPL is in the process of evaluating the proposals received in the RFP process and has set a target date of June 1, 2005 for completion of Definitive Agreements subject to a few external approvals. Although this RFP is not in response to a specific need for natural gas supplies, the potential completion of the transaction contemplated by the RFP would diversify and supplement FPL's natural gas supplies from the Gulf of Mexico region.

FPL's coal price forecast assumes an ample supply of domestic coal, and the availability of imported coal, to meet a gradual but steady increase in U.S. demand in the electric generation sector over the planning horizon. The coal price forecast for FPL's existing coal plants at SJRPP and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements. FPL's petroleum coke price forecast assumes that the petroleum industry will continue to add cokers in the U.S., as well as in the Caribbean Basin, in order to maximize refinery production of light products. This trend will continue to result in sufficient availability of petroleum coke, at delivered prices significantly below delivered coal prices, to support a gradual, but steady growth in the demand for petroleum coke in the U.S. electric utility industry.

In order to support the proposed coal requirements in the 2012 and 2013 time period, FPL is currently exploring the opportunities for a competitive coal and petroleum coke delivery system. This effort includes the opportunity for competing rail service from Central Appalachia to Florida, a waterborne receiving facility on both the east and west coast of Florida, and competing rail service from these potential ports to the solid fuel site. A highly competitive coal and petroleum coke delivery network is essential to ensure both the lowest cost fuel supply to FPL's customers.

Schedule 5
Fuel Requirements 1/

			Actual 2/		Forecasted									
	Fuel Requirements	Units	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	Nuclear	Trillion BTU	257	252	245	254	246	260	255	254	259	256	254	259
(2)	Coal	1,000 TON	3,402	3,319	3,397	3,455	3,597	3,523	3,670	3,430	3,670	4,852	7,503	8,404
(3)	Residual (FO6)- Total	1,000 BBL	32,103	31,250	29,627	33,005	22,926	22,702	22,373	20,586	22,087	21,289	19,735	21,941
(4)	Steam	1,000 BBL	32,103	31,250	29,827	33,005	22,926	22,702	22,373	20,586	22,087	21,289	19,735	21,941
(5)	Distillate (FO2)- Total	1,000 BBL	565	406	118	310	282	247	322	519	519	826	894	890
(6)	CC	1,000 BBL	36	86	95	183	211	195	260	235	248	226	183	193
(7)	CT	1,000 BBL	529	321	23	127	71	52	61	284	271	601	711	698
(8)	Steam	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Natural Gas -Total	1,000 MCF	292,993	311,057	309,932	353,657	411,984	426,120	459,117	507,204	532,877	528,845	511,485	503,230
(10)	Steam	1,000 MCF	50,862	51,792	16,506	23,594	22,918	23,063	22,956	19,926	21,728	20,911	20,478	21,838
(11)	CC	1,000 MCF	229,681	252,692	286,056	323,989	385,511	402,359	434,867	486,602	510,224	506,404	489,241	479,163
(12)	CT	1,000 MCF	12,450	6,573	7,370	6,075	3,554	698	1,294	675	926	1,530	1,766	2,230

1/ Reflects fuel requirements for FPL only.
2/ Source: A Schedules.

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 1/ 2003	2004	Forecasted 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	Annual Energy Interchange 2/	GWH	10,387	10,258	10,855	11,403	10,902	11,437	10,946	10,065	8,633	8,932	8,544	8,635
(2)	Nuclear	GWH	23,524	23,013	21,935	22,804	22,008	23,279	22,884	22,809	23,212	22,950	22,810	23,212
(3)	Coal	GWH	6,625	6,315	6,676	6,569	6,700	6,688	6,892	6,536	6,891	10,469	17,486	20,117
(4)	Residual(FO6) -Total	GWH	20,305	19,709	20,445	18,922	15,220	14,939	14,895	13,782	14,816	14,263	13,228	14,699
(5)	Steam	GWH	20,305	19,709	20,445	18,922	15,220	14,939	14,895	13,782	14,816	14,263	13,228	14,699
(6)	Distillate(FO2) -Total	GWH	248	200	75	170	168	161	202	274	275	392	402	402
(7)	Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	21	57	67	124	144	133	178	160	169	154	125	132
(9)	CT	GWH	226	143	8	46	25	28	24	114	107	238	277	271
(10)	Natural Gas -Total	GWH	37,707	40,970	43,097	48,145	56,914	59,024	63,847	71,258	74,836	74,342	71,980	70,627
(11)	Steam	GWH	4,905	4,918	1,408	2,103	2,034	2,054	2,043	1,774	1,935	1,864	1,836	1,954
(12)	CC	GWH	31,718	35,490	41,251	45,711	54,686	56,915	61,725	69,441	72,845	72,385	70,036	68,539
(13)	CT	GWH	1,084	562	438	331	194	56	80	42	57	93	108	134
(14)	Other 3/	GWH	9,597	7,625	8,478	7,211	7,229	7,490	7,304	5,590	4,226	4,131	3,945	3,837
	Net Energy For Load 4/	GWH	108,393	108,091	111,561	115,224	119,141	123,018	126,970	130,313	132,889	135,479	138,396	141,529

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecst of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
4/ Net Energy For Load is also shown in Column 8 on Schedule 3.3.

Schedule 6.2
Energy Sources % by Fuel Type

			Actual		Forecasted									
	Energy Source	Units	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	Annual Energy Interchange 2/	%	9.6	9.5	9.7	9.9	9.2	9.3	8.6	7.7	6.5	6.6	6.2	6.1
(2)	Nuclear	%	21.7	21.3	19.7	19.8	18.5	18.9	18.0	17.5	17.5	16.9	16.5	16.4
(3)	Coal	%	6.1	5.8	6.0	5.7	5.6	5.4	5.4	5.0	5.2	7.7	12.6	14.2
(4)	Residual (FO6) -Total	%	18.7	18.2	18.3	16.4	12.8	12.1	11.7	10.6	11.1	10.5	9.6	10.4
(5)	Steam	%	18.7	18.2	18.3	16.4	12.8	12.1	11.7	10.6	11.1	10.5	9.6	10.4
(6)	Distillate (FO2) -Total	%	0.2	0.2	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CC	%	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(9)	CT	%	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2
(10)	Natural Gas -Total	%	34.8	37.9	38.6	41.8	47.8	48.0	50.3	54.7	56.3	54.9	52.0	49.9
(11)	Steam	%	4.5	4.5	1.3	1.8	1.7	1.7	1.6	1.4	1.5	1.4	1.3	1.4
(12)	CC	%	29.3	32.8	37.0	39.7	45.9	46.3	48.6	53.3	54.8	53.4	50.6	48.4
(13)	CT	%	1.0	0.5	0.4	0.3	0.2	0.0	0.1	0.0	0.0	0.1	0.1	0.1
(14)	Other 3/	%	8.9	7.1	7.6	6.3	6.1	6.1	5.8	4.3	3.2	3.0	2.9	2.7
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules.
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	% of Peak
2005	20,846	2,247	0	874	23,967	20,614	1,506	19,108	4,859	25.4	0	4,859	25.4
2006	21,012	2,377	0	738	24,127	21,178	1,583	19,595	4,532	23.1	0	4,532	23.1
2007	22,155	1,666	0	738	24,559	21,769	1,659	20,110	4,449	22.1	0	4,449	22.1
2008	22,155	1,888	0	738	24,781	22,306	1,740	20,566	4,215	20.5	0	4,215	20.5
2009	23,262	1,562	0	687	25,511	22,884	1,825	21,059	4,452	21.1	0	4,452	21.1
2010	24,369	1,311	0	640	26,320	23,424	1,914	21,510	4,810	22.4	0	4,810	22.4
2011	24,369	1,311	0	595	26,275	23,964	2,006	21,958	4,317	19.7	0	4,317	19.7
2012	25,219	1,311	0	595	27,125	24,516	2,100	22,416	4,709	21.0	0	4,709	21.0
2013	26,069	1,311	0	595	27,975	25,059	2,198	22,861	5,114	22.4	0	5,114	22.4
2014	26,069	1,311	0	595	27,975	25,633	2,299	23,334	4,641	19.9	0	4,641	19.9

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. All values are Summer net MW. The value shown for FPL's unit capability for the Summer of 2005 is an updated projection from the value used in FPL's 2004 analyses.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2004-on for use with the 2004 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Total Installed 1/ Capability	Firm Capacity Import	Firm Capacity Export	Firm QF	Total Capacity Available 2/	Total Peak 3/ Demand	DSM 4/	Firm Winter Peak Demand	Reserve Margin Before Maintenance 5/		Scheduled Maintenance	Reserve Margin After Maintenance 6/	
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2004/05	20,158	2,329	0	870	23,357	20,791	1,469	19,322	4,035	20.9	0	4,035	20.9
2005/06	22,429	2,459	0	738	25,626	21,336	1,511	19,825	5,801	29.3	0	5,801	29.3
2006/07	22,428	2,683	0	738	25,849	21,898	1,555	20,344	5,505	27.1	0	5,505	27.1
2007/08	23,609	1,897	0	738	26,244	22,369	1,602	20,768	5,476	26.4	0	5,476	26.4
2008/09	23,609	1,571	0	738	25,918	22,916	1,653	21,263	4,655	21.9	0	4,655	21.9
2009/10	24,790	1,321	0	687	26,798	23,466	1,708	21,758	5,040	23.2	0	5,040	23.2
2010/11	25,971	1,320	0	595	27,886	24,035	1,766	22,270	5,616	25.2	0	5,616	25.2
2011/12	25,971	1,320	0	595	27,886	24,608	1,825	22,783	5,103	22.4	0	5,103	22.4
2012/13	26,826	1,320	0	595	28,741	25,197	1,887	23,310	5,431	23.3	0	5,431	23.3
2013/14	27,681	1,320	0	595	29,596	25,798	1,952	23,846	5,750	24.1	0	5,750	24.1

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2004-on for use with the 2004 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2005														
Martin Combustion Turbine	8A	Martin County	CT	NG	FO2	PL	PL	Jun-99	Jun-01	12/1/2004	187,500	—	(160)	OT
Martin Combustion Turbine	8B	Martin County	CT	NG	FO2	PL	PL	Jun-99	Jun-01	12/1/2004	187,500	—	(160)	OT
Martin CC Conversion	8	Martin County	CC	NG	No	PL	No	Jun-03	Jun-05	Unknown	1,223,000	—	1,107	V
Sanford	4	Volusia County	CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,188,900	—	3	OT
Sanford	5	Volusia County	CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,188,900	—	9	OT
Manatee	3	Manatee County	CC	NG	No	PL	No	Jun-03	Jun-05	Unknown		—	1,107	V
										2005 Changes/Additions Total:		**0**	**1,906**	
2006														
Cape Canaveral	1	Brevard County	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	402,050	12	13	OT
Fort Myers	3	Lee County	CT	NG	FO2	PL	PL	Unknown	Jun-06	Unknown	375,700	5	8	OT
Fort Myers	2	Lee County	CC	NG	FO2	PL	PL	Unknown	Jun-06	Unknown	1,775,390	15	—	OT
Fort Myers	CT	Lee County	CT	FO2	No	WA	No	Unknown	Jun-06	Unknown	744,120	16	—	OT
Manatee	1	Manatee County	ST	FO6	No	WA	No	Unknown	Jun-06	Unknown	863,300	26	26	OT
Manatee	2	Manatee County	ST	FO6	No	WA	No	Unknown	Jun-06	Unknown	863,300	11	11	OT
Manatee	3	Manatee County	CC	NG	No	PL	No	Jun-03	Jun-05	Unknown	1,223,000	1,197	—	V
Martin CC Conversion	8	Martin County	CC	NG	No	PL	No	Jun-03	Jun-05	Unknown	1,223,000	835	—	V
Martin	2	Martin County	ST	NG	FO6	PL	PL	Unknown	Jun-06	Unknown	934,500	—	6	OT
Martin	3	Martin County	CC	NG	No	PL	No	Unknown	Jun-06	Unknown	612,000	1	6	OT
Martin	4	Martin County	CC	NG	No	PL	No	Unknown	Jun-06	Unknown	612,000	1	6	OT
Pt Everglades	1	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	247,775	1	8	OT
Pt Everglades	2	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	247,775	1	1	OT
Pt Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	402,050	2	5	OT
Pt Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	402,050	12	15	OT
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	310,420	9	9	OT
Sanford	4	Volusia County	CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,188,900	43	—	OT
Sanford	5	Volusia County	CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,188,900	43	3	OT
Scherer	4	Monroe, GA	BIT	BIT	No	RR	No	Unknown	Jun-06	Unknown	680,368	24	19	OT
St. John's River Power Park	2	Duval County	BIT	BIT	Pet Coke	RR	WA	Unknown	Jun-06	Unknown	135,918	18	22	OT
Turkey Point	1	Miami Dade County	ST	FO6	NG	WA	PL	Unknown	Jul-06	Unknown	402,050	—	9	OT
										2006 Changes/Additions Total:		**2,272**	**167**	
2007														
Pt Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	402,050	(1)	(1)	OT
Turkey Point CC	5	Miami Dade County	CC	NG	FO2	PL	PL	Jan-05	Jun-07	Unknown	1,223,000	—	1,144	P
										2007 Changes/Additions Total:		**(1)**	**1,143**	
2008														
Turkey Point CC	5	Miami Dade County	CC	NG	FO2	PL	PL	Jan-05	Jun-07	Unknown	1,223,000	1,181	—	P
										2008 Changes/Additions Total:		**1,181**	**0**	

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2009														
West County Combined Cycle	1	Palm Beach County	CC	NG	FO2	PL	PL	Jan-07	Jun-09	Unknown	Unknown	—	1,107	P
									2008 Changes/Additions Total:			**0**	**1,107**	
2010														
West County Combined Cycle	1	Palm Beach County	CC	NG	FO2	PL	PL	Jan-07	Jun-09	Unknown	Unknown	1,181	—	P
West County Combined Cycle	2	Palm Beach County	CC	NG	FO2	PL	PL	Jan-08	Jun-10	Unknown	Unknown		1,107	P
									2010 Changes/Additions Total:			**1,181**	**1,107**	
2011														
West County Combined Cycle	2	Palm Beach County	CC	NG	FO2	PL	PL	Jan-08	Jun-10	Unknown	Unknown	1,181	—	P
									2011 Changes/Additions Total:			**1,181**	**0**	
2012														
Unsited Clean Coal Unit	1	Unknown	CC	NG	FO2	PL	PL	Jan-10	Jun-12	Unknown	Unknown	—	850	P
									2012 Changes/Additions Total:			**0**	**850**	
2013														
Unsited Clean Coal Unit	1	Unknown	CC	NG	FO2	PL	PL	Jan-10	Jun-12	Unknown	Unknown	855	—	P
Unsited Clean Coal Unit	2	Unknown	CC	NG	FO2	PL	PL	Jan-11	Jun-13	Unknown	Unknown	—	850	P
									2013 Changes/Additions Total:			**855**	**850**	
2014														
Unsited Clean Coal Unit	2	Unknown	CC	NG	FO2	PL	PL	Jan-11	Jun-13	Unknown	Unknown	855	—	P
									2013 Changes/Additions Total:			**855**	**0**	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All other MW will be picked up in the following year.

Note 2: Capacity additions/changes shown for 2004 reflect changes/additions from values shown in Schedule 1.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Martin Combustion Turbine Conversion to Combined Cycle Unit # 8

(2) **Capacity**
a. Summer 787 MW Incremental (1107 MW Total)
b. Winter 835 MW Incremental (1197 MW Total)

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2003
b. Commercial In-service date: 2005

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 11,300 Acres

(9) **Construction Status:** V (Under Construction >= 50% Complete)

(10) **Certification Status:** Certified

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data ***

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 84%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data **,*****

Book Life (Years):		25 years
Total Installed Cost (In-Service Year $/kW):		584
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.):	(2001 $kW-Yr)	9.09
Variable O&M ($/MWH):	(2001 $/MWH)	0.037
K Factor:		1.5397

* Values represent an operational combined cycle unit after the conversion is completed.
** $/kW values are based on Summer incremental capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Manatee Combined Cycle Unit # 3

(2) **Capacity**
a. Summer 1,107 MW
b. Winter 1,197 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2003
b. Commercial In-service date: 2005

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: None

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low NO_x Combustors, SCR

(7) **Cooling Method:** Cooling Pond

(8) **Total Site Area:** 9,500 Acres

(9) **Construction Status:** V (Under Construction >= 50% Complete)

(10) **Certification Status:** Certified

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 77%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):		25 years
Total Installed Cost (In-Service Year $/kW):		499
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.):	(2001 $kW-Yr)	12.96
Variable O&M ($/MWH):	(2001 $/MWH)	0.037
K Factor:		1.5397

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Turkey Point Combined Cycle Unit # 5	
(2)	**Capacity**		
	a. Summer	1,144 MW	
	b. Winter	1,181 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2005	
	b. Commercial In-service date:	2007	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low No_x Combustors, SCR 0.0015% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Tower
(8)	**Total Site Area:**	11,000	Acres
(9)	**Construction Status:**	U	Under Construction, less than or equal to 50% complete
(10)	**Certification Status:**	Certified	
(11)	**Status with Federal Agencies:**	Certified	

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 97%	(First Base OperationYear)
Average Net Operating Heat Rate (ANOHR):	6,835 Btu/kWh	(Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25 years
Total Installed Cost (In-Service Year $/kW):	507
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2007 $kW-Yr)	10.06
Variable O&M ($/MWH): (2007 $/MWH)	0.13
K Factor:	1.5699

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit # 1

(2) **Capacity ***
a. Summer 1,107 MW
b. Winter 1,181 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2007
b. Commercial In-service date: 2009

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 97%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,835	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data **,*****

Book Life (Years):	25 years
Total Installed Cost (In-Service Year $/kW):	571
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2009 $kW-Yr)	12.25
Variable O&M ($/MWH): (2009 $/MWH)	0.08
K Factor:	1.6010

* Output based on typical 4x1 plant similar to Martin/Manatee/Turkey Point 4x1 plants.
** $/kW values are based on Summer capacity.
*** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes escalation and AFUDC only.
Transmission interconnection, transmission integration, and gas expansion costs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit # 2

(2) **Capacity ***
a. Summer 1,107 MW
b. Winter 1,181 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2008
b. Commercial In-service date: 2010

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 94%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,835	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data **,*****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	561	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2010 $kW-Yr)	12.63	
Variable O&M ($/MWH): (2010 $/MWH)	0.08	
K Factor:	1.6013	

* Output based on a typical 4x1 plant similar to Martin/Manatee/Turkey Point 4 x 1 plants.
** $/kW values are based on Summer capacity.
*** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes escalation and AFUDC only.
Transmission interconnection, transmission integration, and gas expansion costs are not included.
(Note: Costs shown are based on stand-alone construction; i.e. no synergies with Unit # 1.)

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Clean Coal Unit # 1

(2) **Capacity**
a. Summer 850 MW
b. Winter 855 MW

(3) **Technology Type:** Super Critical Steam Generator

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2008
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel Coal
b. Alternate Fuel N/A

(6) **Air Pollution and Control Strategy:** Low No_x Burners, Over-fired Air, SCR, Baghouse
Wet Flue Gas Desulfurization, Wet Electric Static Precipatator

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 3,000 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	6.0%	
Forced Outage Factor (FOF):	4.25%	
Equivalent Availability Factor (EAF):	90%	
Resulting Capacity Factor (%):	Approx. 90%	(First Year Operation)
Average Net Operating Heat Rate (ANOHR):	8,600	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	40	years
Total Installed Cost (In-Service Year $/kW):	2,355	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2012 $kW-Yr)	38.50	
Variable O&M ($/MWH): (2012$/MWH)	1.37	
K Factor:	1.6727	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes escalation and AFUDC only.
Transmission interconnection and transmission integration costs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Clean Coal Unit # 2

(2) **Capacity**
a. Summer 850 MW
b. Winter 855 MW

(3) **Technology Type:** Super Critical Steam Generator

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2008
b. Commercial In-service date: 2013

(5) **Fuel**
a. Primary Fuel Coal
b. Altemate Fuel N/A

(6) **Air Pollution and Control Strategy:** Low No_x Burners, Over-fired Air, SCR, Baghouse
Wet Flue Gas Desulfurization, Wet Electric Static Precipatator

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 3,000 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	6.0%	
Forced Outage Factor (FOF):	4.25%	
Equivalent Availability Factor (EAF):	90%	
Resulting Capacity Factor (%):	Approx. 90%	(First Year Operation)
Average Net Operating Heat Rate (ANOHR):	8,600	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	40	years
Total Installed Cost (In-Service Year $/kW):	1,732	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2013 $kW-Yr)	28.86	
Variable O&M ($/MWH): (2013 $/MWH)	1.39	
K Factor:	1.6731	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes escalation and AFUDC only.
Transmission interconnection and transmission integration costs are not included.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Martin Combustion Turbine Conversion to Combined Cycle Unit # 8

(1)	Point of Origin and Termination:	Indiantown – Martin #2
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned & New acquisitions
(4)	Line Length:	12.9 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 1/5/04 End date: Complete
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$11,700,000
(8)	Substations:	Martin 230kV and Indiantown
(9)	Participation with Other Utilities:	None

---

(1)	Point of Origin and Termination:	Bridge – Indiantown #2
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	10.0 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 3/15/04 End date: Complete
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$8,900,000
(8)	Substations:	Indiantown and Bridge
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Manatee Combined Cycle Unit # 3

The new Manatee CC unit does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Combined Cycle Unit # 5

The new Turkey Point CC unit does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

West County Energy Center Combined Cycle Unit # 1

The proposed new West County Energy Center CC Unit # 1 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

West County Energy Center 2 Combined Cycle Unit # 2

The proposed new West County Energy Center CC Unit # 2 does not require any "new" transmission lines.

CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered plant and animal species. Population growth in its service area is continuing, which heightens competition for air, land, and water resources that are necessary to meet the increased demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

FPL has been recognized for many years as one of the leaders among utilities for its commitment to the environment. Many outside organizations have heralded its environmental leadership. In 2004 FPL Group earned a first place ranking among U.S. power companies, and second globally, in a report from the World Wildlife Fund for voluntary commitments to limit CO_2 emissions. This commitment was made to support initiatives to better manage utility impacts on global warming through use of greenhouse gas emission reductions and improvements in energy efficiency. The report stated that this was "primarily due to the company's leadership in developing wind energy and their commitment to dramatically improve their efficiency". FPL was also recently ranked first out of 28 major electric utilities surveyed in an environmental assessment conducted by Innovest, an independent advisory group. In recognition of its success in executing a strategy to become a clean energy provider harnessing primarily clean and renewable fuels while also boosting shareholder value, FPL Group, Inc. was named in June 2003 as the winner of the Edison Award, the electric power industry's highest honor by the Edison Electric Institute.

FPL was awarded Edison Electric Institute's National Land Management Award for its stewardship of 25,000 acres surrounding its Turkey Point Plant. FPL won the Council for Sustainable Florida's award for its sea turtle conservation and education programs at its St. Lucie Plant. In 2001, FPL was awarded the 2001 Waste Reduction and Pollution Prevention Award from the Solid Waste Association of North America. FPL received the 2001 Program Champion Award from the Environmental Protection Agency's Wastewise Program. The Florida

Department of Environmental Protection named FPL a "Partner for Ecosystem Protection" for its emission-reducing "repowering" projects at its Fort Myers and Sanford Plants. Finally, FPL has been recognized by numerous federal and state agencies for its innovative endangered species programs which include such species as manatees, crocodiles, and sea turtles.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Statement in 1992 to clearly define the Company's position. This statement reflects how FPL incorporates environmental values into all aspects of the Company's activities and serves as a framework for new environmental initiatives throughout the Company. The FPL environmental statement further establishes a long-term direction of environmental initiatives throughout the Company. FPL's Environmental Statement is:

> It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:
>
> - Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
> - Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
> - Encourage the wise use of energy to minimize the impact on the environment.
> - Communicate effectively on environmental issues.
> - Conduct periodic self-evaluations, report performance, and take appropriate actions.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an environmental management system to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program that is discussed below. Other components include: executive management support and commitment, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident/emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to evaluate environmental performance, verify compliance with Company policy as well as with legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to: facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and Company policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2004 environmental outreach activities are noted in Table IV.E.1.

Activity	# of Participants
Visitors to Energy Encounter	20,000
Visitors to Manatee Park	150,000
Number of "visits" to FPL' s Environmental Website	195,000
Number of pieces of environmental literature distributed	>110,000

Table IV.E.1

(All numbers are approximations.)

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified preferred and potential sites for future generation additions. These preferred and potential sites are discussed in separate sections below.

IV.F.1 Preferred Sites

FPL identifies four preferred sites in this Site Plan: the existing Martin plant site, the existing Manatee plant site, the existing Turkey Point plant site, and the West County Energy Center which is adjacent to the existing FPL Corbett substation in Palm Beach County. Three of these four sites are the locations for capacity additions that FPL is committed to make during the 2005-2007 period. The fourth site is the projected location for capacity additions FPL is proposing to make in 2009 and 2010.

The capacity additions at the Martin, Manatee, and Turkey Point sites have been approved by the FPSC. The Martin and Manatee capacity additions will come in-service in mid-2005 and the Turkey Point capacity addition will come in-service in mid-2007. The discussion of capacity additions at the West County Energy Center represent FPL's current projection of how it will meet its capacity needs for 2009 and 2010.

The four preferred sites are discussed below.

Preferred Site # 1: Manatee Plant, Manatee County

The site is located in unincorporated north central Manatee County approximately 2.5 miles south of the Hillsborough-Manatee County line. It is 5 miles east of Parrish, Florida and is approximately 5 miles east of U.S. Highway 301 and 9.5 miles east of Interstate 75 (I-75). State Road (SR) 62 is about 0.5 miles south of the site. Saffold Road marks the eastern boundary of the site.

FPL's Manatee Plant occupies a portion of the approximately 9,500 acre Manatee Site which is wholly owned by FPL. The site includes a 4,000 acre cooling pond including the dike area. The existing approximately 1,590 MW (Summer) of generating capacity is made up of two steam units (Units # 1 and # 2) which have been in-service since 1976 and 1977 respectively. These units burn both fuel oil (residual) with a maximum sulfur content of 1 percent and natural gas. Natural gas may be fired singly or in combination with fuel oil. A recent agreement between FPL and Gulfstream Natural Gas Systems (Gulfstream), and the nearby Florida Gas Transmission (FGT) system, provides two natural gas sources for these units.

Additional generating capacity is being added to the site for operation beginning in 2005 to meet projected FPL system capacity needs. One unit consisting of four new combustion turbines (CT's), four new heat recovery steam generators (HRSG's), and a new steam turbine generator are scheduled for in-service operation beginning in June 2005. The four new CT's, HRSG's, and steam turbine will ultimately be operating in combined cycle (CC) configuration. This new CC unit will add 1,107 MW (Summer) and 1,197 MW (Winter) capability to the site. This new CC Unit will be designated as Manatee Unit # 3.

Unit # 3 is located west of the existing generating Units # 1 and # 2. The location of the new combined cycle Unit # 3 at the Manatee Plant site and the selection of the highly efficient combined cycle technology (firing natural gas) will maximize the beneficial use of the site while minimizing environmental and land use impacts otherwise associated with the development of a new generating plant of this capacity. The Manatee site has been previously listed as a preferred or potential site in FPL Site Plans and continues to be a potential site for future capacity additions, if needed in the future.

a. and b. <u>U.S. Geological Survey (USGS) Map and Proposed Facilities Layout</u>

A map indicating the Manatee plant site showing the general layout of the facilities and a map indicating the land use of the site are found at the end of this chapter.

c. <u>Map of Site and Adjacent Areas</u>

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a 4,000 acre cooling pond. Manatee Units # 1 and # 2 will not be affected by the addition of Unit # 3. The area for Unit # 3 is expected to comprise approximately 73 acres. The site and surrounding land uses are almost exclusively agriculture with the exception of the Willow Shores residential area located northwest of the Manatee Plant site. Individual homes are located in the larger of two out parcels within the Manatee Plant site along SR 62 at the northeast corner of the site. The vast majority of the Manatee Plant site was re-designated from Agricultural/Rural to Major Public/Semi Public (1) (P/SP) land use category by the Manatee County Commission on November 19, 2002 with the approval of Ordinance 02-13. Electric generating plants are specifically allowed in the P/SP category in accordance with the Manatee County Local Government Comprehensive Plan and Land Development Regulation Act, Chapter 163, Part II, Florida Statutes (FS).

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

There are no incorporated areas within 5 miles of the Manatee Plant site. Unincorporated communities in the area include Willow, located about 2 miles north of the Manatee Plant; Parrish, located about 5 miles southwest of the plant; and, in Hillsborough County, Sundance, located 3 miles northwest of the plant; Sun City Center, located 7 miles north of the plant; and Wimauma, located 8 miles northeast of the plant.

The Manatee Plant site includes areas of improved pasture with forested land southeast of the project area. This forested area is comprised of flat woods and oak habitat. The western side of the Manatee Plant site is currently used for agriculture. There are also wetlands to the southeast containing wet pine flat woods mixed with dry pine flat woods. There will not be any disturbance of existing wetlands associated with this project.

2. Listed Species

Construction and operation of the new Unit # 3 at the site is not expected to affect any rare, endangered, or threatened species. The majority of the site is cleared, grassed, and periodically mowed. The project area has been significantly altered by the construction and operation of the existing plant facilities, and, as a result, wildlife utilization of this area is minimal. Common wading birds utilizing the plant site outside of the project area include the great blue heron, little blue heron, great egret, snowy egret, and the white ibis. Typical mammals found in the habitats surrounding the project area are common bobcat, raccoon, deer, feral hog, opossum, armadillo, skunk, and gray squirrel. Avian species observed in the vicinity of the project include bald eagles, a variety of songbirds, red-shouldered hawks, and marsh hawks.

3. Natural Resources of Regional Significance Status

There are no county, State or Federal designated areas located within one mile of the plant site. The construction and operation of Manatee Unit # 3 is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands that are associated with the Little Manatee River within a 5-mile radius of the project site. These lands include: Little Manatee River State Recreation Area, Little Manatee River State Canoe Trail, Florida Gulf Coast Railroad Museum, Cockroach Bay Aquatic Preserve, Critical Manatee Habitat, South Hillsborough Wildlife Corridor, Hillsborough County Environmental Lands Acquisition and Protection Program Parcels, and Save Our River-Little Manatee River.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

Manatee Unit # 3 consists of the addition of four new combustion turbines, four HRSG's, and one new steam turbine generator in combined cycle mode in a 4x1 configuration. Manatee Unit # 3 is scheduled to begin operation in mid-2005. Natural gas, delivered via pipeline, will be the sole fuel for this unit.

Mitigation aspects of Manatee Unit # 3 include: the capture and reuse of plant process water and rainwater, the use of combustion technology that is very efficient and low in air pollutant emissions, plus pollution control technology (dry-low NO_x burners and selected catalytic reduction equipment).

g. Local Government Future Land Use Designations

As mentioned above, the Local Government Future Land Use Plan is consistent with the existing Designated uses of the Manatee Plant Site as major portions of the site are designated as Major Public/Semi Public (1) – P/PS/. Electric generating plants are specifically allowed in this land use category.

h. Site Selection Criteria and Process

The Manatee plant site was selected due to consideration of various factors including system load and economics. The availability of a natural gas pipeline was also a major factor in the selection of the Manatee site for the new 4x1 CC unit. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues.

i. Water Resources

The available surface water source is the Little Manatee River which supplies makeup water for the 4,000-acre cooling pond. Plant process and service water requirements are currently supplied by the cooling pond. There are three wells in the Floridan Aquifer that are reserved for standby purposes.

j. Geological Features of Site and Adjacent Areas

Manatee County has three physiographic provinces: the Gulf Coast Lowlands, the DeSoto Plains, and the Polk Upland. The Manatee Plant is situated on the boundary of the DeSoto Plains and the Gulf Coast Lowland provinces. The geology underlying the Manatee Plant consists of unconsolidated sediments comprised of sand, clay silt, marl shell, limestone, and phosphorite (terrace deposits) from the Pleistocene age to recent. Undifferentiated deposits comprised of sand and clay are generally described to be less than 25 feet thick. Underlying the differentiated materials are the Miocene Hawthorn Formation, the Tampa Member, the Suwanee Limestone of the Oligocene age, the Ocala Limestone of the Eocene Age, the Avon Park Formation, the Oldsmar Formation of the Eocene age, and the Cedar Key Formation of the Paleocene age.

The major hydro-geologic units that exist in the vicinity of the site include, in descending order: the surficial aquifer system, the intermediate aquifer system, and the Upper Floridan aquifer. The surficial aquifer system is generally unconfined in Manatee County and consists of Quaternary deposits of predominately marine and non-marine quartz sand, clayey sand, shell, shelly marl, phosphorite, and occasional stringersmarl and limestone. In the vicinity of the site the surficial sediments are approximately 25 feet thick.

k. Projected Water Quantities for Various Uses

The estimated additional quantity of water for industrial processing is estimated to be 150 gallons per minute (gpm) and provides plant process and service water. FPL operates on-site water treatment systems for each of these uses. Water quantities for other uses such as irrigation and potable water are estimated to be approximately 5 gpm.

l. Water Supply Sources by Type

Manatee Unit # 3 will utilize the existing on-site cooling pond as its source of cooling water. The cooling pond operates as a "closed cycle" system; any makeup water is provided from the Little Manatee River to replace net evaporation and seepage losses from the pond. These makeup needs are within the existing agreement between FPL and the Southwest Florida Water Management District (SWFWMD). There are three wells currently on reserve (stand-by) that are in the Floridan Aquifer.

m. Water Conservation Strategies Under Consideration

Available water including non-contact storm water, treated industrial wastewater, treated sanitary wastewater, and recovered service water are captured and returned to the cooling pond. Storm water from the equipment areas is also treated and returned to the cooling pond.

n. Water Discharges and Pollution Control

The Manatee Plant utilizes a Best Management Practices (BMP) plan and a Spill Prevention, Control, and Countermeasure (SPCC) plan to assist in the control of inadvertent release of pollutants. Storm water runoff is collected and routed to detention ponds. Construction activities are managed so that equipment maintenance and fueling are performed in designated areas so that, in the event of a spill or release of any contaminant, impacts to any surface water or the cooling pond are minimized.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by fuel delivery services and facilities for residual, low sulfur (1 percent) fuel oil and, most recently, natural gas as an alternate fuel for existing Units # 1 and # 2. The Unit # 3 addition will be fueled solely by natural gas that could be supplied by either Gulfstream or FGT as previously discussed.

p. Air Emissions and Control Systems

The addition of natural gas as a permitted fuel for existing Units # 1 and # 2 is expected to lower overall emissions during periods when natural gas, instead of fuel oil, is used. In addition, a NO_x reduction technology, re-burn, has been approved for installation on Units # 1 and # 2 and are being installed.

The use of natural gas and combustion controls will minimize air emissions from Unit # 3 and ensure compliance with applicable emission limiting standards. Using natural gas minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of carbon monoxide and volatile organic compounds. NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. The design of Manatee Unit # 3 incorporates features that will make it one of the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise emissions from the project are not anticipated to be significantly different from the current levels at the existing plant. Similar natural gas-fired facilities in Broward and Martin Counties have been constructed and operated without exceeding allowable noise levels.

r. Status of Applications

FPL filed the Site Certification Application (SCA) for Manatee Unit # 3 with the Florida Department of Environmental Protection (FDEP) on February 20, 2002 and received approval and Site Certification by the Governor and Cabinet in April 2003. FPL acquired all permits needed and commenced construction in May 2003. Modifications to operating permits will be pursued as necessary.

Preferred Site # 2: Martin Plant, Martin County

The Martin site is located approximately 40 miles northwest of West Palm Beach, 5 miles east of Lake Okeechobee, and 7 miles northwest of Indiantown in Martin County, Florida. The site is bounded on the west by the Florida East Coast Railway (FEC) and the adjacent South Florida Water Management District

(SFWMD) L-65 Canal, on the south by the St. Lucie Canal (C-44 or Okeechobee Waterway), and on the northeast by SR 710 and the adjacent CSX Railroad. The Martin site was identified in 1987 as a preferred location for development of coal gasification/combined cycle electric generation facilities and subsequent FPL Site Plans have continued to identify this site as a preferred site.

The existing 2,900 (approximate) MW (Summer) of generating capacity at FPL's Martin site occupies a portion of the approximately 11,300 acres that are wholly owned by FPL. The generating capacity is made up of two steam units (Units # 1 and # 2), plus two combined cycle units (Units # 3 and # 4), and two combustion turbine units (Units # 8a and # 8b) that are being converted to combined cycle through the construction of two additional combustion turbines (Units # 8c and # 8d), four Heat Recovery Steam Generators (HRSG's), and a steam turbine. The new combined cycle unit will be named Martin Unit # 8. The site includes a 6,800 acre cooling pond (6,500 acres of water surface and 300 acres of dike area) and approximately 300 acres for the existing power plant units and related facilities.

Martin Unit # 8 is scheduled to be in-service in mid-2005 and will add approximately 790 MW of capacity. The Martin site has been previously approved for the development of solid fuel generating units and has also been listed as a preferred or potential site in previous FPL Site Plans for combined cycle and simple cycle generation options. The Martin site continues to be a potential option for additional generating units when needed in the future.

a. and b. U.S. Geological Survey (USGS) Map and Proposed Facilities Layout

A USGS map of the Martin plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a 6,800-acre cooling pond. The existing power plant facilities are located on approximately 300 acres. To the east of the power plant there is an area of mixed pine flat wood with a scattering of small wetlands. To the north of the cooling pond there is a 1,200-acre area which has been set aside as a mitigation area. There is a peninsula of wetland forest on the West Side of the reservoir that is named the Barley Barber Swamp. The Barley Barber Swap encompasses 400 acres and is preserved as a natural area. There is also a 10-kilowatt (kW) photovoltaic energy facility at the south end of this site.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

As noted above, the Barley Barber Swamp is located on the site. There is also a 1,200-acre mitigation area in the northern area of the site where wetlands and uplands have been preserved. Along the south and west sides of the cooling pond is an area where the vegetation has been maintained in its natural state in order to serve as a wildlife corridor. There are pine flat woods and small-scattered wetlands to the east of the plant.

2. Listed Species

Construction and operation of a new unit at the site is not expected to affect any rare, endangered, or threatened species. There are two active Bald Eagle (*Haliaeetus leucocephalus*: Federal- and State-listed as Threatened) nests that have been on the site for many years. The Florida Natural Areas Inventory (FNAI) database notes a record of Eastern Indigo Snakes (*Drymachon coralis coupert*, which are Federal- and State-listed as threatened) in the Barley Barber Swamp. A number of other Bald Eagle nests and sightings of Eastern Indigo Snakes are reported by the FNAI database within a two-mile radius of the site. Infrequent sightings of Florida Panther have been made in the vicinity of the site area.

3. Natural Resources of Regional Significance Status

The Treasure Coast Regional Planning Council lists the "FPL Preserve", including the Barley Barber Swamp, as a Significant Regional Facility. Natural communities such as uplands and wetlands are also generically listed as Resources of Regional Significance.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

Martin Unit # 8 consists of the addition of two new CT's, four new HRSG's, and a new steam turbine to the two existing CT's, resulting in a 4x1 configuration combined cycle unit. This unit is scheduled to be in-service in mid-2005. Natural gas delivered via pipeline is the primary fuel type for this unit (with light oil serving as a backup fuel). Natural gas-fired facilities are among the cleanest, most efficient technologies currently available.

Mitigation aspects of Martin Unit # 8 include the capture and reuse of plant process water and rainwater, plus the use of cooling towers.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is "Public Utilities". Designations for the surrounding area are primarily "Agricultural". There are also limited areas of "Agricultural Ranchette", "Industrial", and a small "Commercial" area designation. To the southeast of the property, fronting on the St. Lucie Canal, is an area designated for "Public Conservation".

h. Site Selection Criteria and Process

The Martin plant site has been selected due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues.

i. Water Resources

Surface water resources currently used at the Martin facility include the cooling pond which takes its water from the St. Lucie canal. The available ground water resource is the surficial aquifer system which is used as a source of potable and service water. Both of these sources will be used.

j. Geological Features of Site and Adjacent Areas

FPL's Martin site is underlain by approximately 13,000 feet of sedimentary rock strata. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine bin origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, or clay. The deepest formation in Martin County on which significant published data are available is the Eocene Age Avon Park. Limited information is available from wells penetrating the underlying Lake City formation. The published information on the sediments comprising the formations below the Avon Park Limestone in western Martin County is based on projections from deep wells in Okeechobee, St. Lucie, and Palm Beach Counties.

k. Projected Water Quantities for Various Uses

The estimated additional quantity of water required for industrial processing is 130 gallons per minute (gpm) for uses such as process water and service water. FPL operates on-site water treatment systems for each of these uses. Cooling water for Unit # 8 will be cycled through the addition of cooling towers. Makeup water for the pond is taken from the St. Lucie canal. The current makeup water quantity to the cooling pond (approximately 4,800 gpm) is expected to be adequate for the operation of Unit # 8. Water quantities needed for other uses such as irrigation and potable water are estimated to be approximately 5 gpm.

l. Water Supply Sources by Type

Martin Unit # 8 will utilize the existing on-site cooling pond as the source of cooling water for the cooling towers and as a heat sink for the dissipation of cooling water heat. The cooling towers will also act as a heat sink for the Unit # 8 process water. The cooling pond operates as a "closed cycle" system in which heated water from the generating units loses its heat as it is circulated within the pond and back around to the plant intake. Water is also collected in a seepage ditch surrounding the cooling pond and is then pumped back into the cooling pond. Makeup water to the pond is withdrawn from the St. Lucie canal as needed to replace net evaporation and seepage losses from the pond. Such needs will comply with the existing agreement between FPL and the South Florida Water Management District (SFWMD) regarding allocation of cooling water to the pond and with SFWMD's regulations for consumptive water use.

The existing water treatment system at the plant, which provides treated water for use in the Unit # 1 and # 2 boilers, as well as for the HRSG's associated with Units # 3 and # 4, will be used to provide treated water for Unit # 8.

m. Water Conservation Strategies Under Consideration

The entire plant site captures and reuses process water whenever feasible and manages storm water in such a manner so as to recharge the surficial aquifer.

n. Water Discharges and Pollution Control

Heated water discharges will be dissipated in the cooling tower and cooling pond. Non-point source discharges are not an issue since there are none at this facility. Industrial discharges will be minimized by treating and recycling equipment wash water, boiler blowdown water, and equipment area runoff. Storm water runoff is collected and used to recharge the surficial aquifer via a storm water management system. Design elements have been included to capture suspended sediments. Facility permits mandate various sampling and testing activities that provide indications of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill

Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by multiple fuel delivery facilities including the installation of a new pipeline. Gulfstream has constructed the new pipeline which provides an alternative fuel supply to the existing Florida Gas Transmission natural gas pipeline. The site is also served by an oil pipeline that serves the existing steam boilers. Distillate is received by truck and stored in above-ground storage tanks. An additional above-ground storage tank was constructed to serve the backup distillate fuel needs of Unit # 8.

p. Air Emissions and Control Systems

FPL's Unit # 8 is subject to "New Source Review" under Federal and State Prevention of Significant Deterioration (PSD) regulations. This review requires these units to meet New Source Performance Standards (NSPS) and that Best Available Control Technology (BACT) be selected to control emissions of those pollutants emitted in excess of applicable PSD significant emission rates. The primary purpose of BACT analysis is to minimize the allowable increases in air pollutants taking into account energy, environmental, and economic impacts. This process provides for the potential for future economic growth without significantly degrading air quality.

The use of natural gas as the primary fuel, plus combustion controls, will minimize air emissions from Unit # 8 and ensure compliance with applicable emission limiting standards. Using natural gas minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of carbon monoxide and volatile organic compounds. NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. The design of Unit # 8 incorporates features that will make it one of the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise emissions from the project are not anticipated to be significantly different from the current levels at the existing plant. Similar natural gas-fired facilities in Broward and Martin Counties have been constructed and operated without exceeding allowable noise levels

r. Status of Applications

An SCA was filed in December 1989 for the construction and operation of the Martin Coal Gasification/Combined Cycle project under the Florida Electrical Power Plant Siting Act. In order to convert the two CT's from simple cycle to (4X1) CC configuration (Unit # 8), a modification to the Site Certification was required. FPL filed the SCA modification on February 1, 2002 with the FDEP. Approval and Site Certification was issued by the Governor and Cabinet in April 2003. FPL acquired all construction permits and commenced construction in May 2003. Modifications to operating permits will be pursued as necessary.

Preferred Site # 3: Turkey Point Plant, Miami-Dade County

The Turkey Point Plant site is located on the west side of Biscayne Bay, 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. Public access to the plant site is limited due to the nuclear units located there. The land surrounding the site is owned by FPL and acts as a buffer zone. The site is comprised of two nuclear units and two conventional boiler, fossil units, the cooling canals, an FPL-maintained natural wildlife area, and wetlands that have been set aside as the Everglades Mitigation Bank (EMB).

Units # 1 and # 2 are fossil fuel generating plants with approximate generating capacity of 400 MW each. Unit # 1 was completed in 1967 and Unit # 2 in 1968. Turkey Point also has five diesel peaking units that in total produce approximately 12 MW. These units are primarily used to provide emergency power, but occasionally run during the Summer to provide power during peak load demands.

The location of the new Turkey Point Unit # 5, a "4x1" combined cycle electrical generating unit, is within the existing FPL Turkey Point facility property. The location for Unit # 5 is adjacent to the existing fossil Units # 1 and # 2, and includes the existing parking lot and storage areas immediately northwest of Units # 1 and # 2 as well as mangrove wetlands north of the facility.

a. and b. U.S. Geological Survey (USGS) Map and Proposed Facilities Layout

A USGS map of the Turkey Point plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a self-contained cooling canal system that supplies water to condense steam used by the existing units' turbine generators. The canal system consists of 36 interconnected canals each five miles long, 200 feet wide, and four feet deep. The remaining developed area of the site is where the two fossil steam generating units and 5 diesel generators are located. South of, and adjacent to, the fossil plant are the two nuclear generating units. Further to the south, wetlands have been set aside as part of the Everglades Mitigation Bank in an effort to restore these areas to historical plant communities and hydrological function.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is undeveloped dwarf red mangrove swamp, tidally inundated with waters from Biscayne Bay. Along with the dominant red mangroves, buttonwood is a common canopy component, along with occasional white mangrove. Only a few individual black mangroves were observed within the Site. Biscayne Bay is a shallow, subtropical bay supporting sea grasses, sponges, coral reefs, and a variety of marine life.

2. Listed Species

The construction and operation of Unit # 5 is not expected to adversely affect any rare, endangered, or threatened species. Listed species known to occur in the nearby Biscayne National Park that could potentially utilize the site include the peregrine falcon (Falco peregrinus), wood stork (Mycteria americana), American crocodile (Crocodylus acutus), mangrove rivulus (Rivulus marmoratus), roseate spoonbill (Ajaja ajaja), limpkin (Aramus guarauna), little blue heron (Egretta caerulea), snowy egret (Egretta thula), American oystercatcher (Haematopus palliates), least tern (Sterna antillarum), brown pelican (Pelicanus occidentalis), the white ibis (Eudocimus albus), and bald eagle (Haliaeetus leucocephalus). No bald eagle nests are known to exist in the vicinity of the site. The federally listed, endangered American Crocodile thrives at the Turkey Point site, primarily in and around the southern end of the cooling canals which lie south of the project area. The entire site is considered crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American crocodile. A project-specific crocodile management plan has been developed for construction of Unit # 5.

3. Natural Resources of Regional Significance Status

Significant features in the vicinity of the site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park, comprised of several miles of shoreline north of the Turkey Point facility extending offshore approximately 12 nautical miles. Biscayne National Park contains 180,000 acres, approximately 95% of which is open water interspersed with over 40 keys. The Biscayne National Park headquarters is located approximately 2 miles north of the Turkey Point plant, adjacent to the Miami-Dade County Homestead Bayfront Park, which contains a marina and day use recreational facilities.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

Turkey Point Unit # 5 will consist of four new CT's, four new HRSG's, and a new steam turbine, resulting in a 4x1 configuration CC unit. This unit is scheduled to be in-service in mid-2007. Natural gas delivered via the existing pipeline is the primary fuel type for this unit (with ultra low sulfur light oil serving as a backup fuel). Natural gas-fired facilities are among the cleanest, most efficient technologies currently available.

Mitigation aspects of Turkey Point Unit # 5 related to unavoidable wetland impacts of construction include; on-site hydrologic improvements to enhance existing wetlands, restoration and preservation of areas overgrown with exotic plant species, creation of an on-site lagoon, transfer of some mangrove dominated lands to South Florida Water Management District and Biscayne National Park, and also the purchase of mitigation credits from the EMB which is in the same drainage basin. The capture and reuse of plant process water and rainwater, plus the use of cooling towers will minimize thermal discharges to the cooling canals.

g. Local Government Future Land Use Designations

Local government future land use plan designates most of the site as IU-3 "Industrial, Unlimited Manufacturing District." There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. Site Selection Criteria and Process

For the past several years, a number of FPL's existing power plant sites have been considered as potentially suitable sites for new or repowered generation. The Turkey Point plant site has been selected as a preferred site due to consideration of various factors including system load, an imbalance in the south Florida region between load and generating capacity, and economics. Environmental issues are an important factor at this site. However, the other deciding factors outweigh them. FPL will minimize environmental impacts and mitigate where impacts are unavoidable.

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i. Water Resources

Unique to Turkey Point Plant is the self-contained cooling canal system that supplies water to condense steam used by the existing plant's turbine generators. Although the canal system provides sufficient cooling water for the existing units, there is insufficient cooling capacity for the new unit. Sufficient cooling water for the new unit can be obtained from the Floridan Aquifer that lies beneath the plant site and lies deep beneath the surficial Biscayne Aquifer. The Floridan Aquifer contains an ample supple of water which will be acceptable quality and quantity for plant cooling water needs.

j. Geological Features of Site and Adjacent Areas

FPL's Turkey Point site is underlain by approximately 13,000 feet of sedimentary rock strata. The strata that extends to approximately 500 feet forms the Biscayne Aquifer. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily of marine origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, or clay. The Tamiami formation is named for deposits composed principally of white cream-colored calcareous sandstone, sandy limestone, and beds and pockets of quartz sand. In the Turkey Point area, the Key Largo limestone is present.

The Floridan Aquifer, located approximately 1,100 feet below the land surface, is a confined aquifer. The Floridan Aquifer system is composed entirely of carbonate rocks, except for minor evaporates. The water in the carbonate rock aquifer is more highly mineralized.

k. Projected Water Quantities for Various Uses

The additional quantity of water for industrial processing is estimated to be 150 gallons per minute (gpm) for plant process and service water. Water for this type of use would be supplied by an existing county water system. FPL will construct a dedicated water treatment facility specifically for Unit # 5. Cooling water for new Unit # 5 will be processed through cooling towers. FPL proposes to use water from the Floridan Aquifer as the source of make-up water used by the cooling towers. The estimated makeup water quantity to the cooling towers is approximately 9,600 gpm.

l. Water Supply Sources by Type

Unit # 5 will utilize cooling towers for the dissipation of heat from the cooling water. The Floridan Aquifer will supply the makeup water for the cooling towers. A dedicated new water treatment system will be constructed at the site to serve Unit # 5.

m. Water Conservation Strategies Under Consideration

A plan to treat and recycle equipment wash water, boiler blowdown, and equipment area runoff for use as service water would reduce ground water consumption. FPL anticipates this site will be designed and classified as a wastewater zero discharge site following the completion of Unit # 5.

n. Water Discharges and Pollution Control

Heated water discharges for the existing Turkey Point units are dissipated using the existing once-through cooling water system and the cooling canal system. Unit # 5 cooling water will be processed through a cooling tower which will dissipate the heat prior to discharge to the cooling canal system. Non-point source discharges are collected and reused. Treating and recycling equipment wash water, boiler blow-down, and equipment area runoff helps to minimize industrial discharges. Storm water runoff is collected and used to recharge the surficial aquifer via a storm water management system. Design elements have been included to capture suspended sediments. Various facility permits mandate various sampling and testing activities which provide indication of any pollutant discharges.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by multiple fuel delivery facilities. There is currently a pipeline that supplies natural gas to the facility. The facility also has oil capabilities through on-site storage tanks and accessibility to barge deliveries. Unit # 5 will utilize the existing natural gas pipeline with the addition of compression system(s). A dedicated above-ground storage tank for the ultra-low sulfur distillate backup fuel will also be added. Supply of ultra low sulfur distillate fuel for the new tanks will be made by use of truck deliveries.

p. Air Emissions and Control Systems

The use of natural gas and ultra low sulfur distillate as fuels, plus combustion controls, will minimize air emissions from these units and ensure compliance with applicable emission limiting standards. Using natural gas and ultra low sulfur distillate as fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x), and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NOx combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NOx emissions during operations when using the ultra low sulfur distillate as backup fuel. These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of Turkey Point Unit # 5 will incorporate features that will make it one of the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

A field survey and impact assessment of noise expected to be caused by unit construction at the site indicated that construction noise would be below current noise levels for the residents nearest the site. Noise from the operation of the new unit will also be within allowable levels. Similar natural gas-fired facilities in Broward and Martin counties have been constructed and operated without exceeding allowable noise levels.

r. Status of Applications

The Governor and Cabinet approved certification of the plant on February 7, 2005. Following this certification, the Prevention of Significant Deterioration (PSD) air permit and the Dredge and Fill permits were granted by the respective reviewing agencies. Construction will commence in the Spring 2005 with an anticipated in–service date of mid-2007.

Preferred Site # 4: West County Energy Center, Palm Beach County

FPL has identified the property adjacent to the existing FPL Corbett Substation property in unincorporated western Palm Beach County as a preferred site for the addition of new generating capacity. The preferred site was evaluated for the addition of a new combined cycle natural gas power plant project with ultra low sulfur distillate as a backup fuel. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections. The proposed facility would use natural gas as the primary fuel and state-of-the-art combustion controls.

a. and b. U.S. Geological Survey (USGS) Map and Proposed Facilities Layout

A USGS map of the West County Energy Center site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The land on the site is currently inactive but was previously dedicated to industrial and agricultural use. The site has been excavated, back-filled, and totally re-graded to an elevation approximately 10 ft. above surrounding land surface. No structures are present on the site and vegetation is virtually non-existent.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

The majority of the plant site has been significantly altered by the construction and operation of a limestone mine where vegetation had been cleared and removed. Most of the remaining site property has been previously altered through development for agricultural use and rock mining. The surrounding land use is predominantly sugar cane agriculture and limestone mining. The FPL Corbett substation is located north of the site. The Arthur R. Marshall Loxahatchee National Wildlife Refuge is located to the south of the site.

2. **Listed Species**

Construction and operation of new units at the site is not expected to affect any rare, endangered, or threatened species. Wildlife utilization of the property is minimal as a result of the mining activities. Common wading birds can be observed on areas adjacent to and occasionally within the property. The property is adjacent to areas that have been identified as potential habitat for wood stork.

3. **Natural Resources of Regional Significance Status**

The construction and operation of a gas-fired combined cycle generating facility at the site is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands including the Arthur R. Marshall Loxahatchee National Wildlife Refuge which lies south of the proposed location. It is not anticipated that construction will result in wetland impacts under federal, state or local agency permitting criteria.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The current design option is to construct two new 1,100 MW (approximate) units each consisting of four new CT's, four new HRSG's, and a new steam turbine. The site has sufficient capacity to construct an additional 1,100 MW unit in the future if needed. The first and second units are planned to be placed into service in mid-2009 and mid-2010, respectively. Natural gas delivered via pipeline is the primary fuel type for this unit with ultra low sulfur distillate serving as a backup fuel.

g. Local Government Future Land Use Designations

Local government future land use designation for the project site is "Rural Residential" according to the Palm Beach County Future Land Use Map. Designations for the area under the Palm Beach County Unified Land Development Code classified the project site and surrounding area as Special Agricultural District. The site has been granted conditional use for electrical power facilities under a General Industrial zoning district.

h. Site Selection Criteria and Process

The site has been selected as a preferred site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. This site is considered permittable.

i. Water Resources

The existing adjacent surface water canal, reservoir, and available ground water resources are potential sources for potable and service water for the proposed units. Use of water from the upper and/or lower Floridan Aquifer is also considered a feasible alternative as potential backup sources of water for operation of the proposed units.

j. Geological Features of Site and Adjacent Areas

The site is underlain by approximately 13,000 feet of sedimentary rock strata. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine in origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, clay, and phosphate grains. The deepest formation in Palm Beach County on which significant published data are available is the Eocene Age Avon Park. Limited information is available from wells penetrating the underlying Oldsmar formation. The published information on the sediments comprising the formations below the Avon Park Limestone is based on projections from deep wells in Okeechobee, St. Lucie, and Palm Beach Counties.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for industrial processing is 300 gallons per day (gpd) for uses such as process water and service water. Approximately 25 million gallons per day (mgd) in total of cooling water for the two proposed units would be cycled through the addition of cooling towers. Water quantities needed for other uses such as irrigation and potable water are estimated to be approximately 5 gpm.

l. Water Supply Sources by Type

The proposed units will use available surface or ground water as the source of service water and makeup water for the cooling towers. Potable water needs will be met through the use of the surficial aquifer.

m. Water Conservation Strategies Under Consideration

Impacts on the surficial aquifer would be minimized and used only for potable water. The plant site will capture and reuse process water whenever feasible and manage stormwater in such a manner so as to recharge the surficial aquifer.

n. Water Discharges and Pollution Control

Heated water discharges will be dissipated in the cooling towers. Blow down from the cooling towers will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Industrial discharges will be minimized by treating and recycling equipment wash water, boiler blowdown water, and equipment area runoff. Storm water runoff will be collected and used to recharge the surficial aquifer via a storm water management system. Design elements will be included to capture suspended sediments. The facility will employ a Best Management

Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is not located near an existing natural gas transmission pipeline that is capable of providing a sufficient quantity of gas. Upgrades of existing pipelines and/or lateral connections to other pipelines will be necessary for supply of natural gas. Ultra low sulfur distillate would be received by truck and stored in above-ground storage tanks to serve as backup fuel for the new units.

p. Air Emissions and Control Systems

The use of natural gas and ultra low sulfur distillate as fuels, plus combustion controls, will minimize air emissions from these units and ensure compliance with applicable emission limiting standards. Using natural gas and ultra low sulfur distillate as fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x), and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra low sulfur distillate as backup fuel. These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of the West County Energy Center units will incorporate features that will make them among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by construction of the units at the site is expected to be below current noise levels for the residents nearest the site. Noise from the operation of the new units will be within allowable levels.

r. Status of Applications

An SCA will be filed in 2005 for the construction and operation of the West County Energy Center project under the Florida Electrical Power Plant Siting Act. A PSD permit application and an underground injection control permit application will also be submitted to the FDEP at the same time.

IV.F.2 Potential Sites for Generating Options

Seven (7) sites are identified as "Potential Sites" for near-term future generation additions to meet FPL's capacity needs.[1]

These sites have been identified as Potential Sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies.

Each of these potential sites offer advantages and disadvantages relative to engineering considerations and/or costs associated with the construction and operation of feasible technologies. In addition, each potential site has different characteristics that could require further definition and attention. For discussion purposes, it was assumed that natural gas-fired technologies would be the likely capacity additions at the Potential Sites unless otherwise indicated.

Permits are presently considered to be obtainable for all of these sites, assuming measures can be taken to mitigate any particular site-specific environmental

[1] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites.

concerns that may arise. No significant environmental constraints are currently known for any of these 7 sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time FPL considers each site to be equally viable.

Potential Site # 1: Andytown Substation , Broward County

FPL has identified the FPL Andytown Substation property in western unincorporated Broward County as a potential site for the addition of new generating capacity. Current facilities on-site include an electric substation. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections.

a. U.S. Geological Survey (USGS) Map

A USGS map of the potential site has been included at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land uses for the site are designated as industrial or agricultural use. The site identification process included screening of potential sites to determine potential wetland impacts and impacts to endangered or threatened species. Extensive low-quality wetlands are adjacent to the site. FPL would expect to mitigate any impacts from construction of a power plant at this site. Construction and operation of a new facility on this site is not expected to adversely affect any rare, endangered, or threatened species.

d. and e. Water Quantities and Supply Sources

Surface water sources are not available at the site. Groundwater from the shallow aquifer or a local source of gray water have been identified as potential water sources. The Floridan Aquifer has been identified as a potential cooling water source. It has been estimated that sufficient water is available for generation technologies that might be considered for the site.

Potential Site # 2: Cape Canaveral Plant, Brevard County

This potential site is located on the FPL Cape Canaveral Plant property in unincorporated Brevard County. The city of Port St. Johns is located less than a mile away. The site has direct access to a four-lane highway (US 1). A rail line is located near the plant. The existing facility consists of two 400 MW (approximate) steam boiler type generating units.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Cape Canaveral property site is found at the end of this chapter.

b. and c. Land Uses and Environmental Features

This site is located on the Indian River. The land is primarily dedicated to industrial use with surrounding grassy areas and a few acres of remnant pine forest. The land adjacent to the site is dedicated to light commercial and residential use. There are no significant environmental features on the site.

d. and e. Water Quantities and Supply Sources

It is expected that industrial cooling water needs could be met using the current 550,000 gpm once-through cooling water quantity. For industrial process water, FPL would use existing on-site wells or local gray water. It has been estimated that sufficient water is available for generation technologies that might be considered at the site.

Potential Site # 3: Desoto County Site

This site is an undeveloped site located on a 13,500 acre property in unincorporated Desoto County. The site is adjacent to portions of the Peace River. There are no current facilities on the site. The City of Arcadia is located southwest of the Desoto site.

a. U.S. Geological Survey (USGS) Map

A USGS map of the potnetial site is found at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on the site is currently dedicated to agricultural use (sod farming, cattle grazing, and truck crops). Developed portions of the adjacent properties are primarily agricultural (sod farms, citrus groves, and cattle grazing). Undeveloped portions include mixed scrub with some hardwoods and a few isolated wetlands.

d. and e. Water Quantities and Supply Sources

The primary water source would either be groundwater from the upper and lower Floridan Aquifer or if available and practicable, a local source of gray water. Other facility water uses may include irrigation, potable use, etc., which could be supplied from shallower wells using the surficial aquifer. It has been estimated that sufficient water is available for generation technologies that might be considered for the site.

Potential Site # 4: Fort Myers Plant Site, Lee County

This potential site is located on FPL's existing 460-acre Fort Myers property. Located on the site is one 1,400 MW (approximate) combined cycle unit, Unit # 2, and 12 gas turbines each with a capacity of approximately 54 MW. Two additional simple cycle peaking units have been recently completed at the site in 2003.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Fort Myers plant site is found at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on the site is currently dedicated to industrial use with surrounding grassy and landscaped areas. Much of the site has recently been used for direct construction activities. The adjacent land uses include light commercial and retail to the east of the property, and some residential areas located toward the west. Mixed scrub with some hardwoods can be found to the east and further south.

d. and e. Water Quantities and Supply Sources

The available water source is the Caloosahatchee River and the available groundwater source is the Sandstone Aquifer. It has been estimated that sufficient water is available for generation technologies that might be considered for the site.

Potential Site # 5: Port Everglades Plant, Broward County

This site is located on the 94-acre FPL Port Everglades plant site in Port Everglades, Broward County. The site has convenient access to State Road (SR) 84 and Interstate 595. A rail line is located near the plant. The existing plant consists of four steam boiler generating units: two 200 MW (approximate) and two 400 MW (approximate) sized units. The four steam boilers are capable of firing residual fuel oil, natural gas, or a combination of both. The site also is home to twelve simple cycle gas turbine (GT) peaking units of 30 MW (approximate) each. The GT's are part of the Gas Turbine Power Park that is made up of 24 GT's at the Lauderdale Plant site and the twelve GTs at the Port Everglades site. The GT's are capable of firing either natural gas or liquid fuel.

a. U.S. Geological Survey (USGS) Map

A map of the Port Everglades plant site is found at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on this site is primarily industrial. The adjacent land uses are port facilities and associated industrial activities, oil storage, cruise ships, and light commercial.

d. and e. Water Quantities and Supply Sources

FPL expects to use the existing municipal water supply for industrial process and makeup water. Cooling water would be drawn from the Intra-Coastal Waterway and cooling towers would be constructed. It has been estimated that sufficient water is available for generation technologies that might be considered for the site.

Potential Site # 6: Riviera Plant, Palm Beach County

This site is located on the FPL Riviera Plant property in Riviera Beach, Palm Beach County. The site has direct access to a four-lane highway, US 1, and barge access is available. A rail line is located near the plant. The facility currently houses two operational 300 MW (approximate) steam boiler generating units and one retired 50 MW generating unit.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Riviera plant site is found at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on the site is primarily covered by the existing generation facilities with some open, maintained grass areas. There is a small manatee viewing area on the site, which is operated seasonally by FPL. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development. The site is located on the Intra-Coastal Waterway near the Lake Worth Inlet.

d. and e. Water Quantities and Supply Sources

The existing municipal water supply would be used for industrial processing water and FPL would continue to use Lake Worth as a source of water for once-through cooling water. It has been estimated that sufficient water is available for generation technologies that might be considered for the site.

Potential Site # 7: Southwest St. Lucie County Site

This site is an undeveloped site located in the southwest corner of St. Lucie County. A rail line, a natural gas pipeline, and electrical transmission lines are located near the site. The site is considered as suitable for the construction and operation of electrical generating facilities using a variety of technologies utilizing solid, liquid, or natural gas fuels.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Southwest St. Lucie County site is found at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on the site is currently dedicated to agricultural use. Most of the site is currently in use for agricultural purposes. Developed portions of the adjacent properties are primarily agricultural (cattle grazing). Undeveloped portions include mixed scrub with some hardwoods and some wetlands.

d. and e. Water Quantities and Supply Sources

Nearby surface water are available for use at this site. Additional water sources include groundwater from the shallow aquifer, the deeper Floridan Aquifer, or if available and practicable, a local source of gray water. It has been estimated that sufficient water is available for generation technologies that might be considered for the site.

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Environmental and Land Use Information: Supplemental Information

Preferred Site: Manatee

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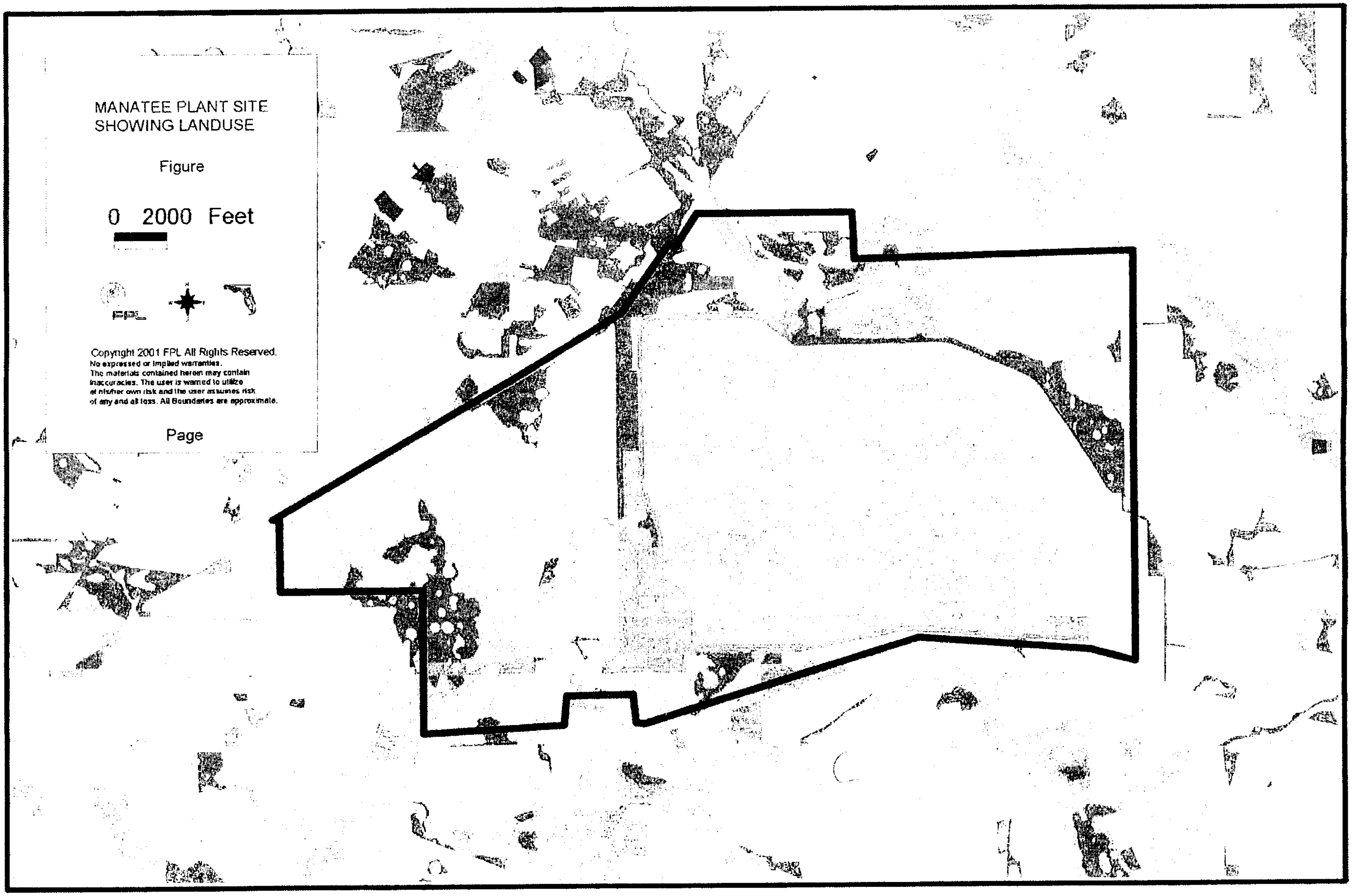
MANATEE PLANT SITE
SHOWING LANDUSE
Figure
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LEGEND FOR LANDUSE MAPS

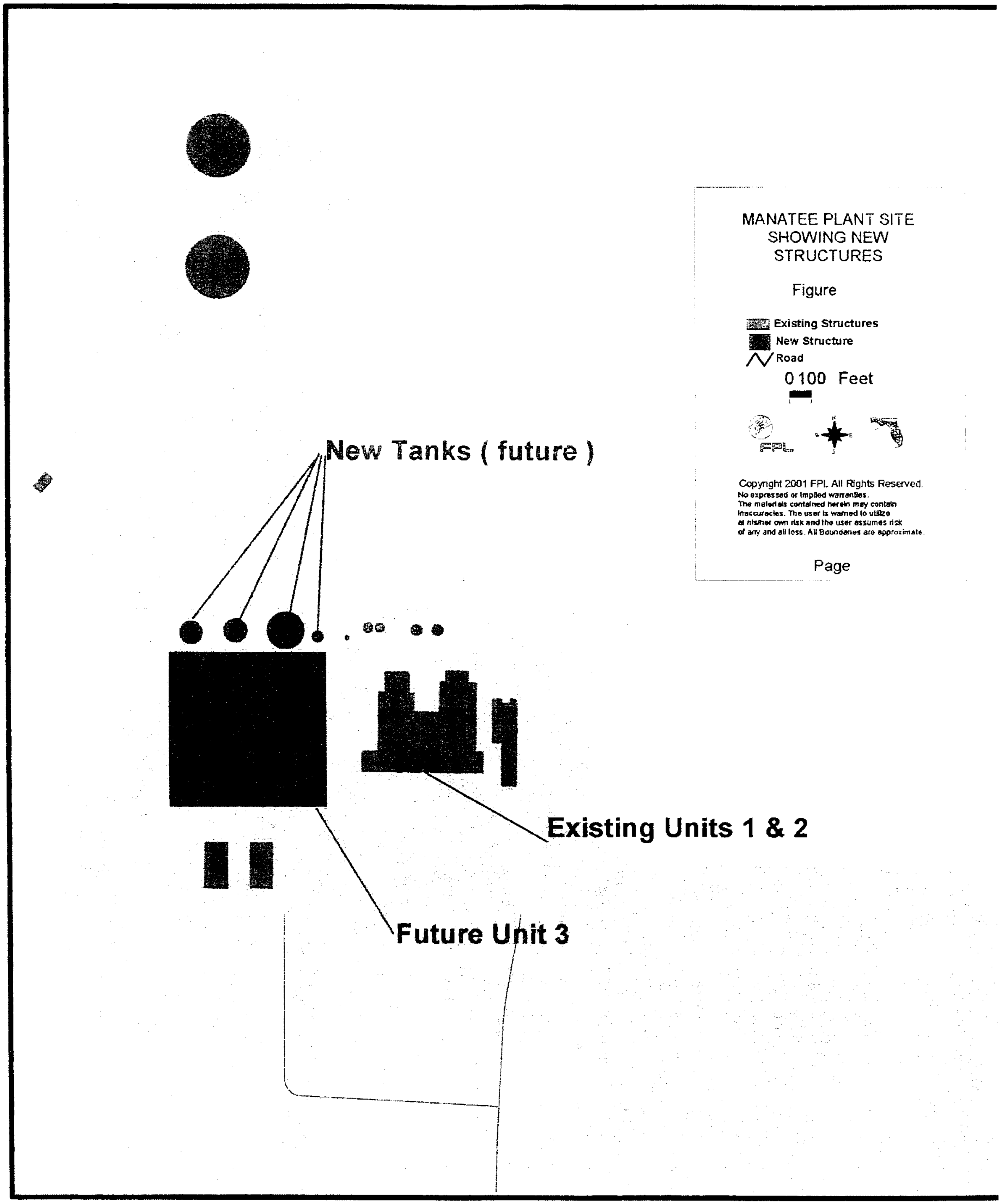
Plant Site Boundary

Level 3 Landuse Categories 1995

- Residential Low Density
- Residential Medium Density
- Residential High Density
- Commercial and Services
- Industrial
- Extractive
- Institutional
- Recreational
- Open Land
- Cropland and Pastureland
- Tree Crops
- Feeding Operations
- Nurseries and Vineyards
- Specialty Farms
- Other Open Lands <Rural>
- Herbaceous
- Shrub and Brushland
- Mixed Rangeland
- Upland Coniferous Forests
- Upland Hardwood Forests
- Tree Plantations
- Streams and Waterways
- Lakes
- Reservoirs
- Bays and Estuaries
- Major Springs
- Slough Waters
- Oceans Seas and Gulfs
- Wetland Hardwood Forests
- Wetland Coniferous Forests
- Wetland Forested Mixed
- Vegetated Non-Forested Wetlands
- Non-Vegetated
- Wetland Shrub
- Beaches OtherThan Swimming Beaches
- Sand Other Than Beaches
- Exposed Rock
- Disturbed Lands
- Riverine Sandbars
- Transportation
- Communications
- Utilities
- Vegetation-Sea Grass

Figure

Page


MANATEE PLANT SITE SHOWING NEW STRUCTURES
Figure
Existing Structures
New Structure
Road
0 100 Feet
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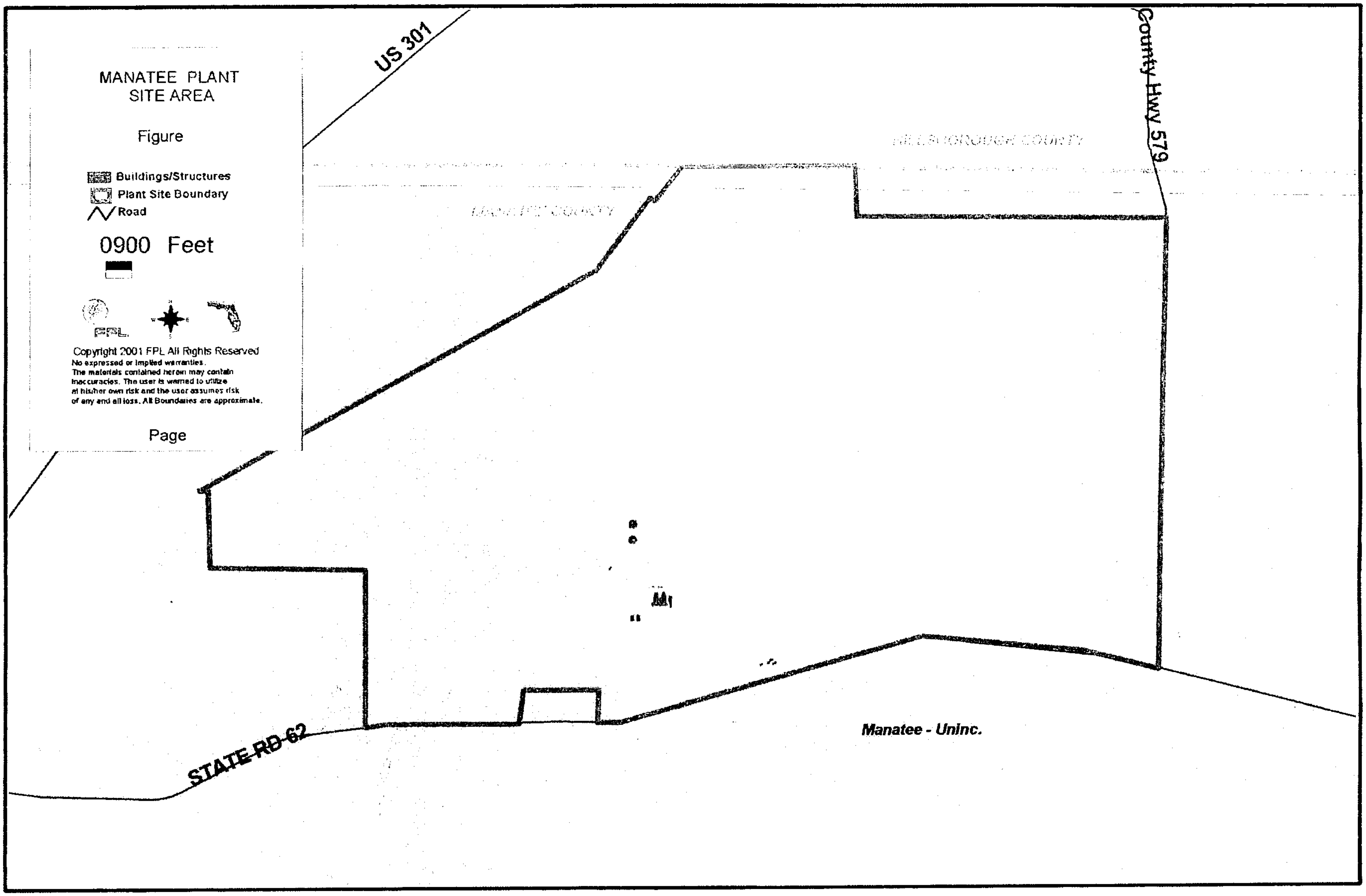
Page
New Tanks (future)
Existing Units 1 & 2
Future Unit 3


MANATEE PLANT
SITE AREA
Figure
Buildings/Structures
Plant Site Boundary
Road
0900 Feet
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Page
US 301
County Hwy 579
HILLSBOROUGH COUNTY
MANATEE COUNTY
STATE RD 62
Manatee - Uninc.

Environmental and Land Use Information: Supplemental Information

Preferred Site: Martin

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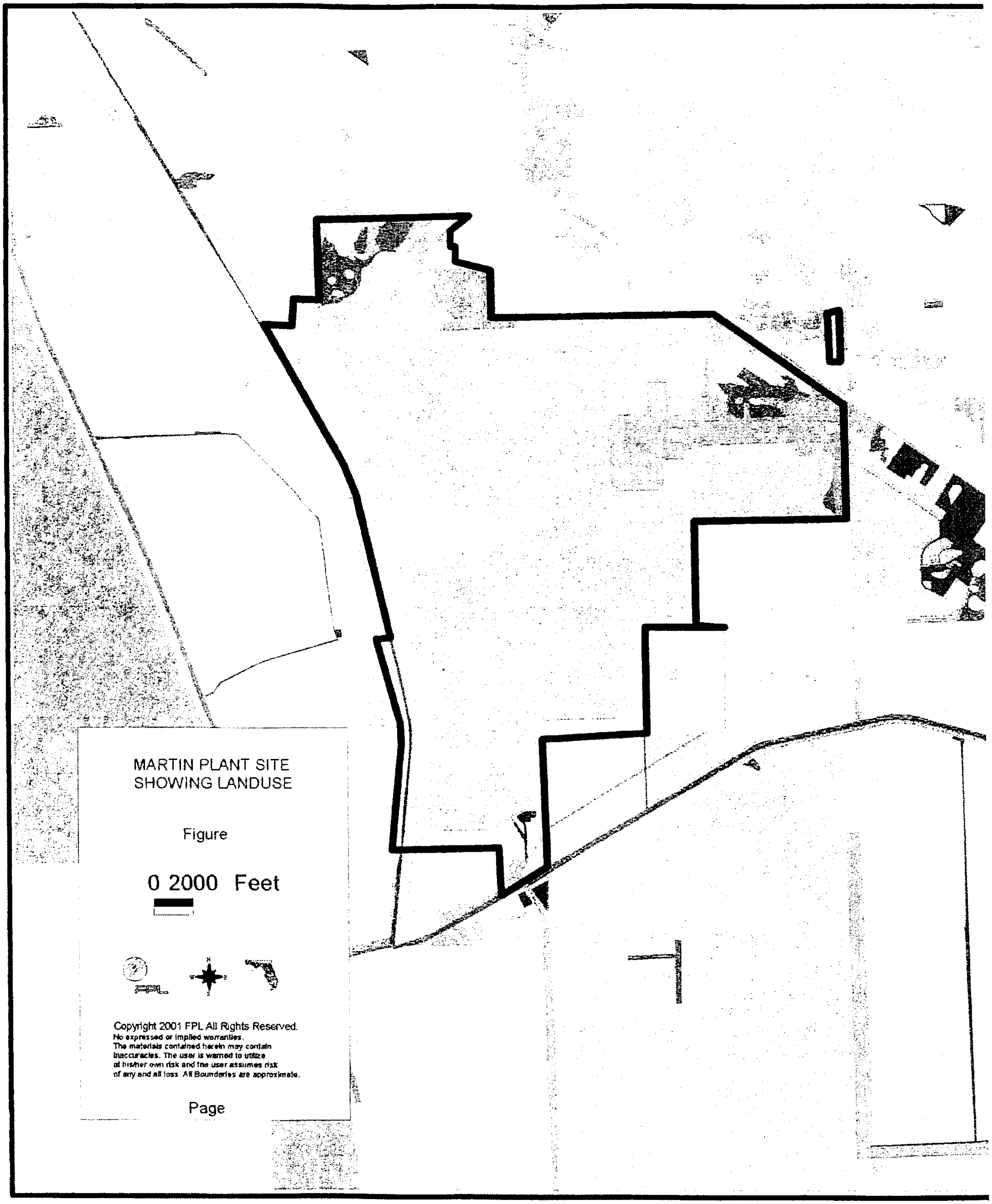
MARTIN PLANT SITE
SHOWING LANDUSE
Figure
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Page

LEGEND FOR LANDUSE MAPS

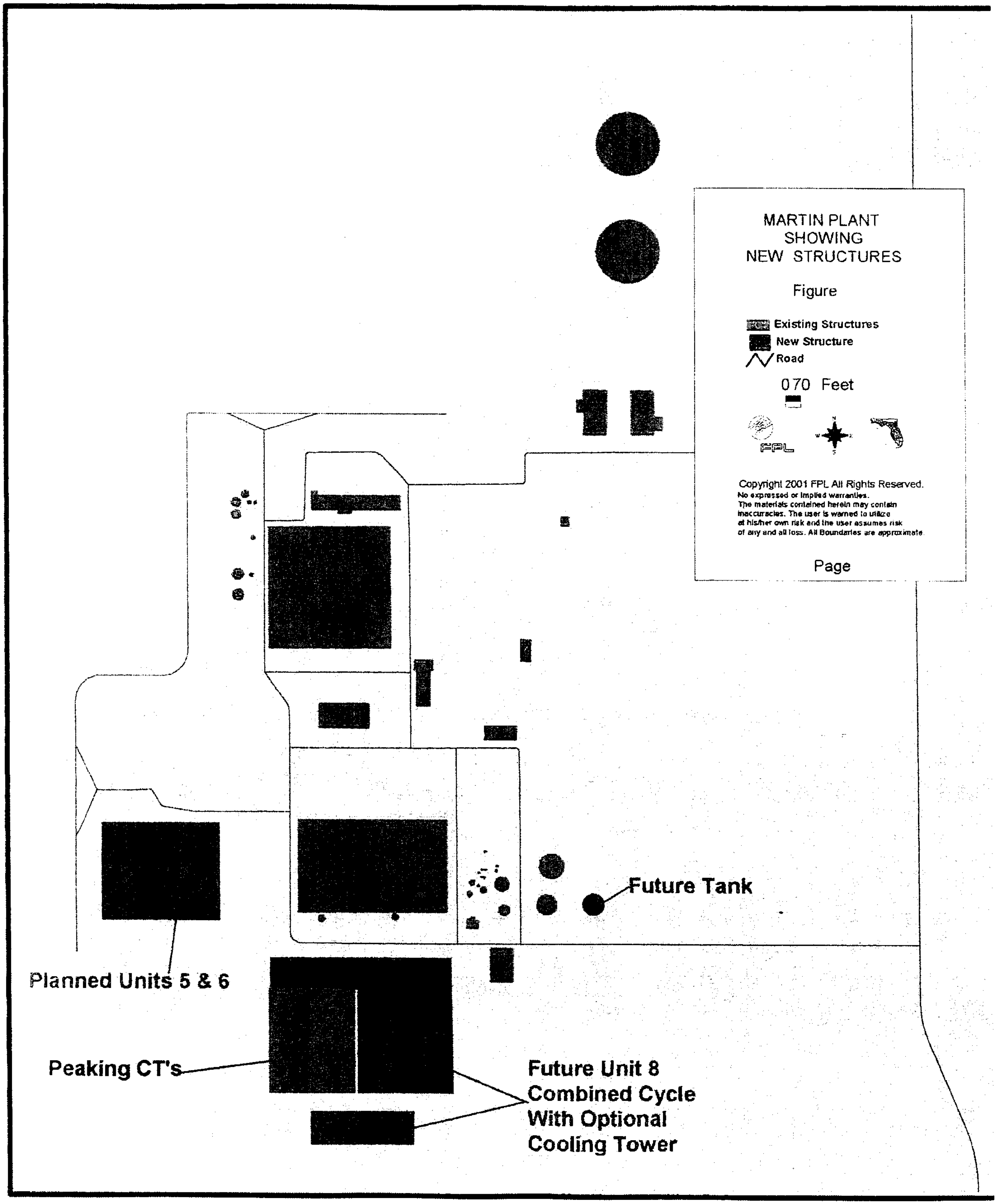
Plant Site Boundary

Level 3 Landuse Categories 1995

Residential Low Density
Residential Medium Density
Residential High Density
Commercial and Services
Industrial
Extractive
Institutional
Recreational
Open Land
Cropland and Pastureland
Tree Crops
Feeding Operations
Nurseries and Vineyards
Specialty Farms
Other Open Lands <Rural>
Herbaceous
Shrub and Brushland
Mixed Rangeland
Upland Coniferous Forests
Upland Hardwood Forests
Tree Plantations
Streams and Waterways
Lakes
Reservoirs
Bays and Estuaries
Major Springs
Slough Waters
Oceans Seas and Gulfs
Wetland Hardwood Forests
Wetland Coniferous Forests
Wetland Forested Mixed
Vegetated Non-Forested Wetlands
Non-Vegetated
Wetland Shrub
Beaches OtherThan Swimming Beaches
Sand Other Than Beaches
Exposed Rock
Disturbed Lands
Riverine Sandbars
Transportation
Communications
Utilities
Vegetation-Sea Grass

Figure

Page


MARTIN PLANT
SHOWING
NEW STRUCTURES
Figure
Existing Structures
New Structure
Road
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FPL
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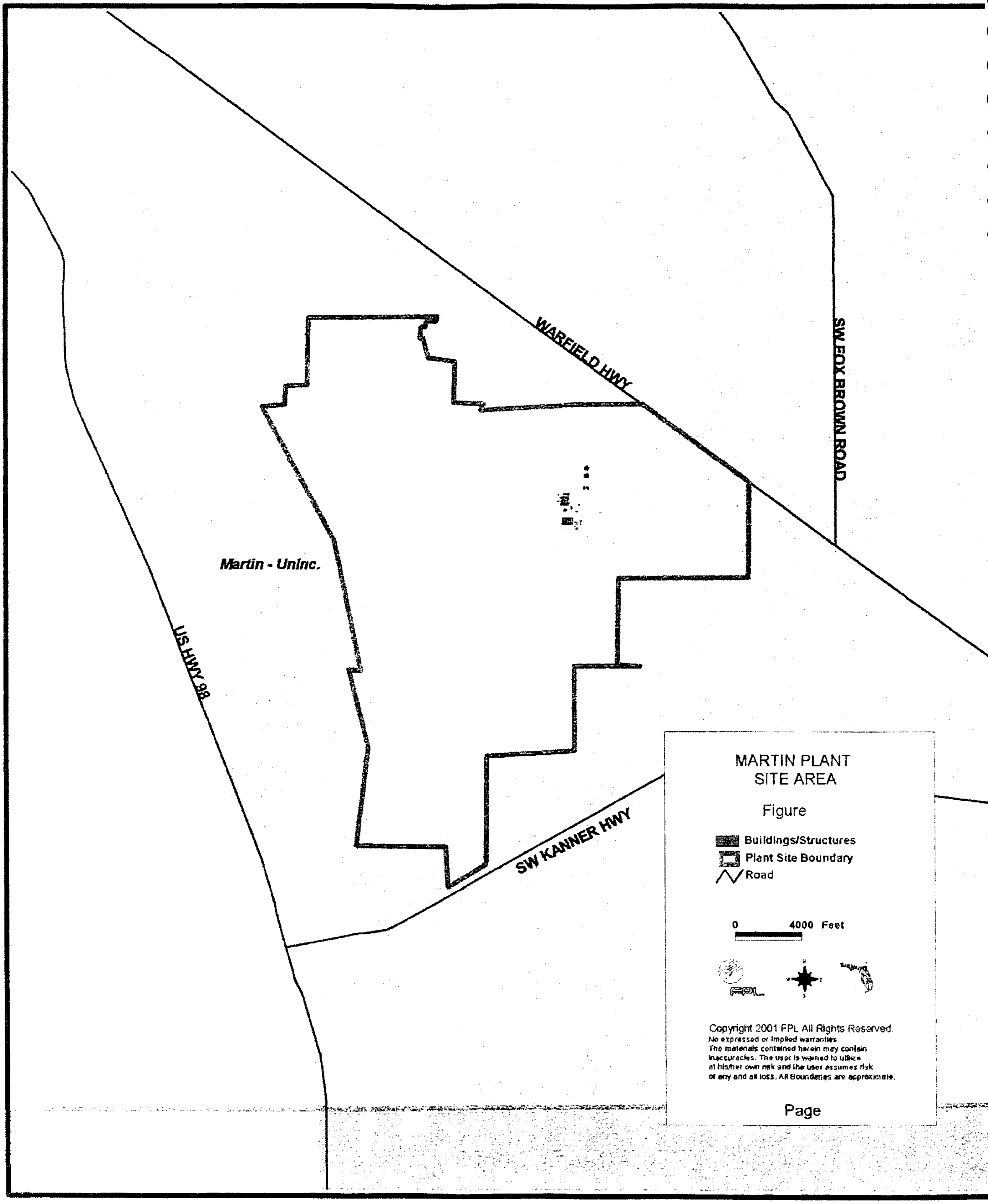
Future Tank
Planned Units 5 & 6
Peaking CT's
Future Unit 8
Combined Cycle
With Optional
Cooling Tower


WARFIELD HWY
SW FOX BROWN ROAD
Martin - Uninc.
US HWY 98
SW KANNER HWY
MARTIN PLANT
SITE AREA
Figure
Buildings/Structures
Plant Site Boundary
Road
0 4000 Feet
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Environmental and Land Use Information: Supplemental Information

Preferred Site: Turkey Point

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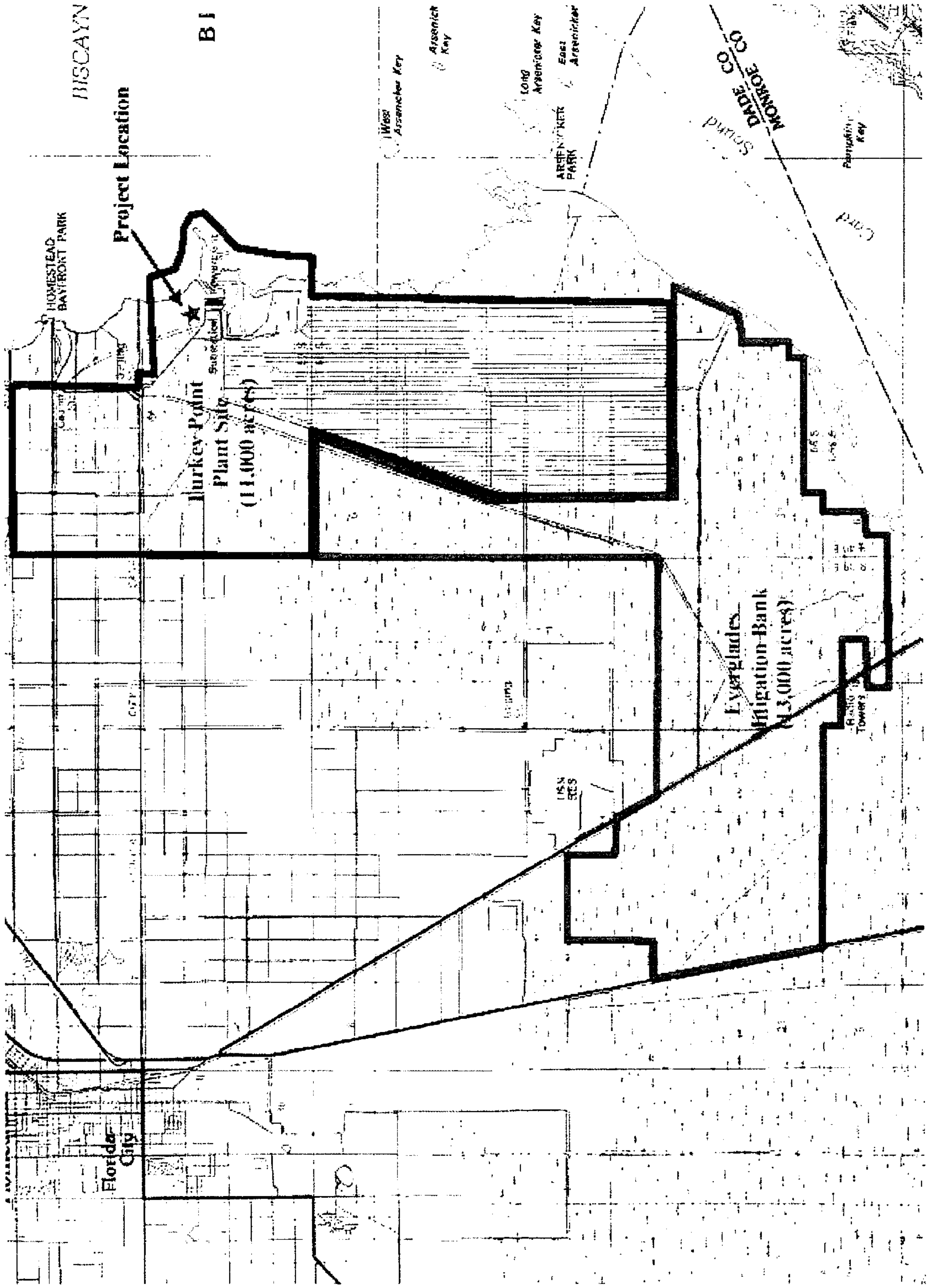
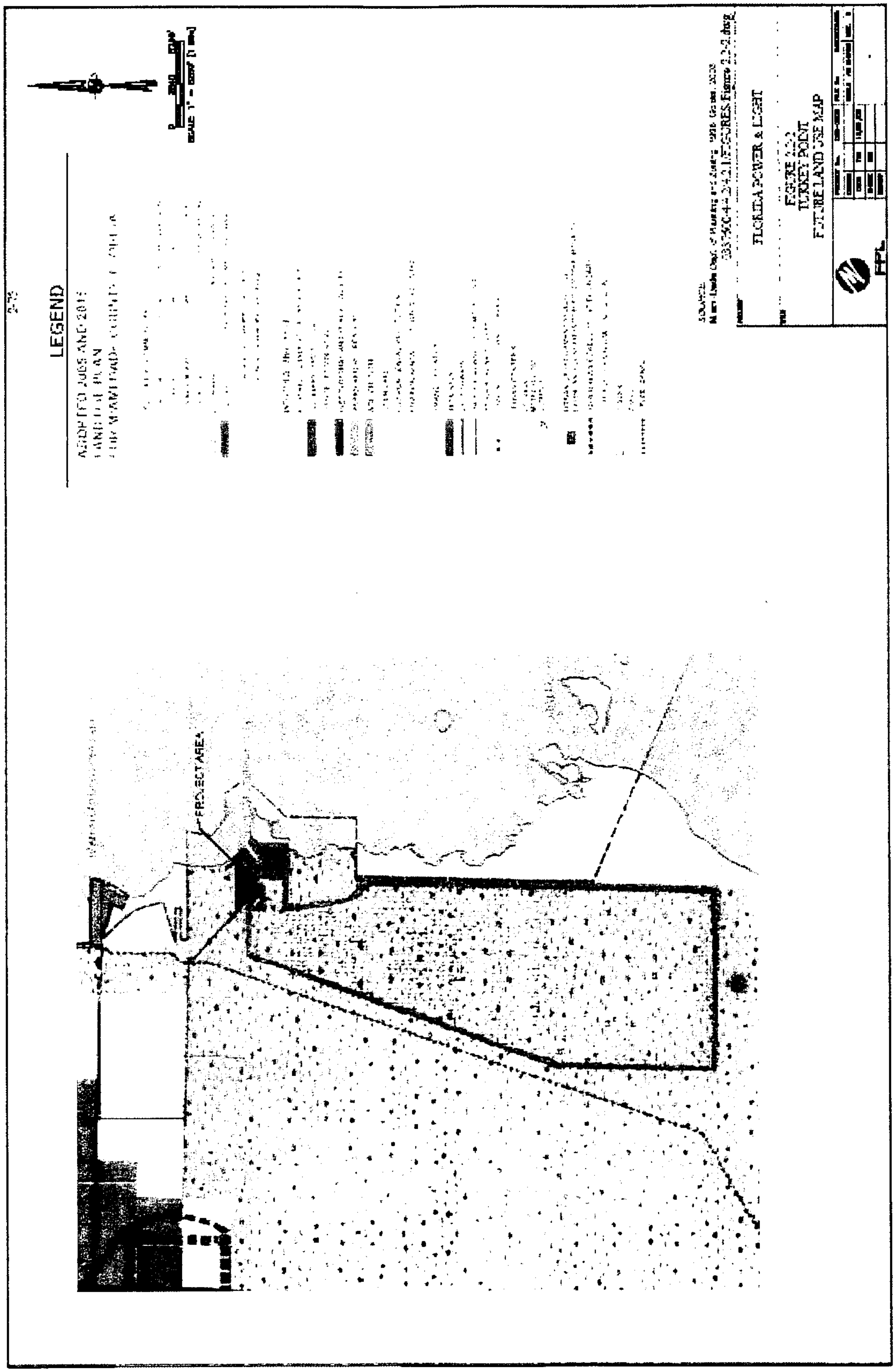
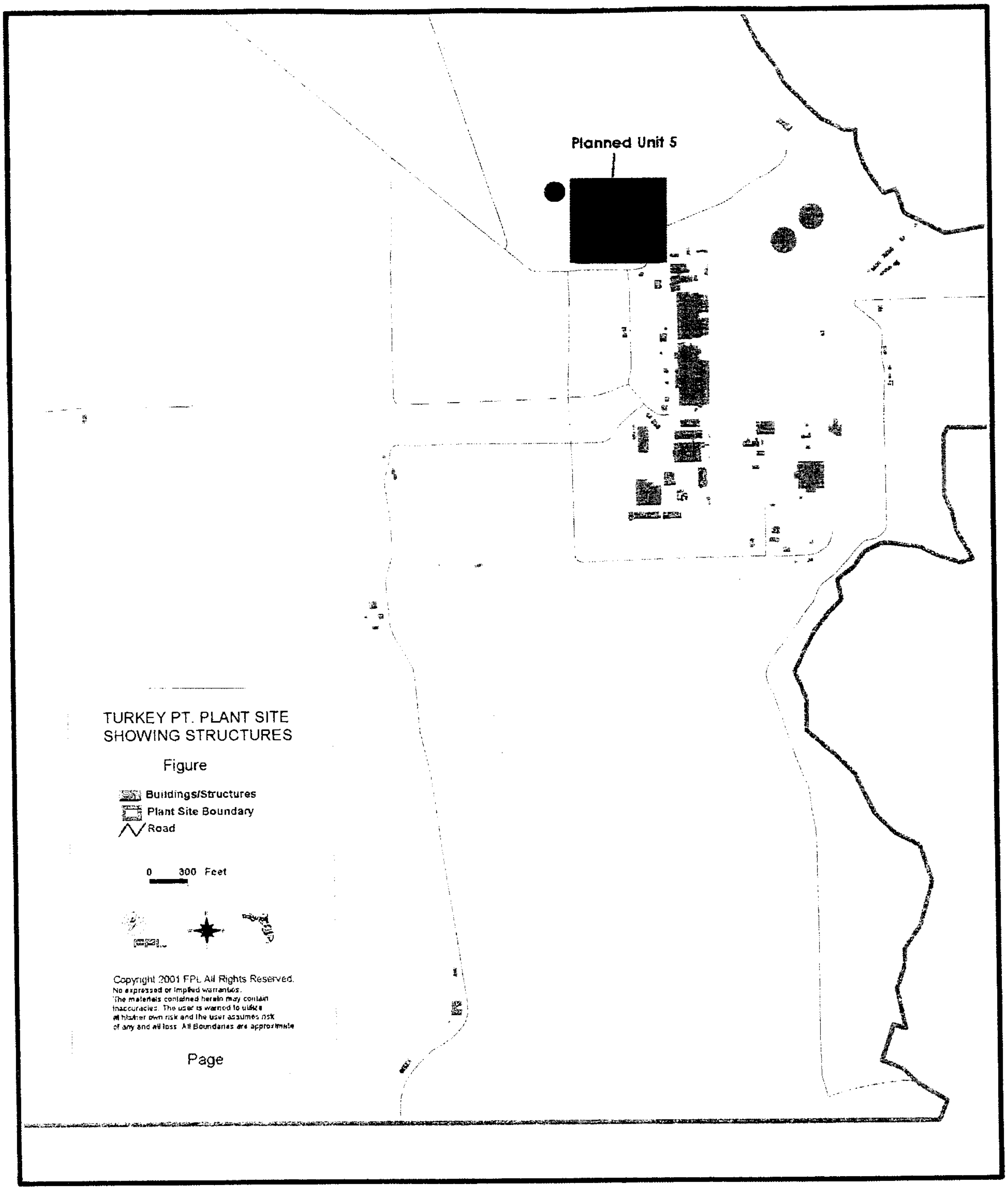

Project Location
Turkey Point
Plant Site
(11,000 acres)
Everglades
Mitigation Bank
(13,000 acres)
Florida
City
HOMESTEAD
BAYFRONT PARK
DADE CO
MONROE CO


LEGEND
PROJECT AREA
FLORIDA POWER & LIGHT
FIGURE 2.2-2
TURKEY POINT
FUTURE LAND USE MAP


Planned Unit 5
TURKEY PT. PLANT SITE
SHOWING STRUCTURES
Figure
Buildings/Structures
Plant Site Boundary
Road
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Environmental and Land Use Information: Supplemental Information

Preferred Site: West County Energy Center

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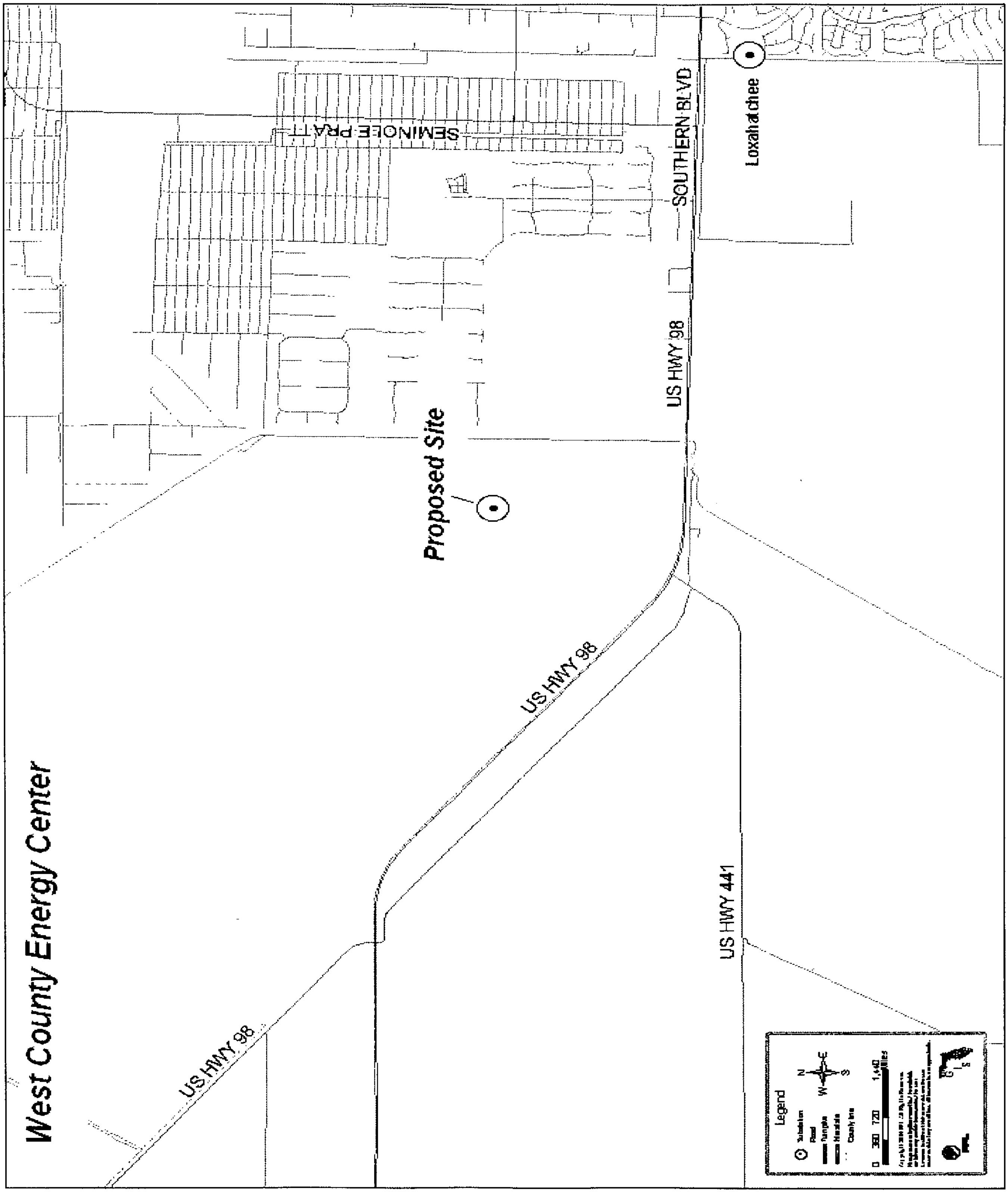
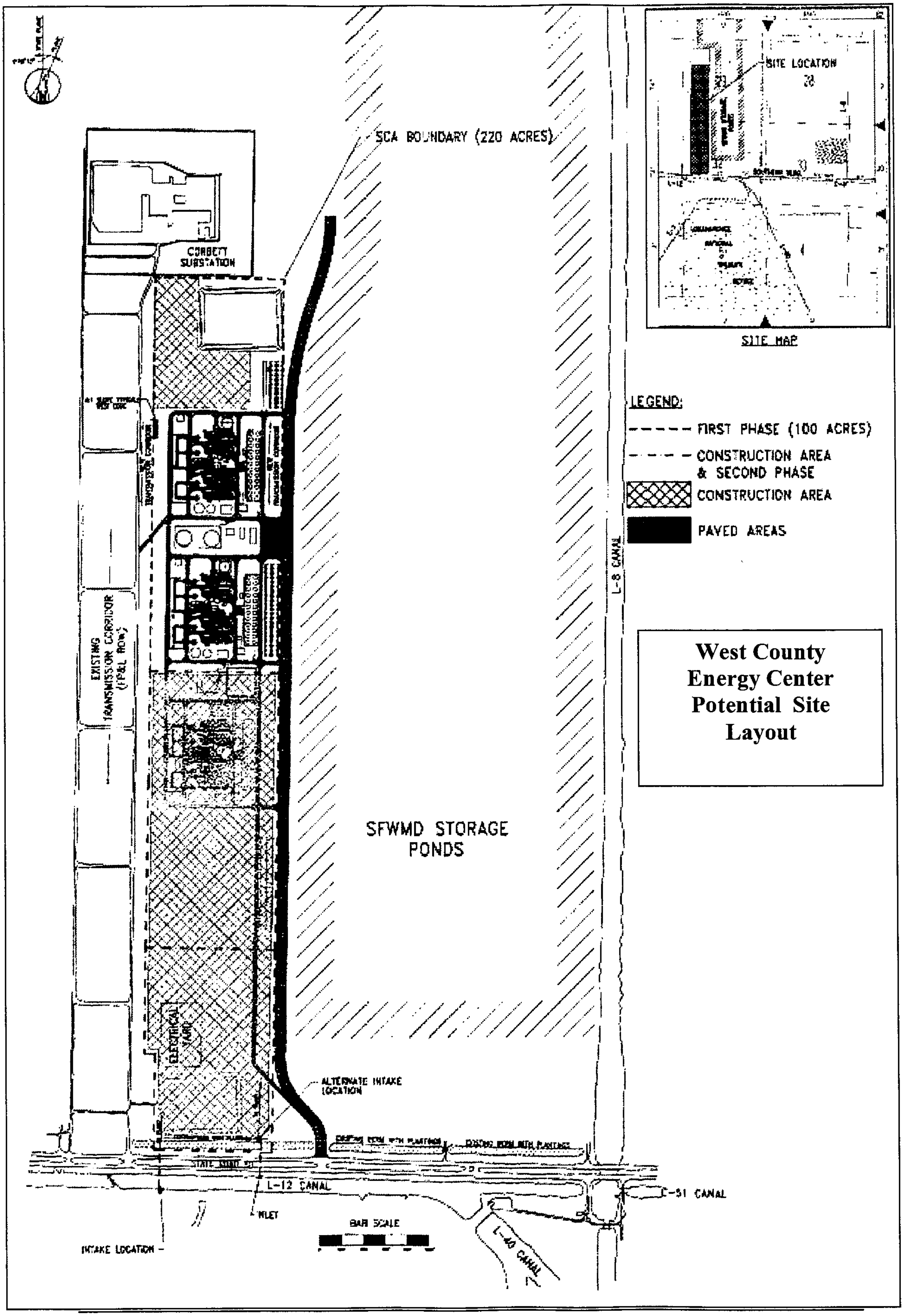

West County Energy Center
Proposed Site
Loxahatchee
SOUTHERN BLVD
SEMINOLE PRATT
US HWY 98
US HWY 98
US HWY 98
US HWY 441
Legend



West County Energy Center Potential Site Layout

Environmental and Land Use Information: Supplemental Information

Potential Site: Andytown

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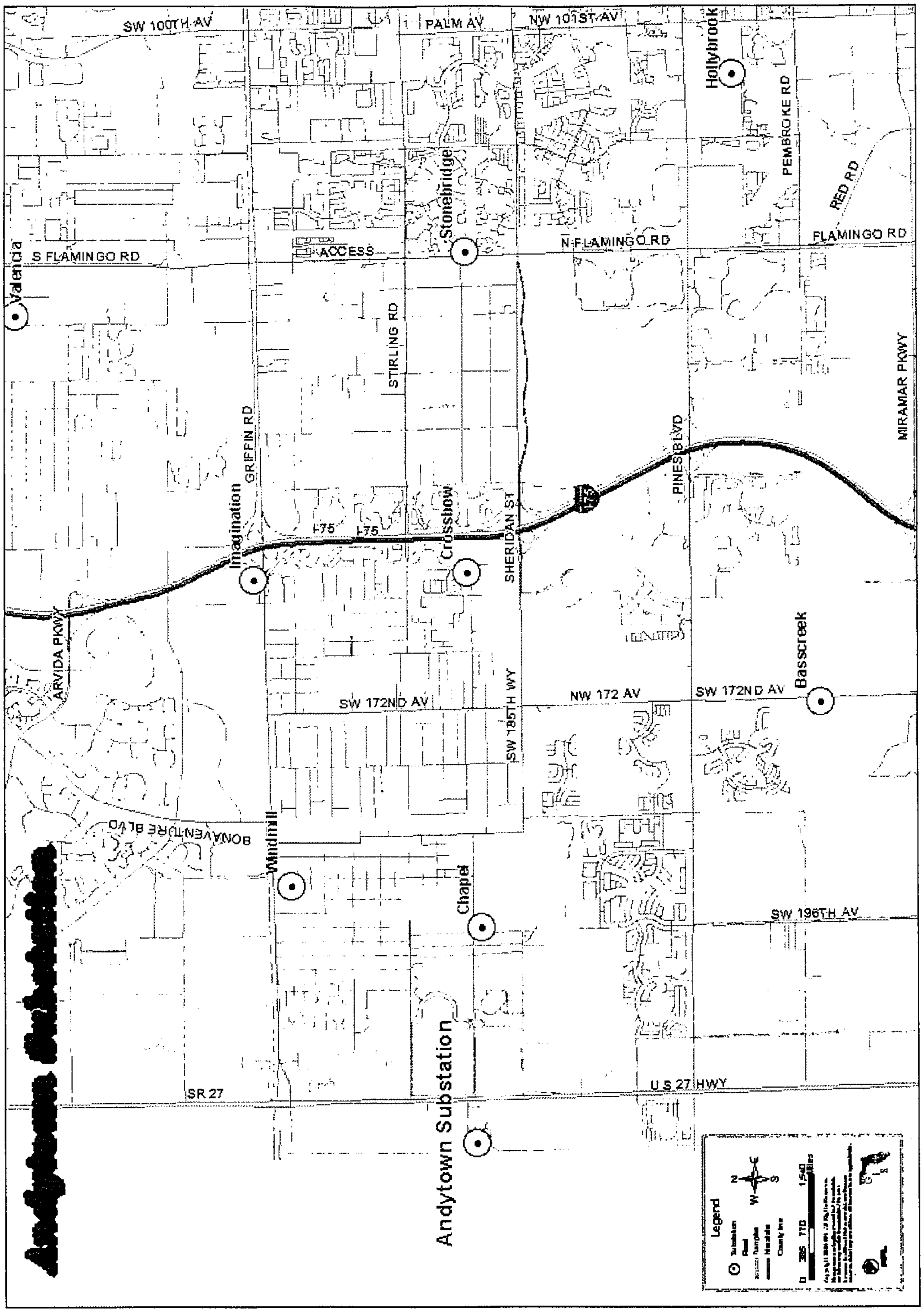
Andytown Substation
SW 100TH AV
PALM AV
NW 101ST AV
Hollybrook
PEMBROKE RD
RED RD
FLAMINGO RD
N FLAMINGO RD
Stonebridge
ACCESS
S FLAMINGO RD
Valencia
STIRLING RD
MIRAMAR PKWY
GRIFFIN RD
PINES BLVD
I-75
Imagination
Crossbow
SHERIDAN ST
ARVIDA PKWY
Basscreek
NW 172 AV
SW 172ND AV
SW 185TH WY
BONAVENTURE BLVD
Windmill
Chapel
SW 196TH AV
Andytown Substation
SR 27
U S 27 HWY
Legend

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Environmental and Land Use Information: Supplemental Information

Potential Site: Cape Canaveral

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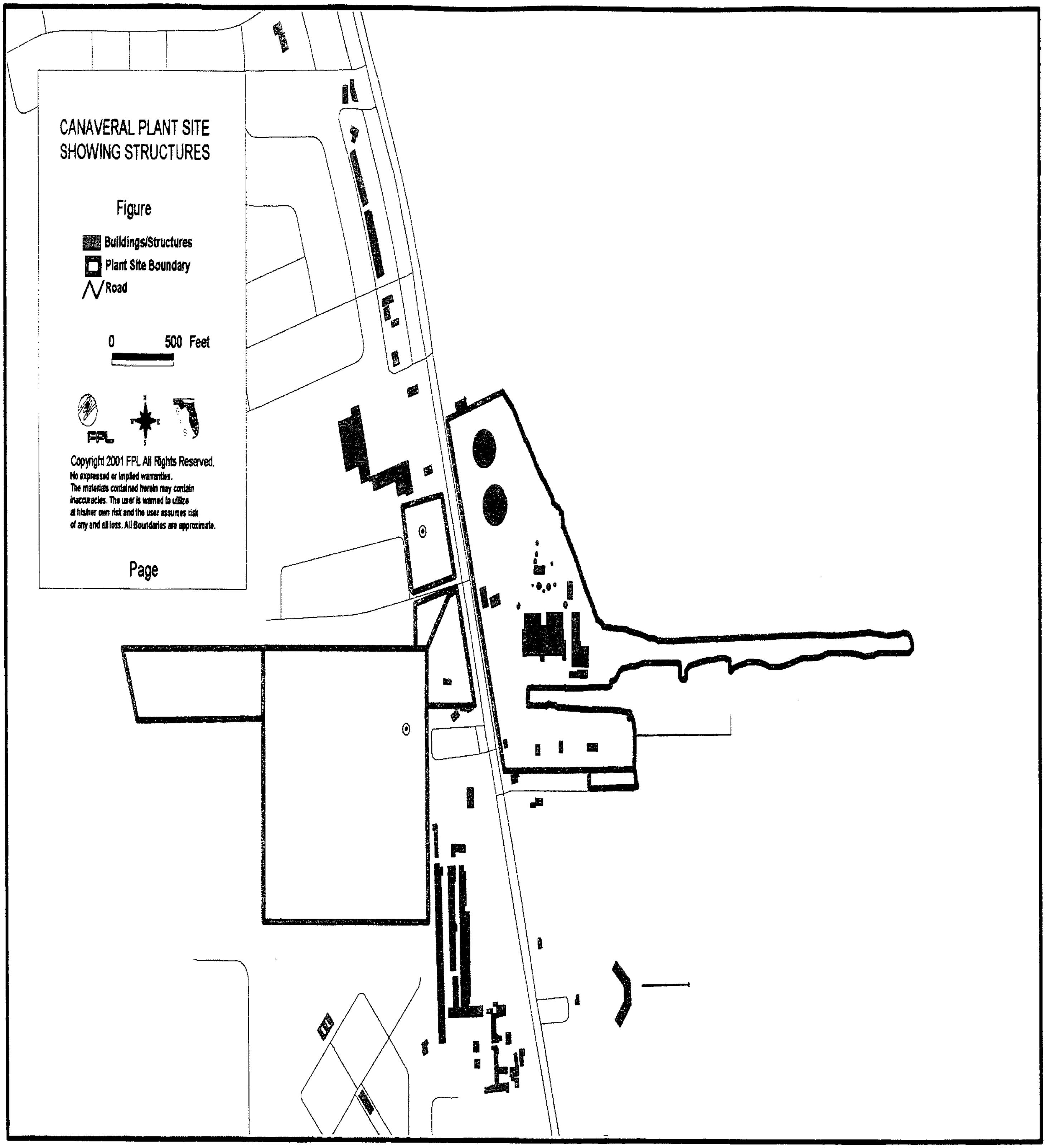
CANAVERAL PLANT SITE
SHOWING STRUCTURES
Figure
Buildings/Structures
Plant Site Boundary
Road
0
500 Feet
FPL
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Environmental and Land Use Information: Supplemental Information

Potential Site: Desoto

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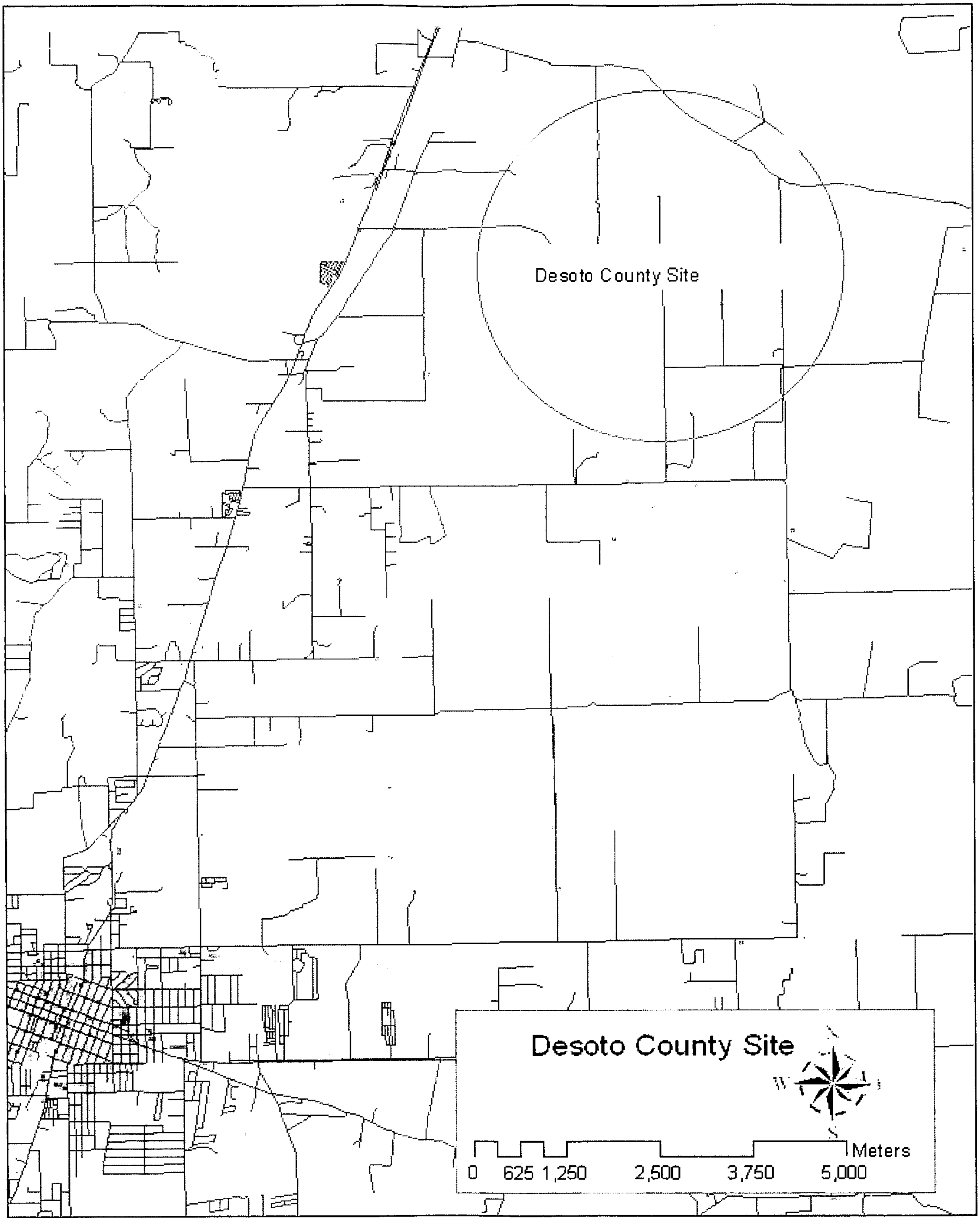
Desoto County Site
Desoto County Site
0 625 1,250 2,500 3,750 5,000
Meters

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Environmental and Land Use Information: Supplemental Information

Potential Site: Ft. Myers

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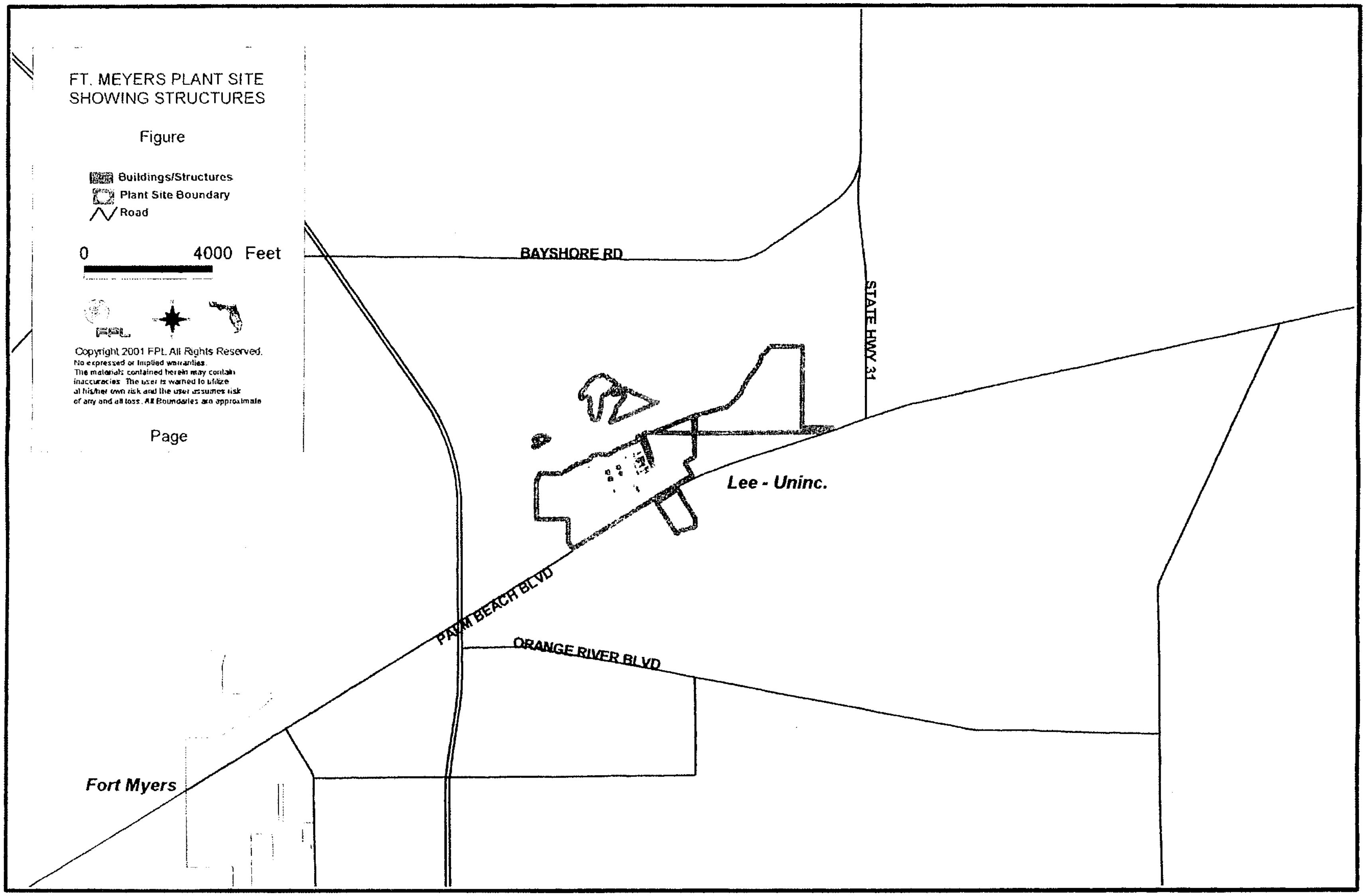
FT. MEYERS PLANT SITE
SHOWING STRUCTURES
Figure
Buildings/Structures
Plant Site Boundary
Road
0
4000 Feet
FPL
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Page
BAYSHORE RD
STATE HWY 31
Lee - Uninc.
PALM BEACH BLVD
ORANGE RIVER BLVD
Fort Myers

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Environmental and Land Use Information: Supplemental Information

Potential Site: Port Everglades

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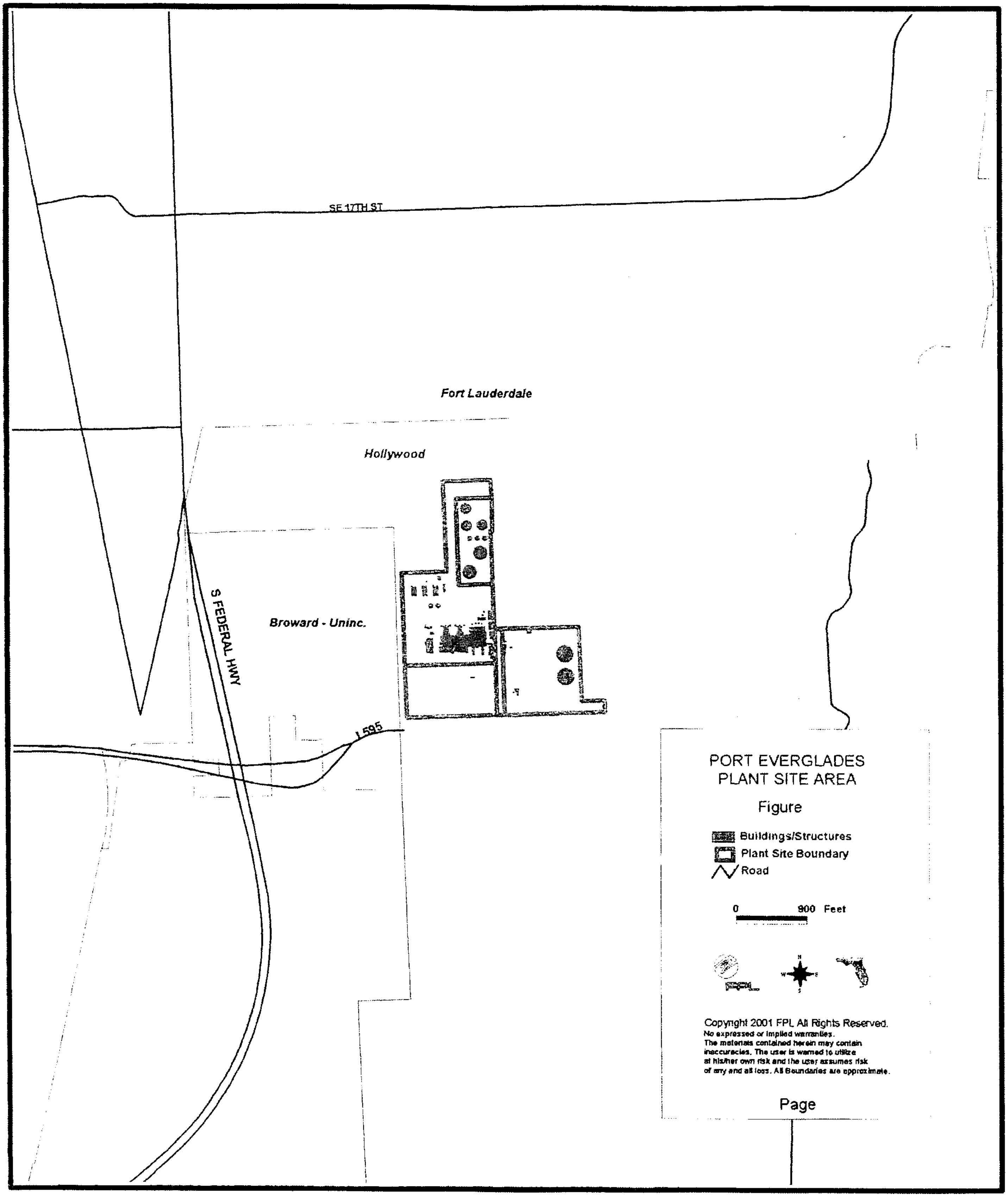
SE 17TH ST
Fort Lauderdale
Hollywood
S FEDERAL HWY
Broward - Uninc.
I 595
PORT EVERGLADES
PLANT SITE AREA
Figure
Buildings/Structures
Plant Site Boundary
Road
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900 Feet
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Environmental and Land Use Information: Supplemental Information

Potential Site: Riviera Plant

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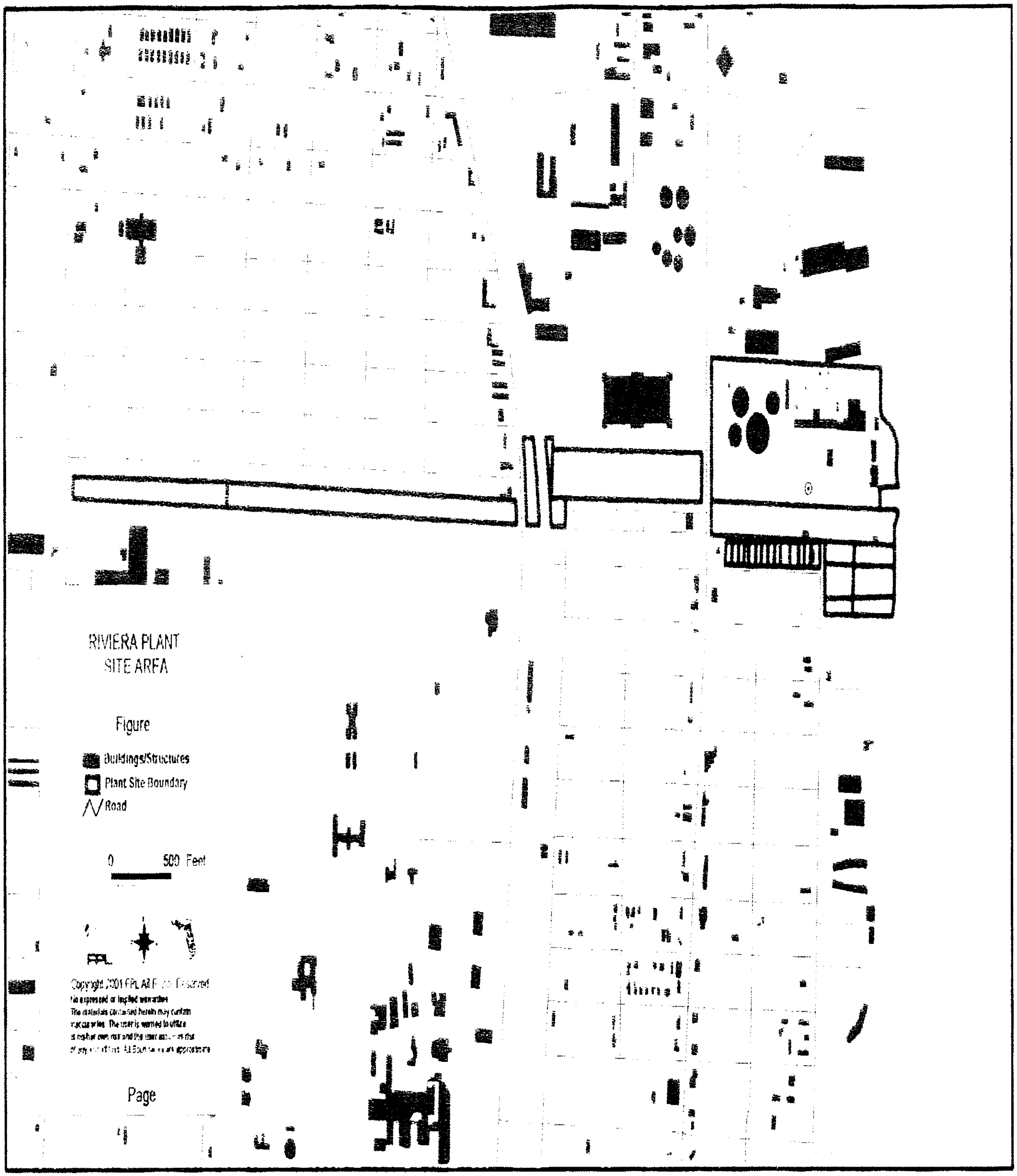
RIVIERA PLANT
SITE AREA
Figure
Buildings/Structures
Plant Site Boundary
Road
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Environmental and Land Use Information: Supplemental Information

Preferred Site: Southwest St. Lucie County Greenfield Site

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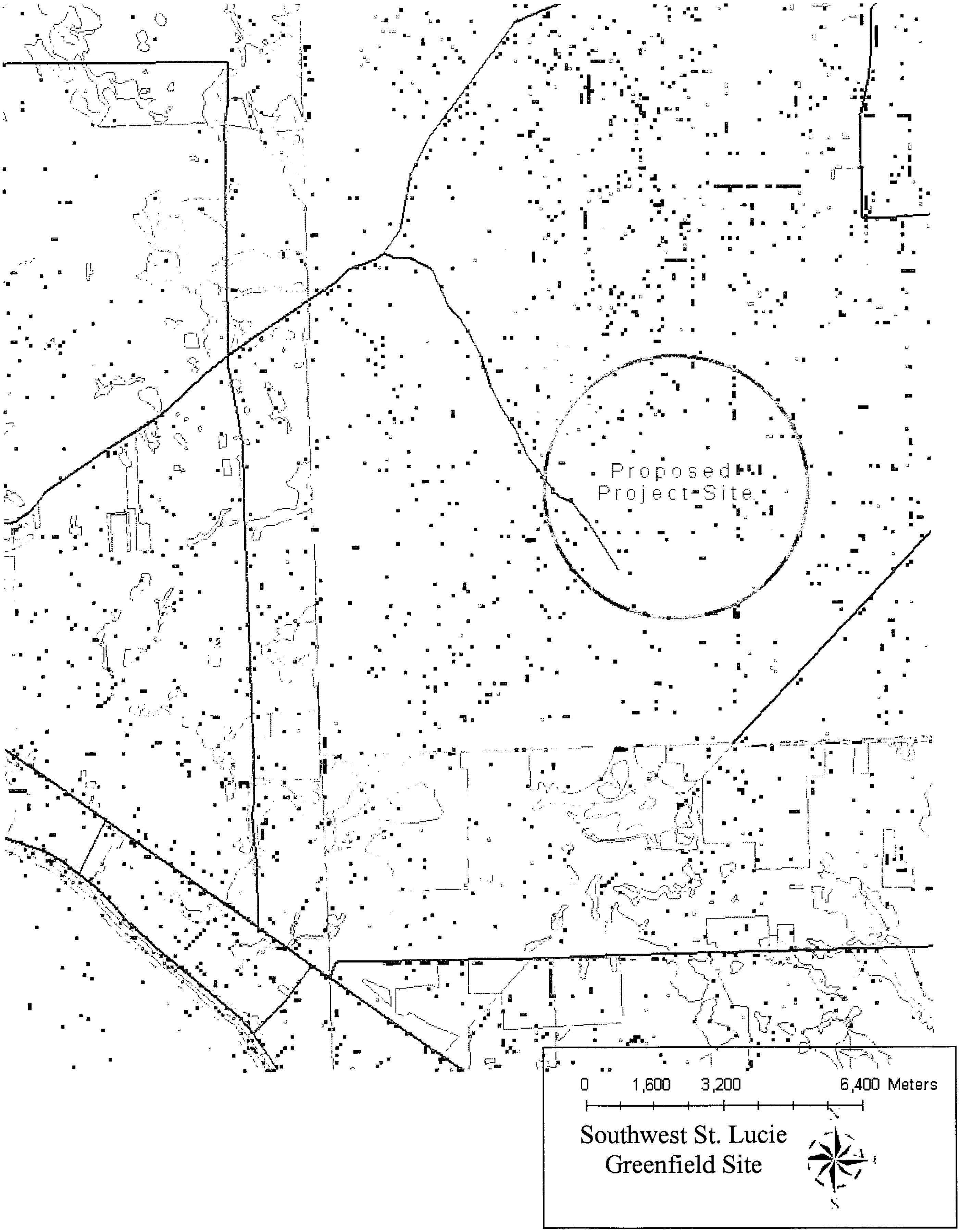
Proposed
Project Site
0 1,600 3,200 6,400 Meters
Southwest St. Lucie
Greenfield Site

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CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information". These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important since they affect the development of assumptions for the amount of external assistance which is available to the FPL system and the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new units that may not adversely impact such limitations. The internal transmission limitations are also addressed by developing the direct costs for siting new units at different locations, and by, evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system. Both site- and system-related transmission costs are developed for each different unit/unit location option or groups of options.

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's transmission plans are presented in Section III.E.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements for the FPL system.
2

No sensitivity case analyses based on different load forecasts were carried out during FPL's most recent planning work. This is due to the fact that the construction options projected for the earliest need years of 2009 and 2010 are combustion turbine-based combined cycle (CC) technology. If higher–than–projected loads begin to appear, the combustion turbine components of the CC options could be placed in service early in simple cycle mode. FPL believed that this fact qualitatively enables it to be able to address higher-than-projected loads. If lower-than-projected loads appear, these additions can be delayed.

[2] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis, the lowest rate basis and the lowest system revenue requirements basis are identical. In such cases (as in FPL's current resource planning work), FPL evaluates options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its base case or "Most Likely" fuel price forecast are discussed in Chapter III of this document.

FPL also conducted an analysis of the comparative economics of a plan that included coal-fired generation compared to an all gas-fired plan. In this study FPL utilized high, low, and expected or "most likely" fuel cost forecasts to explore the relative system fuel cost differences between a clean coal plan and a plan that included all gas-fired generation additions. This approach allowed FPL to examine the relative economics of these two different types of plans with fuel cost forecasts that varied the price difference between coal and natural gas. The results of the analyses using these different fuel cost values for coal-fired and gas-fired options is detailed in FPL's *Report on Clean Coal Generation*, presented to the Commission on March 10, 2005.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item # 3, FPL used three fuel forecasts in the comparative economic analysis of clean coal generation. FPL held the coal prices constant, based on the most likely coal price forecast, and developed three natural gas price forecasts (high, low, and expected). The low gas price sensitivity, when compared to the coal price forecast, results in an essentially fixed differential between natural gas prices and coal prices.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 and Schedule 8 present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options which were considered in the resource planning work. A summary of this information for the new capacity options FPL projects to add over the planning horizon is presented on the Schedule 9 forms

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

The key financial assumptions used in FPL's most recent resource planning work were a 45% debt and 55% equity FPL capital structure, projected debt cost of 7.1%, and an equity return of 12.0%. These assumptions resulted in a weighted average cost of capital of 9.8% and an after-tax discount rate of 8.57%. FPL did not test the sensitivity of its resource plan to varying financial assumptions.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM approach). However, in its most recent planning work, FPL utilized both a levelized system average rate perspective for its DSM Goals and DSM Plan work and the equivalent present value of system revenue requirements perspective when evaluating options that did not result in changes to system DSM levels. (As discussed in response to Discussion Item # 2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective are identical when DSM levels are unchanged between competing plans.)

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses two system reliability criteria in its resource planning work. One of these is a minimum 20% Summer and Winter reserve margin. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the planning criteria established by the North American Electric Reliability Council (NERC) in its *Planning Standards*. FPL has applied these planning criteria in a manner consistent with prudent utility practice. The *NERC Planning Standards* are available on the internet (http://www.nerc.com).

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Facility Rating Methodology* document that are also available on the internet (http://floasis.siemens-asp.com/OASIS/FPL/INFO.HTM).

The normal voltage criteria for FPL stations is given below:

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95	1.05
230	0.95	1.06
500	0.95	1.07

There may be isolated cases for which FPL may determine it prudent to deviate from the general criteria stated above. The overall potential impact on customers and the probability of an outage actually occurring, as well as other factors would influence the decision in such cases.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The impact of FPL's DSM Programs on demand and energy consumption are revised periodically. Engineering models, calibrated with field-metered data, are updated when significant efficiency changes occur in the marketplace. Participation trends are tracked for all of the FPL DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants.

Survey data is collected from non-participants in order to establish the baseline efficiency. Participant data is compared against non-participant data to establish the demand and energy saving benefits of the utility program versus what would be installed in the absence of the program. Finally, FPL is careful to claim only program savings for the average life of the installed efficiency measure. For these DSM measures which involve the utilization of load management, FPL conducts periodic tests of the load control equipment to ensure that it is functioning correctly.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

Among the strategic or non-price factors FPL typically considers when choosing between resource options are the following: (1) fuel diversity; (2) technology risk; (3) environmental risk and (4) site feasibility.

Fuel diversity relates to two concepts, the diversity of sources of fuel (e.g., coal vs. oil vs. natural gas), and the diversity of supply for a single fuel source (for example alternative pipeline suppliers for natural gas). All other factors being equal, supply options that increase diversity in fuel source and/or supply would be favored over those that do not.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology which has not achieved general commercial acceptance has a higher risk than a technology in wide use and, therefore, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts. Technologies regarded as more acceptable from an environmental perspective for a plan are those which minimize environmental impacts through highly efficient fuel use and state of the art controls (e.g. clean coal technologies versus conventional pulverized coal).

Site feasibility assesses a wide range of economic, regulatory and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decisions, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As has been previously discussed, elements of FPL's capacity additions include the construction of new generating capacity at three existing sites: Martin, Manatee, and Turkey Point. These three generation construction projects were selected after evaluating competing bids received in response to three Request for Proposals (RFP's) issued by FPL in mid-2001, mid-2002, and mid-2003 respectively. The decision to construct new combined cycle units at FPL's existing Martin and Manatee sites was subsequently approved by the Florida Public Service Commission (FPSC) in late 2002. The FPSC approved FPL's decision to construct the new combined cycle unit at FPL's existing Turkey Point site in June 2004.

FPL plans to meet its 2008 need with a new short-term purchase agreement from Reliant's Indian River facility. In addition, a 2010–2015 purchase agreement with Southern Company was acquired and has been approved by the FPSC in January 2005.

The construction capacity additions projected in this document for 2009 and beyond will be conducted in a manner consistent with the Commissions Bid Rule through a Request for Proposal (RFP) process. Specifically, FPL intends to publish an RFP in the Summer of 2005 to solicit competitive proposals for comparison to its Next Planned Generating Unit(s) for the capacity need required in the years 2009-2011. In addition, FPL plans to publish a Clean

Coal RFP on or before August 2006 for the capacity need required in the years 2012-2014. It is anticipated that since this Clean Coal RFP is being initiated with a lead time that will support the longer construction schedule of a clean coal plant, this RFP would be restricted to proposals that provide fuel diversity comparable to that of a large coal-fired facility.

Identification of self-build options for 2009 and beyond in FPL's Site Plan is not an indication that FPL has pre-judged any capacity solicitation it may conduct. The identification of future capacity units is required of FPL and represents those alternatives that appear to be FPL's best, most cost-effective self-build options at this time. FPL reserves the right to refine its planning analyses and to identify other self-build options. Such refined analyses have the potential to yield a variety of self-build options, some of which might not require an RFP. If an RFP is issued for supply-side resources, FPL reserves the right to choose the best alternative for its customers, even if that option is not an FPL self-build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

FPL plans to construct a new transmission line (by December 2005) that is presently being certified under the Transmission Line Siting Act (403.52–403.536, F.S.). The new line will connect FPL's Orange River Substation to FPL's Collier Substation (as shown on Table III.F.1). The certification process for this new line should be completed by the summer of 2004. The construction of this line is necessary to serve existing and future customers in the Collier and Lee County areas in a reliable and effective manner. Additionally, FPL has identified the need for a new 230kV transmission line (by December 2008) that requires certification under the Transmission Line Siting Act (403.52–403.536, F.S.). The new line will connect FPL's St. Johns Substation to FPL's proposed Pringle Substation (also shown on Table III.F.1). The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

FPL

ORIGINAL

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COMMISSION
CLERK

April 3, 2006

VIA HAND DELIVERY

M. Blanca S. Bayo, Director
Division of the Commission Clerk and Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: 2006 – 2015 Ten Year Site Plan

Dear Ms. Bayo,

In accordance with Chapter 186 (Section 186.801 – Ten Year Plans) of the Florida Statues, enclosed for filing are twenty-five (25) copies of Florida Power & Light Company's 2006 – 2015 Ten Year Power Plant Site Plan.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Sabrina Spradley
Regulatory Affairs Analyst
(305) 552-4416

CMP
COM
CTR
ECR
GCL
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OTH K. Pena (2)

SS:ec
Enclosures

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 41
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-F

DOCUMENT NUMBER-DATE
02963 APR-3 06
FPSC-COMMISSION CLERK

Ten Year Power Plant Site Plan
2006 - 2015

FPL®

FPL

Ten Year Power Plant Site Plan

2006-2015

Submitted To:

Florida Public Service Commission

Miami, Florida April, 2006

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Table of Contents

List of Figures and Tables

List of Schedules

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Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan. This plan includes an estimate of the utility's electric power generating needs, a projection of how those needs will be met, and a disclosure of information pertaining to the utility's preferred and potential power plant sites. This information is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (FAC).

This Ten Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) integrated resource planning (IRP) analyses that were carried out in 2005 and that were on-going in the first quarter of 2006. The forecasted information presented in this plan addresses the 2006–2015 time frame.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information, especially for the latter years of the ten-year time horizon, and is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's IRP process and outlines FPL's projected resource additions, especially new power plants, as determined in FPL's IRP work in 2005 and early 2006.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as preferred and potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional specific information that is to be included in a Site Plan filing.

FPL
List of Abbreviations

Reference	***Abbreviation***	***Definition***
Unit Type	BIT	Bituminous Coal
	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	IC	Internal Combustion
	NP	Nuclear Power
	NPGU	Next Planned Generating Unit
	SCPC	Supercritical Pulverized Coal
	ST	Steam Unit
Fuel Type	UR	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	LNG	Liquified Natural Gas
	NG	Natural Gas
	No	None
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	P	Planned Unit
	RP	Proposed for repowering
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	P.U.	Per Unit

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Executive Summary

Florida Power & Light Company's (FPL) 2006 Ten Year Power Plant Site Plan (Site Plan) addresses FPL's plans to increase its electric generation capability as part of its efforts to meet its projected incremental resource needs for the 2006-2015 time period.

In response to strong population growth, FPL's total generation capability is required to increase significantly during the 2006-2015 time period as shown in Table ES.1. The table reflects FPL's planned changes to existing generation units (due to unit overhauls, etc.), scheduled changes in the delivered amounts of purchased power, and the planned additions of new generating units. Although not explicitly shown in this table, FPL's demand side management (DSM) resources are included. These resources incorporate the approved DSM Goals (that are assumed to be implemented on schedule) and additional DSM (identified in late 2005/early 2006) scheduled to be implemented in 2006 through 2008.

During the summer of 2005, FPL experienced a season with a significant number of peak demand events, several of which exceeded the forecasted peak demand for the year. Further investigation and review identified that population growth above that forecasted was the primary driver for this increased peak demand. In November of 2005, FPL issued an updated forecast incorporating these changes. The updated load forecast resulted in earlier and greater resource needs, with the first year of resource need moving forward to 2006 from 2009 (as had been identified in the 2005 Site Plan). In response to this emergent need, FPL is implementing additional cost-effective DSM and securing new near-term firm power purchases. It is expected that the combination of these new power purchases and additional DSM will effectively meet the incremental capacity need in 2006 and 2007, and will significantly reduce FPL's 2008 resource needs. FPL's remaining 2008 resource needs will be met by either additional near-term purchases, capacity increases to FPL's existing units, by the construction of one unsited new combustion turbine (CT) or some combination of all of these alternatives.

In 2007, FPL will be adding a new (1,144 Summer MW) combined cycle (CC) unit at its existing Turkey Point plant site. This unit was selected as the best option after comparison to other FPL construction alternatives and outside proposals received in response to an RFP that FPL issued in August 2003. This capacity addition was approved by the Florida Public Service Commission (FPSC) on June 18, 2004. FPL's application for certification under the Florida Electric Power Plant Siting Act was approved by the Governor and Siting Board on February 7, 2005.

FPL currently projects to meet its 2009 and 2010 capacity needs with the addition of two highly efficient 1,219 Summer MW CC units identified as West County Energy Center Units #1 and #2 (West County Units #1 and # 2). The first of these units is scheduled to come in service in June 2009 and the second is scheduled to come in service in June 2010. These units were selected after comparing them to bids received in response to an RFP issued by FPL in September 2005 that requested bids for firm capacity in the 2009-2011 time frame. The addition of these units, which is needed to maintain system reliability, was shown to be more than $750 million (CPVRR) more cost-effective than other alternatives received in response to the RFP. The units will effectively address the pressing need for generation located in southeast Florida to meet regional growth. As a result of their location, these units help to reduce transmission losses for the entire system. Additionally, using state of the art technology, these units will significantly increase the overall generation efficiency of the system which will result in using less fuel to produce each megawatt hour of electricity. FPL recently has filed a petition for a Determination of Need for these two units. A decision from the FPSC is expected before the end of 2006.

The addition of West County Units #1 and #2 will meet FPL's 2009 and 2010 capacity needs; however as a result of the updated load forecast, a resource need for 2011 will remain. FPL will seek to address this 2011 need with additional cost-effective DSM, power purchases, capacity increases to FPL's existing units, construction of new CTs or a combination of these resources. For purpose of this planning document, FPL projects the construction of two unsited CTs.

FPL plans to meet the need in years 2012 and 2013 with two new supercritical pulverized coal (SCPC) units. These units are scheduled to be in service by June 2012 and June 2013, respectively. A site for these two co-located, advanced coal units has not yet been selected; however, FPL is investigating suitable locations that will be identified in an addendum to this Site Plan, expected by June 1, 2006. These planned increases in electric generation capability will allow FPL to continue to maintain system reliability and integrity at a reasonable cost, and to increase fuel diversity.[1]

FPL is currently examining a variety of options to meet the remaining portion of the 2014 and 2015 need including: additional DSM, new/extended purchases and capacity enhancements to existing FPL units. Also under consideration is the construction of CT's or smaller CC units that could be designed to facilitate a conversion to coal gasification operation. For purposes of this planning document, FPL projects the construction of one additional unsited CT in 2014, one additional unsited CT in 2015, and one unsited 2x1 CC in 2015; any of which could be converted to coal gasification when the technology is shown to meet reliability and cost-effectiveness standards. The amount of capacity needed and the technologies that would ultimately be chosen to meet the need for these years will be based on FPL's ongoing review of technology, environmental requirements, regulation and economic factors and will not be restricted to a single technology.

FPL's ongoing planning efforts remain influenced by two recurrent issues. Those two issues are: 1) maintaining an appropriate balance between load and generating capacity located in Southeast Florida; and 2) maintaining and enhancing fuel diversity in the FPL system. The addition of West County Units #1 and #2 will help maintain a balance of generation located within reasonable proximity to the increasing load in the Southeast area, as well as contribute to the overall system reliability. The significant weather events of 2004 and 2005 have underscored the

[1] Repowering of existing FPL sites remains an alternative to new construction and FPL will continue to examine this, and other options including solid fuel options.

value of a balanced fuel supply as it impacts both fuel supply reliability and system fuel costs. FPL continues to actively pursue advanced technology coal generation as the most certain

alternative to measurably increase fuel diversity within the Site Plan planning horizon. FPL also has begun the steps to investigate the next generation of nuclear generation facilities. FPL is involved in several industry consortiums and has held extensive discussions with the leaders in the design, construction and operation segments of the nuclear industry to obtain an updated view of the issues surrounding adding nuclear generation in Florida. Many uncertainties remain at this early stage. However, while the feasible horizon for new nuclear generation is beyond the planning horizon of this Site Plan, FPL is actively pursuing the possibility of new nuclear generation.

Table ES.1: Projected Capacity Changes and Reserve Margins for FPL [1]

Projected Capacity Changes and Reserve Margins for FPL [1]

		Net Capacity Changes (MW)		FPL Reserve Margin (%)	
		Winter[2]	Summer[3]	Winter	Summer
2006	Changes to Existing QF Purchases [4]	(132)	(136)	25.9%	**19.5%**[8]
	Changes to existing Units	205	142		
	Changes to Non-QF Purchases [5]	147	440		
2007	Turkey Point Unit #5 [6]	—	1,144	24.2%	21.3%
	Changes to existing Units	70	77		
	Changes to Non-QF Purchases [5]	73	(412)		
2008	Changes to existing Units	4	12	26.6%	**19.3%**[8]
	Turkey Point Unit #5 [6]	1,181	—		
	Unsited Combustion Turbine [6]	—	160		
	Changes to Non-QF Purchases [5]	(252)	—		
2009	Changes to Existing QF Purchases [4]	—	(51)	23.6%	21.4%
	Changes to Non-QF Purchases [5]	(326)	(105)		
	West County Unit #1 [6]	—	1,219		
	Unsited Combustion Turbine [6]	181	—		
2010	West County Unit #1 [6]	1,335	—	25.0%	20.9%
	Changes to Existing QF Purchases [4]	(51)	(47)		
	West County Unit #2 [6]	—	1,219		
	Changes to Non-QF Purchases [5]	(461)	(683)		
2011	West County Unit #2 [6]	1,335	—	28.5%	**19.7%**[8]
	Unsited 2x0 Simple Cycle CT [6]	—	320		
	Changes to Existing QF Purchases [4]	(92)	(45)		
	Changes to Non-QF Purchases [5]	(1)	—		
2012	Supercritical Pulverized Coal Unit # 1 [6] [7]	—	850	27.9%	20.3%
	Unsited 2x0 Simple Cycle CT [6]	362	—		
	Changes to Non-QF Purchases [5]	—	(158)		
2013	Supercritical Pulverized Coal Unit # 1 [6] [7]	855	—	28.6%	21.3%
	Supercritical Pulverized Coal Unit # 2 [6] [7]	—	850		
	Changes to Non-QF Purchases [5]	(180)	—		
2014	Supercritical Pulverized Coal Unit # 2 [6] [7]	855		29.9%	**19.7%**[8] [9]
	Unsited 1x 0 Simple Cycle CT [6]	—	160		
2015	Unsited 1x 0 Simple Cycle CT [6]	181	—	27.3%	**19.7%**[8] [9]
	Unsited 1x 0 Simple Cycle CT [6]	—	160		
	Unsited 2x1 Combined Cycle [6]	—	553		
	TOTALS =	**5,289**	**5,669**		

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are values for January of year shown.
(3) Summer values are values for August of year shown.
(4) These are firm capacity and energy contracts with Cogen & Small Power Producers. See Table I.B.1 for more details.
(5) These are firm capacity purchases from Non-QF facilities. See Tables I.D.1 and Table I.D.2 for more details.
(6) All new unit additions are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.
(7) FPL is currently in the process of selecting a site(s) for these advanced technology coal units. FPL expects to announce the selected site(s) by June 2006.
(8) FPL reserve margin values are shown to include what is committed or firmly planned. FPL will continue to pursue the most cost effective alternatives available to meet the then forecasted need with a 20% reserve margin, such as DSM resources that may be added in intervening years or additional purchases.
(9) FPL will continue to pursue development of technologies, such as SCPC or IGCC to meet the needs in these later years.

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CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

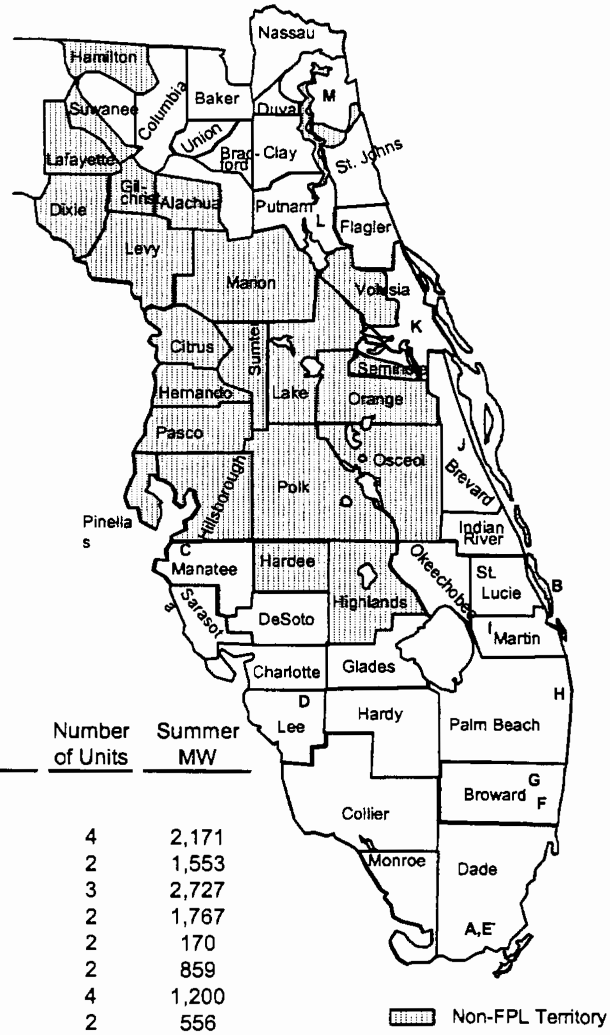
FPL's service area contains approximately 27,650 square miles and has a population of approximately 8.5 million people. FPL served an average of 4,318,739 customer accounts in thirty-five counties during 2005. These customers were served from a variety of resources including: FPL-owned fossil and nuclear generating units, non-utility owned generation, demand side management, and interchange/purchased power.

I.A. FPL-Owned Resources

The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory and also include partial ownership of one unit located in Georgia and two units located in Jacksonville, FL. The current generating facilities consist of four nuclear steam units, three coal units, eleven combined cycle units, seventeen fossil steam units, forty eight combustion gas turbines, one simple cycle combustion turbine, and five diesel units. The location of these units is shown on Figure I.A.1 and in Table I.A.1.

FPL's bulk transmission system is comprised of 6,470 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 542 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3 shows FPL's interconnection ties with other utilities.



Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	4	2,171
B	St. Lucie *	2	1,553
C	Manatee	3	2,727
D	Fort Myers	2	1,767
E	Cutler	2	170
F	Lauderdale	2	859
G	Port Everglades	4	1,200
H	Riviera	2	556
I	Martin	5	3,649
J	Cape Canaveral	2	798
K	Sanford	3	2,042
L	Putnam	2	494
M	SJRPP **	2	232
	Scherer ***	1	639
	Gas Turbines	48	1,908
	Internal Combustion Turbines	5	12
	FPL Generation =	**89**	**20,777**

* Represents FPL's ownership share: St. Lucie nuclear: 100% unit 1, 85% unit 2; SJRPP coal: 20% of two units

** SJRPP = St. John's River Power Park

*** The Scherer unit is located in Georgia and is not shown on this map

Figure I.A.1: Capacity Resources by Location (as of December 31, 2005)

Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2005)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Combined-Cycle				
Lauderdale	Dania, FL	2	Gas/Oil	859
Martin	Indiantown,FL	2	Gas	899
Martin	Indiantown,FL	1	Gas/Oil	1,107
Sanford	Lake Monroe, FL	2	Gas	1,904
Putnam	Palatka, FL	2	Gas/Oil	494
Fort Myers	Fort Myers, FL	1	Gas	1,441
Manatee	Parrish,FL	1	Gas	1,107
Total Combined Cycle		**11**		**7,811**
Combustion Turbines				
Fort Myers *	Fort Myers, FL	1	Gas/Oil	326
Total Combustion Turbines		**1**		**326**
Nuclear				
Turkey Point	Florida City, FL	2	Nuclear	1,386
St. Lucie **	Hutchinson Island, FL	2	Nuclear	1,553
Total Nuclear		**4**		**2,939**
Coal Steam				
SJRPP **	Jacksonville, FL	2	Coal	232
Scherer	Monroe County, Ga	1	Coal	639
Total Coal Steam		**3**		**871**
Oil/Gas Steam				
Cape Canaveral	Cocoa, FL	2	Oil/Gas	798
Cutler	Miami, FL	2	Gas	170
Manatee	Parrish, FL	2	Oil/Gas	1,620
Martin	Indiantown,FL	2	Oil/Gas	1,643
Port Everglades	Port Everglades, FL	4	Oil/Gas	1,200
Riviera	Riviera Beach, FL	2	Oil/Gas	556
Sanford	Lake Monroe, FL	1	Oil/Gas	138
Turkey Point	Florida City, FL	2	Oil/Gas	785
Total Oil/Gas Steam		**17**		**6,910**
Gas Turbines(GT)/Diesels(IC)				
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Turkey Point (IC)	Florida City, FL	5	Oil	12
Total Gas Turbines/Diesels		**53**		**1,920**
Total Units:		**89**		
Total Net Generating Capability:				**20,777**

Each unit consists of two combustion turbines totaling approximately 300 MW.
Represents FPL's ownership share: St. Lucie nuclear: 100% unit 1, 85% unit 2; SJRPP coal: 20% of two units

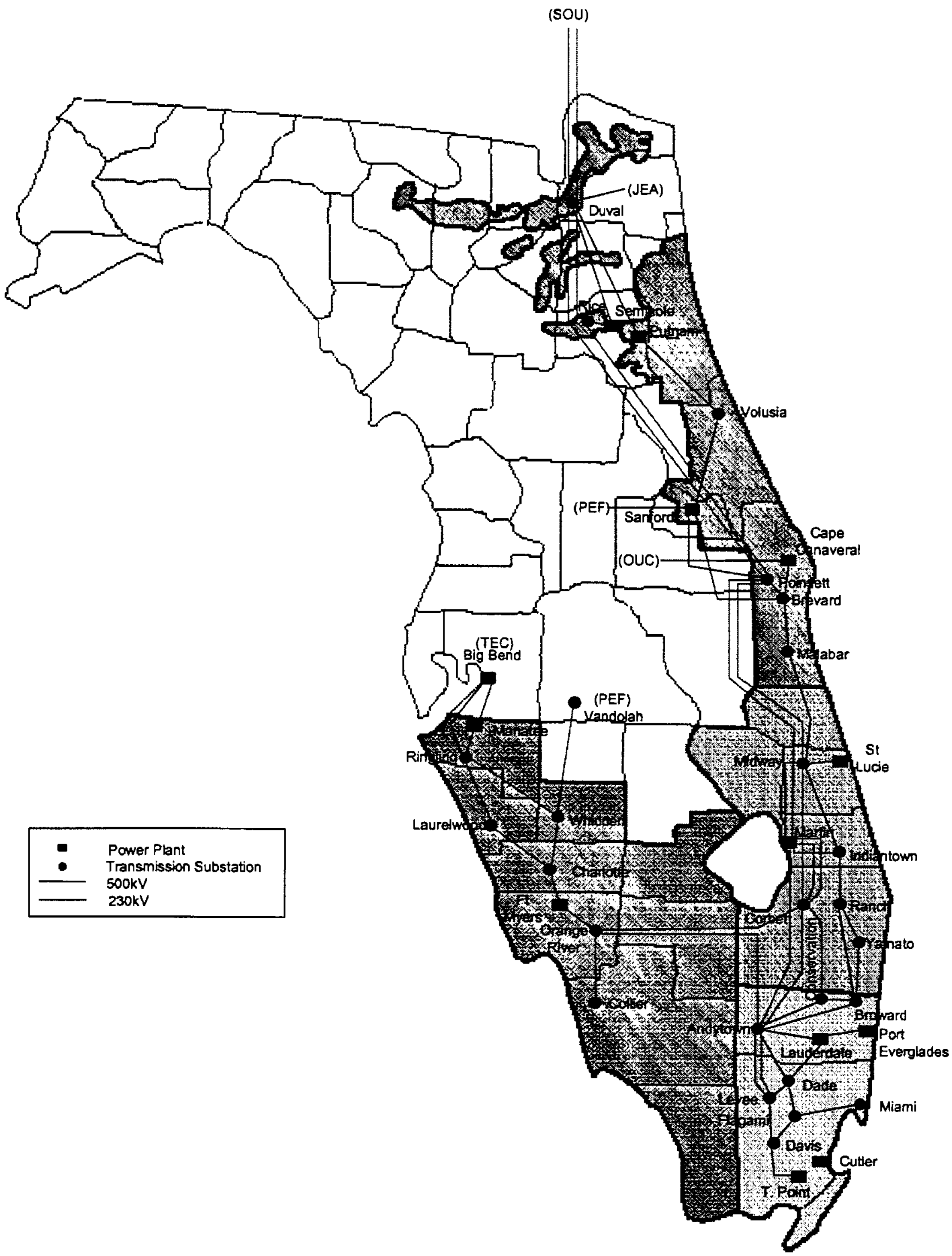


Figure I.A.2: FPL Substation and Transmission System Configuration

2006 10-year site plan
Exhibit KRR-3-F, Page 26 of 192

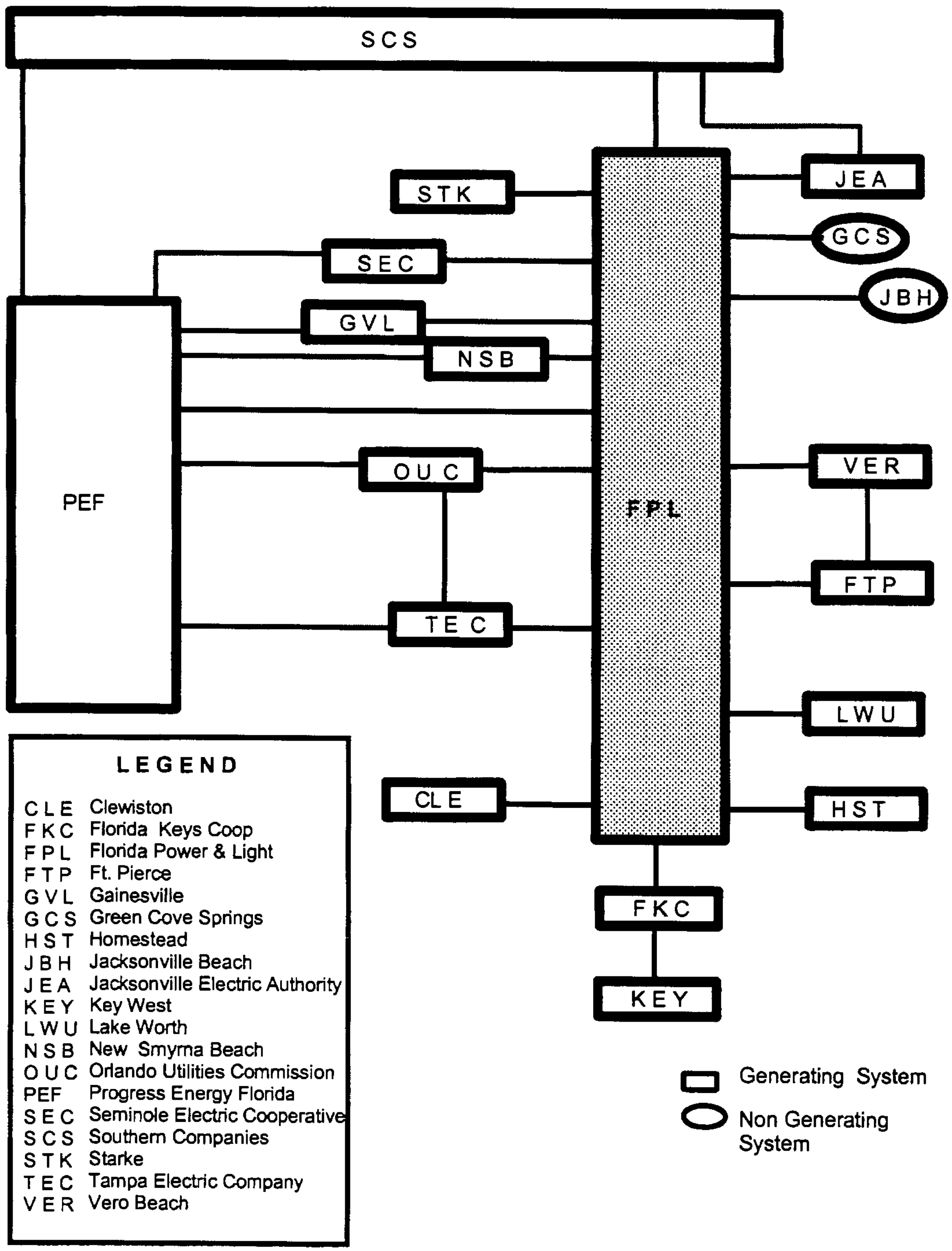


Figure I.A.3: FPL Interconnection Diagram

I.B Firm Capacity Power Purchases

Purchases From Qualifying Facilities (QF):

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has contracts with five cogeneration/small power production facilities to purchase firm capacity and energy.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

Purchases from Utilities:

Purchased power remains an important part of FPL's resource mix. FPL has a Unit Power Sales (UPS) contract to purchase 931 MW, with a minimum of 381 MW, of coal-fired generation from the Southern Company (Southern) through May, 2010. In January 2005, the Commission approved a new firm purchase contract with Southern that will result in FPL receiving 930 MW from June 2010 through the end of 2015. This capacity will be supplied by Southern from a mix of gas-fired and coal-fired units.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 381 MW (Summer) and 390 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. (FPL also has ownership interest in these units. The ownership amount is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.)

Other Purchases:

FPL has other firm capacity purchase contracts through 2009 with a variety of Non-QF suppliers. These purchases are generally near-term in nature. Table I.B.1 presents the Summer and Table I.B.2 represents the Winter MW resulting from all firm purchased power contracts discussed above through the year 2015.

Table I.B.1: FPL's Firm Purchased Power Summer MW

I. Purchases from QF's:

(Cogeneration/ Small Power Production Facilities)	Start Date	End Date	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. Broward South	04/01/91	08/01/09	50.6	50.6	50.6	0	0	0	0	0	0	0
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
2. Broward North	04/01/92	12/31/10	45.0	45.0	45.0	45.0	45.0	0	0	0	0	0
Broward North	01/01/93	12/31/26	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
3. Cedar Bay Generating Co.	01/25/94	12/31/24	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
4. Indiantown Cogen., LP	12/22/95	12/01/25	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
5. Palm Beach SWA	04/01/92	03/31/10	47.5	47.5	47.5	47.5	0	0	0	0	0	0
		QF Purchases Sub Total =	738	738	738	687	640	595	595	595	595	595

II. Purchases from Utilities:

	Start Date	End Date	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. UPS from Southern Co.	07/20/88	05/31/10	931	931	931	931	0	0	0	0	0	0
2. UPS Replacement	06/01/10	12/31/15	0	0	0	0	930	930	930	930	930	930
3. SJRPP	04/02/82	10/31/15	381	381	381	381	381	381	381	381	381	381
		Utility Purchases Sub Total =	1312	1312	1312	1312	1311	1311	1311	1311	1311	1311

III. Other Purchases:

	Start Date	End Date	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. Oleander/Constellation 1	06/01/02	05/31/05	0	0	0	0	0	0	0	0	0	0
2. Progress Energy Ventures/Desoto	06/01/02	05/31/05	0	0	0	0	0	0	0	0	0	0
3. Reliant/Pasco/Shady Hills	02/28/02	02/28/07	474	0	0	0	0	0	0	0	0	0
4. Reliant/Indian River	01/01/06	12/31/09	130	354	576	250	0	0	0	0	0	0
4a. Reliant/Indian River (Addl. Trans.)	05/01/06	12/31/09	346	222	0	326	0	0	0	0	0	0
5. Progress Energy Ventures/Desoto (Put option)	06/01/05	05/31/07	140	0	0	0	0	0	0	0	0	0
6. Oleander/Southern Co (Put option)	06/01/05	05/31/07	156	0	0	0	0	0	0	0	0	0
6a. Oleander (Extension)	06/01/07	05/31/12	0	158	158	158	158	158	0	0	0	0
7. Williams	03/01/06	12/31/09	56	106	106	106	0	0	0	0	0	0
8. Progress Energy Ventures	04/01/06	03/31/09	55	105	105	0	0	0	0	0	0	0
		Other Purchases Sub Total =	1357	945	945	840	158	158	0	0	0	0

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Summer Purchases Total MW =	3407	2995	2995	2839	2109	2064	1906	1906	1906	1906

Table I.B.2: FPL's Firm Purchased Power Winter MW

I. Purchases from QF's:

(Cogeneration/ Small Power Production Facilities)	Start Date	End Date	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. Broward South	04/01/91	08/01/09	50.6	50.6	50.6	50.6	0	0	0	0	0	0
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
2. Broward North	04/01/92	12/31/10	45.0	45.0	45.0	45.0	45.0	0	0	0	0	0
Broward North	01/01/93	12/31/26	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
3. Cedar Bay Generating Co.	01/25/94	12/31/24	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
4. Indiantown Cogen., LP	12/22/95	12/01/25	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
5. Palm Beach SWA	04/01/92	03/31/10	47.5	47.5	47.5	47.5	47.5	0	0	0	0	0
		QF SubTotal =	**738**	**738**	**738**	**738**	**687**	**595**	**595**	**595**	**595**	**595**

II. Purchases from Utilities:

	Start Date	End Date	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. UPS from Southern Co.	07/20/88	05/31/10	931	931	931	931	931	0	0	0	0	0
2. UPS Replacement	06/01/10	12/31/15	0	0	0	0	0	930	930	930	930	930
3. SJRPP	04/02/82	10/31/15	390	390	390	390	390	390	390	390	390	390
Utility Purchases Sub Total =			**1321**	**1321**	**1321**	**1321**	**1321**	**1320**	**1320**	**1320**	**1320**	**1320**

III. Other Purchases:

	Start Date	End Date	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. Oleander/Constellation 1	06/01/02	05/31/05	0	0	0	0	0	0	0	0	0	0
2. Progress Energy Ventures/Desoto	06/01/02	05/31/05	0	0	0	0	0	0	0	0	0	0
3. Reliant/Pasco/Shady Hills	02/28/02	02/28/07	474	474	0	0	0	0	0	0	0	0
4. Reliant/Indian River	01/01/06	12/31/09	130	354	576	250	0	0	0	0	0	0
4a. Reliant/Indian River (Addl. Trans.)	05/01/06	12/31/09	0	0	0	0	0	0	0	0	0	0
5. Progress Energy Ventures/Desoto (Put option)	06/01/05	05/31/07	362	0	0	0	0	0	0	0	0	0
6. Oleander/Southern Co (Put option)	06/01/05	05/31/07	180	180	0	0	0	0	0	0	0	0
6a. Oleander (Extension)	06/01/07	05/31/12	0	0	180	180	180	180	180	0	0	0
7. Williams	03/01/06	12/31/09	0	106	106	106	0	0	0	0	0	0
8. Progress Energy Ventures	04/01/06	03/31/09	0	105	105	105	0	0	0	0	0	0
Other Purchases Sub Total =			**1146**	**1219**	**967**	**641**	**180**	**180**	**180**	**0**	**0**	**0**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter Purchases Total MW =	**3205**	**3278**	**3026**	**2700**	**2188**	**2095**	**2095**	**1915**	**1915**	**1915**

I.C Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. Table I.C.1 shows the amount of energy purchased in 2005 from these facilities.

Table I.C.1: As Available Energy Purchases From Non-Utility Generators in 2005

Project	***County***	***Fuel***	***In-Service Date***	***Energy (MWH) Delivered to FPL in 2005***
US Sugar-Bryant	Palm Beach	Bagassee	2/80	3,351
Tropicana	Manatee	Natural Gas	2/90	11,327
Okeelanta	Palm Beach	Bagassee/Wood	11/95	275,971
Tomoka Farms	Volusia	Landfill Gas	7/98	17,745
Georgia Pacific	Putnam	Paper By-Product	2/94	7,340
Elliot	Palm Beach	Natural Gas	7/05	120

I.D. Demand Side Management (DSM)

FPL's DSM activities continue what has been FPL's practice since 1978 of encouraging cost-effective conservation and load management. FPL's DSM efforts through 2005 have resulted in a cumulative Summer peak reduction of approximately 3,519 MW at the generator and an estimated cumulative energy saving of 33,981 GWH at the generator.

FPL's new DSM Goals for the 2005-2014 timeframe were approved by the Florida Public Service Commission (Commission) on August 9, 2004. FPL's DSM Plan (with which FPL will meet the approved DSM Goals) was approved by the Commission on February 9, 2005 except for the BuildSmart and Residential Conservation Services programs. These two programs received Commission approval on January 10, 2006.

Due to the changes in FPL's resource needs resulting from FPL's updated (November 2005) load forecast previously mentioned in the Executive Summary, FPL is currently planning a number of modifications to its existing DSM programs that will result in additional DSM MW reduction capability above what was projected in the approved DSM

Plan. FPL will seek approval of these program modifications during the second quarter of 2006. To-date, FPL has developed a projection for additional cost-effective DSM that can be implemented in 2006 through 2008. The schedule for new generation additions presented in this document are based on the implementation of these additional DSM MW through 2008. FPL will continue to analyze the potential for additional cost–effective DSM for 2009–on in its ongoing resource planning work in 2006.

Schedule 1

Existing Generating Facilities
As of December 31, 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Cape Canaveral		Brevard County 19/24S/36F									804,100	806	798
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	403	399
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	403	399
Cutler		Miami Dade County 27/55S/40E									236,500	176	170
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	75,000	67	65
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	161,500	109	105
Fort Myers		Lee County 35/43S/25E									2,822,390	2,759	2,415
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,701,890	1,610	1,441
	3A & B		CT	NG	FO2	PL	PL	Unknown	Jun-01	Unknown	376,380	380	326
	1-12		GT	FO2	No	PL	No	Unknown	May-74	Unknown	744,120	769	648
Lauderdale		Broward County 30/50S/42E									1,873,968	1,947	1,699
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	465	430
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	464	429
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	509	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,734	509	420
Manatee		Manatee County 18/33S/20E									2,951,110	2,831	2,727
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	817	810
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	817	810
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,197	1,107

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Martin		Martin County 29/29S/38E									4,317,510	3,799	3,649
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	830	828
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	829	815
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	471	449
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	472	450
	8		CC	NG	FO2	PL	PL	Unknown	Jun-01	Unknown	1,224,510	1,197	1,107
Port Everglades		City of Hollywood 23/50S/42E									1,710,384	1,721	1,620
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	247,775	220	219
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	247,775	220	219
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	382	377
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	390	385
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	509	420
Putnam		Putnam County 16/10S/27E									580,008	568	494
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,004	282	245
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,004	286	249
Riviera		City of Riviera Beach 33/42S/43E									620,840	560	556
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	274	272
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	286	284
Sanford		Volusia County 16/19S/30E									2,534,050	2,232	2,042
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	156,250	142	138
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,900	1,045	952
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,900	1,045	952

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2005

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW
Scherer 2/		Monroe, GA									680,368	642	639
	4		BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	680,368	642	639
St. Johns River Power Park 3/		Duval County 12/15/28E (RPC4)									271,836	242	232
	1		BIT	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	130	127
	2		BIT	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	112	105
St. Lucie		St. Lucie County 16/36S/41E									1,573,775	1,579	1,553
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	850,000	853	839
	2	4/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	723,775	726	714
Turkey Point		Miami Dade County 27/57S/40E									2,336,138	2,237	2,183
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	388	385
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	403	400
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	760,000	717	693
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	759,900	717	693
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	12,138	12	12
										Total System as of December 31, 2005 =		22,099	20,777

1/ These ratings are peak capability.
2/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.
3/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No. 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80%.
4/ Total capability is 853/839 MW. Capabilities shown represnet FPL's share of the unit and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 15%.

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CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are developed on an annual basis for resource planning work at FPL. These forecasts are a key input to the models used to develop the Integrated Resource Plan. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

The primary drivers to develop these forecasts are demographic trends, weather, economic conditions, and prices of electricity. In addition, the resulting forecasts are an integration of economic evaluations, inputs of local economic development boards, weather assessments from the National Oceanic and Atmospheric Administration (NOAA), and inputs from FPL's own customer service planning areas. In the area of demographics, population trends by county, plus housing characteristics such as housing starts, housing size, and vintage of homes are assessed.

Forecasts for electric usage in the residential and commercial classes include end-use information such as appliance saturation studies, efficiencies, and intensity of energy use. In addition to these inputs, residential forecasts also make use of household characteristics such as ages of members in households, number of members in households, and income distributions.

The projections for the national and Florida economy are obtained from Global Insight. Population projections for the counties served by FPL are obtained from the Bureau of Economic and Business Research (BEBR) of the University of Florida. In addition, FPL actively participates with local development councils and universities to obtain their assessments of the local economy, specifically in the area of expansion of new businesses and retention of the current business base. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects the company's sales and peak demand. Weather variables are used in the forecasting models for energy sales and peak demand. There are two sets of weather variables developed and used in forecasting models:

1. Cooling and Heating Degree-Days are used to forecast energy sales.
2. Temperature data is used to forecast Summer and Winter peaks.

The Cooling and Heating Degree-Days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. A composite temperature hourly profile is derived using hourly temperatures across FPL's service territory (Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained) weighted by regional energy sales. This composite temperature is used to derive Cooling and Heating Degree-Days which are based on starting point temperatures of 72°F and 66°F, respectively. Similarly, composite temperature and hourly profile of temperature are used for the Summer and Winter peak models.

II.A. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for each revenue class for the forecasting period of 2005-2024 and are adjusted to match the Net Energy for Load (NEL) forecast. The results of these sales forecasts for the years 2006-2015 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and Net Energy for Load forecast are outlined below.

1. Residential Sales

Residential electric usage per customer is estimated by using a regression model which contains the real residential price of electricity, real Florida personal income, Cooling and Heating Degree-Days as explanatory variables. The price of electricity plays a role in explaining electric usage since electricity, like all other goods and services, will be used in greater or lesser quantities depending upon its price. To capture economic conditions, the model includes Florida's real personal income. The degree of economic prosperity can, and does, affect residential electricity sales. The impact of weather is captured by the Heating Degree-Days and, two weighted variables for cooling degree days accounting for cooling degree days from the previous month are also included as an explanatory variable. The degree of economic prosperity can, and does, affect residential electricity sales. Residential energy sales are forecast by multiplying the residential use per customer forecast by the number of residential customers forecasted. The long-term annual model is similar except that Florida real per capita in included as an economic explanatory variable rather than Florida total personal income. Also the annual model includes annual cooling degree days.

2. Commercial Sales

The commercial sales forecast is also developed using a regression model. Commercial sales are a function of the following variables: Florida's real personal income, commercial real price of electricity, two variables for Cooling Degree-Days weighted for previous month and current month, and an autoregressive term. The long-term model is similar, except annual cooling degree days is used as explanatory weather variable as opposed to weighted monthly cooling degree days. In addition the long term model does not include an autoregressive term. Florida's real personal income is used to capture the economic activity in FPL's service territory. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. Cooling Degree-Days are used to capture weather-sensitive load in the commercial sector.

3. Industrial Sales

The industrial sales forecast is also developed using a regression model. Industrial sales are a function of lagged industrial sales, the real price of electricity, Cooling Degree-Days, a dummy variable for outliers, and an autoregressive term. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. The Cooling Degree-Day term is included to capture the weather-sensitive load in the industrial class. The Long term model consists of real price of electricity and Florida's manufacturing employment.

4. Other Public Authority Sales

At present, this class consists of sports fields and one government account. The forecast for this class is based on historical knowledge of its characteristics.

5. Street & Highway Sales and Railroad & Railways Sales

The forecast for street and highway sales is developed by first assuming a constant use per customer and then multiplying that value by the number of projected customers. The forecast of sales to railroad & railways is based on historical knowledge of its characteristics. This class consists of Miami-Dade County's Metrorail system.

6. Sales for Resale

Sales for resale (wholesale) customers are composed of municipalities and/or electric cooperatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers.

Currently, there are four customers in this class: the Florida Keys Electric Cooperative (Florida Keys), City Electric System of the Utility Board of Key West, Florida (City of Key West), Miami-Dade County, and the Florida Municipal Power Agency (FMPA). Sales to the Florida Keys are forecasted using a regression model. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor. Miami-Dade County sells 60 MW to Progress Energy. Line losses are billed to Miami-Dade under a wholesale contract. FMPA has contracted for delivery of 75 MW from FPL through October, 2007.

7. Total Sales

Sales forecasts by revenue class are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, an expansion factor is applied to generate a forecast of annual Net Energy for Load (NEL).

II.B. Net Energy for Load

An annual econometric model is developed to produce a net energy for load (NEL) forecast. The key inputs to the model are: the real price of electricity, Heating and Cooling Degree-Days, Florida Non-Agricultural Employment, and an autoregressive term. The monthly model is similar, except the economic variables utilized are Florida's real personal income and a dummy variable for February. The first year of the forecast is developed from a daily model which consists of similar explanatory variables as monthly model except includes variables for weekends and holiday. The forecasts thereafter for the following four years are obtained from the short-term monthly model. Forecasts for subsequent years are generated using the growth rates from the annual model.

Once an annual NEL forecast is obtained using the above-mentioned methodology, the results are then compared for reasonableness to the NEL forecast generated using the total sales forecast. The sales by class forecasts previously discussed are then adjusted to match the NEL from the annual NEL model.

The forecasted NEL values for 2006 – 2015 are presented in Schedule 3.3 that appears at the end of this chapter.

II.C. System Peak Forecasts

The rate of absolute growth in FPL system load has been a function of a growing customer base, varying weather conditions, continued economic growth, changing patterns of customer behavior (including an increased stock of electricity-consuming appliances), and more efficient heating and cooling appliances. FPL developed the peak forecast models to capture these behavioral relationships.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2006–2015 are presented in Schedules 3.1 and 3.2 as well as in Schedules 7.1 and 7.2.

System Summer Peak

The Summer peak forecast is developed using an econometric model. The variables included in the model are the price of electricity, Florida real personal income, average temperature and a heat buildup weather variable consisting of the sum of the cooling degree hours during the peak day and three prior days. The model below is based on Summer peak load per customer. The Summer peak load per customer value is multiplied by total customers to derive FPL's system Summer peak.

System Winter Peak

Like the system Summer peak model, this model is also an econometric model. The model consists of two weather-related variables: the square of the minimum temperature on the peak day, heating degree hours for the prior day as well as for the morning of the winter peak day. In addition, Florida real personal income is a variable used in the model. The model below is based on Winter peak load per customer. The Winter peak load per customer value is multiplied by total customers to derive FPL's system Winter peak.

Monthly Peak Forecasts

Monthly peaks for the 2005-2024 period are forecasted to provide information for the scheduling of maintenance for power plants and fuel budgeting. The forecasting process is basically the same as for the monthly NEL forecast and consists of the following actions:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to seasonal peaks (Summer = April-October, Winter = November-March.)

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.D. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2005-2024 are produced using a System Load Forecasting "shaper" program. This model uses sixteen years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. These daily load shapes are ranked and used with forecasted monthly peaks, NEL, and calendars in developing an hourly forecast. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population*	Members per Household	GWH**	Average*** No. of Customers	Average KWH Consumption Per Customer	GWH**	Average*** No. of Customers	Average KWH Consumption Per Customer
1996	6,948,951	2.20	41,302	3,152,625	13,101	31,211	380,860	81,949
1997	7,105,592	2.21	41,849	3,209,298	13,040	32,942	388,906	84,703
1998	7,249,627	2.22	45,482	3,266,011	13,926	34,618	396,749	87,255
1999	7,412,744	2.22	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,603,964	2.23	46,320	3,414,002	13,568	37,001	415,295	89,096
2001	7,754,846	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,898,628	2.21	50,865	3,566,167	14,263	40,029	435,313	91,955
2003	8,079,316	2.21	53,485	3,652,663	14,643	41,425	444,650	93,163
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,638,053	2.21	56,541	3,910,167	14,460	44,236	481,993	91,777
2007	8,808,004	2.21	57,995	3,985,164	14,553	46,430	492,462	94,281
2008	8,975,540	2.21	60,255	4,060,181	14,840	49,095	502,802	97,643
2009	9,138,039	2.21	62,322	4,133,181	15,079	51,195	512,943	99,806
2010	9,298,715	2.21	64,299	4,205,546	15,289	53,188	522,916	101,714
2011	9,456,660	2.21	65,762	4,275,556	15,381	54,552	531,830	102,574
2012	9,609,275	2.21	67,240	4,343,167	15,482	55,995	540,464	103,605
2013	9,758,884	2.21	68,811	4,409,366	15,606	57,536	548,937	104,813
2014	9,907,794	2.21	70,206	4,475,348	15,687	59,194	557,395	106,197
2015	10,056,605	2.21	71,546	4,541,033	15,756	60,887	565,826	107,607

* Population represents only the area served by FPL.

** Actual energy sales include the impacts of existing conservation. Forecasted energy sales do not include the impact of incremental conservation.

*** Average No. of Customers is the annual average of the twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial					Other	Total****
Year	GWH **	Average*** No. of Customers	Average KWH Consumption Per Customer	Railroads & Railways GWH	Street & Highway Lighting GWH **	Sales to Public Authorities GWH	Sales to Ultimate Consumers GWH **
1996	3,792	14,783	256,511	83	368	577	77,334
1997	3,894	14,761	263,803	85	383	702	79,855
1998	3,951	15,126	261,206	81	373	625	85,130
1999	3,948	16,040	246,135	79	473	465	84,676
2000	3,768	16,410	229,616	81	408	381	87,960
2001	4,091	15,445	264,875	86	419	67	90,212
2002	4,057	15,533	261,186	89	420	63	95,523
2003	4,004	17,029	235,128	93	425	64	99,496
2004	3,964	18,512	214,139	93	413	58	99,095
2005	3,913	20,392	191,873	95	424	49	102,296
2006	3,926	21,315	184,173	96	468	50	105,316
2007	3,904	20,574	189,743	96	485	50	108,959
2008	3,922	19,936	196,711	96	501	50	113,918
2009	3,936	19,421	202,680	96	517	50	118,116
2010	3,945	19,042	207,186	96	534	50	122,111
2011	3,916	18,987	206,259	96	545	50	124,920
2012	3,891	18,842	206,509	96	555	50	127,827
2013	3,862	18,825	205,142	96	566	50	130,920
2014	3,821	18,859	202,607	96	577	50	133,942
2015	3,772	18,936	199,176	96	587	50	136,938

** Actual energy sales include existing conservation. Forecasted energy sales do not include the impact of incremental conservation.

*** Average No.of Customers is the annual average of the twelve month values.

**** GWH Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWH	(18) Utility Use & Losses GWH	(19) Net***** Energy For Load GWH **	(20) Average *** No. of Other Customers	(21) Total Average***,****** Number of Customers
1996	1,353	6,306	84,993	2,480	3,550,748
1997	1,228	5,771	86,853	2,520	3,615,485
1998	1,326	6,206	92,662	2,584	3,680,470
1999	953	5,829	91,458	2,605	3,756,009
2000	970	7,059	95,989	2,694	3,848,401
2001	970	7,222	98,404	2,722	3,935,281
2002	1,233	7,443	104,199	2,792	4,019,805
2003	1,511	7,386	108,393	2,879	4,117,221
2004	1,531	7,464	108,091	3,029	4,224,509
2005	1,506	7,498	111,301	3,156	4,321,895
2006	1,545	8,104	114,965	3,263	4,416,737
2007	1,522	8,339	118,820	3,368	4,501,569
2008	1,066	8,736	123,720	3,472	4,586,391
2009	1,082	9,013	128,211	3,576	4,669,120
2010	1,098	9,310	132,519	3,679	4,751,183
2011	1,098	9,522	135,540	3,750	4,830,124
2012	1,098	9,742	138,666	3,819	4,906,292
2013	1,098	9,976	141,993	3,887	4,981,014
2014	1,098	10,204	145,244	3,955	5,055,556
2015	1,098	10,430	148,466	4,022	5,129,818

** Actual energy sales include existing conservation. Forecasted energy sales do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

*** Average No.of Customers is the annual average of the twelve month values.

***** GWH Col. (19) = Col. (16) + Col. (17) + Col. (18). Actual NEL include the impacts of existing conservation and agrees to Col. (8) on schedule 3.3.

****** Total Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20)

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
1996	16,064	364	15,700	0	525	339	422	297	15,117
1997	16,613	380	16,233	0	582	440	435	343	15,596
1998	17,897	426	17,471	0	628	526	458	385	16,811
1999	17,615	169	17,446	0	673	592	452	420	16,490
2000	17,808	161	17,647	0	719	645	467	451	16,622
2001	18,754	169	18,585	0	737	697	488	481	17,529
2002	19,219	261	18,958	0	770	755	489	517	17,960
2003	19,668	253	19,415	0	781	799	577	554	18,310
2004	20,545	258	20,287	0	783	847	588	578	19,174
2005	22,361	263	22,098	0	790	895	600	611	19,465
2006	21,916	268	21,648	0	799	87	619	49	20,361
2007	22,543	271	22,272	0	926	128	688	79	20,722
2008	23,179	201	22,978	0	962	172	724	105	21,216
2009	23,782	206	23,576	0	984	218	744	122	21,714
2010	24,375	211	24,164	0	1001	267	756	133	22,218
2011	24,915	211	24,704	0	1,020	318	767	144	22,665
2012	25,474	211	25,263	0	1,040	371	779	154	23,130
2013	26,079	211	25,868	0	1,062	425	791	164	23,637
2014	26,642	211	26,431	0	1,086	481	803	174	24,098
2015	27,263	211	27,052	0	1,095	500	807	178	24,684

Historical Values (1996 - 2005):

Col. (2) - Col. (4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) for 1996 through 2005 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC) and Commercial /Industrial Demand Reduction (CDR). Col.(5) - Col.(9) for year 2004 are "estimated actuals" and are August values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula:Col. (10) = Col.(2) - Col.(6) - Col.(8).

Projected Values (2006 - 2015):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2004 are incorporated into the load forecast.

Col. (5) - Col. (9) represent all incremental conservation and cumulative load control. These values are projected August values and the conservation values are based on projections with a 1/2004 starting point for use with the 2004 load forecast.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
1996/97	16,490	626	15,864	0	578	311	417	139	15,495
1997/98	13,060	239	12,821	0	641	369	426	151	11,993
1998/99	16,802	149	16,653	0	692	404	446	164	15,664
1999/00	17,057	142	16,915	0	741	434	438	176	15,878
2000/01	18,199	150	18,049	0	791	459	448	183	16,960
2001/02	17,597	145	17,452	0	811	500	457	196	16,329
2002/03	20,190	246	19,944	0	847	546	453	206	18,890
2003/04	14,752	211	14,541	0	857	570	532	230	13,363
2004/05	18,108	225	17,883	0	862	583	542	233	16,704
2005/06	19,683	225	19,458	0	870	600	550	240	17,424
2006/07	22,294	228	22,066	0	964	58	605	20	20,647
2007/08	22,753	231	22,522	0	1,001	85	631	28	21,007
2008/09	23,245	161	23,084	0	1,042	113	656	38	21,395
2009/10	23,714	166	23,548	0	1,062	139	663	42	21,807
2010/11	24,155	171	23,984	0	1,084	167	669	47	22,188
2011/12	24,597	171	24,426	0	1,107	194	676	52	22,568
2012/13	25,061	171	24,890	0	1,133	222	683	57	22,967
2013/14	25,561	171	25,390	0	1,160	249	690	62	23,400
2014/15	26,244	171	26,073	0	1,189	275	696	67	24,017

Historical Values (1996/97 - 2005/06):

Col. (2) - Col. (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col.(9) for 1996/97 through 2005/06 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC) and Commercial/Industrial Demand Reduction (CDR).Col.(5) - Col.(9) for year 2004/05 are "estimated actuals" and are January values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (6) - Col. (8).

Projected Values (2006/07- 2014/15):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2004 are incorporated into the load forecast.

Col. (5) - Col.(9) represent all incremental conservation and cumulative load control. These values are projected January values and the conservation values are based on projections with a 1/2004 starting point for use with the 2004 load forecast.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH: Base Case

(1) Year	(2) Total	(3) Residential Conservation	(4) C/I Conservation	(5) Retail	(6) Sales for Resale GWH	(7) Utility Use & Losses	(8) Net Energy For Load	(9) Load Factor(%)
1996	87,007	971	1,043	85,654	1,353	6,306	84,993	60.2%
1997	89,243	1,213	1,177	88,015	1,228	5,771	86,853	59.7%
1998	95,318	1,374	1,282	93,992	1,326	6,206	92,662	59.1%
1999	94,365	1,542	1,365	93,412	953	5,829	91,458	59.3%
2000	99,097	1,674	1,434	98,127	970	7,059	95,989	61.4%
2001	101,739	1,789	1,545	100,768	970	7,222	98,404	59.9%
2002	107,755	1,917	1,639	106,522	1,233	7,443	104,199	61.9%
2003	112,160	2,008	1,759	110,648	1,511	7,386	108,393	62.9%
2004	112,031	2,106	1,834	110,500	1,531	7,464	108,091	59.9%
2005	115,440	2,205	1,934	113,933	1,506	7,498	111,301	58.9%
2006	114,965	148	84	113,420	1,545	8,104	114,733	59.9%
2007	118,820	234	153	117,298	1,522	8,339	118,433	60.2%
2008	123,720	325	192	122,654	1,066	8,736	123,203	60.8%
2009	128,211	423	217	127,129	1,082	9,013	127,571	61.5%
2010	132,519	526	228	131,421	1,098	9,310	131,765	62.1%
2011	135,540	632	238	134,443	1,098	9,522	134,670	62.1%
2012	138,666	742	249	137,569	1,098	9,742	137,675	62.0%
2013	141,993	856	260	140,896	1,098	9,976	140,877	62.2%
2014	145,244	972	272	144,146	1,098	10,204	144,000	62.2%
2015	148,456	1,021	278	147,368	1,098	10,430	147,167	62.2%

Historical Values (1996 - 2005):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (8).

Col.(3) & Col.(4) for 1996 through 2005 are DSM values starting in January 1988 and are annual (12-month) values.Col. (3) and Col. (4) for 2004 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWH reductions actually experienced each year .

Col. (5) & Col. (6) are a breakdown of Net Energy For Load in Col (2) into Retail and Wholesale .

Col. (9) is calculated using Col. (8) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (8)*1000) / ((Col.(2) * 8760)

Projected Values (2006 - 2015):

Col. (2) represents Net Energy for Load w/o DSM values. The values are extracted from Schedule 2.3, Col. (19).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation and are mid-year (6-month) values. The effects of conservation implemented prior to 2004 are incorporated into the load forecast.

Col. (5) & Col. (6) are a breakdown of Net Energy For Load in Col (2) , into Retail and Wholesale.

Col. (8) NEL projected values shown here do include the impact of conservation in Col. (3) and Col. (4). Therefore, these NEL values do not match those shown on schedule 2.3 because those values do not account for incremental conservation.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of
Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2005 ACTUAL		2006* FORECAST		2007* FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	18,108	8,062,406	21,792	8,499,714	22,294	8,729,836
FEB	14,738	7,029,844	17,964	7,723,932	18,378	8,113,972
MAR	16,747	8,247,459	16,949	8,609,537	17,340	8,778,122
APR	16,534	8,274,067	18,245	8,997,943	18,767	9,143,792
MAY	19,303	9,246,124	20,240	9,548,023	20,820	10,064,433
JUN	20,388	10,390,767	21,064	10,713,354	21,668	11,055,940
JUL	21,611	11,519,030	21,468	10,887,249	22,083	11,512,493
AUG	22,361	11,869,036	21,916	11,303,053	22,543	11,677,199
SEP	20,731	11,334,797	21,273	11,072,657	21,882	11,367,714
OCT	20,176	9,268,267	19,793	9,772,296	20,360	10,202,113
NOV	16,346	8,283,616	18,471	9,106,983	18,852	9,162,628
DEC	15,068	7,775,355	18,857	8,730,477	19,245	9,011,423
TOTALS		111,300,768		114,965,218		118,819,664

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation and are consistent with values shown in Col. (19) of Schedule 2.3 and Col (2) of Schedule 3.3.

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CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990's and has since utilized the process to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of potential new power plants, the primary subjects of this document, are determined as part of the IRP process work. This section discusses how FPL applied this process in its 2005 and early 2006 resource planning work.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental "steps" to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Determine the economics for the total utility system with each of the competing options and resource plans; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

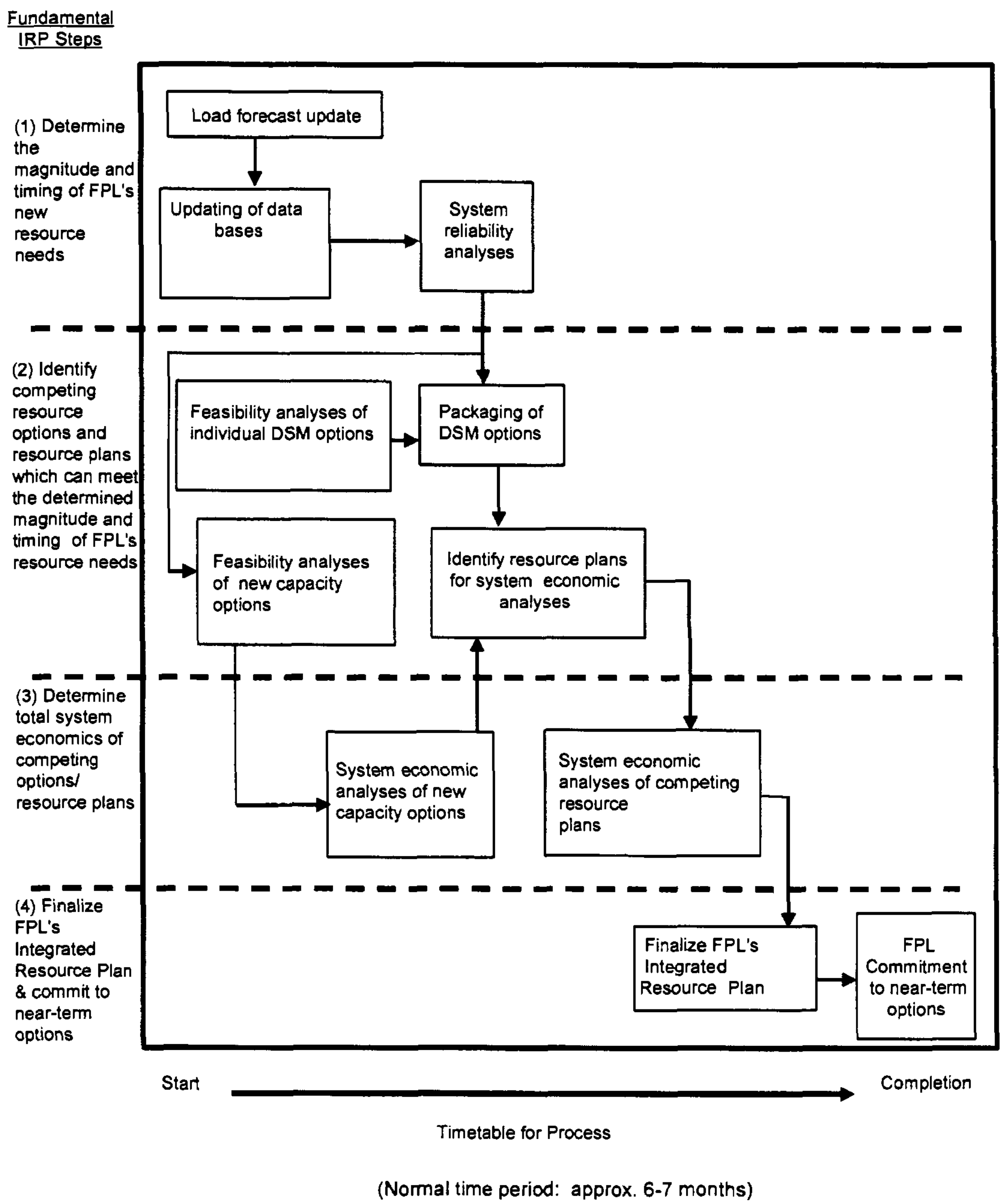

Figure III.A.1: Overview of FPL's IRP Process

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of these four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed. Also determined in this step is when the MW are needed to meet FPL's planning criteria. This step is often referred to as a resource adequacy or reliability assessment for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include: delivered fuel price projections, current financial and economic assumptions, and power plant capability and reliability assumptions. FPL also includes key assumptions regarding three specific resource areas: (1) near-term construction capacity additions, (2) short-term, firm capacity purchase additions, and (3) short-term and long-term DSM implementation.

The first of these assumptions is based on FPL's ongoing engineering and construction activities to add near-term capacity. These construction activities involve a new CC unit at FPL's Turkey Point site scheduled to come in-service by mid-2007. FPL selected this capacity option after conducting an RFP during 2003. The addition was approved by the FPSC in June of 2004 and the Governor and Siting Board approved certification of the plant location, construction, and operation of the new CC unit in February, 2005.

The second of these assumptions involves short-term, firm capacity purchase additions. These firm capacity purchases are from a combination of utility and independent power producers. Several new near-term firm capacity purchases are now projected in this year's Site Plan. Details, including the annual total capacity values for these purchases are presented in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's recent resource planning work.

The third of these assumptions involves DSM. Since 1994, FPL's resource planning work has assumed that the DSM MW called for in FPL's approved DSM Goals is achieved per plan in its analyses. This was again the case in FPL's most recent planning work, as its new DSM Goals that address the years 2005 through 2014, and that were approved by the FPSC in August 2004, are assumed to be achieved per plan.

FPL realized significant load growth in 2005. When this growth was reviewed it was determined that population growth beyond that forecast was responsible for the change. As a result, the load forecast was updated in November 2005. At that time, the amount and timing of cost-effective DSM was reviewed resulting in the identification of an additional 309 MW of Summer demand reduction capability. This additional DSM capability can be implemented with additional program signups through 2008, plus modifications to existing programs. These additional MW of DSM were also accounted for prior to making projections of new construction additions that are discussed in this document.

These key assumptions, plus the other updated information, are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's resource needs. This determination is accomplished by system reliability analyses which are typically based on a dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry.

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its native load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the generation resource adequacy of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss–of-load probability or LOLP. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of the "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program currently used by FPL.

The result of the first fundamental step of resource planning is a projection of how many new MW of resources are needed to meet both reserve margin and LOLP criteria, and thus maintain system reliability, and of when the MW are needed. Following the significantly higher loads experienced during the summer of 2005, FPL's peak load forecast was revised upwards in November 2005 as discussed in Chapter II. Consequently, FPL's projected capacity needs have both accelerated and increased in magnitude. Information regarding the timing and magnitude of these resource needs is used in the second fundamental step: identifying resource options and resource plans that can meet the determined magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, feasibility analysis of new capacity options are conducted to determine which new capacity options appear to be the most competitive on FPL's system. These analyses also establish capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs.

The individual new capacity options are then "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new resource needs are met. The creation of these competing resource plans is typically carried out using dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs were identified. These resource plans were then compared on an economic basis to determine FPL's most cost-effective self build alternative.

In 2005, FPL issued a Request for Proposals (RFP) seeking proposals for firm capacity additions in 2009–2011. FPL received five such proposals in response to this solicitation (one proposal was subsequently withdrawn by its bidder). These options were also analyzed in FPL's resource planning work as alternatives to FPL's most cost-effective self build alternative.

Step 3: Determining the Total System Economics:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for comparing the system economics of these resource plans. In its 2005 resource planning work, FPL performed much of this work of combining resource options into resource plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI). The EGEAS model was also used to perform much of the basic economic analyses of the resource plans. For various analyses, including the analyses of proposals received in response to FPL's RFP, FPL also applied the P-MArea production cost model to develop a more detailed perspective of the production costs for the various resource plans developed in the EGEAS model. The P-MArea model is the model used by FPL to develop the Fuel Cost Budget and to conduct other production cost-related analyses including the detailed economic analysis of RFP proposals.

In 2005, FPL also utilized several other models in its resource planning work. For DSM analyses, FPL used its DSM cost-effectiveness model; an FPL spreadsheet model utilizing the FPSC's approved methodology for analyzing the cost-effectiveness of individual DSM measures/programs, and its non-linear programming model for analyzing the potential for lowering system peak loads through additional load management capacity.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the intent of minimizing FPL's leveled system average rate (i.e., a Rate Impact Measure or RIM methodology). However, in cases such as existed for much of FPL's most recent planning work in which the DSM contribution was assumed as a given and the only competing options were new generating units and purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. Consequently, the competing options and plans were evaluated on a cumulative present value system revenue requirement basis that includes the system capital and operating costs of the new capacity options and existing FPL units.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps were used to develop the future generation plan. This plan is presented in the following section.

III.B Incremental Resource Additions

FPL's projected incremental generation capacity additions/changes for 2006 through 2015 are depicted in Table III.B.1 (the planned DSM additions are shown separately in Tables III.D.1 and III.D.2). These capacity additions/changes result from a variety of actions including: changes to existing units (which are frequently achieved as a result of plant component replacements during major overhauls), changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, implementation of additional cost-effective DSM, and by projected construction of new generating units.

As shown in Table III.B.1, the capacity additions are largely made up of committed new construction, new purchases, and proposed self-build alternatives. (The additional DSM MW are not presented in this table but have been accounted for prior to making these new capacity option projections.) The new construction contribution includes the addition of a new CC unit in 2007 at FPL's Turkey Point site and the planned addition of new CC units in 2009 and 2010 at the West County Energy Center site. FPL is also projecting additional firm capacity power purchase contributions for the 2006 through 2009 time period. These purchases, combined with the Turkey Point and West County Energy Center construction projects (plus the additional cost-effective DSM MW), address FPL's resource needs for 2006 through 2010 with the exception of 2008. The 2008 need is partially addressed by these resource additions.

FPL anticipates addressing its remaining 2008 need with additional purchases/leases, enhancements to its existing units, and/or the construction of one CT. For purposes of this planning document, FPL projects the construction of one unsited CT.

FPL's resource need for 2011 will be addressed with additional cost-effective DSM, power purchases, capacity increases to FPL's existing units, or by construction of new CTs. For purposes of this planning document, FPL projects the construction of two unsited CT's.

FPL projects the construction of two new advanced technology coal units; one each in 2012 and 2013. These two units will use supercritical pulverized combustion technology in concert with an advanced emissions control suite to meet FPL's resource needs for 2012 and 2013 and greatly enhance FPL's fuel diversity. The amount of capacity needed and the technologies that would ultimately be chosen to meet the need for these years will be based on FPL's ongoing review of technology, environmental requirements, regulation and economic factors and will not be restricted to a single technology.

For addressing its 2014 and 2015 resource needs in this planning document, FPL projects the construction of one unsited CT in 2014, one unsited CT in 2015, and one unsited 2x1 CC any of which could be converted to coal gasification once the technology is able to meet reliability and cost-effectiveness standards.

Table III.B.1: Projected Capacity Changes for FPL [1]

Projected Capacity Changes and Reserve Margins for FPL [1]

		Net Capacity Changes (MW)	
		Winter [2]	Summer [3] [8]
2006	Changes to Existing QF Purchases [4]	(132)	(136)
	Changes to existing Units	205	142
	Changes to Non-QF Purchases [5]	147	440
2007	Turkey Point Combined Cycle #5 [6]	---	1,144
	Changes to existing Units	70	77
	Changes to Non-QF Purchases [5]	73	(412)
2008	Changes to existing Units	4	12
	Turkey Point Unit #5 [6]	1,181	---
	Unsited Combustion Turbine [6]	---	160
	Changes to Non-QF Purchases [5]	(252)	---
2009	Changes to Existing QF Purchases [4]	---	(51)
	Changes to Non-QF Purchases [5]	(326)	(105)
	West County Unit #1 [6]	---	1,219
	Unsited Combustion Turbine [6]	181	---
2010	West County Unit #1 [6]	1,335	---
	Changes to Existing QF Purchases [4]	(51)	(47)
	West County Unit #2 [6]	---	1,219
	Changes to Non-QF Purchases [5]	(461)	(683)
2011	West County Unit #2 [6]	1,335	---
	Unsited 2x0 Simple Cycle CT [6]	---	320
	Changes to Existing QF Purchases [4]	(92)	(45)
	Changes to Non-QF Purchases [5]	(1)	---
2012	Supercritical Pulverized Coal Unit # 1 [6] [7]	---	850
	Unsited 2x0 Simple Cycle CT [6]	362	---
	Changes to Non-QF Purchases [5]	---	(158)
2013	Supercritical Pulverized Coal Unit # 1 [6] [7]	855	---
	Supercritical Pulverized Coal Unit # 2 [6] [7]	---	850
	Changes to Non-QF Purchases [5]	(180)	---
2014	Supercritical Pulverized Coal Unit # 2 [6] [7]	855	
	Unsited 1x 0 Simple Cycle CT [6] [9]	---	160
2015	Unsited 1x 0 Simple Cycle CT [6] [9]	181	---
	Unsited 1x 0 Simple Cycle CT [6] [9]	---	160
	Unsited 2x1 Combined Cycle [6] [9]	---	553
	TOTALS =	**5,289**	**5,669**

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are values for January of year shown.
(3) Summer values are values for August of year shown.
(4) These are firm capacity and energy contracts with Cogen & Small Power Producers. See Table I.B.1 for more details.
(5) These are firm capacity purchases from Non-QF facilities. See Tables I.D.1 and Table I.D.2 for more details.
(6) All new unit additions are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.
(7) FPL is currently in the process of selecting a site(s) for these advanced technology coal units. FPL expects to announce the selected site(s) by June 2006.
(8) FPL reserve margin values are shown to include what is committed or firmly planned. FPL will continue to pursue the most cost effective alternatives available to meet the then forecasted need with a 20% reserve margin, such as DSM resources that may be added in intervening years or additional purchases.
(9) FPL will continue to pursue development of technologies, such as SCPC or IGCC to meet the needs in these later years.

III.C Issues Impacting FPL's Recent Planning Work

FPL's 2005 and early 2006 planning efforts have continued to address two issues that were identified in previous Site Plans as being items of on-going importance. Those two issues are: (1) the need to address the imbalance between regional load and generating capacity located in southeast Florida, and (2) the desire to maintain and enhance a balanced fuel supply in the FPL system.

1. Southeast Imbalance

There currently is an imbalance between regionally installed generation and peak load in southeast Florida. A significant amount of energy required in the southeast Florida region during peak periods is provided through the transmission system from plants located outside the region. Based on the forecast for continued load growth in this region, the imbalance between generation and load is projected to increase unless additional generation capacity is periodically located within this region.

FPL's prior planning work concluded that either additional installed capacity in this region or transmission capacity capable of delivering additional electricity from outside the region would be required to address this imbalance. Delivering additional electricity from outside the region incurs both increased transmission-related costs (system integration equipment, losses, and impact to operating costs) and the costs of additional capacity that would be built outside of the region. The evaluation conducted as part of FPL's Request for Proposals (RFP) process determines the most cost-effective means to meet FPL's needs by considering all cost components of FPL's next planned generating unit (NPGU) and alternative options, including transmission-related costs. The locations of the NPGU, and the locations of proposed units included in the alternative option combinations, contribute to the transmission-related costs determined in the evaluation. The results of the RFP evaluations confirm that because of the existing imbalance, generating units located in the southeast Florida region contribute significantly lower transmission-related costs than do those located outside the region.

Partly because of the lower transmission-related costs resulting from their location, Turkey Point Unit #5 and West County Units #1 and #2 were evaluated as the most cost-effective options to meet FPL's 2007 and 2009-2010 capacity needs, respectively. Adding Turkey Point Unit #5 will significantly reduce the imbalance between generation and load in southeast Florida. However, assuming no other resources are added, the imbalance is projected to re-develop within several years because of the continued load growth of approximately 250-300 MW per year in this region. Therefore, the southeast Florida imbalance is a recurring factor in the calculation of transmission-related costs which are an integral part of the evaluation of new capacity additions. This was again the case in FPL's 2005 RFP, which resulted in the identification of West County Units #1 and #2 as the most cost effective alternatives to meet the need of a growing system. The RFP analysis showed that the West County units offered significantly lower transmission related costs in comparison to other proposals evaluated. Based on the current load forecast and system resources the combined effect of the Turkey Point Unit #5 and the West County Units #1 and #2 unit additions (assuming an affirmative Determination of Need is granted for West County Units #1 and #2) would substantially mitigate the imbalance issue until near the end of the ten year planning horizon addressed in this Site Plan.

2. Balanced Fuel Supply.

FPL also has taken positive steps in 2005 to address the issue of fuel diversity in the FPL system on a number of fronts. Once a resource need is established, and after accounting for all reasonably available, cost-effective DSM alternatives, FPL recognizes that there are many resource options that can contribute to fuel diversity. The following discusses the key activities FPL has undertaken to develop resources that are not reliant on oil or natural gas as the primary fuels.

In March 2005, FPL presented its analysis of the benefits and risks of adding advanced technology coal generation to the FPL System. The *Report on Clean Coal Generation* (Coal Study) was presented to the FPSC summarizing FPL's findings. Based on the assumptions at the time these findings showed that, while there are uncertainties surrounding the costs of coal-fueled generation, significant cost and fuel reliability benefits may be obtained by adding advanced technology coal generation. During 2005, FPL and its customers were subjected to a volatile natural gas and oil commodity market. The long-term future price expectation for these fuels has risen, increasing the value offered by advanced technology coal generation above that documented in the Coal Study. Understandably, FPL maintains its pursuit of two new supercritical pulverized coal units with advanced emission control technology, one each in 2012 and 2013.

In September 2005, FPL issued a two-part RFP. Part I solicited proposals to address FPL's 2009-2011 capacity needs and this solicitation was open to all fuel-types and technologies. These proposals were received on November 9, 2005. Only natural gas-fired generation or utility system-based capacity was offered in response to Part I of the RFP. Part II of the RFP identified that FPL plans to request proposals in 2006 limited to fuel diverse generation alternatives for its 2012-2014 capacity needs. FPL held a meeting in December 2005 with interested parties to identify issues of concern and encourage market interest in the process. As part of its development efforts in 2005, FPL attempted but was unsuccessful in its petition for a zoning variance in St. Lucie County to accommodate a selected site for an advanced technology coal plant. Because of the significant economic and reliability benefits offered by advanced technology coal generation, FPL continues to actively pursue other sites for advanced technology coal plant and will make every effort to bring two units into service in 2012 and 2013, respectively.

During early 2005, FPL completed an RFP for Liquified Natural Gas (LNG) supply by concluding that no proposal offered economic benefits that warranted entering into a long-term supply arrangement necessary to support such a facility. FPL's view remains that LNG can be an effective means to add fuel supply diversity to FPL, and the company will continue to investigate the feasibility of such projects in the coming years.

FPL has maintained an interest in pursuing Integrated Gasification Combined Cycle (IGCC) technology. In the past year, FPL has worked with the industry's leading IGCC developers to explore creative means that might bring this technology to FPL's customers. This effort is focused on resolving reliability and cost uncertainty and demonstrating that addition of the technology will benefit our customers. FPL's planned capacity for 2014 and 2015 in this Site Plan are such that they could support an IGCC technology alternative, should these areas of uncertainty be resolved by 2008.

During 2005 and early 2006, 9 major US utilities have announced an intent to pursue new nuclear generation facilities. FPL has begun the process to review the prospect for new nuclear generation and the advisability of initiating significant financial commitments in the face of schedule, cost and regulator uncertainties. FPL believes that being an active participant in this process is necessary in order to preserve new nuclear generation as a viable alternative in maintaining a balanced fuel supply. Therefore, FPL will be taking the necessary steps in the near future to preserve new nuclear generation as an option for enhancing fuel diversity in the FPL system.

FPL also has been involved in activities in 2005 to investigate adding or maintaining renewable resources as a part of its generation supply. These activities include discussions with existing facilities aimed at maintaining or extending current agreements. Additionally, FPL is actively investigating a site for a demonstration wind generation project on the East coast of Florida. The project is estimated to be in the 10 MW range and may be on-line as early as 2007. FPL maintains its interest in new and developing technologies, such as solar photovoltaic and ocean current turbine technology. FPL supports pilot projects in solar photovoltaic technology throughout its system helping to provide platforms to refine the technology and reduce its cost. The common outlook for renewable technologies is that they may become more cost-effective over the next ten years and may be feasible additions to provide some diversity to the system fuel supply. FPL shares, with others, the objective of fostering the development and operation of additional cost-effective renewable sources of generation. Based upon available information, however, FPL does not believe that renewable resources are likely to contribute more than a modest amount to satisfying the annual electric load growth in FPL's territory.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance fuel diversity in its capacity resource mix including purchasing power from coal-fired facilities when such power becomes available. FPL also plans to maintain the ability to utilize fuel oil at those existing units that have that capability, although price factors currently limit the expected use of these facilities.

III.D Demand Side Management (DSM)

1. Currently Approved Programs and Goals:

FPL's currently approved DSM programs are summarized as follows:

Residential Conservation Service: This is an energy audit program designed to assist residential customers in understanding how to make their homes more energy-efficient through the installation of conservation measures/practices.

Residential Building Envelope: This program encourages the installation of energy-efficient ceiling insulation and reflective roofs in residential dwellings that utilize whole-house electric air conditioning.

Duct System Testing and Repair: This program encourages demand and energy conservation through the identification of air leaks in whole-house air conditioning duct systems and by the repair of these leaks by qualified contractors.

Residential Air Conditioning: This is a program to encourage customers to purchase higher efficiency central cooling and heating equipment.

Residential Load Management (On-Call): This program offers load control of major appliances/household equipment to residential customers, in exchange for monthly electric bill credits.

New Construction (BuildSmart): This program encourages the design and construction of energy-efficient homes that cost-effectively reduce coincident peak demand and energy consumption.

Residential Low Income Weatherization: This program addresses the needs of low-income housing retrofits by providing monetary incentives to various housing authorities, including weatherization agency providers (WAPS), and non-weatherization agency providers (non-WAPS). These incentives are used by the housing authorities to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting.

Business Energy Evaluation: This program encourages energy efficiency in both new and existing commercial/industrial facilities by identifying DSM opportunities and providing recommendations to the customer.

Commercial/Industrial Heating, Ventilating, and Air Conditioning: This program encourages the use of high-efficiency heating, ventilation, and air conditioning (HVAC) systems in commercial/industrial facilities.

Commercial/Industrial Efficient Lighting: This program encourages the installation of energy-efficient lighting measures in commercial/industrial facilities.

Business Custom Incentive: This program encourages commercial/industrial customers to implement unique energy conservation measures or projects not covered by other FPL programs.

Commercial/Industrial Load Control: This program reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages, in exchange for monthly electric bill credits. (This program was closed to new participants in 2000).

Commercial/Industrial Demand Reduction: This program, which started in 2002, is similar to the Commercial/Industrial Load Control program mentioned above in continuing the objective to reduce peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits.

Commercial/Industrial Building Envelope: This program encourages the installation of energy-efficient building envelope measures, such as roof/ceiling insulation and reflective roof coatings for commercial/industrial facilities.

Business On Call: This program offers load control of central air conditioning units to both small non–demand-billed and medium demand-billed commercial/industrial customers in exchange for monthly electric bill credits.

FPL's approved DSM Goals for summer MW reduction from these programs are presented in Table III.D.1.

Year	Goal Cumulative Summer MW
2005	74
2006	142
2007	212
2008	287
2009	366
2010	448
2011	532
2012	619
2013	708
2014	802

Table III.D.1: FPL's Summer MW Reduction Goals for DSM (At the Meter)

Table III.D.1 reflects FPL's DSM Goals for 2005–2014 as approved by the Florida Public Service Commission in June, 2004. These annual cumulative values assume a 1/1/05 starting point.

2. Research and Development

FPL continues to support research and development activities. Historically, FPL has performed extensive DSM research and development. FPL will continue such activities, not only through its Conservation Research and Development program, but also through individual research projects. These efforts will examine a wide variety of technologies that build on prior FPL research where applicable and will expand the research to new and promising technologies as they emerge.

Conservation Research and Development Program

FPL's Conservation Research and Development Program is designed to evaluate emerging conservation technologies to determine which are worthy of pursuing for program development and approval. FPL has researched a wide variety of technologies such as condenser coil cleaner and coating, ultraviolet lights for evaporator coils, Energy Recovery Ventilators (ERV), fuel cell demonstrations, CO_2 ventilation control, two-speed air handlers, and duct plenum repair. Many of the technologies examined have resulted in enhancements to existing programs or the development of new programs such as

Residential New Construction, Commercial/Industrial Building Envelope, and Business On Call.

Green Power Pricing Research Project

Under this project, FPL is examining the feasibility of purchasing tradable renewable energy credits generated from new renewable resources including solar-powered technologies, biomass energy, landfill methane, wind energy, low impact hydroelectric energy, and/or other renewable sources. Residential customers who participate are charged higher premiums for purchasing the tradable renewable energy credits associated with electric energy generated by these sources.

Development of the Green Pricing program was completed and filed with the FPSC in August 2003. As part of this process, a supply contract was put into place that allows FPL to match supply with demand for green energy. Tradable renewable energy credits are used to supply the renewable benefits required of this project. The FPSC approved the program on December 2, 2003 with program implementation the first quarter of 2004. As of year-end 2005, FPL had over 23,000 project participants.

On Call Incentive Reduction Pilot

In March 2003, FPL received FPSC approval to perform a pilot for its On Call Program. Under the pilot FPL is offering to new participants a residential load control service similar to the On Call Program at a reduced incentive level. The offering of this pilot is allowing FPL to test its market research data and gauge whether FPL can repackage its current residential load control service, minimize customer attrition, achieve current goals for residential load control, and, ultimately, change On Call incentive levels without damaging FPL system reliability.

Business Green Energy Research Project

As mentioned above, FPL currently has a R&D project addressing residential customer acceptance of green energy. In an attempt to determine business customer acceptance of green pricing rates, FPL is investigating if it is feasible to design and implement a Green Energy Program that addresses these customer segments.

3. Additional DSM Contributions

FPL's updated load forecast previously discussed in Chapter II, and the corresponding acceleration and growth in FPL's projected resource needs previously discussed in this chapter, will enable FPL to cost-effectively implement additional DSM above what is projected in FPL's approved DSM Plan. FPL will petition the FPSC starting in the second quarter of 2006 for approval of modifications to a number of its existing DSM programs that will enable FPL to achieve additional cost-effective DSM MW. The projected additional peak load reduction impacts of these DSM program modifications, which includes both new program measures and increased program signups, is presented in Table III.D.2

Year	Additional Summer MW @ Generator
2006	39
2007	229
2008	289
2009	309

Table III.D.2: FPL's Additional Summer MW of DSM

FPL's analyses of these additional DSM contributions has focused to-date on addressing FPL's near-term (2006–2008) capacity needs. Program implementation that occurs between the summer of 2008 and the end of 2008 are shown as a "carryover" impact to the summer of 2009. On-going analyses will continue to examine the potential for additional cost-effective DSM contributions for subsequent years 2009-on.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy for FPL's retail and wholesale customers. The following table presents certain of FPL's proposed future additions of 230 kV and 500 kV bulk transmission lines including those corresponding to proposed generating facilities and those that must be certified under the Transmission Line Siting Act.

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (kV)	(7) Capacity (MVA)
FPL	Collier (1)	Orange River #3	54	Dec-06	230	759
FPL	St. Johns	Pringle	26	Dec-08	230	759
FPL	Manatee	BobWhite	30	Dec-11	230	1190
FPL	Eve	Sweatt	25	Jun-12	230	759

(1) Final order certifying the corridor was issued on July 19 of 2004.

Table III.E.1: List of Proposed Power Lines

In addition, there will be transmission facilities needed to connect several of FPL's committed and projected capacity additions to the system transmission grid. These transmission facilities for the committed capacity additions at FPL's existing Turkey Point plant and for the projected capacity additions at the West County Energy Center site areas are described below.

Since the projected capacity additions for 2008, and for 2011 through 2015, are as-yet unsited, or their transmission facility needs can only be determined after sites for earlier units are determined, no transmission facilities information is provided for these units. This information will be provided in the 2006 Site Plan Addendum for the 2012 and 2013 advanced technology coal projects when sites have been selected.

III.E.1 Transmission Facilities for Turkey Point Unit #5

The work required to connect the new capacity addition at Turkey Point in 2007 with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 5 breakers to connect the four CT's and one steam turbine.
2. Construct two string busses to connect the collector busses and main switchyard.
3. Add five main step-up transformers (4-225MVA, 1-560 MVA), one for each CT and one for the steam turbine.
4. Add a new two breaker bay to connect the collector bus at the Turkey Point switchyard.
5. Add a second two breaker bay at the Turkey Point switchyard to connect the other collector bus.
6. Add relays and other protective equipment.
7. Expand site and relay vault for two new line terminals at Turkey Point switchyard.

II. Transmission:

1. Upgrade the Turkey Point-Galloway Tap 230kV transmission line section to 1418 Amps.
2. Upgrade the Turkey Point–McGregor-Florida City 230kV transmission line section to 1403 Amps.
3. Upgrade the Turkey Point-Miller 230kV transmission line section to 1356 Amps.
4. Upgrade the Miller-Killian 230kV transmission line section to 1315 Amps.

III.E.2 Transmission Facilities for West County Unit #1

The work required to connect West County Energy Center Unit #1 projected to be added in 2009 with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 5 breakers to connect the four CT's and one steam turbine.
2. Construct two string busses to connect the collector busses and main switchyard to Corbett 230 kV Substation.
3. Add five main step-up transformers (4-225 MVA, 1-560 MVA), one for each CT and one for the steam turbine.
4. Add a new Bay #4 with 3 breakers at the Corbett 230 kV main switchyard. Connect one string buss from the collector yard and relocate the Alva 230 kV terminal from Bay #3 to new Bay #4.
5. Connect second collector string buss to Bay #3.
6. Add relays and other protective equipment.

II. Transmission:

1. No upgrades expected to be necessary at this time.

III.E.3 Transmission Facilities for West County Unit #2

The work required to connect West County Energy Center Unit #2 projected to be added in 2010 with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 4 breakers to connect the three CT's, and one ST.
2. Construct two string busses to connect the collector busses and main switchyard to Corbett 500kV Substation.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA) one for each CT, and one for the ST.
4. At Corbett Sub, install one breaker and relocate Martin #2 500 kV line from Bay 2S to Bay 2N. Install one West County 500 kv string bus into Bay 2S.
5. At Corbett Sub, install one breaker and second West County 500 kV string bus into Bay 1S.
6. Add relays and other protective equipment.

II. Transmission:

1. No upgrades expected to be necessary at this time.

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to utilize renewable energy technologies to meet its customers' current and future needs. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various technologies.

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970's in demonstrating the first residential solar photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities on both a daily and annual basis in Florida. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-Kilowatt (KW) system was placed into operation in 1984. (The system was removed in 1990 to make room for substation expansion after the testing of this PV installation was completed.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. The FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's recent Green Pricing effort (which is discussed on the following page).

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first and only utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was not cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980's, FPL introduced another renewable energy program. FPL's Passive Home Program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for 6 passive homes with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the Florida Public Service Commission to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test may be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, and various customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

More recently, FPL has analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach does not require all of its customers to bear PV's high cost, but allows customers who are interested in facilitating the use of renewable energy the means to do so. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund that FPL used to make PV purchases in bulk quantities. PV modules were then installed and delivered PV-generated electricity directly into the FPL grid. Thus, when sunlight is available, the PV-generated electricity displaces an equivalent amount of fossil fuel-generated electricity.

FPL's basic approach, which has been termed Green Pricing, was initially discussed with the FPSC in 1994. FPL's efforts to implement this approach were then formally presented to the FPSC as part of FPL's DSM Plan in 1995 and FPL received approval from the FPSC in 1997 to proceed. FPL began the effort in 1998 and received approximately $89,000 in contributions (that significantly exceeded the goal of $70,000). FPL purchased the PV modules and installed them at FPL's Martin Plant site.

FPL initiated two new renewable efforts in 2000. FPL's first new initiative in 2000 was the Green Energy Project. The objectives of this Project were to: determine customer interest in an on–going renewable energy program, determine their price responsiveness and views on the different renewable technologies, and identify potential renewable energy supply sources that would meet the forecasted customer demand for this type of product. FPL both conducted customer research and issued a Request for Proposals (RFP) in 2001 to solicit proposals to potentially supply energy only (MWH) from new renewable sources. This Project formed the basis for FPL's existing Green Power Pricing Research Project, and then led to FPL's Business Green Energy Research Project, that are discussed in Section III.D.2.

The second effort initiated in 2000 was FPL's Photovoltaic Research, Development, and Education Project. This demonstration project's objectives were to: increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks (as well as the total annual energy capabilities of roof tile PV systems), and assess the homeowner's financial benefits and costs of PV roof tile systems. This project was completed in 2003.

FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy and as-available energy have been purchased by FPL from these developers. (Please refer to Tables I.B.1,I.B.2, and Table I.C.1).

Additionally, FPL is actively investigating a site for a demonstration wind generation project on the East Coast of Florida. The project is estimated to be in the 10 MW range and may be on-line as early as 2007. FPL also maintains an interest in other developing renewable technologies such as ocean current turbine technology.

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980's, FPL relied primarily on a combination of oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fired generation. In the early 1980's FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership and additional purchases from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the

partial acquisition (76%) of Scherer Unit #4 in 1989. Starting in 1997, petroleum coke was added to the fuel mix as a blend stock with coal at SJRPP.

The trend in recent years has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective combined cycle generating units. This planning document shows a slowing of that trend as FPL's plans have realized the benefits of efficient gas-fired generation but also recognize that adding natural gas-fired additions exclusively would, in the long term, create an unbalanced generation portfolio. FPL projects the addition of a new gas-fired unit in 2007 at Turkey Point and new gas-fired units at West County in 2009 and 2010. These units will provide highly efficient generation that will benefit the entire FPL system by reducing transmission related costs, mitigate the load to generation imbalance in the southeast portion of the system and dramatically improve the overall system generation efficiency. FPL plans to compliment these additions with two advanced technology coal units in 2012 and 2013, respectively. The addition of coal-fueled generation will provide fuel supply diversity and assist in stabilizing fuel cost volatility through diversification.

FPL's future resource planning work will remain focused on identifying and evaluating alternatives that would maintain or enhance FPL's long-term fuel diversity. These fuel diversity-enhancing alternatives may include: the purchase of power from new coal-based facilities, obtaining access to diversified sources of natural gas such as LNG, and preserving FPL's ability to utilize fuel oil at its existing units. The evaluation of the feasibility and cost-effectiveness of these, and other possible alternatives, will be an ongoing part of future planning cycles.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2015 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

2. Fuel Price Forecasts

FPL's long-term oil price forecast assumes that worldwide demand for petroleum products will grow moderately throughout the planning horizon. Non-OPEC crude oil supply is projected to increase as new and improved drilling technology and seismic information will reduce the cost of producing crude oil and increase both recoveries from existing fields and new discoveries. However, the rate of increase in non-OPEC supply is projected to be slower than that of petroleum demand, resulting in an increase in OPEC's market share throughout the planning horizon. As OPEC gains market share, prices for crude oil and petroleum products are projected to increase.

FPL's natural gas price forecast assumes that domestic demand for natural gas will grow throughout the planning horizon, primarily due to increased requirements for electric generation. Domestic natural gas production will slowly decline as new and improved drilling technology and seismic information and resulting new finds will only reduce the projected rate of decline in the overall domestic resource base. The rate of decline in domestic natural gas production is projected to be offset by the anticipated increase in U.S. imports from Canada during the next decade, with the development of the MacKenzie Delta region, and the continued increase in re-gasified Liquefied Natural Gas (LNG) imports over the planning horizon. Further enhancement in domestic supply is assumed with the development and delivery of the proven natural gas reserves on the North Slope of Alaska sometime in the next decade.

As demand for natural gas in Florida grows, it is anticipated that the Gulfstream pipeline will fill existing capacity, and along with the Florida Gas Transmission (FGT) pipeline system, expand beyond current capacity to meet the growing requirements of the State of Florida. When coupled with the new Cypress Pipeline from the Elba Island, Georgia LNG Re-gasification Terminal to FGT and the potential for a additional re-gasified LNG Terminal, there is expected to be sufficient natural gas supply for FPL's customers and the State of Florida's continued needs.

FPL's coal price forecast assumes an ample supply of domestic coal, and the availability of imported coal, to meet a gradual but steady increase in U.S. demand in the electric generation sector over the planning horizon. The coal price forecast for FPL's existing coal plants at SJRPP and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements. FPL's petroleum coke price forecast assumes that the petroleum industry will continue to add coke production facilities in the U.S., as well as in the Caribbean Basin, in order to maximize refinery production of light products. This trend will continue to result in sufficient availability of petroleum coke, at delivered prices significantly below delivered coal prices, to support a gradual, but steady growth in the demand for petroleum coke in the U.S. electric utility industry.

In order to support the proposed coal requirements in the 2012 and 2013 time period, FPL is currently exploring the opportunities for a competitive coal and petroleum coke delivery system. This effort includes the opportunity for competing rail service from Central Appalachia to Florida, a waterborne receiving facility on both the east and west coasts of Florida, and competing rail service from these potential ports to the solid fuel site. A highly competitive coal and petroleum coke delivery network is essential to ensure both the lowest cost and most reliable fuel supply to FPL's customers.

Schedule 5
Fuel Requirements 1/

	Fuel Requirements	Units	Actual 2/		Forecasted									
			2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	Nuclear	Trillion BTU	252	235	264	254	269	265	264	268	265	264	268	265
(2)	Coal	1,000 TON	3,319	3,098	3,563	3,751	4,086	4,044	3,757	4,041	5,194	7,665	8,528	8,770
(3)	Residual (FO6)- Total	1,000 BBL	31,250	30,217	22,292	21,358	18,188	9,484	5,841	6,188	4,957	4,037	4,022	3,480
(4)	Steam	1,000 BBL	31,250	30,217	22,292	21,358	18,188	9,484	5,841	6,188	4,957	4,037	4,022	3,480
(5)	Distillate (FO2)- Total	1,000 BBL	406	344	37	20	53	10	15	13	0	6	0	0
(6)	Steam	1,000 BBL	86	0	0	0	0	0	0	0	0	0	0	0
(7)	CC	1,000 BBL	321	194	35	12	43	0	0	0	0	0	0	0
(8)	CT	1,000 BBL	0	150	2	8	10	10	15	13	0	6	0	0
(9)	Natural Gas -Total	1,000 MCF	311,057	345,851	390,582	417,682	452,403	537,775	602,318	626,362	625,398	610,206	608,704	636,225
(10)	Steam	1,000 MCF	51,792	44,167	28,713	28,922	26,501	66,298	79,330	71,405	58,759	68,380	56,227	53,792
(11)	CC	1,000 MCF	252,692	296,076	361,019	387,877	424,440	470,259	521,024	547,784	555,975	526,485	533,778	556,639
(12)	CT	1,000 MCF	6,573	5,608	850	882	1,462	1,217	1,965	7,173	10,664	15,341	18,699	25,795

1/ Reflects fuel requirements for FPL only.
2/ Source: A Schedules.

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 1/ 2004	2005	Forecasted 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	Annual Energy Interchange 2/	GWH	10,258	10,221	10,938	11,103	11,286	11,268	9,844	8,556	8,545	8,539	8,400	8,085
(2)	Nuclear	GWH	23,013	21,406	24,025	23,198	24,537	24,111	24,042	24,467	24,192	24,043	24,467	24,121
(3)	Coal	GWH	6,315	5,765	6,710	7,052	7,627	7,610	7,117	7,603	11,208	18,167	20,743	21,174
(4)	Residual(FO6) -Total	GWH	19,709	19,069	14,628	14,016	11,907	6,340	3,921	4,153	3,333	2,717	2,703	2,341
(5)	Steam	GWH	19,709	19,069	14,628	14,016	11,907	6,340	3,921	4,153	3,333	2,717	2,703	2,341
(6)	Distillate(FO2) -Total	GWH	200	186	26	13	38	4	6	5	0	2	0	0
(7)	Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	57	123	25	9	33	0	0	0	0	0	0	0
(9)	CT	GWH	143	63	1	4	5	4	6	5	0	2	0	0
(10)	Natural Gas -Total	GWH	40,970	47,114	52,913	57,082	61,810	72,458	81,700	85,553	85,784	82,889	83,160	86,847
(11)	Steam	GWH	4,918	4,253	2,784	2,803	2,563	6,510	7,793	7,024	5,778	6,726	5,524	5,284
(12)	CC	GWH	35,490	42,422	50,052	54,202	59,112	65,836	73,735	77,854	78,984	74,696	75,843	79,085
(13)	CT	GWH	562	439	77	77	135	111	172	676	1,023	1,466	1,793	2,478
(14)	Other 3/	GWH	7,625	7,541	5,494	5,968	5,998	5,781	5,136	4,334	4,613	4,520	4,528	4,599
	Net Energy For Load 4/	GWH	108,091	111,301	114,733	118,433	123,203	127,571	131,765	134,670	137,675	140,877	144,000	147,167

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecst of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
4/ Net Energy For Load is also shown in Column 8 on Schedule 3.3.

Schedule 6.2
Energy Sources % by Fuel Type

	Energy Source	Units	Actual 1/ 2004	2005	Forecasted 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	Annual Energy Interchange 2/	%	9.5	9.2	9.5	9.4	9.2	8.8	7.5	6.4	6.2	6.1	5.8	5.5
(2)	Nuclear	%	21.3	19.2	20.9	19.6	19.9	18.9	18.2	18.2	17.6	17.1	17.0	16.4
(3)	Coal	%	5.8	5.2	5.8	6.0	6.2	6.0	5.4	5.6	8.1	12.9	14.4	14.4
(4)	Residual (FO6) -Total	%	18.2	17.1	12.7	11.8	9.7	5.0	3.0	3.1	2.4	1.9	1.9	1.6
(5)	Steam	%	18.2	17.1	12.7	11.8	9.7	5.0	3.0	3.1	2.4	1.9	1.9	1.6
(6)	Distillate (FO2) -Total	%	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CC	%	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	CT	%	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	37.9	42.3	46.1	48.2	50.2	56.8	62.0	63.5	62.3	58.8	57.7	59.0
(11)	Steam	%	4.5	3.8	2.4	2.4	2.1	5.1	5.9	5.2	4.2	4.8	3.8	3.6
(12)	CC	%	32.8	38.1	43.6	45.8	48.0	51.6	56.0	57.8	57.4	53.0	52.7	53.7
(13)	CT	%	0.5	0.4	0.1	0.1	0.1	0.1	0.1	0.5	0.7	1.0	1.2	1.7
(14)	Other 3/	%	7.1	6.8	4.8	5.0	4.9	4.5	3.9	3.2	3.4	3.2	3.1	3.1
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules.
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed Capacity MW	Firm Capacity Import 1/ MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	Reserve Margin Before Maintenance 5/ % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	Reserve Margin After Maintenance 6/ % of Peak
2006	20,919	2,669	0	738	24,326	21,916	1,555	20,361	3,965	19.5	0	3,965	19.5
2007	22,139	2,257	0	738	25,134	22,543	1,821	20,722	4,412	21.3	0	4,412	21.3
2008	22,311	2,257	0	738	25,306	23,179	1,963	21,216	4,090	19.3	0	4,090	19.3
2009	23,530	2,152	0	687	26,369	23,782	2,068	21,714	4,655	21.4	0	4,655	21.4
2010	24,749	1,469	0	640	26,858	24,375	2,158	22,217	4,641	20.9	0	4,641	20.9
2011	25,069	1,469	0	595	27,133	24,915	2,250	22,665	4,468	19.7	0	4,468	19.7
2012	25,919	1,311	0	595	27,825	25,474	2,344	23,130	4,695	20.3	0	4,695	20.3
2013	26,769	1,311	0	595	28,675	26,079	2,442	23,637	5,038	21.3	0	5,038	21.3
2014	26,929	1,311	0	595	28,835	26,642	2,544	24,098	4,737	19.7	0	4,737	19.7
2015	27,642	1,311	0	595	29,548	27,263	2,579	24,684	4,864	19.7	0	4,864	19.7

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. All values are Summer net MW. The value shown for FPL's unit capability for the Summer of 2006 is an updated projection from the value used in FPL's 2005 analyses.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2005-on for use with the 2005 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	Reserve Margin Before Maintenance 5/ % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	Reserve Margin After Maintenance 6/ % of Peak
2005/06	22,304	2,467	0	738	25,509	21,792	1,535	20,257	5,252	25.9	0	5,252	25.9
2006/07	22,373	2,540	0	738	25,651	22,294	1,647	20,647	5,004	24.2	0	5,004	24.2
2007/08	23,558	2,288	0	738	26,584	22,753	1,746	21,007	5,577	26.5	0	5,577	26.5
2008/09	23,739	1,962	0	738	26,439	23,245	1,850	21,395	5,044	23.6	0	5,044	23.6
2009/10	25,074	1,501	0	687	27,262	23,714	1,907	21,807	5,455	25.0	0	5,455	25.0
2010/11	26,409	1,500	0	595	28,504	24,155	1,967	22,188	6,316	28.5	0	6,316	28.5
2011/12	26,771	1,500	0	595	28,866	24,597	2,029	22,568	6,298	27.9	0	6,298	27.9
2012/13	27,626	1,320	0	595	29,541	25,061	2,094	22,967	6,574	28.6	0	6,574	28.6
2013/14	28,481	1,320	0	595	30,396	25,561	2,161	23,400	6,996	29.9	0	6,996	29.9
2014/15	28,662	1,320	0	595	30,577	26,244	2,227	24,017	6,560	27.3	0	6,560	27.3

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2005-on for use with the 2005 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2006														
Cape Canaveral	1	Brevard County	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	402,050	(5)	(5)	OT
Cape Canaveral	2	Brevard County	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	402,050	7	8	OT
Cutler	5	Miami Dade County	ST	NG	No	PL	No	Unknown	Jun-06	Unknown	74,500	3	3	OT
Cutler	6	Miami Dade County	ST	NG	No	PL	No	Unknown	Jun-06	Unknown	161,500	33	33	OT
Ft. Myers	2	Lee County	CC	NG	No	PL	No	Unknown	Jun-06	Unknown	1,775,390	8	—	OT
Ft. Myers	3A & B	Lee County	CT	NG	FO2	PL	PL	Unknown	Jun-06	Unknown	375,700	4	—	OT
Ft. Myers	1-12	Lee County	GT	FO2	No	PL	No	Unknown	Jun-06	Unknown	744,120	16	—	OT
Manatee	1	Manatee County	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	863,300	(6)	(6)	OT
Manatee	2	Manatee County	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	863,300	(7)	(7)	OT
Martin	1	Martin County	ST	FO6	NG	PL	PL	Unknown	Jun-06	Unknown	934,500	6	6	OT
Martin	3	Martin County	CC	NG	No	PL	No	Unknown	Jun-06	Unknown	612,000	24	22	OT
Martin	4	Martin County	CC	NG	No	PL	No	Unknown	Jun-06	Unknown	612,000	24	22	OT
Pt Everglades	1	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	247,775	—	(7)	OT
Pt Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	402,050	8	8	OT
Pt Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	402,050	12	12	OT
Putnam	1	Putnam County	CC	NG	FO2	PL	WA	Unknown	Jun-06	Unknown	290,004	4	4	OT
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	310,420	14	14	OT
Sanford	4	Volusia County	CC	NG	No	PL	No	Unknown	Jun-06	Unknown	1,188,900	10	—	OT
Sanford	5	Volusia County	CC	NG	No	PL	No	Unknown	Jun-06	Unknown	1,188,900	10	—	OT
SJRPP	2	Duval County	BIT	BIT	Pet Coke	RR	WA	Unknown	Jun-06	Unknown	135,918	18	22	OT
Turkey Point	1	Miami Dade County	ST	FO6	NG	WA	PL	Unknown	Jun-06	Unknown	402,050	22	13	OT
									2006 Changes/Additions Total:			**205**	**142**	
2007														
Pt Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	402,050	8	8	OT
Manatee	1	Manatee County	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	863,300	15	15	OT
Manatee	2	Manatee County	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	863,300	16	16	OT
Martin	2	Martin County	ST	FO6	NG	PL	PL	Unknown	Jun-07	Unknown	934,500	7	19	OT
Scherer	4	Monroe, GA	BIT	BIT	No	RR	No	Unknown	Jun-07	Unknown	680,368	24	19	OT
Turkey Point CC	5	Miami Dade County	CC	NG	FO2	PL	PL	Jan-05	Jun-07	Unknown	1,223,000	—	1,144	U
									2007 Changes/Additions Total:			**70**	**1,221**	
2008														
Cape Canaveral	1	Brevard County	ST	FO6	NG	WA	PL	Unknown	Jun-08	Unknown	402,050	3	4	OT
Pt Everglades	1	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-08	Unknown	247,775	1	8	OT
Unsited 1x0 Simple Cycle CT		Unknown	CT	NG	FO2	PL	PL	Jan-07	Jun-08	Unknown	Unknown	—	160	P
Turkey Point CC	5	Miami Dade County	CC	NG	FO2	PL	PL	Jan-05	Jun-07	Unknown	1,223,000	1,181	—	U
									2008 Changes/Additions Total:			**1,188**	**172**	
2009														
Unsited 1x0 Simple Cycle CT		Unknown	CT	NG	FO2	PL	PL	Jan-07	Jun-08	Unknown	Unknown	181	—	P
West County Combined Cycle	1	Palm Beach County	CC	NG	FO2	PL	PL	Jan-07	Jun-09	Unknown	Unknown	—	1,219	P
									2009 Changes/Additions Total:			**181**	**1,219**	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All other MW will be picked up in the following year.

Note 2: Changes shown include different ratings than shown in Schedule 1 due solely to ambient temperature consisten with those in FPL 's peak load forecast to maintain consistency in Reserve Margin calculation.

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Const. Start Mo./Yr.	(10) Comm. In-Service Mo./Yr.	(11) Expected Retirement Mo./Yr.	(12) Gen. Max. Nameplate KW	(13) Net Capability Winter MW	(14) Net Capability Summer MW	(15) Status
ADDITIONS/ CHANGES														
2010														
West County Combined Cycle	1	Palm Beach County	CC	NG	FO2	PL	PL	Jan-07	Jun-09	Unknown	Unknown	1,335	—	P
West County Combined Cycle	2	Palm Beach County	CC	NG	FO2	PL	PL	Jan-08	Jun-10	Unknown	Unknown	—	1,219	P
									2010 Changes/Additions Total:			**1,335**	**1,219**	
2011														
West County Combined Cycle	2	Palm Beach County	CC	NG	FO2	PL	PL	Jan-08	Jun-10	Unknown	Unknown	1,335	—	P
Unsited 2x0 Simple Cycle CT		Unknown	CT	NG	FO2	PL	PL	Jan-10	Jun-11	Unknown	Unknown	—	320	P
									2011 Changes/Additions Total:			**1,335**	**320**	
2012														
Unsited 2x0 Simple Cycle CT		Unknown	CT	NG	FO2	PL	PL	Jan-10	Jun-11	Unknown	Unknown	362	—	P
Supercritical Pulverized Coal	1	TBA *	BIT	BIT	No	RR	No	Jan-08	Jun-12	Unknown	Unknown	—	850	P
									2012 Changes/Additions Total:			**362**	**850**	
2013														
Supercritical Pulverized Coal	1	TBA *	BIT	BIT	No	RR	No	Jan-08	Jun-12	Unknown	Unknown	855	—	P
Supercritical Pulverized Coal	2	TBA *	BIT	BIT	No	RR	No	Jan-08	Jun-13	Unknown	Unknown	—	850	P
									2013 Changes/Additions Total:			**855**	**850**	
2014														
Supercritical Pulverized Coal	2	TBA *	BIT	BIT	No	RR	No	Jan-08	Jun-13	Unknown	Unknown	855	—	P
Unsited 1x0 Simple Cycle CT		Unknown	CT	NG	FO2	PL	PL	Jan-13	Jun-14	Unknown	Unknown	—	160	P
									2014 Changes/Additions Total:			**855**	**160**	
2015														
Unsited 1x0 Simple Cycle CT		Unknown	CT	NG	FO2	PL	PL	Jan-13	Jun-14	Unknown	Unknown	181	—	P
Unsited 1x0 Simple Cycle CT		Unknown	CT	NG	FO2	PL	PL	Jan-14	Jun-15	Unknown	Unknown	—	160	P
Unsited 2x1 Combined Cycle		Unknown	CC	NG	FO2	PL	PL	Jan-13	Jun-15	Unknown	Unknown		553	P
									2015 Changes/Additions Total:			**181**	**713**	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All other MW will be picked up in the following year.

Note 2: Changes shown include different ratings than shown in Schedule 1 due solely to ambient temperature consisten with those in FPL 's peak load forecast to maintain consistency in Reserve Margin calculation.

* FPL is currently in the process of selecting a site(s) for these advanced technology coal units. FPL expects to announce the selected site(s) by June 2006.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Turkey Point Combined Cycle Unit # 5
(2)	**Capacity**		
	a. Summer	1,144 MW	
	b. Winter	1,181 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2005	
	b. Commercial In-service date:	2007	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low No_x Combustors, SCR 0.0015% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Tower
(8)	**Total Site Area:**	11,000	Acres
(9)	**Construction Status:**	U	Under Construction, less than or equal to 50% complete
(10)	**Certification Status:**	Certified	
(11)	**Status with Federal Agencies:**	Certified	

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 97%	(First Base OperationYear)
Average Net Operating Heat Rate (ANOHR):	6,835	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2007 $/kW):	507	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2007 $kW-Yr)	10.06	
Variable O&M ($/MWH): (2007 $/MWH)	0.13	
K Factor:	1.5699	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Simple Cycle Combustion Turbine

(2) **Capacity**
a. Summer 160 MW
b. Winter 181 MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2007
b. Commercial In-service date: 2008

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, Natural Gas 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Air Coolers

(8) **Total Site Area:** 392 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.0%	
Forced Outage Factor (FOF):	1.0%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 10%	(First Year Operation)
Average Net Operating Heat Rate (ANOHR):	10,400	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25 years
Total Installed Cost (2008 $/kW):	522
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2008 $kW-Yr)	8.72
Variable O&M ($/MWH): (2008 $/MWH)	0.81
K Factor:	1.8084

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes escalation and AFUDC only.
Transmission interconnection and transmission integration costs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit # 1

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2007
b. Commercial In-service date: 2009

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 97%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2009 $/kW):	565	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2009 $kW-Yr)	11.65	
Variable O&M ($/MWH): (2009 $/MWH)	0.138	
K Factor:	1.5834	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit # 2

(2) **Capacity ***
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2008
b. Commercial In-service date: 2010

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 94%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data **,*****

Book Life (Years):	25 years
Total Installed Cost (2010 $/kW):	519
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2010 $kW-Yr)	10.11
Variable O&M ($/MWH): (2010 $/MWH)	0.138
K Factor:	1.5873

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.
(Note: Costs shown are based on the constuction of Unit 1 first.)

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited 2x0 Simple Cycle Combustion Turbine

(2) **Capacity**
a. Summer 320 MW
b. Winter 362 MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2010
b. Commercial In-service date: 2011

(5) **Fuel**
a. Primary Fuel — Natural Gas
b. Alternate Fuel — Distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, Natural Gas 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Air Coolers

(8) **Total Site Area:** Uknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.0%	
Forced Outage Factor (FOF):	1.0%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 10%	(First Year Operation)
Average Net Operating Heat Rate (ANOHR):	10,400	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25 years
Total Installed Cost (2011 $/kW):	562
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2011 $kW-Yr)	9.35
Variable O&M ($/MWH): (2011 $/MWH)	0.97
K Factor:	1.6397

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes escalation and AFUDC only.
Gas expansion,transmission interconnection, transmission integration costs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Supercritical Pulverized Coal Unit # 1

(2) **Capacity**

a. Summer	850	MW
b. Winter	855	MW

(3) **Technology Type:** Supercritical Steam Generator

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2008
b. Commercial In-service date:	2012

(5) **Fuel**

a. Primary Fuel	Coal
b. Alternate Fuel	N/A

(6) **Air Pollution and Control Strategy:** Low No_x Burners, Over-fired Air, SCR, Baghouse Wet Flue Gas Desulfurization, Wet Electric Static Precipatator

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 3,000 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	4.0%	
Forced Outage Factor (FOF):	4.0%	
Equivalent Availability Factor (EAF):	92%	
Resulting Capacity Factor (%):	Approx. 90%	(First Year Operation)
Average Net Operating Heat Rate (ANOHR):	8,600	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	40	years
Total Installed Cost (2012 $/kW):	2,355	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2012 $kW-Yr)	38.07	
Variable O&M ($/MWH): (2012$/MWH)	1.384	
K Factor:	1.6616	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes escalation and AFUDC only.
Transmission interconnection and transmission integration costs are not included.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Supercritical Pulverized Coal Unit # 2

(2) **Capacity**

a. Summer	850	MW
b. Winter	855	MW

(3) **Technology Type:** Supercritical Steam Generator

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2008
b. Commercial In-service date:	2013

(5) **Fuel**

a. Primary Fuel	Coal
b. Alternate Fuel	N/A

(6) **Air Pollution and Control Strategy:** Low No_x Burners, Over-fired Air, SCR, Baghouse Wet Flue Gas Desulfurization, Wet Electric Static Precipatator

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 3,000 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	4.0%	
Forced Outage Factor (FOF):	4.0%	
Equivalent Availability Factor (EAF):	92%	
Resulting Capacity Factor (%):	Approx. 90%	(First Year Operation)
Average Net Operating Heat Rate (ANOHR):	8,600	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	40	years
Total Installed Cost (2013 $/kW):	1,732	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2013 $kW-Yr)	28.60	
Variable O&M ($/MWH): (2013 $/MWH)	1.43	
K Factor:	1.6616	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes escalation and AFUDC only.
Transmission interconnection and transmission integration costs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited 1x0 Simple Cycle Combustion Turbine

(2) **Capacity**
a. Summer 160 MW
b. Winter 181 MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2013
b. Commercial In-service date: 2014

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, Natural Gas 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Air Coolers

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.0%	
Forced Outage Factor (FOF):	1.0%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 15%	(First Year Operation)
Average Net Operating Heat Rate (ANOHR):	10,400	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25 years
Total Installed Cost (2014 $/kW):	689
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2014 $kW-Yr)	10.11
Variable O&M ($/MWH): (2014 $/MWH)	1.05
K Factor:	1.7323

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes escalation and AFUDC only.
Gas expansion,transmission interconnection, transmission integration costs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited 1x0 Simple Cycle Combustion Turbine

(2) **Capacity**
a. Summer 160 MW
b. Winter 181 MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2014
b. Commercial In-service date: 2015

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, Natural Gas 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Air Coolers

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.0%	
Forced Outage Factor (FOF):	1.0%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 15%	(First Year Operation)
Average Net Operating Heat Rate (ANOHR):	10,400	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2015 $/kW):	710	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2015 $kW-Yr)	10.37	
Variable O&M ($/MWH): (2015 $/MWH)	1.10	
K Factor:	1.7252	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes escalation and AFUDC only.
Gas expansion,transmission interconnection, transmission integration costs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited 2x1Combined Cycle

(2) **Capacity**
a. Summer 553 MW
b. Winter 610 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2013
b. Commercial In-service date: 2015

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 11,300 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.0%	
Forced Outage Factor (FOF):	1.0%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 70%	(First Year Operation)
Average Net Operating Heat Rate (ANOHR):	6,835	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2015 $/kW):	1,218	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2015 $kW-Yr)	11.71	
Variable O&M ($/MWH): (2015 $/MWH)	0.17	
K Factor:	1.5900	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes escalation and AFUDC only.
Gas expansion,transmission interconnection, transmission integration costs are not included.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Combined Cycle Unit #5

The new Turkey Point CC unit that is scheduled to come in-service in 2007 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Unsited Combustion Turbine in 2008

No projection of a new transmission line(s) can be made until a site is selected for this unit.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

West County Energy Center Unit #1

The proposed new West County Energy Center Unit #1 that is projected to come in-service in 2009 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

West County Energy Center Unit #2

The proposed new West County Energy Center Unit #2 that is projected to come in-service in 2010 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Two Unsited Combustion Turbine Units in 2011

No projection of a new transmission line(s) can be made until a site is selected for these units.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Supercritical Pulverized Coal Unit #1 in 2012

No projection of a new transmission line(s) can be made until a site is selected for this unit.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Supercritical Pulverized Coal Unit #2 in 2013

No projection of a new transmission line(s) can be made until a site is selected for this unit.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Unsited Combustion Turbine in 2014

No projection of a new transmission line(s) can be made until a site is selected for this unit.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Unsited Combustion Turbine in 2015

No projection of a new transmission line(s) can be made until a site is selected for this unit.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Unsited Combined Cycle Unit in 2015

No projection of a new transmission line(s) can be made until a site is selected for this unit.

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered plant and animal species. Population growth in our service area is continuing, which heightens competition for air, land, and water resources that are necessary to meet the increased demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

FPL has been recognized for many years as one of the leaders among utilities for our commitment to the environment. Our environmental leadership has been heralded by many outside organizations. In 2004 FPL Group earned a first place ranking among U.S. power companies and second globally in a report from the World Wildlife Fund for voluntary commitments to limit CO_2 emissions. This commitment was made to support initiatives to better manage utility impacts on climate change through use of greenhouse gas emission reductions and improvements in energy efficiency. The report stated that this was "primarily due to the company's leadership in developing wind energy and their commitment to dramatically improve their efficiency". As a further demonstration of FPL's efforts in sustainability the EPA and the Department of Energy awarded FPL for its Sunshine Energy Program which allows customers to choose environmentally friendly electricity produced from biomass, wind and solar sources. FPL was also recently awarded its fourth number one rating of major electric utilities surveyed in an environmental assessment conducted by Innovest, an independent advisory group. In recognition of its success in executing a strategy to become a clean energy provider harnessing primarily clean and renewable fuels while also boosting shareholder value, FPL Group, Inc. was named in June 2003 as the winner of the Edison Award, the electric power industry's highest honor by the Edison Electric Institute.

FPL was awarded Edison Electric Institute's National Land Management Award for our stewardship of 25,000 acres surrounding our Turkey Point Plant. FPL won the Council for Sustainable Florida's award for our sea turtle conservation and education programs at our St. Lucie Plant. In 2001, FPL was awarded the 2001 Waste Reduction and Pollution Prevention Award from the Solid Waste Association of North America. FPL received the 2001 Program Champion Award from the Environmental Protection Agency's Wastewise

Program. The Florida Department of Environmental Protection named FPL a "Partner for Ecosystem Protection" for our emission-reducing "repowering" projects at our Fort Myers and Sanford Plants. Finally, FPL has been recognized by numerous federal and state agencies for our innovative endangered species programs which include such species as manatees, crocodiles, and sea turtles.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Statement in 1992 to clearly define the Company's position. This statement reflects how FPL incorporates environmental values into all aspects of the Company's activities and serves as a framework for new environmental initiatives throughout the Company. The FPL environmental statement further establishes a long-term direction of environmental initiatives throughout the Company. FPL's Environmental Statement is:

> It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:
>
> - Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
> - Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
> - Encourage the wise use of energy to minimize the impact on the environment.
> - Communicate effectively on environmental issues.
> - Conduct periodic self-evaluations, report performance, and take appropriate actions.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an environmental management system to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program that is discussed below. Other components include: executive management support and commitment, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident/emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to evaluate environmental performance, verify compliance with Company policy as well as with legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to: facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and Company policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2005 environmental outreach activities are noted in Table IV.E.1.

Table IV.E.1: 2005 FPL Environmental Outreach Activities

Activity	*# of Participants*
Visitors to Energy Encounter	20,000
Visitors to Manatee Park	150,000
Number of "visits" to FPL's Environmental Website	839,000
Number of pieces of Environmental literature distributed	>120,000

(All numbers are approximations.)

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified two preferred and eight potential sites for future generation additions. Preferred sites are those locations where FPL has conducted significant reviews and taken action to site generation. Potential sites are those sites that have attributes that support the siting of generation and are under consideration as a location for future generation. Some of these sites are currently in use as existing generation sites and some are not. The identification of a "Potential" site does not indicate that FPL has made a definitive decision to pursue generation (or generation expansion in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of generator has been determined. These preferred and potential sites are discussed in separate sections below.

IV.F.1 Preferred Sites

FPL identifies two preferred sites in this Site Plan: the existing Turkey Point plant site, and the West County Energy Center adjacent to the existing Corbett FPL substation. The Turkey Point site is the location for a capacity addition that FPL is committed to make in mid - 2007. The West County Energy Center site is the projected location for capacity additions FPL is proposing to make in 2009 and 2010.

The capacity addition at the Turkey Point site has been approved by the FPSC. FPL has petitioned the FPSC for approval of the West County Energy Center additions. A decision is expected by the FPSC later this year.

The two preferred sites are discussed below.

<u>Preferred Site # 1: Turkey Point Plant, Miami-Dade County</u>

The Turkey Point Plant site is located on the west side of Biscayne Bay, 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. Public access to the plant site is limited due to the nuclear units located there. The land surrounding the site is owned by FPL and acts as a buffer zone. The site is comprised of two nuclear units and two conventional boiler, fossil units, the cooling canals, an FPL-maintained natural wildlife area, and wetlands that have been set aside as the Everglades Mitigation Bank (EMB).

Units #1 and #2 are fossil fuel generating plants with approximate generating capacity of 400 MW each. Unit #1 was completed in 1967 and Unit #2 in 1968. Units #3 and #4 are nuclear generating units with approximate generating capacity of 700 MW each. Unit #3 was completed in 1972 and Unit #4 in 1973. Turkey Point also has five diesel peaking units that in total produce approximately 12 MW. These units are primarily used to provide emergency power, but occasionally run during the Summer to provide power during peak load demands.

The Site for the new Turkey Point Unit #5, a "4-on-1" combined cycle electrical generating unit, is within the existing FPL Turkey Point facility property, located on Biscayne Bay in Miami-Dade County, Florida. The Site is adjacent to the existing fossil Units #1 and #2, and includes the existing parking lot and storage areas immediately northwest of Units #1 and #2 as well as mangrove wetlands north of the facility.

a. and b. <u>U.S. Geological Survey (USGS) Map and Proposed Facilities Layout</u>

A USGS map of the Turkey Point plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. <u>Map of Site and Adjacent Areas</u>

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. <u>Existing Land Uses of Site and Adjacent Areas</u>

A major portion of the site consists of a self-contained cooling canal system that supplies water to condense steam used by the existing units' turbine generators. The canal system consists of 36 interconnected canals each five miles long, 200 feet wide and approximately four feet deep. The remaining developed area of the site is where the two fossil steam generating units and 5 diesel generators are located. South of and adjacent to the fossil plant are the two nuclear generating units. Further to the south, wetlands have been set aside as part of the Everglades Mitigation Bank (EMB) in an effort to restore these areas to historical plant communities and hydrological function.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the Site was undeveloped dwarf red mangrove swamp, tidally inundated with waters from Biscayne Bay. Along with the dominant red mangroves, buttonwood is a common canopy component, along with occasional white mangrove. Only a few individual black mangroves were observed within the Site. Biscayne Bay is a shallow, subtropical bay supporting seagrasses, sponges, coral reefs, and a variety of marine life.

2. Listed Species

The construction and operation of Unit #5 is not expected to adversely affect any rare, endangered, or threatened species. Listed species known to occur in the nearby Biscayne National Park that could potentially utilize the Site include the peregrine falcon (Falco peregrinus), wood stork (Mycteria americana), American crocodile (Crocodylus acutus), mangrove rivulus (Rivulus marmoratus), roseate spoonbill (Ajaja ajaja), limpkin (Aramus guarauna), little blue heron (Egretta caerulea), snowy egret (Egretta thula), American oystercatcher (Haematopus palliates), least tern (Sterna antillarum), brown pelican (Pelicanus occidentalis), the white ibis (Eudocimus albus), and bald eagle (Haliaeetus leucocephalus). No bald eagle nests are known to exist in the vicinity of the Site. The federally listed, endangered American Crocodile thrives at the Turkey Point site, primarily in and around the southern end of the cooling canals which lie south of the proposed project area. The entire site is considered crocodile habitat due to the mobility of the species and use of the site for foraging, traversing and basking. FPL manages a program for the conservation and enhancement of the American crocodile. A project-specific crocodile management plan has been developed for construction of Unit #5.

3. **Natural Resources of Regional Significance Status**

Significant features in the vicinity on the Site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park. The portion of Biscayne Bay adjacent to the Site is included within the Biscayne National Park, comprised of several miles of shoreline north of the Turkey Point facility extending offshore approximately 12 nautical miles. Biscayne National Park contains 180,000 acres, approximately 95% of which is open water interspersed with over 40 keys. The Biscayne National Park headquarters is located approximately 2 miles north of the Turkey Point plant, adjacent to the Miami-Dade County Homestead Bayfront Park, which contains a marina and day use recreational facilities.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

Additional generating capacity is being added to the site for operation beginning in 2007 to meet projected FPL system capacity needs. The new generating unit will consist of four new CT's and four new HRSG's and a new steam turbine that will comprise Turkey Point Unit #5. Natural gas delivered via the existing pipeline is the primary fuel type for this unit (with ultra low sulfur light oil serving as a backup fuel). Natural gas-fired facilities are among the cleanest, most efficient technologies currently available.

Mitigation for unavoidable wetland impacts related to construction of Unit #5 includes: on-site hydrologic improvements to enhance existing wetlands, restoration and preservation of areas overgrown with exotic plant species, creation of an on-site lagoon, transfer of some mangrove dominated lands to South Florida Water Management District and Biscayne National Park, and also the purchase of mitigation credits from the EMB, which is in the same drainage basin. The capture and reuse of plant process water and rainwater, plus the use of a cooling tower will minimize thermal discharges to the cooling canals. The facility already encompasses several preserved areas where wildlife is abundant.

g. **Local Government future Land Use Designations**

Local government future land use plan designates most of the site as IU-3 "Industrial, Unlimited Manufacturing District." There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. **Site Selection Criteria Process**

For the past several years, a number of FPL's existing power plant sites have been considered as potentially suitable sites for new or repowered generation. The Turkey Point plant has been selected as a preferred site due to consideration of various factors including system load, an imbalance in the South Florida region between load and generating capacity, and economics. Environmental issues are an important factor at this site. However, the other deciding factors outweigh them. FPL will minimize environmental impacts and mitigate where impacts are unavoidable.

i. **Water Resources**

Unique to Turkey Point Plant is the self-contained cooling canal system that supplies water to condense steam used by the plant's turbine generators. The canal system consists of 36 interconnected canals each five miles long, 200 feet wide and approximately four feet deep. The system performs the same function as a giant radiator. The water is circulated through the 153-mile maze of canals in a two-day journey, ending at the plant's intake pumps. During the slow journey down the canals, the water cools as much as 15 degrees

j. **Geological Features of Site and Adjacent Areas**

FPL's Turkey Point site is underlain by approximately 13,000 feet of sedimentary rock strata. The strata that extends to approximately 500 feet forms the Biscayne aquifer. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily of marine origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, or clay. The Tamiami formation is named for deposits composed principally of white cream-colored calcareous sandstone, sandy limestone, and beds and pockets of quartz sand. In the Turkey Point area, the Key Largo limestone is present.

The Floridan Aquifer, located approximately 1,100 feet below the land surface, is a confined aquifer. The Floridan Aquifer system is composed entirely of carbonate rocks, except for minor evaporates. The water in the carbonate rock aquifer is more highly mineralized.

k. Projected Water Quantities for Various

The additional quantity of water for industrial processing is estimated to be 150 gallons per minute (gpm) for plant process and service water. Water for this type of use would be supplied by an existing county water system. The current plant water treatment system, which provides treated water for use in Units #1 and #2 boilers, would be expanded. Cooling water for new Unit #5 will be processed through a cooling tower. FPL will use approximately 14 million gallons per day (mgd) of water from the Floridan Aquifer as the source of makeup water used by the cooling tower.

l. Water Supply Sources and Type

This additional capacity at the site will utilize the cooling tower for the dissipation of heat from the cooling water. The existing water treatment system at the plant, which provides treated water for use in the Unit #1 and #2 boilers will be expanded to provide treated water for new Unit. The Floridan Aquifer will supply the makeup cooling water.

m. Water Conservation Strategies Under Consideration

A plan to treat and recycle equipment wash water, boiler blowdown, and equipment area runoff for use as service water would reduce ground water consumption. FPL anticipates this site will be designed and classified as a wastewater zero discharge site following the completion of the expansion project.

n. Water Discharges and Pollution Control

Heated water discharges are dissipated using the existing once through cooling water system and the cooling canal system. Unit #5 cooling water will be processed through a cooling tower which will dissipate the heat prior to discharge to the cooling canal system. Non-point source discharges are collected and reused. Treating and recycling equipment wash water, boiler blow-down, and equipment area runoff helps to minimize industrial discharges. Storm water runoff is collected and used to recharge the surficial aquifer via a stormwater management system. Design elements have been included to capture suspended sediments. Various facility permits mandate various sampling and testing activities, which provide indication of any pollutant discharges.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by multiple fuel delivery facilities. There is currently a pipeline that supplies natural gas to the facility. The facility also has oil capabilities through on-site storage tanks and accessibility to barge deliveries. The additional capacity will utilize the existing pipeline with the addition of compression system(s). An above ground storage tank for the ultra-low sulfur light oil backup fuel will be added. The backup fuel for Unit #5 will be delivered to the site by truck.

p. Air Emissions and Control Systems

The use of clean fuels and combustion controls will minimize air emissions from this unit and ensure compliance with applicable emission limiting standards. Using clean fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x), and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using the ultra-low sulfur light oil as backup fuel. These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of Turkey Point Unit #5 will incorporate features that will make it one of the most efficient and cleanest power plants in the State of Florida.

q. <u>Noise Emissions and Control Systems</u>

A field survey and impact assessment of noise expected to be caused by unit construction at the site indicated that construction noise would be below current noise levels for the residents nearest the site. Noise from the operation of the new unit will also be within allowable levels. Similar natural gas-fired facilities in Broward and Martin counties have been constructed and operated without exceeding allowable noise levels.

r. <u>Status of Applications</u>

FPL filed the Site Certification Application (SCA) for the Turkey Point Plant Unit #5 with the Florida Department of Environmental Protection (FDEP) on November 14, 2003, and received Site Certification by the Governor and Cabinet in February 2005. The U.S. Army Corps of Engineers issued a federal Dredge and Fill permit in February 2005. FDEP issued the Prevention of Significant Deterioration (PSD) air permit in February 2005. FPL acquired all permits and authorizations needed, and commenced construction in spring 2005 with an anticipated, in-service date of mid 2007.

<u>Preferred Site # 2: West County Energy Center, Palm Beach County</u>

FPL has identified the property adjacent to the existing Corbett Substation property in unincorporated western Palm Beach County as a preferred site for the addition of new generating capacity. The preferred site was selected for the addition of a new greenfield combined cycle natural gas power plant project with ultra-low sulfur oil as a backup fuel. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections. The proposed facility would use clean burning natural gas as the primary fuel and state-of-the-art combustion controls.

a. and b. U.S. Geological Survey (USGS) Map and Proposed Facilities Layout

A USGS map of the West County Energy Center site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The land on the site is currently inactive but was previously dedicated to industrial and agricultural use. The site has been excavated, back-filled, and totally re-graded to an elevation approximately 10 ft. above surrounding land surface. No structures are present on the site and vegetation is virtually non-existent.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The plant site has been significantly altered by the construction and operation of a limestone mine where vegetation had been cleared and removed. The surrounding land use is predominantly sugar cane agriculture and limestone mining. FPL's existing Corbett substation is located north of the site. The Arthur R. Marshall Loxahatchee National Wildlife Refuge is located to the south of the proposed site.

2. Listed Species

Construction and operation of new units at the site is not expected to affect any rare, endangered, or threatened species. Wildlife utilization of the property is minimal as a result of the mining activities. Common wading birds can be observed on areas adjacent to and occasionally within the property. The property is adjacent to areas that have been identified as potential habitat for wood stork.

3. Natural Resources of Regional Significance Status

The construction and operation of a gas-fired combined cycle generating facility at the proposed location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands including the Arthur R. Marshall Loxahatchee National Wildlife Refuge which lies south of the proposed location. It is not anticipated that construction will result in wetland impacts under federal, state or local agency permitting criteria.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option is to construct two new 1,200 MW (approximate) units each consisting of three new CT's and three new HRSG's and a new steam turbine. These units are scheduled to be in-service in mid-2009 and 2010. Natural gas delivered via pipeline is the primary fuel type for this unit with ultra-low sulfur light oil serving as a backup fuel. Natural gas-fired facilities are available nearby and are among the cleanest, most efficient technologies currently available.

g. Local Government Future Land Use Designations

Local government future land use designation for the project site is "Rural Residential" according to the Palm Beach County Future Land Use Map. Designations for the area under the Palm Beach County Unified Land Development Code classified the project site and surrounding area as Special Agricultural District. The site has been granted conditional use for electrical power facilities under a General Industrial zoning district.

h. **Site Selection Criteria Process**

The site has been selected as a preferred site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. This site is considered permittable.

i. **Water Resources**

The existing adjacent surface water canals and available ground water resources are potential sources for potable and service water for the proposed units. Adjacent to the site, hydro storage water conservation areas may be created through development of the site as a limestone mine. Use of water from the upper and/or lower Floridan Aquifer is also considered a feasible alternative as potential backup sources of water for operation of the proposed units.

j. **Geological Features of Site and Adjacent Areas**

The site is underlain by approximately 13,000 feet of sedimentary rock strata. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine in origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, clay, and phosphate grains. The deepest formation in Palm Beach County on which significant published data are available is the Eocene Age Avon Park. Limited information is available from wells penetrating the underlying Oldsmar formation. The published information on the sediments comprising the formations below the Avon Park Limestone is based on projections from deep wells in Okeechobee, St. Lucie, and Palm Beach Counties.

k. **Projected Water Quantities for Various Uses**

The estimated quantity of water required for industrial processing for both units is approximately 450 gallons per minute (gpm) for uses such as process water and service water. Approximately 20 million gallons per day (mgd) in total of cooling water for the two proposed units would be cycled through the addition of cooling towers. Water quantities needed for other uses such as potable water are estimated to be approximately 35,000 gallons per day (gpd).

l. Water Supply Sources by Type

The proposed units will use available surface or ground water as the source of cooling water for the cooling towers. The cooling towers will also act as a heat sink for the facility process water. Such needs for cooling and process water will comply with the existing South Florida Water Management District (SFWMD) regulations for consumptive water use.

m. Water Conservation Strategies Under Consideration

Impacts on the surficial aquifer would be minimized and used only for potable water. Water will be obtained from the Floridan Aquifer as a source of cooling water as a backup supply. In addition, the entire plant site will capture and reuse process water whenever feasible and manage stormwater in such a manner as to recharge the surficial aquifer.

n. Water Discharges and Pollution Control

Heated water discharges will be dissipated in the cooling towers. Blow down from the cooling towers will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Industrial discharges will be minimized by treating and recycling equipment wash water, boiler blowdown water, and equipment area runoff. Storm water runoff will be collected and used to recharge the surficial aquifer via a storm water management system. Design elements will be included to capture suspended sediments. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is not located near an existing natural gas transmission pipeline that is capable of providing a sufficient quantity of gas. Upgrades of existing pipelines and/or lateral connections to other pipelines will be necessary for supply of natural gas. Ultra-low sulfur distillate fuel oil would be received by truck and stored in above-ground storage tanks to serve as backup fuel for the new units.

p. Air Emissions and Control Systems

The use of clean fuels and combustion controls will minimize air emissions from these units and ensure compliance with applicable emission limiting standards. Using clean fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter and other fuel bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x), and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light oil as backup fuel. These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of the West County Energy Center units will incorporate features that will make them among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site. Noise from the operation of the new unit will be within allowable levels.

r. Status of Applications

A Site Certification Application (SCA) for the construction and operation of the West County Energy Center project under the Florida Electrical Power Plant Siting Act was filed on April 14, 2005. A Prevention of Significant Deterioration (PSD) permit application and an Underground Injection Control permit application were also submitted to the Florida Department of Environmental Protection (FDEP) at the same time. FDEP issued a Class I Underground Injection Control Exploratory Well permit on January 11, 2006. A petition for approval of a Determination of Need for both West County Energy Center units was filed with the FPSC on March 13, 2006. A Draft PSD Air Permit was issued by FDEP on March 1, 2006.

IV.F.2 Potential Sites for Generating Options

Eight (8) sites are currently identified as "Potential Sites" for near-term future generation additions to meet FPL's capacity needs.[2] These sites have been identified as Potential Sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies.

Each of these potential sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each potential site has different characteristics that will require further definition and attention. For the purpose of estimating water requirements for each site, it was assumed that either one dual-fuel (natural gas and light oil) simple cycle combustion turbine or a natural gas-fired combined cycle unit would be constructed at the Potential Sites. A simple cycle CT would require approximately 50 gallons per minute (gpm) for both process and cooling water (assuming air cooling). A combined cycle unit would require approximately 150 gpm for service and process water and approximately 14 million gallons per day (mgd) for cooling water.

Permits are presently considered to be obtainable for all of these sites, assuming measures can be taken to mitigate any particular site-specific environmental concerns that may arise. No significant environmental constraints are currently known for any of these eight sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time FPL considers each site to be equally viable.

Potential Site # 1: Andytown Substation, Broward County

FPL has identified the Andytown Substation property in western unincorporated Broward County as a potential site for the addition of new generating capacity. Current facilities on-site include an electric substation. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections.

[2] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site has been included at the end of this chapter.

b. and c. **Land Uses and Environmental Features**

The land uses for the potential site were designated as industrial or agricultural use. The site identification process included screening to determine potential wetland impacts and impacts to endangered or threatened species. Extensive low-quality wetlands are adjacent to the potential site. FPL would expect to mitigate any impacts from construction of a power plant at this site. Construction and operation of a new facility on this site is not expected to adversely affect any rare, endangered, or threatened species.

d. and e. **Water Quantities and Supply Sources**

Surface water sources are not available at the potential site. Groundwater from the shallow aquifer or a local source of gray water have been identified as potential water sources. The Floridan Aquifer has been identified as a potential cooling water source. We believe these sources would provide sufficient water for either simple cycle or combined cycle generation.

Potential Site # 2: Cape Canaveral Plant, Brevard County

This site is located on the FPL Cape Canaveral Plant property in unincorporated Brevard County. The city of Port St. Johns is located less than a mile away. The site has direct access to a four-lane highway (US 1). A rail line is located near the plant. The existing facility consists of two 400 MW (approximate) steam boiler type generating units.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site is found at the end of this chapter.

b. and c. **Land Uses and Environmental Features**

This site is located on the Indian River. The land is primarily dedicated to industrial use with surrounding grassy areas and a few acres of remnant pine forest. The land

2006 10-year site plan
Exhibit KRR-3-F, Page 130 of 192

adjacent to the site is dedicated to light commercial and residential use. There are no significant environmental features on the site.

d. and e. Water Quantities and Supply Sources

FPL would use existing on-site wells or local gray water, and the existing once-through cooling water system. We believe these sources would provide sufficient water for either simple cycle or combined cycle generation.

Potential Site # 3: Desoto County Greenfield Site

This site is a "Greenfield" undeveloped site located on a 13,500 acre property in unincorporated Desoto County. The site is adjacent to portions of the Peace River. There are no current facilities on the site. The City of Arcadia is located southwest of the Desoto site.

a. U.S. Geological Survey (USGS) Map

A USGS map of the site is found at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on the site is currently dedicated to agricultural use (sod farming, cattle grazing, and truck crops). Developed portions of the adjacent properties are primarily agricultural (sod farms, citrus groves and cattle grazing). Undeveloped portions include mixed scrub with some hardwoods and a few isolated wetlands.

d. and e. Water Quantities and Supply Sources

The primary sources for water would either be groundwater from the upper and lower Floridan Aquifer or if available and practicable, a local source of gray water. We believe these sources would provide sufficient water for either simple cycle or combined cycle generation.

Potential Site # 4: Fort Myers Plant Site, Lee County

This site is located on FPL's existing 460-acre Fort Myers property. The existing facilities on the site include one 1,440 MW (approximate) combined cycle unit, 12 gas turbines, each with an approximate capacity of 54 MW, and 2 combustion turbines, each with an approximate capacity of 160 MW.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Fort Myers plant site is found at the end of this chapter.

b. and c. Land Uses and Environmental Features

The land on the site is currently dedicated to industrial use with surrounding grassy and landscaped areas. Much of the site has recently been used for direct construction activities. The adjacent land uses include light commercial and retail to the east of the property, and some residential areas located toward the west. Mixed scrub with some hardwoods can be found to the east and further south.

d. and e. Water Quantities and Supply Sources

The available water source is the Caloosahatchee River and the available groundwater source is the sandstone aquifer. We believe these sources would provide sufficient water for either simple cycle or combined cycle generation.

Potential Site # 5: Lauderdale Plant, Broward County

The Lauderdale site is located in Eastern Broward County approximately 5 miles inland from Dania Beach and less than 2 miles west of Ft. Lauderdale International Airport. The site is bounded on the south by Dania Cutoff Canal, the east by SW 30th Avenue, and the North by I-595.

The existing 1,680 MW of generating capacity at FPL's Lauderdale site occupies a portion of the approximately 210 acres that are wholly owned by FPL. The generating capacity is made up of two combined cycle units (Units #4 and #5). The site also is home to 24 simple cycle gas turbine (GT) peaking units of 30 MW (approximate) each. The GT's are part of the Gas Turbine Power Park that is made up of 24 GT's at the

Lauderdale Plant site and the twelve GTs at the Port Everglades site. The GT's are capable of firing either natural gas or liquid fuel. The site is considered as suitable for the construction and operation of simple cycle peaking utilizing liquid or natural gas fuels.

a. U.S. Geological Survey (USGS) Map

A USGS map of the site is found at the end of this chapter.

b. and c. Land Uses and Environmental Features

The existing power plant facilities are located on approximately 130 acres. The existing site has been in use since the 1920's and is adjacent to a county resource recovery project. To the north of the power plant is an area of mixed uplands with a scattering of small wetlands.

d. and e. Water Quantities and Supply Sources

Existing groundwater or the municipal water supply could be used for industrial process and makeup water. We believe these sources would provide sufficient water for either simple cycle or combined cycle generation.

Potential Site # 6: Martin Plant, Martin County

The Martin site is located approximately 40 miles northwest of West Palm Beach, 5 miles east of Lake Okeechobee, and 7 miles northwest of Indiantown in Martin County, Florida. The site is bounded on the west by the Florida East Coast Railway (FEC) and the adjacent South Florida Water Management District (SFWMD) L-65 Canal, on the south by the St. Lucie Canal (C-44 or Okeechobee Waterway), and on the northeast by SR 710 and the adjacent CSX Railroad.

The existing 3,700 MW (Summer) of generating capacity at FPL's Martin site occupies a portion of the approximately 11,300 acres that are wholly owned by FPL. The generating capacity is made up of two steam units (Units #1 and #2), plus three combined cycle units (Units #3, #4, and #8). The site includes a 6,800-acre cooling pond (6,500 acres of water surface and 300 acres of dike area) and approximately 300 acres for the existing power plant units and related facilities.

a. U.S. Geological Survey (USGS) Map

A USGS map for the site is found at the end of this chapter.

b. and c. Land Uses and Environmental Features

A major portion of the site consists of a 6,800-acre cooling pond. The existing power plant facilities are located on approximately 300 acres. To the east of the power plant there is an area of mixed pine flat wood with a scattering of small wetlands. To the north of the cooling pond there is a 1,200-acre area which has been set aside as a mitigation area. There is a peninsula of wetland forest on the West Side of the reservoir that is named the Barley Barber Swamp. The Barley Barber Swap encompasses 400 acres and is preserved as a natural area. There is also a 10-kilowatt (kW) photovoltaic energy facility at the south end of this site.

d. and e. Water Quantities and Supply Sources

Surface water resources currently used at the Martin facility include the cooling pond which takes its water from the St. Lucie canal. The available ground water resource is the surficial aquifer system which is used as a source of potable and service water. Both of these sources are available for use with any potential site expansion. We believe these sources would provide sufficient water for either simple cycle or combined cycle generation.

Potential Site # 7: Port Everglades Plant, Broward County

This site is located on the 94-acre FPL Port Everglades plant site in Port Everglades, Broward County. The site has convenient access to State Road (SR) 84 and Interstate 595. A rail line is located near the plant. The existing plant consists of four steam boiler generating units: two 200 MW (approximate) and two 400 MW (approximate) sized units. The four steam boilers are capable of firing residual fuel oil, natural gas, or a combination of both. The site also is home to twelve simple cycle gas turbine (GT) peaking units of 30 MW (approximate) each. The GT's are part of the Gas Turbine Power Park that is made up of 24 GT's at the Lauderdale Plant site and the twelve GTs at the Port Everglades site. The GT's are capable of firing either natural gas or liquid fuel.

a. **U.S. Geological Survey (USGS) Map**

A map of the site is found at the end of this chapter.

b. and c. **Land Uses and Environmental Features**

The land on this site is primarily industrial. The adjacent land uses are port facilities and associated industrial activities, oil storage, cruise ships, and light commercial.

d. and e. **Water Resources and Supply Sources**

Cooling water could be drawn from the Intra-coastal Waterway. We believe this source would provide sufficient water for either simple cycle or combined cycle generation.

Potential Site # 8: Riviera Plant, Palm Beach County

This site is located on the FPL Riviera Plant property in Riviera Beach, Palm Beach County. The site has direct access to a four-lane highway, US 1, and barge access is available. A rail line is located near the plant. The facility currently houses two operational 300 MW (approximate) steam boiler generating units and one retired 50 MW generating unit.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site is found at the end of this chapter.

b. and c. **Land Uses and Environmental Features**

The land on the site is primarily covered by the existing generation facilities with some open, maintained grass areas. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development. The site is located on the Intra-coastal Waterway near the Lake Worth Inlet.

d. and e. Water Quantities and Supply Sources

The existing municipal water supply could be used for industrial processing water. Industrial cooling water needs could be met using the existing once-through cooling water system. For once-through cooling water, FPL would continue to use Lake Worth as a source of water. We believe these sources would provide sufficient water for either simple cycle or combined cycle generation.

IV.F.2 Potential Sites for Advanced Technology Coal-Fired Generating Options

As previously discussed, FPL is in the process of analyzing the feasibility of advanced technology coal-fired generating options. FPL believes that the earliest such an option could be permitted and constructed is 2012. FPL's plans to pursue advanced technology coal-fired generation was set forth in its 2005 Request for Proposals (RFP) document issued in September 2005. Part I of the RFP solicited proposals for 2009-2011 that led to FPL's plans to construct the two West County Energy Center units. Part II of the RFP describes FPL's plans to solicit only those proposals that will add to a balanced fuel supply in meeting FPL's 2012-2014 capacity needs. That solicitation is scheduled for later this year.

At the time this Site Plan is being prepared, FPL is analyzing potential sites for such options. Selection criteria for potential sites have been delineated in FPL's *Report on Clean Coal Generation* (March 2005). It is expected that this selection process will have progressed to a point that FPL will be able to share site specific information by June 1, 2006. An Addendum to the 2006 Site Plan will be developed that provides this information when it is available.

Environmental and Land Use Information: Supplemental Information

Preferred Site: Turkey Point

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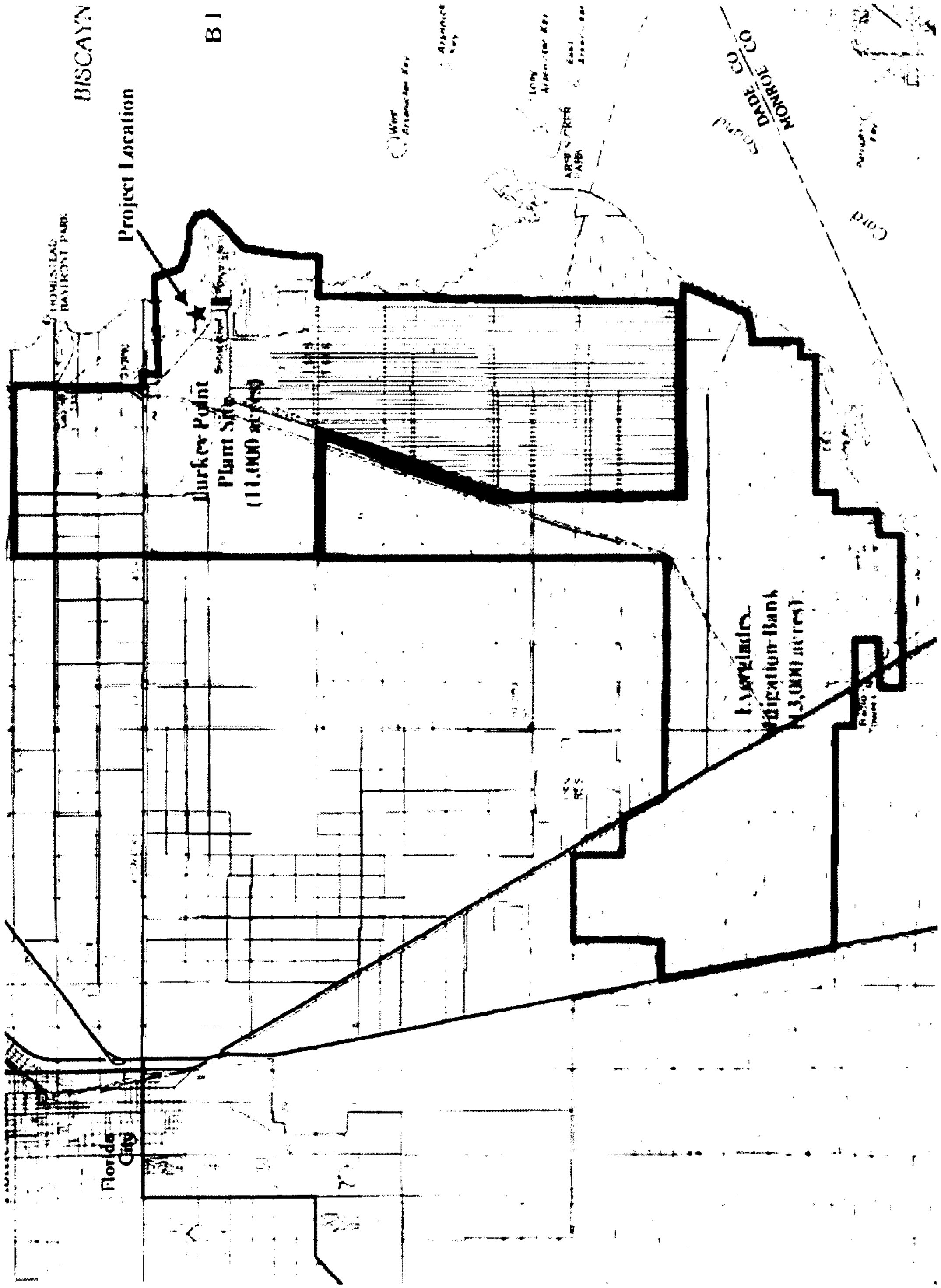
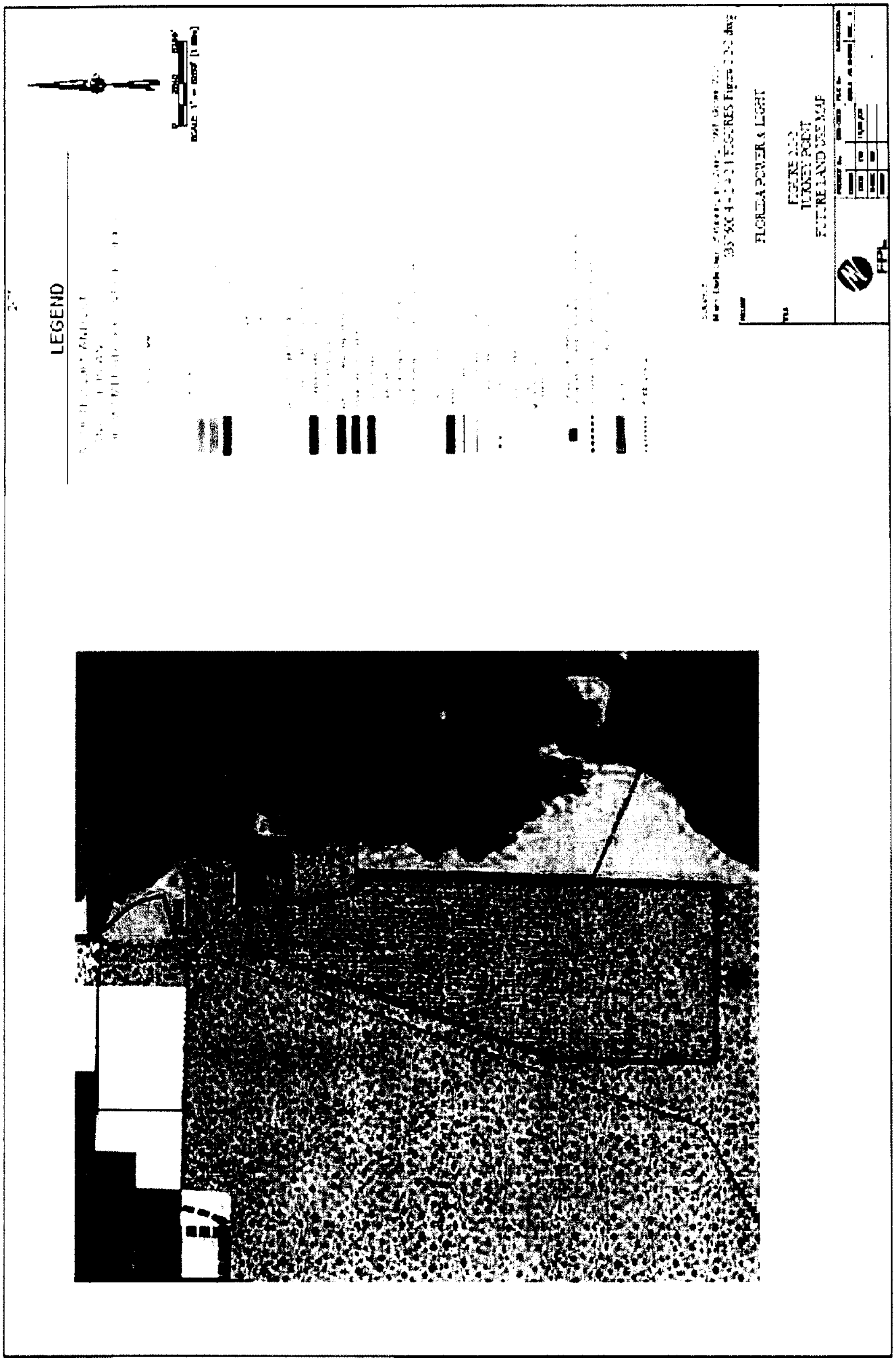
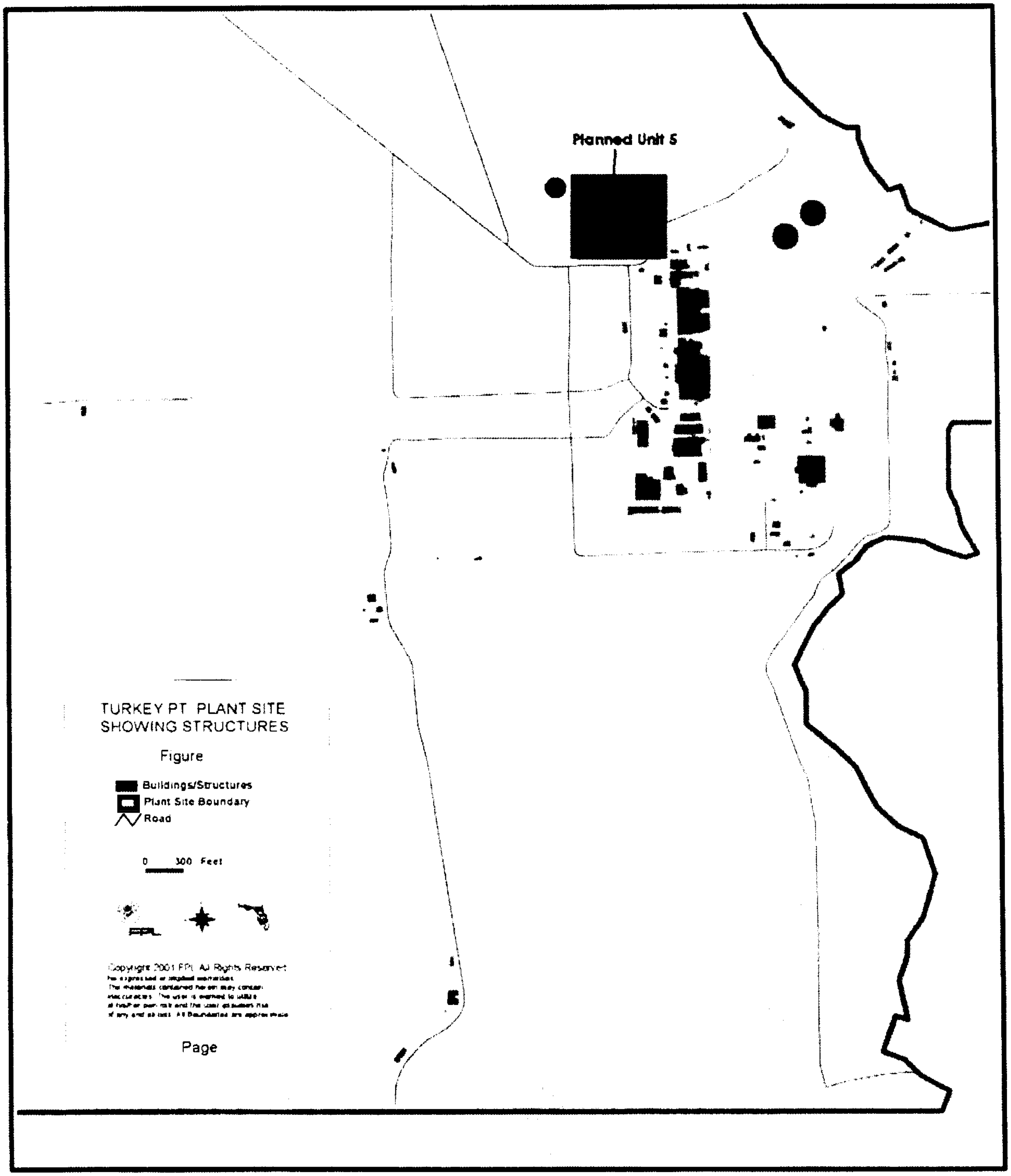

BISCAYN
B I
Project Location
HOMESTEAD BAYFRONT PARK
Turkey Point Plant Site (11,000 acres)
Everglades Mitigation Bank (13,000 acres)
Florida City
DADE CO
MONROE CO


LEGEND
FLORIDA POWER & LIGHT


Planned Unit 5
TURKEY PT PLANT SITE
SHOWING STRUCTURES
Figure
Buildings/Structures
Plant Site Boundary
Road
0 300 Feet
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Environmental and Land Use Information: Supplemental Information

Preferred Site: West County Energy Center

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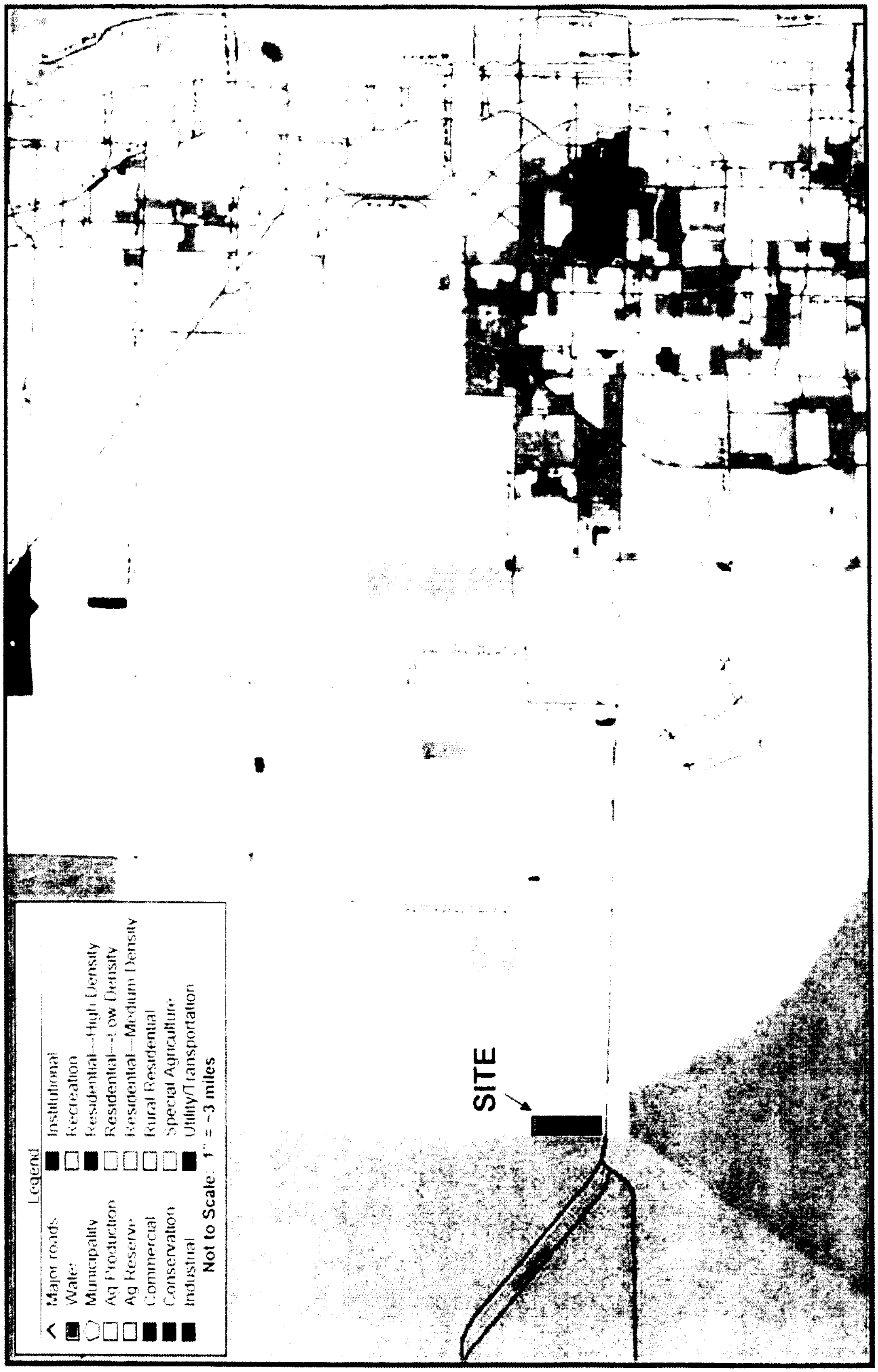
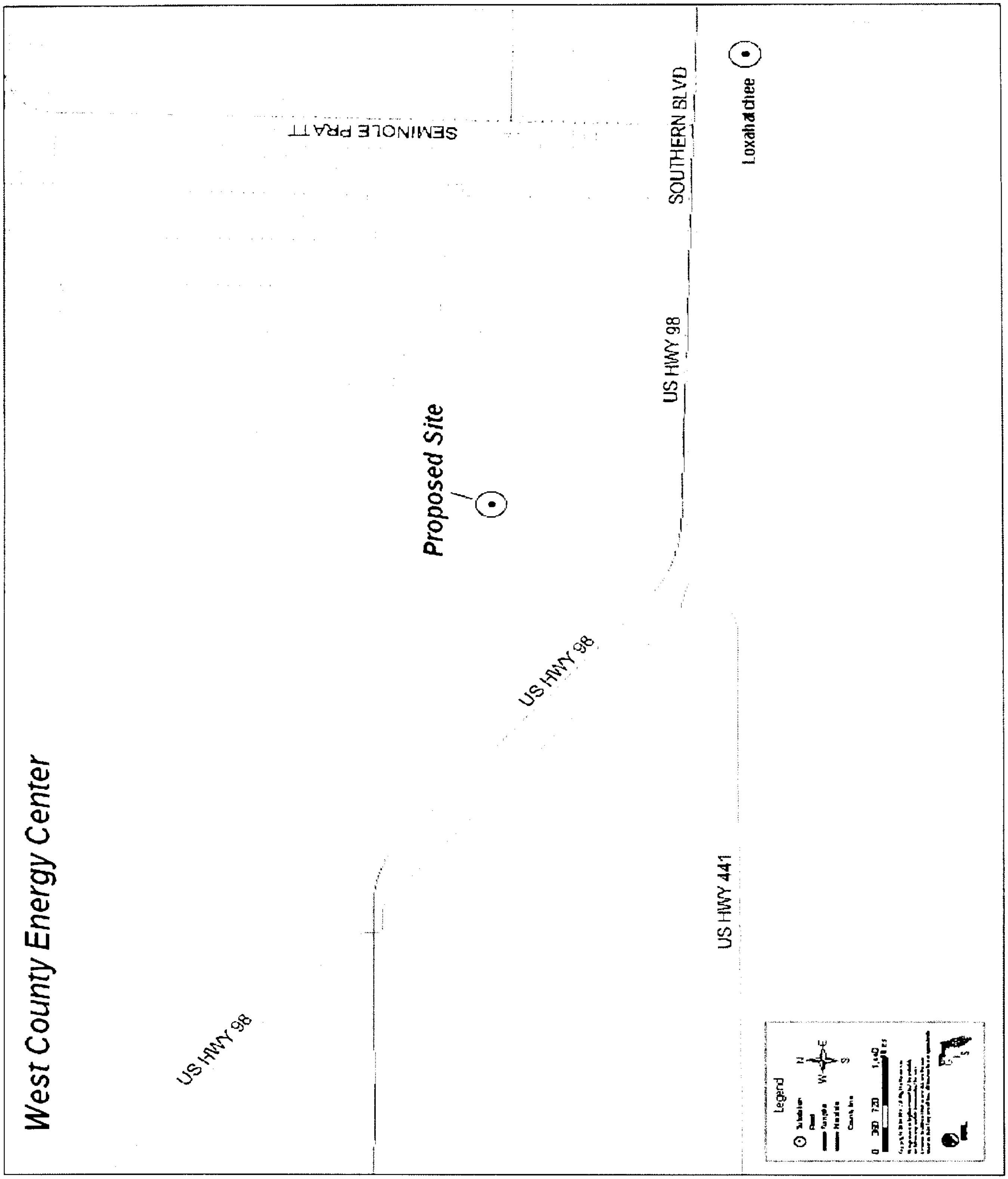

SITE
Legend
Major roads
Water
Municipality
Ag Production
Ag Reserve
Commercial
Conservation
Industrial
Institutional
Recreation
Residential—High Density
Residential—Low Density
Residential—Medium Density
Rural Residential
Special Agriculture
Utility/Transportation
Not to Scale: 1" = ~3 miles


West County Energy Center
Proposed Site
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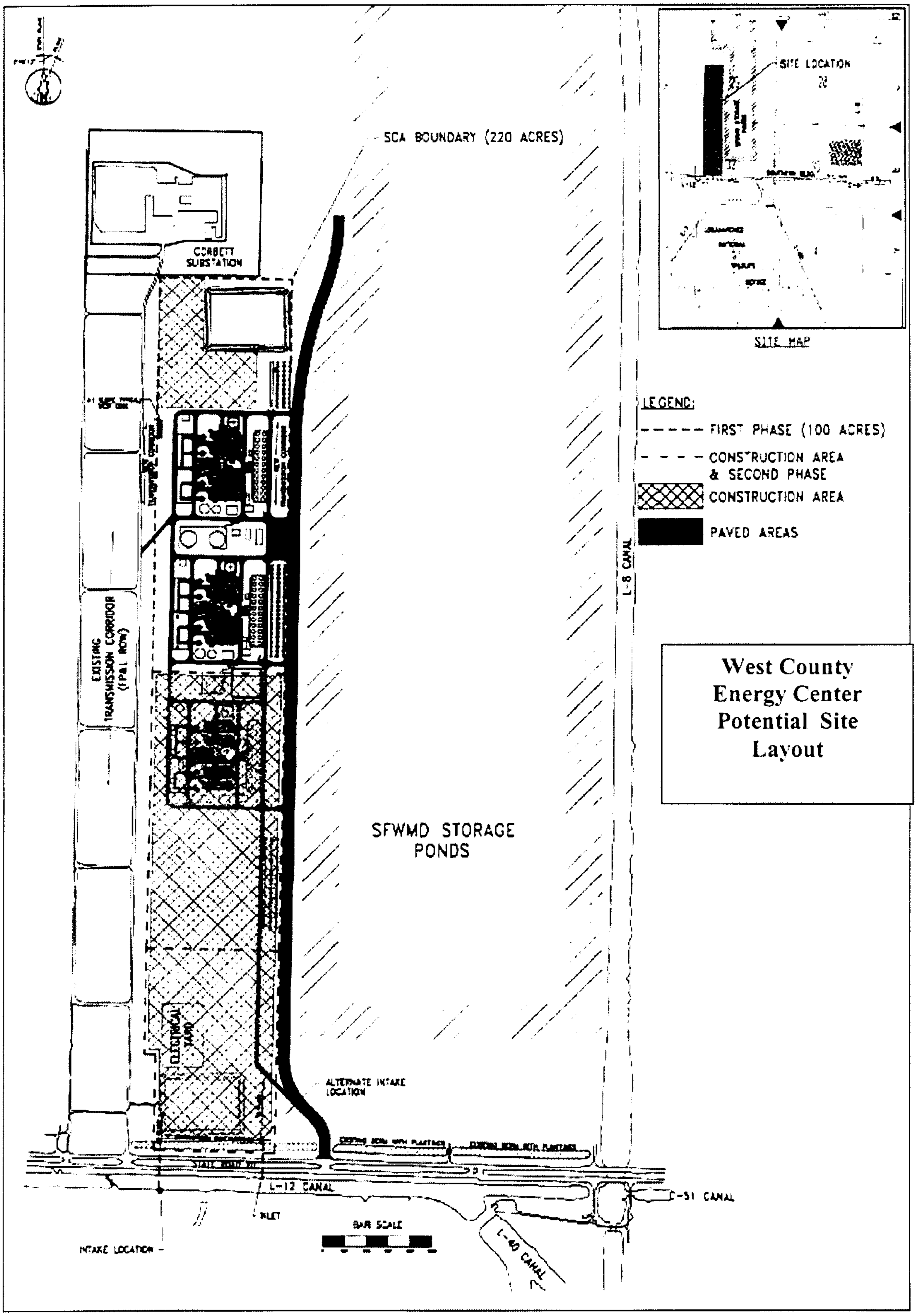
SOUTHERN BLVD
Loxahatchee
US HWY 98
US HWY 98
US HWY 98
US HWY 441
Legend


SCA BOUNDARY (220 ACRES)
CORBETT SUBSTATION
SITE LOCATION
SITE MAP
LEGEND:
FIRST PHASE (100 ACRES)
CONSTRUCTION AREA & SECOND PHASE
CONSTRUCTION AREA
PAVED AREAS
L-8 CANAL
West County Energy Center Potential Site Layout
EXISTING TRANSMISSION CORRIDOR (FP&L ROW)
SFWMD STORAGE PONDS
ELECTRICAL YARD
ALTERNATE INTAKE LOCATION
L-12 CANAL
C-51 CANAL
INLET
BAR SCALE
L-40 CANAL
INTAKE LOCATION

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Environmental and Land Use Information: Supplemental Information

Potential Site #1: Andytown

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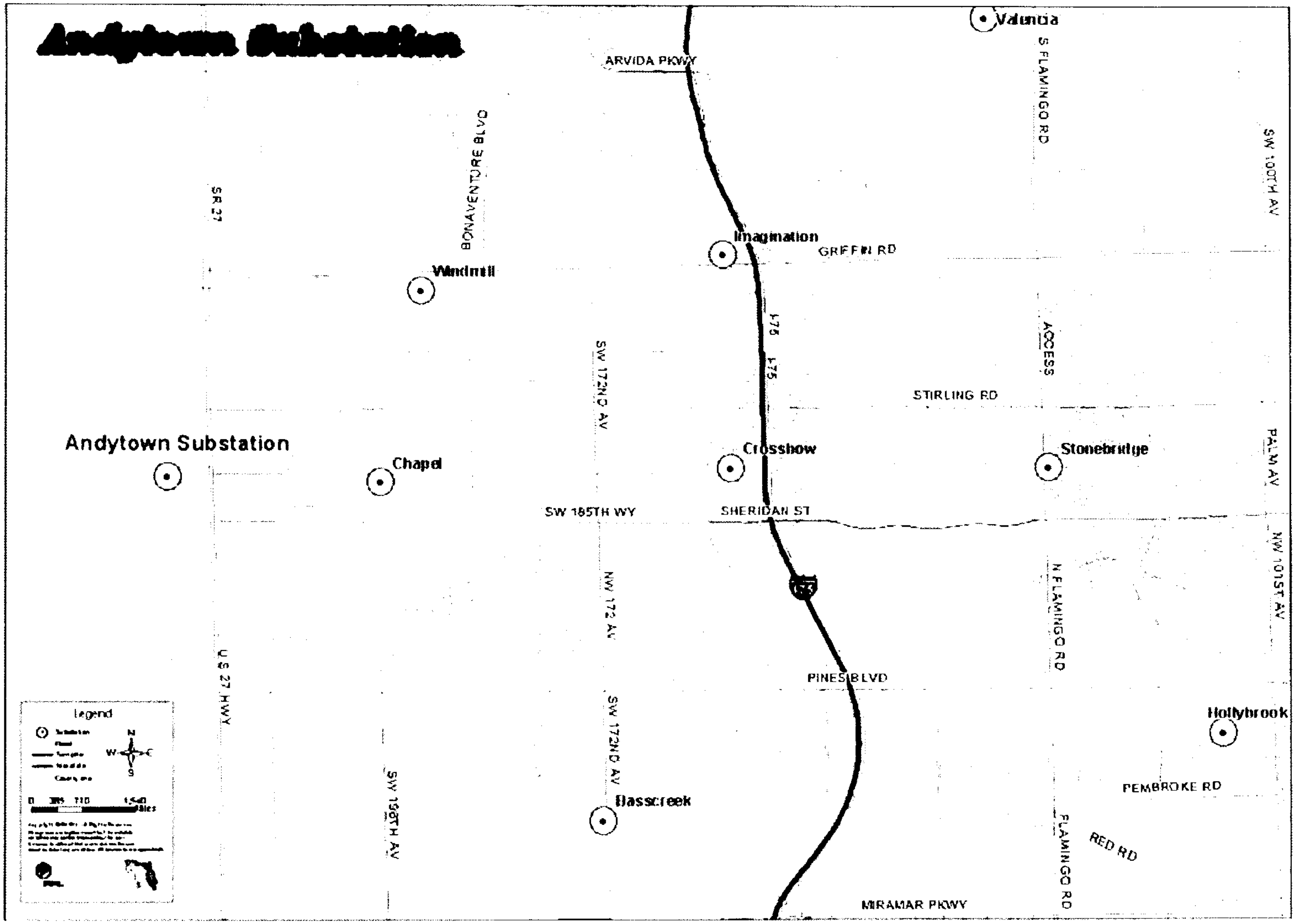

Andytown Substation
Valencia
ARVIDA PKWY
S FLAMINGO RD
SW 100TH AV
BONAVENTURE BLVD
SR 27
Imagination
GRIFFIN RD
Windmill
I-75
ACCESS
SW 172ND AV
STIRLING RD
Andytown Substation
Chapel
Crosshow
Stonebridge
PALM AV
SW 185TH WY
SHERIDAN ST
NW 101ST AV
NW 172 AV
N FLAMINGO RD
U S 27 HWY
PINES BLVD
Hollybrook
Legend
SW 172ND AV
SW 196TH AV
Basscreek
PEMBROKE RD
RED RD
FLAMINGO RD
MIRAMAR PKWY

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Environmental and Land Use Information: Supplemental Information

Potential Site #2: Cape Canaveral

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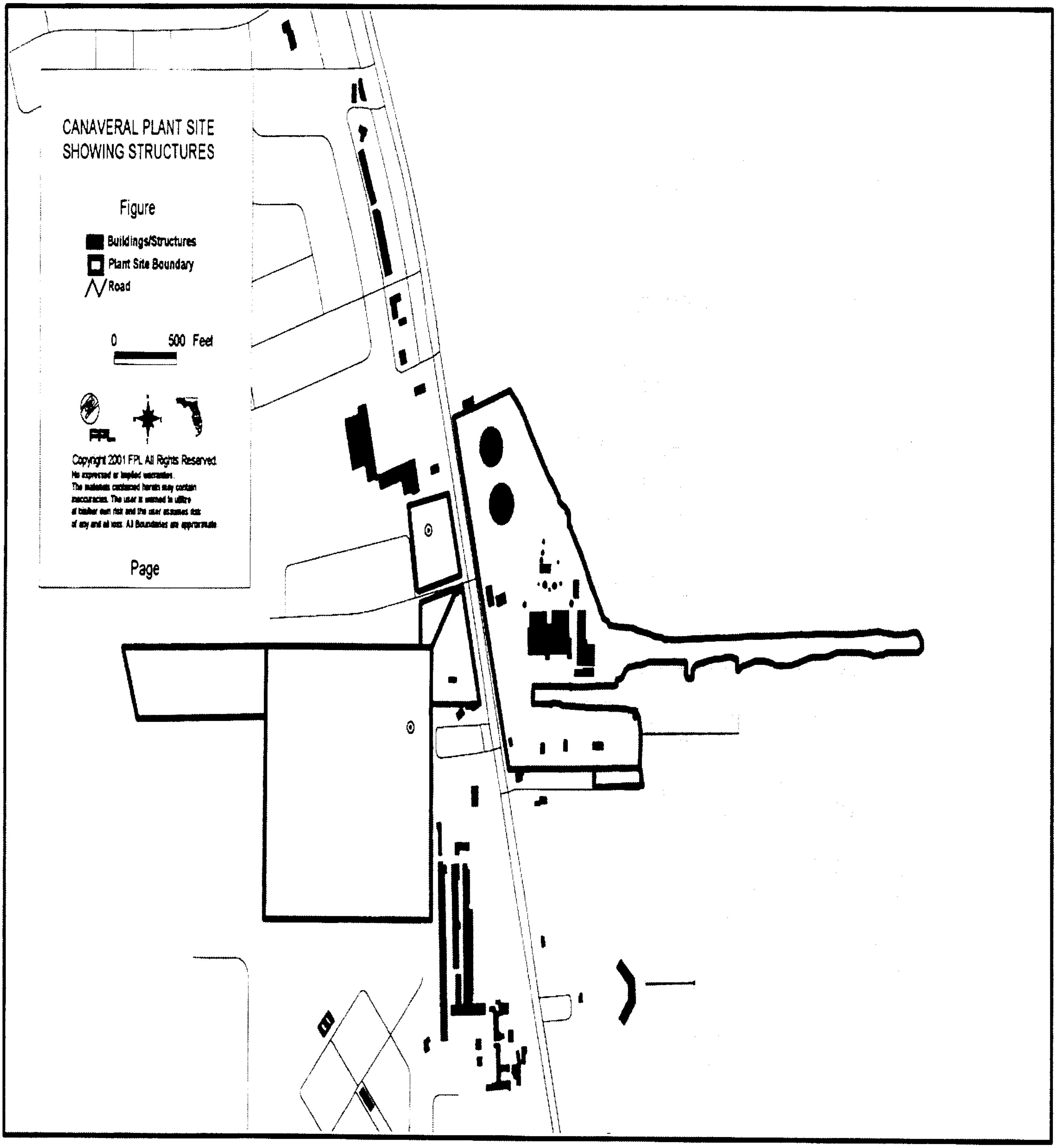
CANAVERAL PLANT SITE
SHOWING STRUCTURES
Figure
Buildings/Structures
Plant Site Boundary
Road
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500 Feet
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Environmental and Land Use Information: Supplemental Information

Potential Site #3: Desoto

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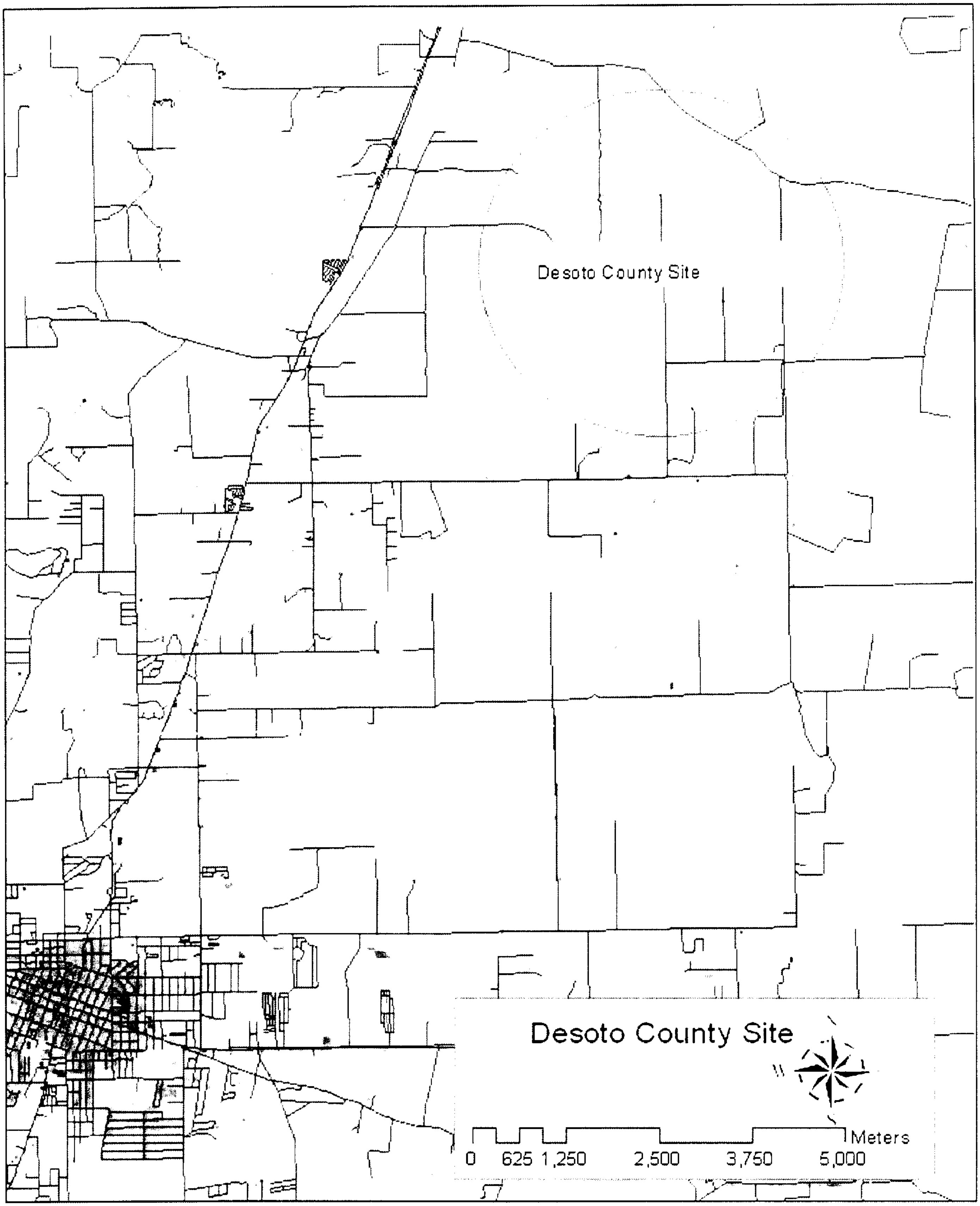
Desoto County Site
Desoto County Site
0 625 1,250 2,500 3,750 5,000
Meters

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Environmental and Land Use Information: Supplemental Information

Potential Site #4: Ft. Myers

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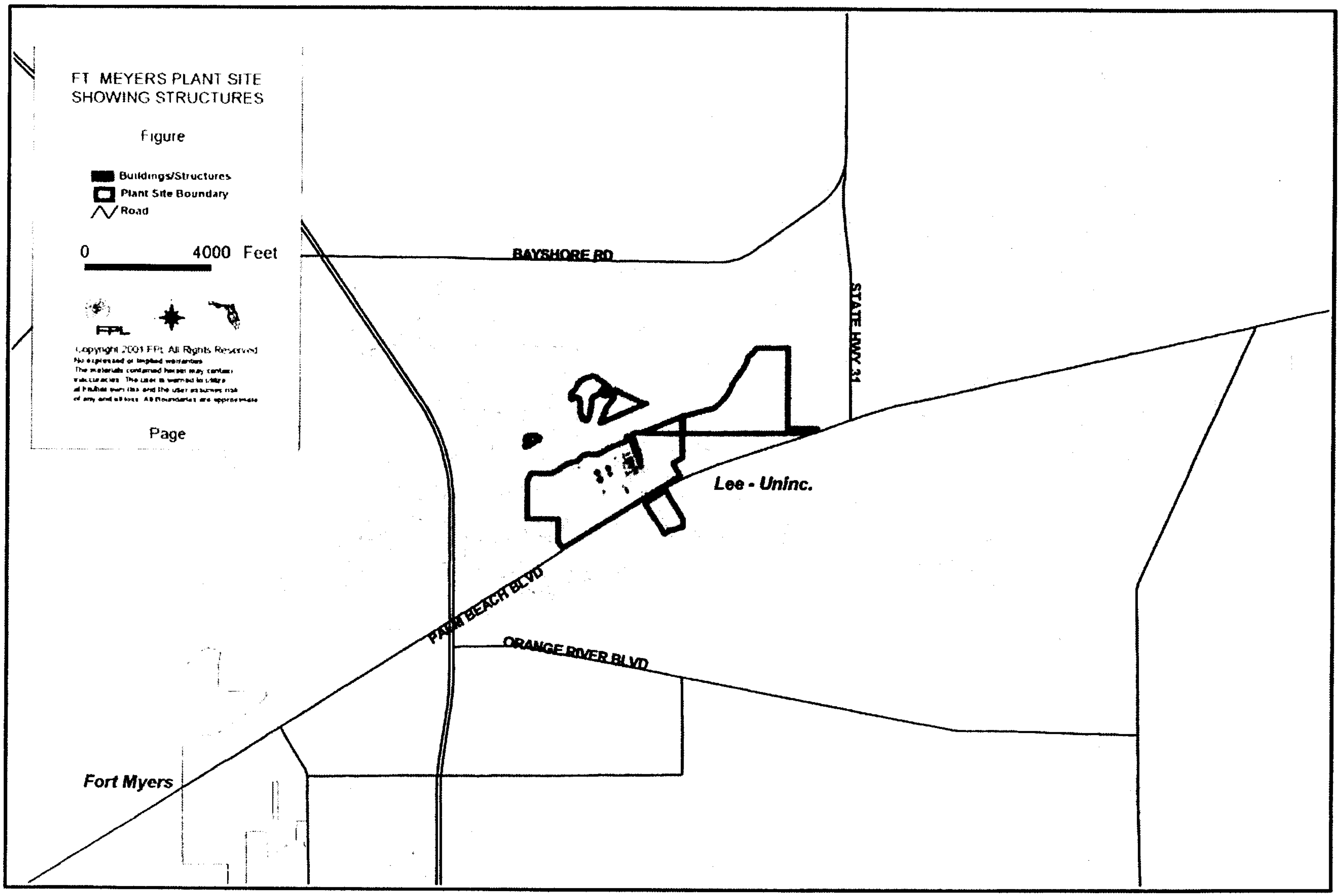
FT MEYERS PLANT SITE
SHOWING STRUCTURES
Figure
Buildings/Structures
Plant Site Boundary
Road
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Page
BAYSHORE RD
STATE HWY 31
Lee - Uninc.
PALM BEACH BLVD
ORANGE RIVER BLVD
Fort Myers

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Environmental and Land Use Information: Supplemental Information

Potential Site #5: Lauderdale

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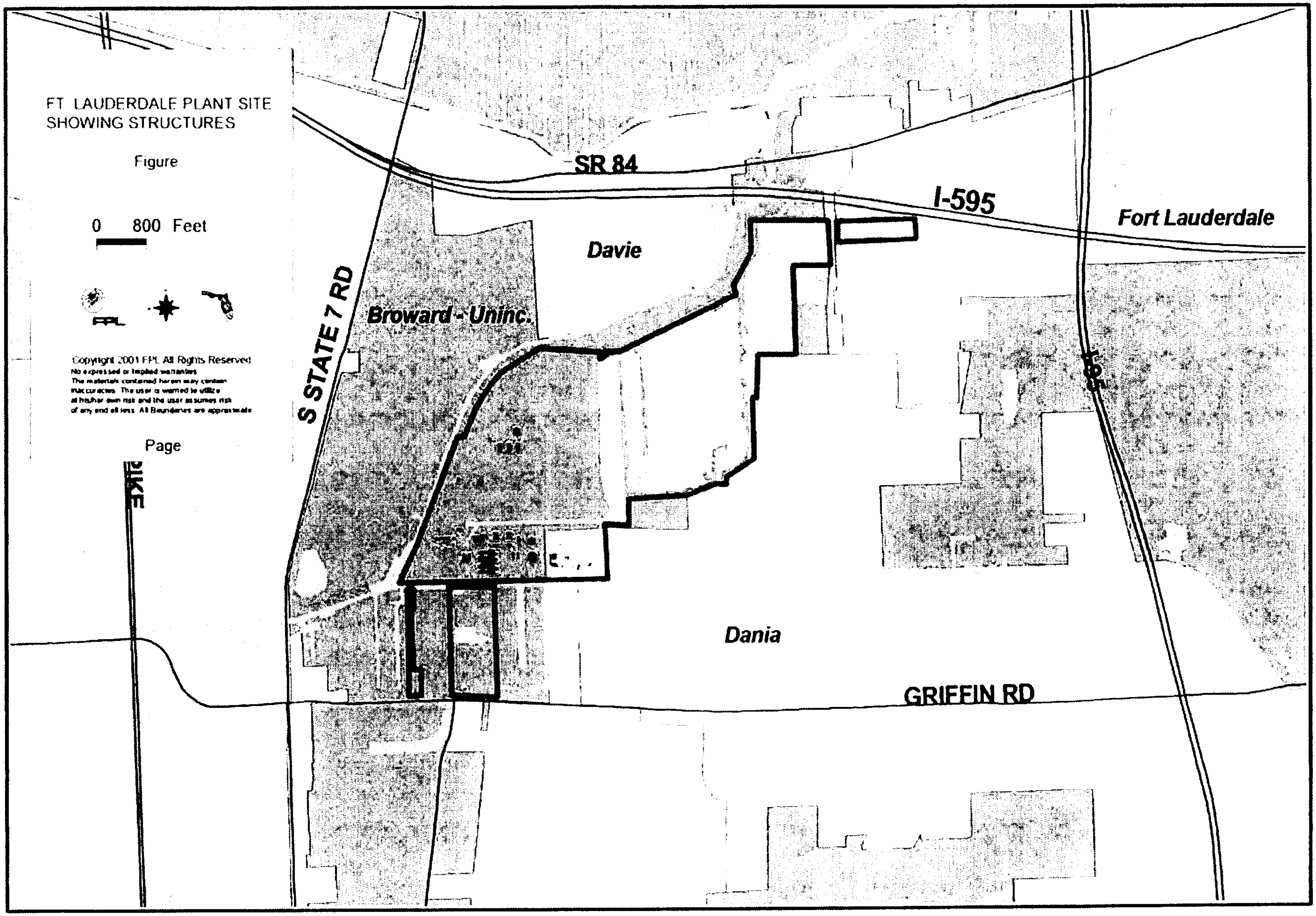
FT LAUDERDALE PLANT SITE
SHOWING STRUCTURES
Figure
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FPL
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Page
SR 84
I-595
Fort Lauderdale
Davie
Broward - Uninc.
S STATE 7 RD
I-95
Dania
GRIFFIN RD

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Environmental and Land Use Information: Supplemental Information

Potential Site #6: Martin

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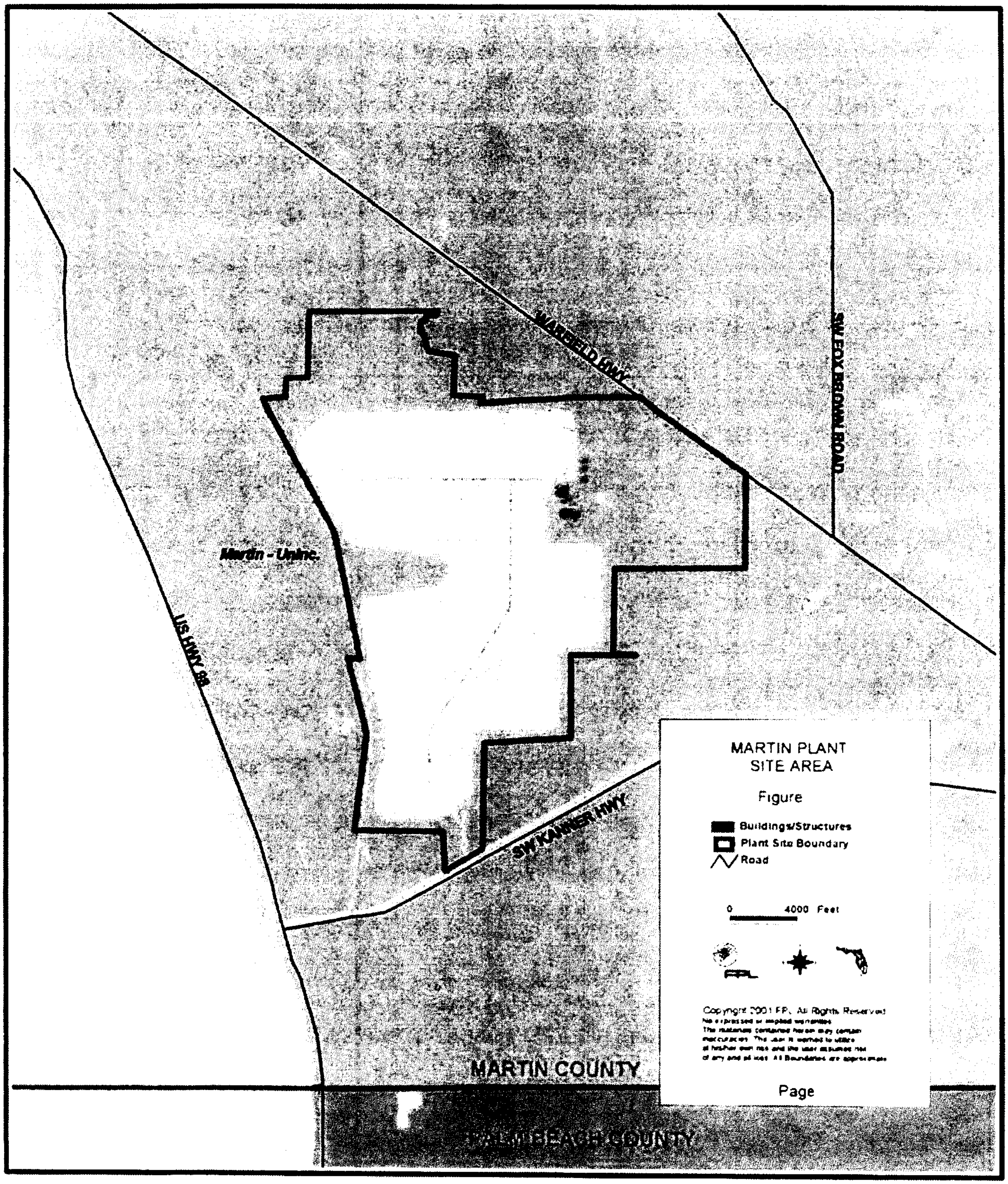
WARFIELD HWY
SW FOX BROWN ROAD
Martin - Uninc.
US HWY 98
SW KANNER HWY
MARTIN COUNTY
PALM BEACH COUNTY
MARTIN PLANT
SITE AREA
Figure
Buildings/Structures
Plant Site Boundary
Road
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4000 Feet
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Environmental and Land Use Information: Supplemental Information

Potential Site #7: Port Everglades

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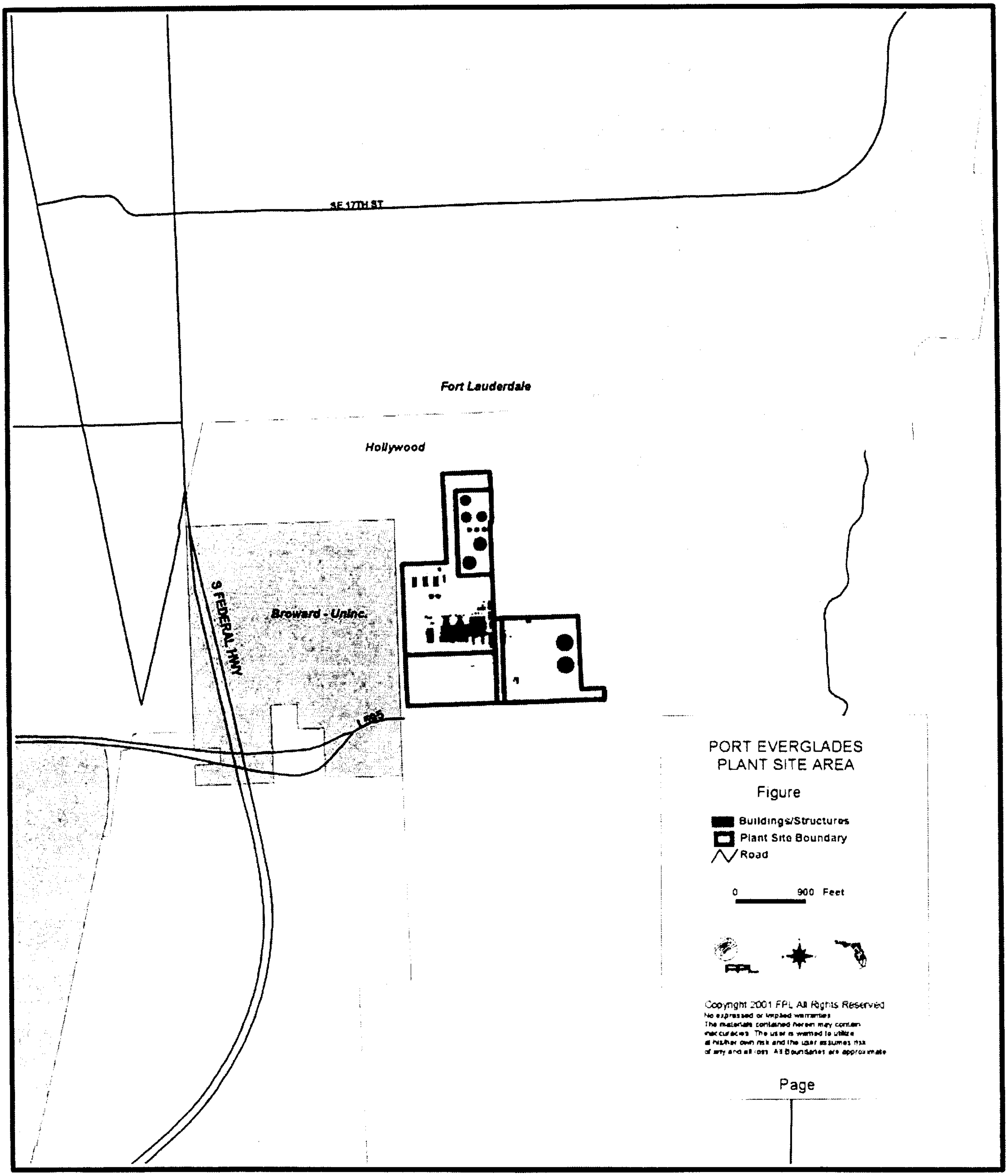
SE 17TH ST
Fort Lauderdale
Hollywood
S FEDERAL HWY
Broward - Uninc.
I-595
PORT EVERGLADES
PLANT SITE AREA
Figure
Buildings/Structures
Plant Site Boundary
Road
0 900 Feet
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The materials contained herein may contain
inaccuracies. The user is warned to utilize
at his/her own risk and the user assumes risk
of any and all loss. All Boundaries are approximate
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Environmental and Land Use Information: Supplemental Information

Potential Site #8: Riviera Plant

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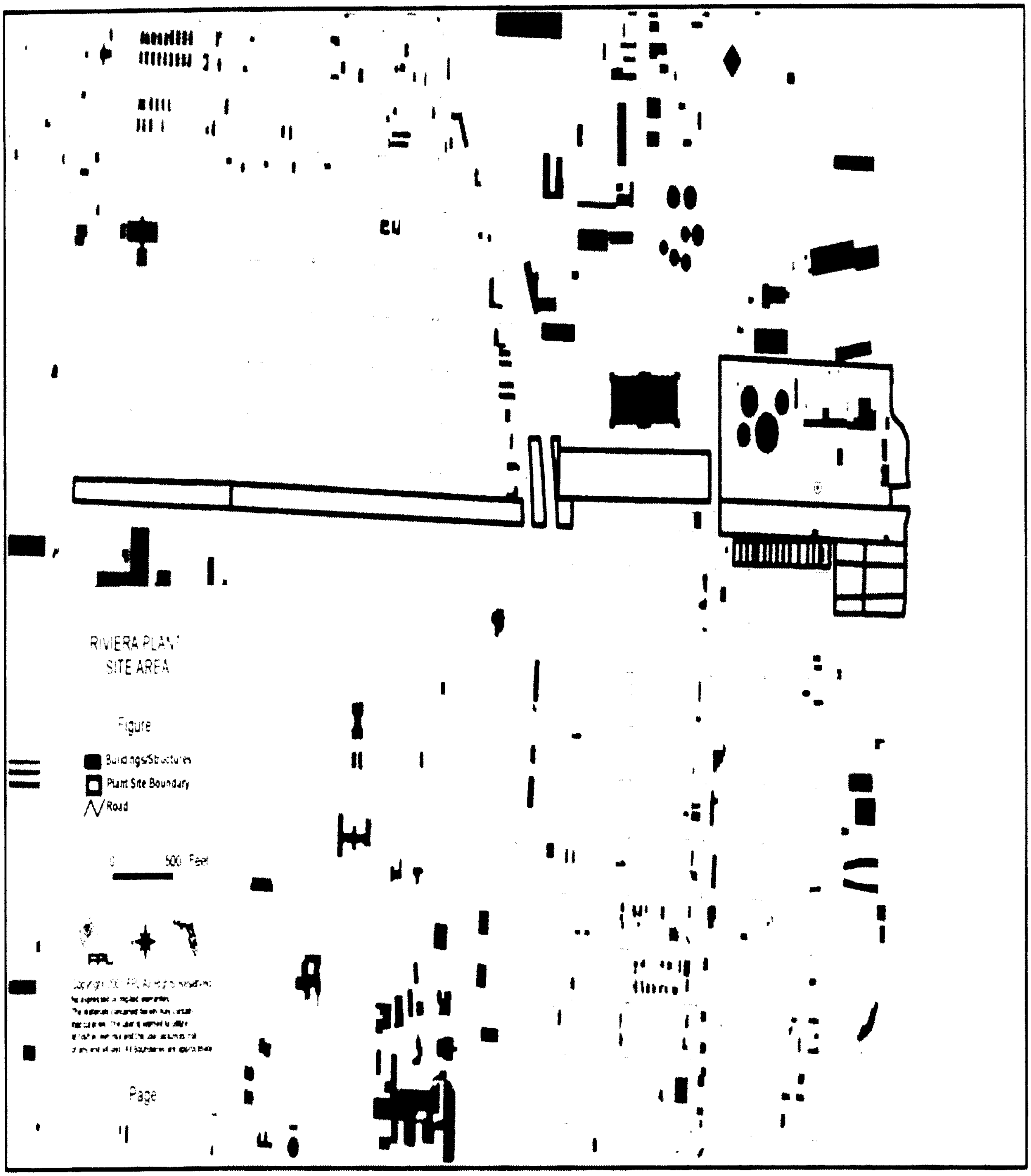

RIVIERA PLANT
SITE AREA
Figure
Buildings/Structures
Plant Site Boundary
Road
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CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information". These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important since they affect the development of assumptions for the amount of external assistance which is available to the FPL system and the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new units that may not adversely impact such limitations. The internal transmission limitations are also addressed by developing the direct costs for siting new units at different locations, and by, evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system. Both site- and system-related transmission costs are developed for each different unit/unit location option or groups of options.

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's transmission plans are presented in Section III.E.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements for the FPL system.[2]

During late 2005, the load forecast was revised upward to incorporate the observed increase in population growth and resulting increase in system demand. This increased forecast, compared to the base forecast used earlier in the year, allowed FPL to bracket a range of expected load growth and the corresponding changes to the generation plan. FPL's response to the increased load was to address the near term needs (2006 - 2008) with a combination of increased DSM, available purchases and securing increased transmission capacity for existing purchases. FPL also identified a single CT in 2008 to meet the balance of the near term needs. In the event the load forecast is reduced, this CT can be avoided or delayed. Should load increase, additional DSM, purchased power or additional self-build CT's may be added to maintain the reliability criteria.

[2] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis, the lowest rate basis and the lowest system revenue requirements basis are identical. In such cases (as in most of FPL's current resource planning work), FPL evaluates options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its base case or "Most Likely" fuel price forecast are discussed in Chapter III of this document.

FPL conducted an analysis of the comparative economics of a plan that included coal-fired generation compared to an all gas-fired plan. The results of the analysis were presented to the Commission in March, 2005. In this study FPL utilized high, low, and expected or "most likely" fuel cost forecasts to explore the relative system fuel cost differences between a clean coal plan and a plan that included all gas-fired generation additions. This approach allowed FPL to examine the relative economics of these two different types of plans with fuel cost forecasts that varied the price difference between coal and natural gas. Significant changes occurred in long term fuel price forecasts as a result of the events of 2005. Since the natural gas - coal price differential has increased compared to the forecast used in the 2005 Clean Coal Study, it is expected that the economics for coal versus gas have significantly improved.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item #3, FPL used three fuel forecasts in the comparative economic analysis of clean coal generation. FPL held the coal prices constant, based on the most likely coal price forecast, and developed three natural gas price forecasts (high, low, and expected). The low gas price sensitivity, when compared to the coal price forecast, results in an essentially fixed differential between natural gas prices and coal prices.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 and Schedule 8 present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options which were considered in the resource planning work. A summary of this information for the new capacity options FPL projects to add over the planning horizon is presented on the Schedule 9 forms

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

The key financial assumptions used in FPL's most recent resource planning work were a 45% debt and 55% equity FPL capital structure, projected debt cost of 6.90%, and an equity return of 11.75%. These assumptions resulted in a weighted average cost of capital of 9.57% and an after-tax discount rate of 8.37%. FPL did not test the sensitivity of its resource plan to varying financial assumptions.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM approach). However, in its most recent planning work, FPL utilized both a levelized system average rate perspective for its DSM Goals and DSM Plan work and the equivalent present value of system revenue requirements perspective when evaluating options that did not result in changes to system DSM levels. (As discussed in response to Discussion Item # 2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective are identical when DSM levels are unchanged between competing plans.)

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses two system reliability criteria in its resource planning work. One of these is a minimum 20% Summer and Winter reserve margin. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the planning criteria established by the North American Electric Reliability Council (NERC) in its *Planning Standards*. FPL has applied these planning criteria in a manner consistent with prudent utility practice. The *NERC Planning Standards* are available on the internet (http://www.nerc.com).

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Facility Rating Methodology* document that are also available on the internet (http://floasis.siemens-asp.com/OASIS/FPL/INFO.HTM).

The normal voltage criteria for FPL stations is given below:

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09

There may be isolated cases for which FPL may determine it prudent to deviate from the general criteria stated above. The overall potential impact on customers and the probability of an outage actually occurring, as well as other factors would influence the decision in such cases.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The impact of FPL's DSM Programs on demand and energy consumption are revised periodically. Engineering models, calibrated with field-metered data, are updated when significant efficiency changes occur in the marketplace. Participation trends are tracked for all of the FPL DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants.

Survey data is collected from non-participants in order to establish the baseline efficiency. Participant data is compared against non-participant data to establish the demand and energy saving benefits of the utility program versus what would be installed in the absence of the program. Finally, FPL is careful to claim only program savings for the average life of the installed efficiency measure. For these DSM measures which involve the utilization of load management, FPL conducts periodic tests of the load control equipment to ensure that it is functioning correctly.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

Among the strategic or non-price factors FPL typically considers when choosing between resource options are the following: (1) fuel diversity; (2) technology risk; (3) environmental risk and (4) site feasibility.

Fuel diversity relates to two concepts, the diversity of sources of fuel (e.g., coal vs. oil vs. natural gas), and the diversity of supply for a single fuel source (for example alternative pipeline suppliers for natural gas). All other factors being equal, supply options that increase diversity in fuel source and/or supply would be favored over those that do not.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology which has not achieved general commercial acceptance has a higher risk than a technology in wide use and, therefore, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts. Technologies regarded as more acceptable from an environmental perspective for a plan are those which minimize environmental impacts through highly efficient fuel use and state of the art controls (e.g. clean coal technologies versus conventional pulverized coal).

Site feasibility assesses a wide range of economic, regulatory and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decisions, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As has been previously discussed, elements of FPL's capacity additions include the construction of new generating capacity at an existing site: Turkey Point. This generation construction project was selected after evaluating competing bids received in response to a Request for Proposals (RFP) issued by FPL in mid-2003. The FPSC approved FPL's decision to construct the new combined cycle unit at FPL's existing Turkey Point site in June 2004.

Similarly, FPL's projected capacity additions in 2009 and 2010 at the West County Energy Center site were selected after comparing these units to four bids received in response to an RFP issued in September 2005. FPL has petitioned the FPSC for approval of a Determination of Need for these units. A decision is expected before the end of the year.

The construction capacity additions projected in this document for 2011 and beyond will be conducted in a manner consistent with the Commissions Bid Rule.

Identification of self-build options for 2008 and for 2011 beyond in FPL's Site Plan is not an indication that FPL has pre-judged any capacity solicitation it may conduct. The identification of future capacity units is required of FPL and represents those alternatives that appear to be FPL's best, most cost-effective self-build options at this time. FPL reserves the right to refine its planning analyses and to identify other self-build options. Such refined analyses have the potential to yield a variety of self-build options, some of which might not require an RFP. If an

RFP is issued for supply-side resources, FPL reserves the right to choose the best alternative for its customers, even if that option is not an FPL self-build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

FPL plans to construct a new transmission line (by July 2006) that was certified under the Transmission Line Siting Act (403.52–403.536, F.S.). The new line will connect FPL's Orange River Substation to FPL's Collier Substation (as shown on Table III.F.1). The final order certifying the corridor was issued on July 19 of 2004. The construction of this line is necessary to serve existing and future customers in the Collier and Lee County areas in a reliable and effective manner. FPL has identified the need for a new 230kV transmission line (by December 2008) that requires certification under the Transmission Line Siting Act. The new line will connect FPL's St. Johns Substation to FPL's proposed Pringle Substation (also shown on Table III.F.1). The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner. FPL has identified the need for a new 230kV transmission line (by December 2011) that requires certification under the Transmission Line Siting Act. The new line will connect FPL's Manatee Substation to FPL's proposed BobWhite Substation (also shown on Table III.F.1). The construction of this line is necessary to serve existing and future customers in the Manatee and Sarasota areas in a reliable and effective manner. Additionally, FPL has identified the need for a new 230kV transmission line (by June 2012) that requires certification under the Transmission Line Siting Act. The new line will connect FPL's future Eve Substation to FPL's Sweatt Substation (also shown on Table III.F.1). The construction of this line is necessary to serve existing and future customers in the Okeechobee and St. Lucie areas in a reliable and effective manner.

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ORIGINAL

P.O. Box 029100, Miami, FL 33102-9100

FPL

April 2, 2007

VIA HAND DELIVERY

Ms. Ann Cole
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

Re: 2007 – 2016 Ten Year Site Plan 070000

Dear Ms. Cole:

In accordance with Chapter 186 (Section 186.801 – Ten Year Plans) of the Florida Statues, enclosed for filing are twenty-five (25) copies of Florida Power & Light Company's 2007 – 2016 Ten Year Power Plant Site Plan.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Sabrina Spradley
Senior Regulatory Affairs Analyst
(305) 552-4416

CMP ______
COM ______
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Enclosures

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 42
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-G

DOCUMENT NUMBER-DATE
02865 APR-2 8
FPSC-COMMISSION CLERK

Ten Year Power Plant Site Plan
2007 – 2016

FPL

FPL

Ten Year Power Plant Site Plan

2007-2016

Submitted To:

Florida Public
Service Commission

Miami, Florida
April, 2007

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List of Schedules

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Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan. This plan includes an estimate of the utility's electric power generating needs, a projection of how those needs will be met, and a disclosure of information pertaining to the utility's preferred and potential power plant sites. This information is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (FAC).

This Ten Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) integrated resource planning (IRP) analyses that were carried out in 2006 and that were on-going in the first quarter of 2007. The forecasted information presented in this plan addresses the 2007–2016 time frame.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information, especially for the latter years of the ten-year time horizon, and is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, as determined in FPL's IRP work in 2006 and early 2007.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as preferred and potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve “discussion items” which pertain to additional specific information that is to be included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	***Abbreviation***	***Definition***
Unit Type	BIT	Bituminous Coal
	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	IC	Internal Combustion
	NP	Nuclear Power
	ST	Steam Unit
Fuel Type	UR	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	P	Planned Unit
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete

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Executive Summary

Florida Power & Light Company's (FPL) 2007 Ten Year Power Plant Site Plan (Site Plan) addresses FPL's plans to increase its electric generation capability (owned or purchased) as part of its efforts to meet its projected incremental resource needs for the 2007-2016 time period.

In response to continued strong population growth, FPL's total generation capability is required to increase significantly during the 2007-2016 time period as shown in Table ES.1. The table reflects FPL's planned changes to existing generation units (due to unit overhauls, etc.), projected changes in the delivered amounts of purchased power, and the planned additions of new generating units. Although not explicitly shown in this table, FPL's demand side management (DSM) resources are included. These resources incorporate the approved DSM Goals (that are assumed to be implemented on schedule) and approximately 684 MW of additional DSM that FPL projects will be implemented through 2016. This represents approximately 1,486 MW of cost-effective DSM beyond the significant amount of DSM achieved by FPL through 2006. After accounting for FPL's 20% reserve margin requirement, these 1,486 MW of additional DSM will avoid the need for approximately 1,780 MW of additional generating capacity that otherwise would be needed.

In 2007, FPL will be adding a new 1,144 MW (Summer) combined cycle (CC) unit, Turkey Point Unit #5, at its existing Turkey Point plant site. In 2009, and again in 2010, FPL will be adding one 1,219 MW (Summer) CC unit in western Palm Beach County. The site is named the West County Energy Center (WCEC) and these units are identified as West County Energy Center Units #1 and #2 (WCEC #1 and # 2). All three of these CC units were approved by the Florida Public Service Commission (FPSC). The Turkey Point unit was approved by the FPSC in June 2004 and the two WCEC units were approved in June 2006. FPL's applications for site certification under the Florida Electric Power Plant Siting Act were approved by the Governor and Siting Board in February 2005 for the Turkey Point unit and in December 2006 for the WCEC units. The addition of these three highly efficient units will meet FPL's capacity needs through 2010.

FPL plans to address its capacity needs in years 2013 and 2014 with two new ultra-supercritical pulverized coal (USCPC) units. For planning purposes, these units are projected to be in service by June 2013 and June 2014, respectively. However, FPL intends to bring these advanced technology coal units in service as quickly as possible in order to maintain system fuel diversity and reduce system fuel costs. It is likely that the in-service date of the first USCPC unit will occur in late 2012 or early 2013 and likewise, that the in-service date of the second USCPC unit will likely occur in late 2013 or early 2014. The new units will be located in FPL Glades Power Park

(FGPP) located in Glades County and are identified as FGPP Units #1 and #2. FPL filed a petition with the FPSC for a determination of need for the two FGPP coal units on February 1, 2007 and a decision is expected from the FPSC by July 2007.

In addition to the capacity needs to be met by the addition of Turkey Point Unit #5, WCEC Units #1 and #2, and FGPP Units #1 and #2, FPL currently projects capacity needs in 2011 (167 MW), in 2012 (777 MW), in 2013 (214 MW), in 2015 (323 MW), and in 2016 (1,327 MW). These capacity needs will be met by a combination of resources including: additional cost-effective DSM, power purchases, enhancements to existing generating units, and new power plant construction.[1] At the time this document is filed, no decision is needed regarding how these additional capacity needs will be met. FPL will continue to analyze alternatives that could be implemented to meet its projected capacity needs as part of its on-going resource planning work in 2007 and subsequent years. This future analysis work will take into account a number of factors including: the outcome of FPL's petition for need determination and site certification for FGPP Units #1 and #2, changes in forecasts of load, fuel costs, and environmental compliance costs to the extent reasonably ascertainable, and changes in both supply and demand side options.

For purposes of this planning document, FPL anticipates that the remaining projected capacity needs for the years 2011, 2012, and 2013 will be met by short-term firm power purchases of 167

MW, 800 MW, and 200 MW, respectively. Power purchases of these magnitudes are currently projected to be available for these years. FPL also projects, for purposes of this planning document, the addition of a new 1,219 MW CC unit similar to the WCEC CC units in 2015. A specific site for this potential addition has not yet been determined and the unit is referred to in this document as South Florida CC #1. The addition of this unit, or an equivalent amount of capacity, would meet FPL's capacity needs in 2015 and 2016.

FPL's ongoing resource planning efforts will continue to be influenced by two recurrent issues. Those two issues are: (1) maintaining fuel diversity in the FPL system; and (2) maintaining a balance between load and generating capacity in Southeast Florida. In regard to the first issue, the addition of the FGPP Units #1 and #2 coal units will maintain fuel diversity on FPL's system by maintaining the contribution of coal generation and limiting the increase in reliance on natural gas. FPL is also actively investigating the potential for renewable energy in Florida to contribute to system fuel diversity.

[1] Repowering of existing FPL sites remains an alternative to new construction and FPL will continue to examine this option.

Also in regard to the first issue, FPL is undertaking steps to investigate the next generation of nuclear generation facilities. Although the feasible in-service date for new nuclear generation is beyond the planning horizon of this Site Plan, FPL is actively pursuing the possibility of new nuclear generation. In regard to the second issue, the addition of Turkey Point Unit #5, and WCEC Units #1 and #2, will help maintain a balance of generation located in the Southeast area with that region's load, and contribute to overall system reliability.

Table ES.1: Projected Capacity Changes and Reserve Margins for FPL [1]

Projected Capacity Changes and Reserve Margins for FPL [1]		Net Capacity Changes (MW)		FPL Reserve Margin (%)	
		Winter[2]	Summer[3]	Winter	Summer
2007	Turkey Point Unit #5 [5]	---	1,144	26.4%	22.6%
	Changes to Existing Units	16	(2)		
	Changes to Existing Purchases [4]	657	(387)		
2008	Turkey Point Unit #5 [5]	1,181	---	26.5%	20.5%
	Changes to Existing Units	28	27		
	Changes to Existing Purchases [4]	(836)	---		
2009	West County Unit #1 [5]	---	1,219	22.8%	20.9%
	Changes to Existing Units	28	1		
	Changes to Existing Purchases [4]	(326)	(482)		
2010	West County Unit #1 [5]	1,335	---	24.3%	22.1%
	West County Unit #2 [5]	---	1,219		
	Changes to Existing Purchases [4]	(512)	(405)		
2011	West County Unit #2 [5]	1,335	---	27.7%	20.0%
	Power Purchase in 2011		167		
	Changes to Existing Purchases [4]	(94)	(45)		
2012	Changes to Existing Purchases [4]	---	(156)	25.5%	20.1%
	Changes to Power Purchase in 2011	---	(167)		
	Power Purchase in 2012	---	800		
2013	FGPP Unit # 1 [5]	---	980	22.6%	19.9%
	Changes to Power Purchase in 2012	---	(800)		
	Power Purchase in 2013	---	200		
	Changes to Existing Purchases [4]	(180)	---		
2014	FGPP Unit # 1 [5]	990	---	24.9%	21.3%
	FGPP Unit # 2 [5]	---	980		
	Changes to Power Purchase in 2013	---	(200)		
2015	FGPP Unit # 2 [5]	990	---	26.1%	23.7%
	South Florida CC #1 [5]	---	1,219		
2016	South Florida CC #1 [5]	1,335	---	27.1%	19.6%
	Changes to Existing Purchases [4]	(390)	(381)		
	TOTALS =	5,557	4,931		

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are values for January of year shown.
(3) Summer values are values for August of year shown.
(4) These are firm capacity and energy contracts with QF, Utilities and other purchases. See Table I.B.1 and Table I.B.2 for more details.
(5) All new unit additions are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 8.6 million people. FPL served an average of 4,409,563 customer accounts in thirty-five counties during 2006. These customers were served from a variety of resources including: FPL-owned fossil and nuclear generating units, non-utility owned generation, demand side management, and interchange/purchased power.

I.A. FPL-Owned Resources

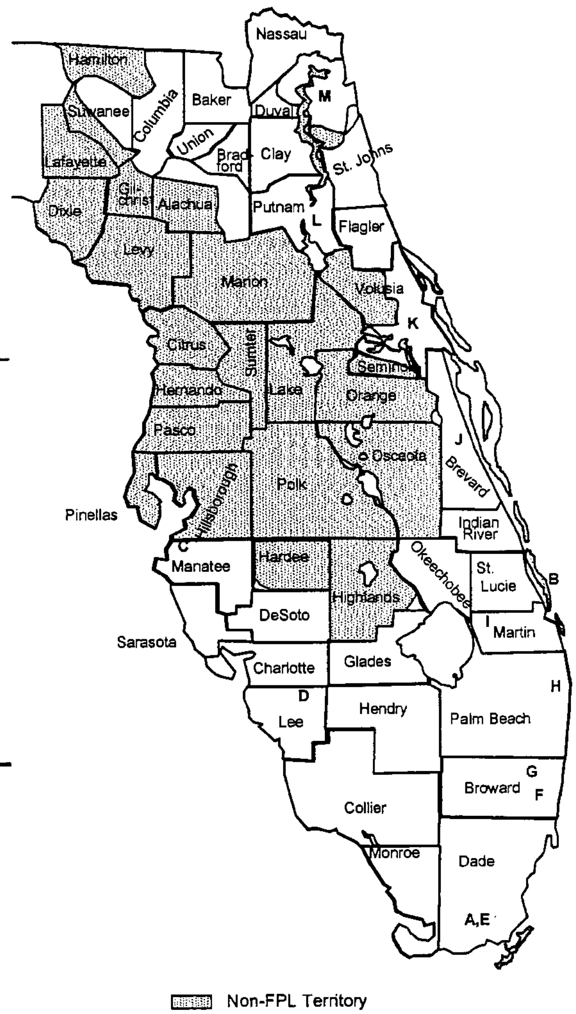
The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory and also include partial ownership of one unit located in Georgia and two units located in Jacksonville, FL. The current generating facilities consist of four nuclear steam units, three coal units, eleven combined cycle units, seventeen fossil steam units, forty eight combustion gas turbines, one simple cycle combustion turbine, and five diesel units. The location of these units is shown on Figure I.A.1 and in Table I.A.1.

FPL's bulk transmission system is comprised of 6,620 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 542 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3 shows FPL's interconnection ties with other utilities.

FPL Generating Resources by Location

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	4	2,174
B	St. Lucie *	2	1,553
C	Manatee	3	2,742
D	Fort Myers	2	1,764
E	Cutler	2	205
F	Lauderdale	2	872
G	Port Everglades	4	1,219
H	Riviera	2	565
I	Martin	5	3,738
J	Cape Canaveral	2	792
K	Sanford	3	2,044
L	Putnam	2	498
M	SJRPP **	2	250
	Scherer ***	1	646
	Gas Turbines	48	1,908
	Internal Combustion Turbines	5	12
	FPL Generation =	**89**	**20,981**



* Represents FPL's ownership share: St Lucie nuclear: 100% unit 1, 85% unit 2: St. Johns River: 20% of two units.

** SJRPP = St. John's River Power Park

*** The Scherer unit is located in Georgia and is not shown on this map.

Figure I.A.1: Capacity Resources by Location (as of December 31, 2006)

Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2006)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Combined-Cycle				
Lauderdale	Dania, FL	2	Gas/Oil	872
Martin	Indiantown,FL	2	Gas	956
Martin	Indiantown,FL	1	Gas/Oil	1,104
Sanford	Lake Monroe, FL	2	Gas	1,906
Putnam	Palatka, FL	2	Gas/Oil	498
Fort Myers	Fort Myers, FL	1	Gas	1,440
Manatee	Parrish,FL	1	Gas	1,104
Total Combined Cycle		**11**		**7,879**
Combustion Turbines				
Fort Myers *	Fort Myers, FL	1	Gas/Oil	324
Total Combustion Turbines		**1**		**324**
Nuclear				
Turkey Point	Florida City, FL	2	Nuclear	1,386
St. Lucie **	Hutchinson Island, FL	2	Nuclear	1,553
Total Nuclear		**4**		**2,939**
Coal Steam				
SJRPP ***	Jacksonville, FL	2	Coal	250
Scherer	Monroe County, Ga	1	Coal	646
Total Coal Steam		**3**		**896**
Oil/Gas Steam				
Cape Canaveral	Cocoa, FL	2	Oil/Gas	792
Cutler	Miami, FL	2	Gas	205
Manatee	Parrish, FL	2	Oil/Gas	1,638
Martin	Indiantown,FL	2	Oil/Gas	1,678
Port Everglades	Port Everglades, FL	4	Oil/Gas	1,219
Riviera	Riviera Beach, FL	2	Oil/Gas	565
Sanford	Lake Monroe, FL	1	Oil/Gas	138
Turkey Point	Florida City, FL	2	Oil/Gas	788
Total Oil/Gas Steam		**17**		**7,023**
Gas Turbines(GT)/Diesels(IC)				
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Turkey Point (IC)	Florida City, FL	5	Oil	12
Total Gas Turbines/Diesels		**53**		**1,920**
Total Units:		**89**		
Total Net Generating Capability:				**20,981**

* Each unit consists of two combustion turbines totaling approximately 300 MW.

** Total capability of each unit is 853/839 MW. FPL's ownership share of St. Lucie 1 and 2 is 100% and 85% respectively. Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.

*** Represents FPL's ownership share: SJRPP coal: 20% of two units

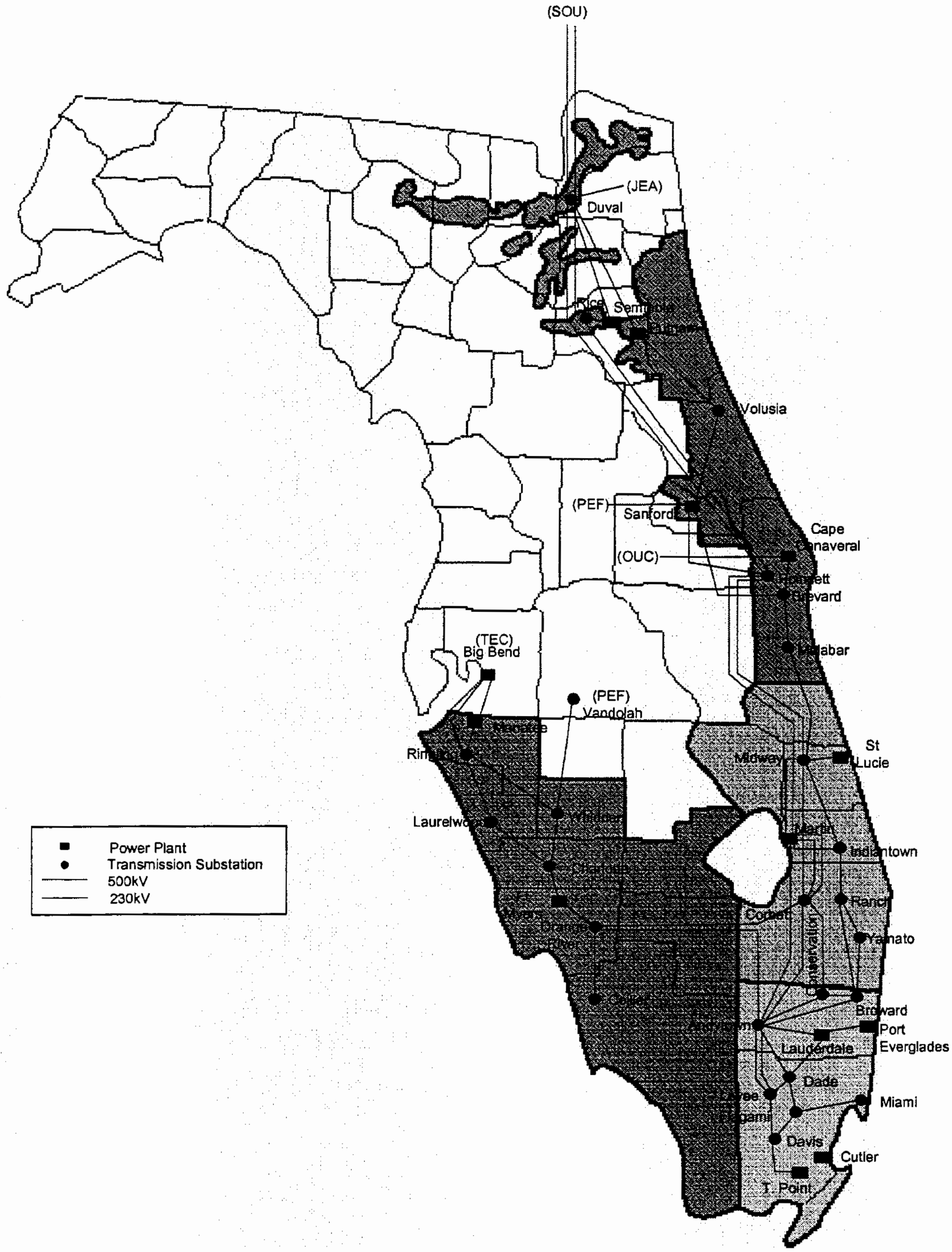


Figure I.A.2: FPL Substation and Transmission System Configuration

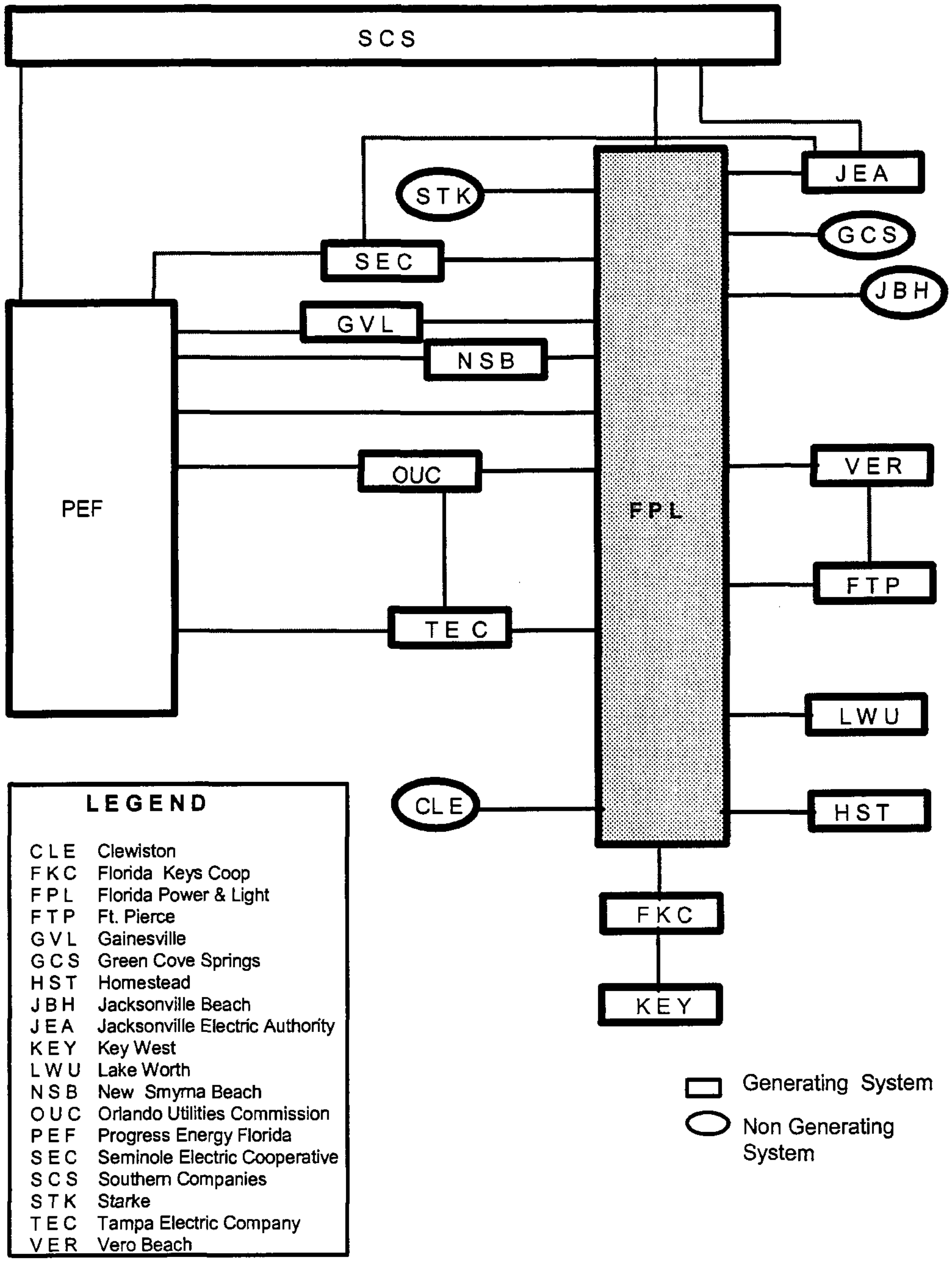


Figure I.A.3: FPL Interconnection Diagram

I.B Firm Capacity Power Purchases

Purchases from Qualifying Facilities (QF):

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has contracts with five qualifying facilities; i.e., cogeneration/small power production facilities, to purchase firm capacity and energy.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

Purchases from Utilities:

FPL has a Unit Power Sales (UPS) contract to purchase 931 MW, with a minimum of 381 MW, of coal-fired generation from the Southern Company (Southern). through May, 2010. An additional contract with Southern will result in FPL receiving 930 MW from June 2010 through the end of 2015. This capacity will be supplied by Southern from a mix of gas-fired and coal-fired units. For planning purposes, FPL is projecting a subsequent purchase of the same amount of MW from north of Florida starting in 2016.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 381 MW (Summer) and 390 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. (FPL also has ownership interest in these units. The ownership amount is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.)

Other Purchases:

FPL has other firm capacity purchase contracts through 2009 with a variety of Non-QF suppliers. These purchases are generally near-term in nature. Table I.B.1 and I.B.2 present the Summer and Winter MW, respectively, resulting from all firm purchased power contracts discussed above through the year 2016 as well as other purchases in 2011 – 2013 assumed in this document for planning purposes.

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Start Date	End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1. Broward South	04/01/91	08/01/09	50.6	50.6	0	0	0	0	0	0	0	0
2. Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
3. Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
4. Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
5. Broward North	04/01/92	12/31/10	45.0	45.0	45.0	45.0	0	0	0	0	0	0
6. Broward North	01/01/93	12/31/26	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
7. Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
8.Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
9. Cedar Bay Generating Co.	01/25/94	12/31/24	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
10. Indiantown Cogen., LP	12/22/95	12/01/25	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
11. Palm Beach SWA	04/01/92	03/31/10	47.5	47.5	47.5	0	0	0	0	0	0	0
		QF Purchases Sub Total:	**738**	**738**	**687**	**640**	**595**	**595**	**595**	**595**	**595**	**595**

II. Purchases from Utilities:

	Start Date	End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1. UPS from Southern Co.	07/20/88	05/31/10	931	931	931	0	0	0	0	0	0	0
2. UPS Replacement	06/01/10	12/31/15	0	0	0	930	930	930	930	930	930	930
3. SJRPP	04/02/82	10/31/15	381	381	381	381	381	381	381	381	381	0
		Utility Purchases Sub Total:	**1312**	**1312**	**1312**	**1311**	**1311**	**1311**	**1311**	**1311**	**1311**	**930**

III. Other Purchases:

	Start Date	End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1. Reliant/Indian River	01/01/06	12/31/09	354	576	250	0	0	0	0	0	0	0
2. Indian River (Additional)	05/01/06	12/31/09	222	0	0	0	0	0	0	0	0	0
3. Progress Energy Ventures/Desoto (Put option)	06/01/05	05/31/07	0	0	0	0	0	0	0	0	0	0
4. Oleander/Southern Co (Put option)	06/01/05	05/31/07	0	0	0	0	0	0	0	0	0	0
5. Oleander (Extension)	06/01/07	05/31/12	156	156	156	156	156	0	0	0	0	0
6. Williams	03/01/06	12/31/09	106	106	106	0	0	0	0	0	0	0
7. Progress Energy Ventures	04/01/06	03/31/09	105	105	0	0	0	0	0	0	0	0
8. Other Short-Term Purchases	May-Sept of Year Shown		0	0	0	0	167	800	200	0	0	0
		Other Purchases Sub Total	**943**	**943**	**512**	**156**	**323**	**800**	**200**	**0**	**0**	**0**

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Summer Firm Capacity Purchases Total MW:	**2993**	**2993**	**2511**	**2107**	**2229**	**2706**	**2106**	**1906**	**1906**	**1525**

Table I.B.2: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Start Date	End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1. Broward South	04/01/91	08/01/09	50.6	50.6	50.6	0	0	0	0	0	0	0
2. Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
3. Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
4. Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
5. Broward North	04/01/92	12/31/10	45.0	45.0	45.0	45.0	0	0	0	0	0	0
6. Broward North	01/01/93	12/31/26	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
7. Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
8.Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
9. Cedar Bay Generating Co.	01/25/94	12/31/24	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
10. Indiantown Cogen., LP	12/22/95	12/01/25	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
11. Palm Beach SWA	04/01/92	03/31/10	47.5	47.5	47.5	47.5	0	0	0	0	0	0
		QF Purchases Sub Total:	**738**	**738**	**738**	**687**	**595**	**595**	**595**	**595**	**595**	**595**

II. Purchases from Utilities:

	Start Date	End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1. UPS from Southern Co.	07/20/88	05/31/10	931	931	931	931	0	0	0	0	0	0
2. UPS Replacement	06/01/10	12/31/15	0	0	0	0	930	930	930	930	930	930
3. SJRPP	04/02/82	10/31/15	390	390	390	390	390	390	390	390	390	0
		Utility Purchases Sub Total:	**1321**	**1321**	**1321**	**1321**	**1320**	**1320**	**1320**	**1320**	**1320**	**930**

III. Other Purchases:

	Start Date	End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
3. Reliant/Pasco/Shady Hills	02/28/02	02/28/07	474	0	0	0	0	0	0	0	0	0
4. Reliant/Indian River	01/01/06	12/31/09	354	576	250	0	0	0	0	0	0	0
4a. Indian River (Additional)	05/01/06	12/31/09	222	0	0	0	0	0	0	0	0	0
5. Progress Energy Ventures/Desoto (Put option)	06/01/05	05/31/07	362	0	0	0	0	0	0	0	0	0
6. Oleander/Southern Co (Put option)	06/01/05	05/31/07	180	0	0	0	0	0	0	0	0	0
6a. Oleander (Extension)	06/01/07	05/31/12	0	180	180	180	180	180	0	0	0	0
7. Williams	03/01/06	12/31/09	106	106	106	0	0	0	0	0	0	0
8. Progress Energy Ventures	04/01/06	03/31/09	105	105	105	0	0	0	0	0	0	0
9. Other Short-Term Purchases	May-Sept of Year Shown		0	0	0	0	0	0	0	0	0	0
		Other Purchases Sub Total	**1803**	**967**	**641**	**180**	**180**	**180**	**0**	**0**	**0**	**0**

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Winter Firm Capacity Purchases Total MW:	**3862**	**3026**	**2700**	**2188**	**2095**	**2095**	**1915**	**1915**	**1915**	**1525**

I.C Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. Table I.C.1 shows the amount of energy purchased in 2006 from these facilities.

Table I.C.1: As Available Energy Purchases From Non-Utility Generators in 2006

Project	***County***	***Fuel***	***In-Service Date***	***Energy (MWH) Delivered to FPL in 2006***
US Sugar-Bryant	Palm Beach	Bagassee	2/80	2,455
Tropicana	Manatee	Natural Gas	2/90	16,329
Okeelanta	Palm Beach	Bagassee/Wood	11/95	360,364
Tomoka Farms	Volusia	Landfill Gas	7/98	17,681
Georgia Pacific	Putnam	Paper By-Product	2/94	9,161
Elliot	Palm Beach	Natural Gas	7/05	412

I.D. Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include both conservation initiatives and load management. FPL's DSM efforts through 2006 have resulted in a cumulative Summer peak reduction of approximately 3,659 MW at the generator and an estimated cumulative energy saving of approximately 38,169 Gigawatt Hour (GWh) at the generator. Accounting for reserve margin requirements, FPL's DSM efforts through 2006 have eliminated the need to construct the equivalent approximately 11 new 400 MW generating units.

Table I.D.1 presents FPL's approved DSM Goals for Summer MW reduction. These DSM Goals are over and above the significant levels of DSM implementation FPL achieved before the year 2005. FPL's current DSM Plan was approved by the Commission in 2004 and was designed to achieve the DSM Goals for the 2005–2014 time periods.

In addition, FPL recently received approval from the Commission to modify 8 existing DSM programs and to introduce two new DSM programs. These additional efforts will result in a projected increase of 564 Summer MW at the generator of additional DSM beyond FPL's DSM Goals by 2015 as is also presented in Table I.D.1. The table shows that when these additional 564 MW of DSM are added to the 802 MW of DSM Goals at the generator from 2006 – 2015, FPL is adding 1,366 MW at the generator of cost-effective DSM by 2015.

For planning purposes, FPL is also assuming a continuation of DSM implementation in 2016 and projects the addition of approximately 120 MW of incremental DSM in that year so that through 2016 FPL currently projects 1,486 MW of cost-effective DSM beyond the significant amount of DSM achieved by FPL through 2006.

Table I.D.1. : FPL's DSM Goals and Additional DSM: 2006 – 2015 (Summer MW)

Year	(1) DSM Goals 2005 - 2015 Summer MW at Meter (1)	(2) = (1) /(1-0.0923) DSM Goals 2005 - 2015 Summer MW at Generator (2)	(3) DSM Goals 2006 - 2015 Summer MW at Generator (3)	(4) Additional DSM 2006 - 2015 Summer MW at Generator (4)	(5) = (3) + (4) 2006 - 2015 Total Projected Summer MW at Generator (5)
2005	74.0	82	---	---	---
2006	141.7	156	75	39	114
2007	211.9	233	152	229	381
2008	287.2	316	235	289	524
2009	365.9	403	322	334	656
2010	447.9	493	412	372	784
2011	532.1	586	505	413	918
2012	618.8	682	600	456	1,056
2013	707.9	780	698	501	1,199
2014	801.7	883	802	548	1,350
2015	801.7	883	802	564	1,366

Notes: (1) The Commission-approved DSM Goals address 2005 - 2014 and represent DSM MW at the meter.

(2) The DSM Summer MW at the Generator are approximate values based on a 9.23% line loss factor.

(3) These values represent DSM Goals values from 2006 through 2015 and omit the 2005 Goals values.

(4) The values shown above for 2006 through 2008 were originally presented in FPL's 2006 Ten Year Site Plan in Table III.D.2 on page 62. Those values represented the additional DSM MW contribution through 2008 at the time the Site Plan was filed. The 2009 - on values represent a current projection of additional DSM due to FPSC approval in mid-2006 of modifications to existing FPL DSM programs and of new DSM programs.

Schedule 1

Existing Generating Facilities
As of December 31, 2006

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport. Pri.	(8) Fuel Transport. Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW
Cape Canaveral		Brevard County 19/24S/36F									804,100	796	792
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	398	396
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	398	396
Cutler		Miami Dade County 27/55S/40E									236,500	207	205
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	75,000	69	68
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	161,500	138	137
Fort Myers		Lee County 35/43S/25E									2,822,390	2,740	2,412
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,701,890	1,599	1,440
	3A & B		CT	NG	FO2	PL	PL	Unknown	Jun-01	Unknown	376,380	372	324
	1-12		GT	FO2	No	PL	No	Unknown	May-74	Unknown	744,120	769	648
Lauderdale		Broward County 30/50S/42E									1,873,968	1,946	1,712
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	464	436
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	464	436
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	509	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,734	509	420
Manatee		Manatee County 18/33S/20E									2,951,110	2,859	2,742
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	831	819
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	831	819
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,197	1,104

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2006

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Martin		Martin County 29/29S/38E									4,317,510	3,874	3,738
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	844	839
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	844	839
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	503	478
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	503	478
	8		CC	NG	FO2	PL	PL	Unknown	Jun-01	Unknown	1,224,510	1,180	1,104
Port Everglades		City of Hollywood 23/50S/42E									1,710,384	1,736	1,639
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	247,775	222	220
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	247,775	222	220
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	389	387
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	394	392
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	509	420
Putnam		Putnam County 16/10S/27E									580,008	566	498
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,004	283	249
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,004	283	249
Riviera		City of Riviera Beach 33/42S/43E									620,840	571	565
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	280	277
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	291	288
Sanford		Volusia County 16/19S/30E									2,534,050	2,264	2,044
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	156,250	140	138
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,900	1,067	958
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,900	1,057	948

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2006

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW
Scherer 2/		Monroe, GA									680,368	652	646
	4		BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	680,368	652	646
St. Johns River Power Park 3/		Duval County 12/15/28E (RPC4)									271,836	250	250
	1		BIT	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	125	125
	2		BIT	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	125	125
St. Lucie		St. Lucie County 16/36S/41E									1,573,775	1,579	1,553
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	850,000	790	777
	2	4/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	723,775	790	777
Turkey Point		Miami Dade County 27/57S/40E									2,336,138	2,238	2,186
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	398	396
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	394	392
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	760,000	717	693
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	759,900	717	693
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	12,138	12	12
										Total System as of December 31, 2006 =		22,278	20,981

1/ These ratings are peak capability.
2/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.
3/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No. 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80%.
4/ Total capability of each unit is 853/839 MW. FPL's ownership share of St. Lucie 1 and 2 is 100% and 85% respectively.Capabilities shown represent FPL's share of capacity from each of the units (approx. 92.5%) and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.

CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are developed on an annual basis for resource planning work at FPL. These forecasts are a key input to the models used to develop FPL's Integrated Resource Plan. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

The primary drivers to develop these forecasts are demographic trends, weather, economic conditions, and prices of electricity. In addition, the resulting forecasts are an integration of economic evaluations, inputs of local economic development boards, weather assessments from the National Oceanic and Atmospheric Administration (NOAA), and inputs from FPL's own customer service planning areas. In the area of demographics, population trends by county, plus housing characteristics such as housing starts, housing size, and vintage of homes are assessed.

Forecasts for electric usage in the residential and commercial classes include end-use information such as appliance saturation studies, efficiencies, and intensity of energy use. In addition to these inputs, residential forecasts also make use of household characteristics such as ages of members in households, number of members in households, and income distributions.

The projections for the national and Florida economy are obtained from Global Insight. Population projections for the counties served by FPL are obtained from the Bureau of Economic and Business Research (BEBR) of the University of Florida. In addition, FPL actively participates with local development councils and universities to obtain their assessments of the local economy, specifically in the area of expansion of new businesses and retention of the current business base. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects the company's sales and peak demand. Weather variables are used in the forecasting models for energy sales and peak demand. There are two sets of weather variables developed and used in forecasting models:

1. Cooling and Heating Degree-Days are used to forecast energy sales.
2. Temperature data is used to forecast Summer and Winter peaks.

The Cooling and Heating Degree-Days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. A composite temperature hourly profile is derived using hourly temperatures across FPL's service territory (Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained) weighted by regional energy sales. This composite temperature is used to derive Cooling and Heating Degree-Days which are based, respectively, on starting point temperatures of 65°F and an additional cooling degree variable based on a temperature of 75°F degrees. Similarly, composite temperature and hourly profile of temperature are used for the Summer and Winter peak models.

II.A. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for each revenue class for the forecasting period of 2006-2025 and are adjusted to match the Net Energy for Load (NEL) forecast. The results of these sales forecasts for the years 2007-2016 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and Net Energy for Load forecast are outlined below.

1. **Residential Sales**

   Residential electric usage per customer is estimated by using a regression model which contains the real residential price of electricity, real Florida personal income, Cooling and Heating Degree-Days as explanatory variables, as well as a dummy variable for hurricanes and other outliers. The price of electricity plays a role in explaining electric usage since electricity, like all other goods and services, will be used in greater or lesser quantities depending upon its price. To capture economic conditions, the model includes Florida's Real Personal Income. The degree of economic prosperity can, and does, affect residential electricity sales. The impact of weather is captured by the Heating Degree-Days and Cooling Degree-Days. Residential energy sales are forecast by multiplying the residential use per customer forecast by the number of residential customers forecasted.

2. **Commercial Sales**

The commercial sales forecast is also developed using a regression model. Commercial sales are a function of the following variables: Real Gross Domestic Product, commercial real price of electricity, Cooling Degree-Days, as well as dummy variables for hurricanes and outliers. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. Cooling Degree-Days are used to capture weather-sensitive load in the commercial sector.

3. **Industrial Sales**

Industrial sales were forecasted using a linear multiple regression model. The linear multiple regression model utilizes the following variables: Gross Domestic Product, Cooling Degree-Days, and several dummy variables for outliers, hurricanes, and months. The Cooling Degree-Day term is used to capture the weather-sensitive load in the industrial class.

4. **Other Public Authority Sales**

The sales for other public authority sales are developed using an econometric model with Cooling Degree-Days and several dummy variables for outliers.

5. **Street & Highway Sales and Railroad & Railways Sales**

The forecast for street and highway sales is developed using an econometric model with Real Domestic Gross Product as the primary driver and several variables for outliers. Similarly the forecast of sales to railroad & railways is developed using an econometric model with the Florida population as the primary driver and several monthly dummy variables to capture seasonality. This class consists solely of the Miami-Dade County's Metrorail system.

6. **Sales for Resale**

Sales for resale (wholesale) customers are composed of municipalities and/or electric cooperatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers.

Currently, there are four customers in this class: the Florida Keys Electric Cooperative (Florida Keys), City Electric System of the Utility Board of Key West, Florida (City of Key West), Miami-Dade County, and the Florida Municipal Power Agency (FMPA)[2]. Sales to the Florida Keys are forecasted using a regression model. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor. Miami-Dade County sells 60 MW to Progress Energy. Line losses are billed to Miami-Dade under a wholesale contract. FMPA has contracted for delivery of 75 MW from FPL through October, 2007.

7. **Total Sales**

Sales forecasts by revenue class are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, an expansion factor is applied to generate a forecast of annual Net Energy for Load (NEL).

II.B. Net Energy for Load

An econometric model is developed to produce a net energy for load (NEL) forecast. The key inputs to the model are: the real price of electricity, Heating and Cooling Degree-Days, and Florida Real Personal Income.

Once the NEL forecast is obtained using the above-mentioned methodology, the results are then compared for reasonableness to the NEL forecast generated using the total sales forecast. The sales by class forecasts previously discussed are then adjusted to match the NEL from the annual NEL model.

The forecasted NEL values for 2007 – 2016 are presented in Schedule 3.3 that appears at the end of this chapter.

II.C. System Peak Forecasts

The rate of absolute growth in FPL system load has been a function of a growing customer base, varying weather conditions, continued economic growth, changing patterns of customer behavior (including an increased stock of electricity-consuming appliances), and more efficient heating and cooling appliances. FPL developed the peak forecast models to capture these behavioral relationships.

[2] At the time this document is being prepared, FPL is in discussion with Lee County Electric Co-Operative (Lee County) regarding potential wholesale service by FPL to Lee County. If such an agreement is reached, FPL will list the agreement and incorporate its impacts in future Site Plans.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2007–2016 are presented in Schedules 3.1 and 3.2 as well as in Schedules 7.1 and 7.2.

System Summer Peak

The Summer peak forecast is developed using an econometric regression model. This econometric model utilizes the following explanatory variables: total average customers, the real price of electricity, Florida Real Personal Income, average temperature on peak day, and a heat buildup weather factor consisting of the sum of the Cooling Degree - Hours during the peak day and three prior days.

System Winter Peak

The Winter peak forecast is developed using the same econometric regression methodology as is used for Summer peak forecasts. The Winter peak model is a per customer model which contains the following explanatory variables: the square of the minimum temperature on the peak day and Heating Degree-Hours for the prior day as well as for the morning of the Winter peak day. The model also includes an economic variable: Florida Real Personal Income.

Monthly Peak Forecasts

Monthly peaks for the 2006-2025 period are forecasted to provide information for the scheduling of maintenance for power plants and fuel budgeting. The forecasting process is basically the same as for the monthly NEL forecast and consists of the following actions:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to seasonal peaks (Summer = April-October, Winter = November-March.)

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.D. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2006-2025 are produced using a System Load Forecasting "shaper" program. This model uses sixteen years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population 1/	Members per Household	GWH 2/	Average 3/ No. of Customers	Average KWH Consumption Per Customer	GWH 2/	Average 3/ No. of Customers	Average KWH Consumption Per Customer
1997	7,105,592	2.21	41,849	3,209,298	13,040	32,942	388,906	84,703
1998	7,249,627	2.22	45,482	3,266,011	13,926	34,618	396,749	87,255
1999	7,412,744	2.22	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,603,964	2.23	46,320	3,414,002	13,568	37,001	415,295	89,096
2001	7,754,846	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,898,628	2.21	50,865	3,566,167	14,263	40,029	435,313	91,955
2003	8,079,316	2.21	53,485	3,652,663	14,643	41,425	444,650	93,163
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,620,855	2.21	54,570	3,906,201	13,970	44,487	478,930	92,889
2007	8,802,732	2.21	56,487	3,990,266	14,156	46,626	485,886	95,960
2008	8,989,254	2.21	58,895	4,074,544	14,454	49,044	494,614	99,156
2009	9,177,066	2.21	60,744	4,160,072	14,602	51,011	503,762	101,260
2010	9,361,268	2.21	62,719	4,244,343	14,777	52,956	511,556	103,519
2011	9,539,356	2.20	64,719	4,326,923	14,957	54,899	518,549	105,870
2012	9,711,719	2.20	66,691	4,407,802	15,130	56,709	524,700	108,080
2013	9,880,048	2.20	68,288	4,487,318	15,218	58,145	530,966	109,509
2014	10,044,669	2.20	70,136	4,564,281	15,366	59,857	537,801	111,299
2015	10,207,278	2.20	72,023	4,639,626	15,523	61,679	545,099	113,152
2016	10,368,782	2.20	74,025	4,713,544	15,705	63,627	552,946	115,068

1/ Population represents only the area served by FPL.
2/ Actual energy sales include the impacts of existing conservation. Forecasted energy sales do not include the impact of incremental conservation.
3/ Average No. of Customers is the annual average of the twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial					Other	Total 4/
		Average 3/	Average KWH	Railroads	Street &	Sales to	Sales to
		No. of	Consumption	&	Highway	Public	Ultimate
				Railways	Lighting	Authorities	Consumers
Year	GWH 2/	Customers	Per Customer	GWH	GWH 2/	GWH	GWH
1997	3,894	14,761	263,803	85	383	702	79,855
1998	3,951	15,126	261,206	81	373	625	85,130
1999	3,948	16,040	246,135	79	473	465	84,676
2000	3,768	16,410	229,616	81	408	381	87,960
2001	4,091	15,445	264,875	86	419	67	90,212
2002	4,057	15,533	261,186	89	420	63	95,523
2003	4,004	17,029	235,128	93	425	64	99,496
2004	3,964	18,512	214,139	93	413	58	99,095
2005	3,913	20,392	191,873	95	424	49	102,296
2006	4,036	21,216	190,232	94	422	49	103,659
2007	3,956	18,706	211,476	100	456	49	107,673
2008	3,965	18,002	220,269	102	465	49	112,519
2009	3,992	16,420	243,111	104	475	49	116,375
2010	4,024	15,971	251,964	106	483	49	120,337
2011	4,056	15,672	258,807	108	492	49	124,322
2012	4,088	15,672	260,827	110	500	49	128,147
2013	4,121	15,266	269,963	112	509	49	131,224
2014	4,153	15,146	274,210	113	519	49	134,827
2015	4,188	15,090	277,503	115	529	49	138,583
2016	4,224	15,089	279,911	117	540	49	142,582

2/ Actual energy sales include existing conservation. Forecasted energy sales do not include the impact of incremental conservation.

3/ Average No.of Customers is the annual average of the twelve month values.

4/ GWH Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(17)	(18)	(19)	(20)	(21)
Year	Sales for Resale GWH	Utility Use & Losses GWH	Net 5/ Energy For Load GWH 2/	Average 3/ No. of Other Customers	Total Average 3/,6/ Number of Customers
1997	1,228	5,771	86,853	2,520	3,615,485
1998	1,326	6,206	92,662	2,584	3,680,470
1999	953	5,829	91,458	2,605	3,756,009
2000	970	7,059	95,989	2,694	3,848,401
2001	970	7,222	98,404	2,722	3,935,281
2002	1,233	7,443	104,199	2,792	4,019,805
2003	1,511	7,386	108,393	2,879	4,117,221
2004	1,531	7,464	108,091	3,029	4,224,509
2005	1,506	7,498	111,301	3,157	4,321,896
2006	1,569	7,909	113,137	3,216	4,409,563
2007	1,477	8,401	117,551	3,311	4,498,169
2008	1,004	8,501	122,024	3,402	4,590,561
2009	1,019	8,877	126,270	3,495	4,683,749
2010	1,034	9,128	130,499	3,589	4,775,460
2011	1,034	9,410	134,766	3,687	4,864,831
2012	1,034	9,857	139,038	3,783	4,951,957
2013	1,034	10,121	142,379	3,878	5,037,427
2014	1,034	10,396	146,257	3,971	5,121,200
2015	1,034	10,675	150,291	4,063	5,203,878
2016	1,034	10,940	154,556	4,154	5,285,732

2/ Actual energy sales include existing conservation. Forecasted energy sales do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

3/ Average No.of Customers is the annual average of the twelve month values.

5/ GWH Col. (19) = Col. (16) + Col. (17) + Col. (18). Actual NEL include the impacts of existing conservation and agrees to Col. (8) on schedule 3.3.

6/ Total Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1997	16,613	380	16,233	0	582	440	435	343	15,596
1998	17,897	426	17,471	0	628	526	458	385	16,811
1999	17,615	169	17,446	0	673	592	452	420	16,490
2000	17,808	161	17,647	0	719	645	467	451	16,622
2001	18,754	169	18,585	0	737	697	488	481	17,529
2002	19,219	261	18,958	0	770	755	489	517	17,960
2003	19,668	253	19,415	0	781	799	577	554	18,310
2004	20,545	258	20,287	0	783	847	588	578	19,174
2005	22,361	264	22,097	0	790	895	600	611	20,971
2006	21,819	256	21,563	0	809	948	635	640	18,787
2007	22,259	230	22,029	0	932	85	701	50	20,491
2008	22,770	155	22,615	0	966	129	738	75	20,862
2009	23,435	155	23,280	0	997	174	760	103	21,401
2010	24,003	155	23,848	0	1016	221	776	133	21,857
2011	24,612	155	24,457	0	1037	270	791	166	22,348
2012	25,115	155	24,960	0	1,059	322	806	201	22,727
2013	25,590	110	25,480	0	1,083	375	822	236	23,074
2014	26,100	110	25,990	0	1,110	430	837	274	23,449
2015	26,772	110	26,662	0	1,139	486	852	312	23,982
2016	27,410	110	27,300	0	1,175	505	864	347	24,499

Historical Values (1997 - 2006):

Col. (2) - Col. (4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) for 1997 through 2006 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC) and Commercial /Industrial Demand Reduction (CDR). Col.(5) - Col.(9) for year 2004 are "estimated actuals" and are August values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula:Col. (10) = Col.(2) - Col.(6) - Col.(8).

***Projected Values* (2007 - 2016):**

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2004 are incorporated into the load forecast.

Col. (5) - Col. (9) represent all incremental conservation and cumulative load control. These values are projected August values and the conservation values are based on projections with a 1/2006 starting point for use with the 2006 load forecast.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1997/98	13,060	239	12,821	0	641	369	426	151	11,993
1998/99	16,802	149	16,653	0	692	404	446	164	15,664
1999/00	17,057	142	16,915	0	741	434	438	176	15,878
2000/01	18,199	150	18,049	0	791	459	448	183	16,960
2001/02	17,597	145	17,452	0	811	500	457	196	16,329
2002/03	20,190	246	19,944	0	847	546	453	206	18,890
2003/04	14,752	211	14,541	0	857	570	532	230	13,363
2004/05	18,108	225	17,883	0	862	583	542	233	16,704
2005/06	19,683	225	19,458	0	870	600	550	240	18,263
2006/07	16,815	223	16,592	0	894	620	577	249	15,344
2007/08	22,627	230	22,397	0	902	27	618	8	21,072
2008/09	23,115	155	22,960	0	935	54	644	17	21,466
2009/10	23,587	155	23,432	0	972	82	670	27	21,837
2010/11	24,047	155	23,892	0	989	109	678	38	22,233
2011/12	24,498	155	24,343	0	1,009	137	686	51	22,615
2012/13	24,952	155	24,797	0	1,030	166	694	65	22,998
2013/14	25,416	155	25,261	0	1,052	194	702	79	23,388
2014/15	26,048	110	25,938	0	1,077	224	711	95	23,942
2015/16	26,692	110	26,582	0	1,105	253	719	112	24,504
2016/17	27,342	110	27,232	0	1,131	280	726	127	25,078

Historical Values (1997 - 2006):

Col. (2) - Col. (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col.(9) for 1996/97 through 2005/06 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC) and Commercial/Industrial Demand Reduction (CDR).Col.(5) - Col.(9) for year 2004/05 are "estimated actuals" and are January values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (6) - Col. (8).

Projected Values (2007/08- 2015/16):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2004 are incorporated into the load forecast.

Col. (5) - Col.(9) represent all incremental conservation and cumulative load control. These values are projected January values and the conservation values are based on projections with a 1/2004 starting point for use with the 2004 load forecast.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH: Base Case

(1) Year	(2) Total	(3) Residential Conservation	(4) C/I Conservation	(5) Retail	(6) Sales for Resale GWH	(7) Utility Use & Losses	(8) Net Energy For Load	(9) Load Factor(%)
1997	89,243	1,213	1,177	88,015	1,228	5,771	86,853	59.7%
1998	95,318	1,374	1,282	93,992	1,326	6,206	92,662	59.1%
1999	94,365	1,542	1,365	93,412	953	5,829	91,458	59.3%
2000	99,097	1,674	1,434	98,127	970	7,059	95,989	61.5%
2001	101,739	1,789	1,545	100,768	970	7,222	98,404	59.9%
2002	107,755	1,917	1,639	106,522	1,233	7,443	104,199	61.9%
2003	112,160	2,008	1,759	110,648	1,511	7,386	108,393	62.9%
2004	112,031	2,106	1,834	110,500	1,531	7,464	108,091	60.1%
2005	115,440	2,205	1,934	113,934	1,506	7,498	111,301	56.8%
2006	117,490	2,312	2,041	115,921	1,569	7,909	113,137	59.2%
2007	117,551	162	134	116,074	1,477	8,401	117,255	60.3%
2008	122,024	253	176	121,021	1,004	8,501	121,596	61.2%
2009	126,270	343	220	125,251	1,019	8,877	125,707	61.3%
2010	130,499	437	268	129,465	1,034	9,128	129,794	62.1%
2011	134,766	535	319	133,732	1,034	9,410	133,912	62.5%
2012	139,038	637	372	138,005	1,034	9,857	138,029	63.2%
2013	142,379	742	429	141,345	1,034	10,121	141,208	63.3%
2014	146,257	850	488	145,223	1,034	10,396	144,918	64.0%
2015	150,291	959	548	149,258	1,034	10,675	148,785	64.1%
2016	154,556	963	550	153,522	1,034	10,940	153,042	64.4%

Historical Values (1997 - 2006):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (8).

Col.(3) & Col.(4) for 1997 through 2006 are DSM values starting in January 1988 and are annual (12-month) values.Col. (3) and Col. (4) for 2006 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWH reductions actually experienced each year .

Col. (5) & Col. (6) are a breakdown of Net Energy For Load in Col (2) into Retail and Wholesale.

Col. (9) is calculated using Col. (8) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (8)*1000) / ((Col.(2) * 8760)

Projected Values (2007 - 2016):

Col. (2) represents Net Energy for Load w/o DSM values. The values are extracted from Schedule 2.3, Col. (19).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation and are mid-year (6-month) values. The effects of conservation implemented prior to 2006 are incorporated into the load forecast.

Col. (5) & Col. (6) are a breakdown of Net Energy For Load in Col (2) , into Retail and Wholesale.

Col. (8) NEL projected values shown here do include the impact of conservation in Col. (3) and Col. (4). Therefore, these NEL values **do not match** those shown on schedule 2.3 because those values do not account for incremental conservation.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of
Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2006 ACTUAL		2007* FORECAST		2008* FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	14,800	8,059	22,247	8,439	22,627	8,811
FEB	19,683	7,473	18,338	7,615	18,652	8,240
MAR	16,946	8,179	17,303	8,757	17,599	9,042
APR	18,975	9,296	18,531	9,212	18,956	9,533
MAY	19,321	9,458	20,558	9,692	21,030	10,033
JUN	21,123	11,031	21,395	11,221	21,886	11,568
JUL	21,493	10,690	21,805	11,192	22,305	11,592
AUG	21,819	11,634	22,259	11,819	22,770	12,251
SEP	20,580	10,926	21,607	11,633	22,103	11,981
OCT	19,440	9,746	20,104	10,024	20,565	10,369
NOV	17,260	8,382	18,748	9,106	19,152	9,519
DEC	15,798	8,263	19,139	8,839	19,552	9,086
TOTALS		113,137		117,551		122,024

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation and are consistent with values shown in Col. (19) of Schedule 2.3 and Col (2) of Schedule 3.3.

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CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990s and has since utilized the process to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of potential new power plants, the primary subjects of this document, are determined as part of the IRP process work. This section discusses how FPL applied this process in its 2006 and early 2007 resource planning work.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental "steps" to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Determine the economics for the total utility system with each of the competing options and resource plans; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

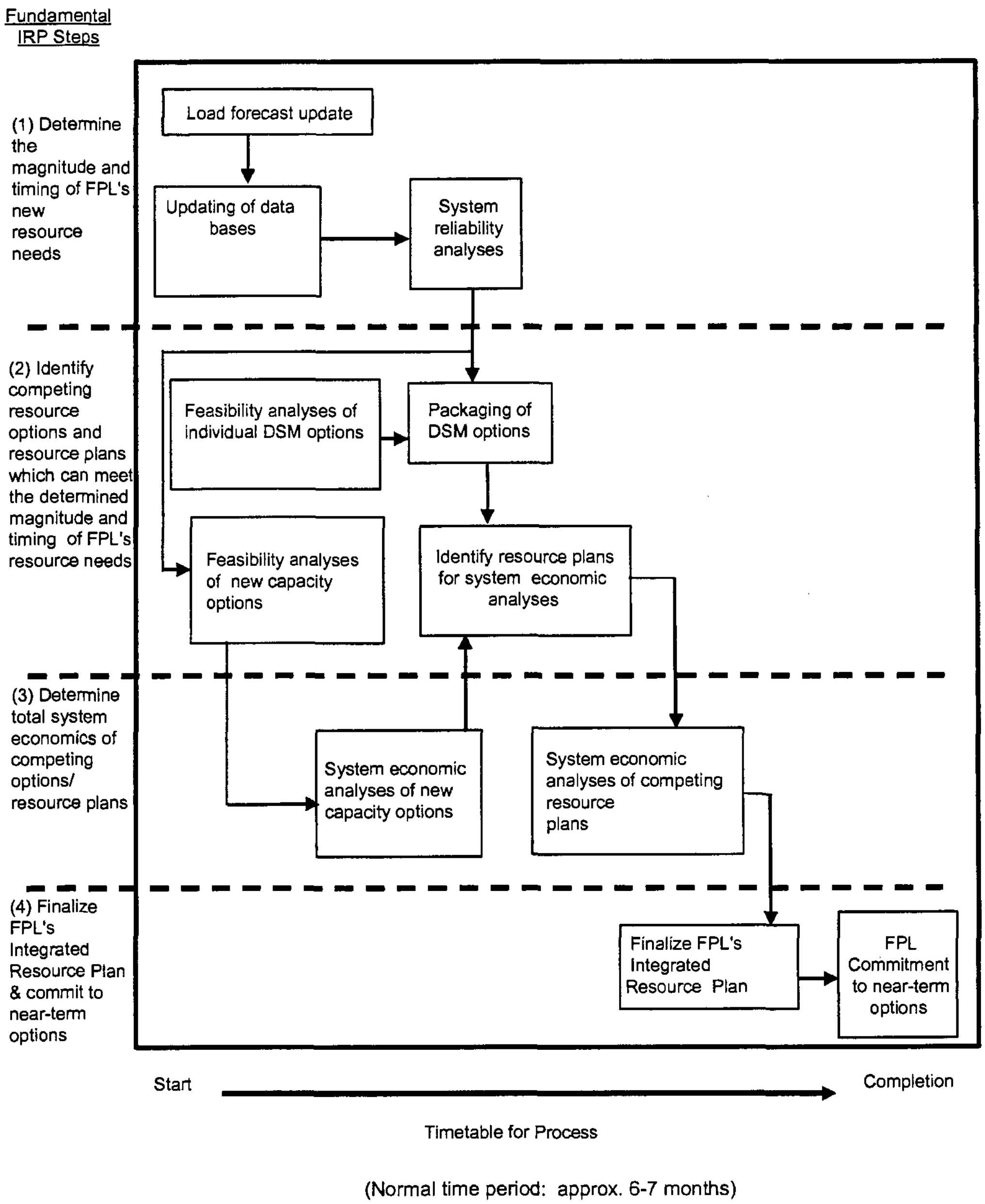

Figure III.A.1: Overview of FPL's IRP Process

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of these four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed. Also determined in this step is when the MW are needed to meet FPL's planning criteria. This step is often referred to as a reliability, or resource adequacy, assessment for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include: delivered fuel price projections, current financial and economic assumptions, and power plant capability and reliability assumptions. FPL also includes key assumptions regarding three specific resource areas: (1) near-term construction capacity additions, (2) firm capacity power purchases, and (3) DSM implementation.

The first of these assumptions is based on FPL's ongoing engineering and construction activities to add near-term capacity. These construction activities include three new combined cycle (CC) units: one at FPL's Turkey Point site scheduled to come in-service by mid-2007 and two at FPL's West County Energy Center (WCEC) site scheduled to come in-service by mid-2009 and mid-2010 respectively. FPL selected these CC options after conducting separate Request for Proposals (RFP) solicitations and evaluating the options received in response to the RFPs. These additions were subsequently approved by the FPSC and the Governor and Siting Board.

The second of these assumptions involves firm capacity power purchases. These firm capacity purchases are from a combination of utility and independent power producers. Details, including the annual total capacity values for these purchases are presented in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's recent resource planning work.

The third of these assumptions involves DSM. Since 1994, FPL's resource planning work has assumed that the DSM MW called for in FPL's approved DSM Goals will be achieved per plan. This was again the case in FPL's most recent planning work as its new DSM

Goals that address the years 2005 through 2014, and that were approved by the FPSC in August 2004, are assumed to be achieved per plan.

In addition, FPL recently received approval from the Commission to modify 8 existing DSM programs and to introduce two new DSM programs. These efforts will result in a projected increase of 564 Summer MW at the generator of additional DSM and curtailable beyond FPL's DSM Goals by 2015. In addition, FPL is also assuming a continuation of DSM implementation in 2016 and projects the additions of approximately 120 MW of incremental DSM in that year so that through 2016 FPL currently projects 1,486 MW of cost-effective DSM beyond the significant amount of DSM achieved by FPL through 2006. These additional MW of DSM were also accounted for prior to making projections of new resource needs.

These key assumptions, plus the other updated information, are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's resource needs. This determination is accomplished by system reliability analyses which are typically based on a dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry.

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its native load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the generation resource adequacy of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss–of-load probability or LOLP. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of the "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

The result of the first fundamental step of resource planning is a projection of how many new MW of resources are needed to meet both reserve margin and LOLP criteria, and thus maintain system reliability, and of when the MW are needed. Information regarding the timing and magnitude of these resource needs is used in the second fundamental step: identifying resource options and resource plans that can meet the determined magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, feasibility analyses of new capacity options are conducted to determine which new capacity options appear to be the most competitive on FPL's system. These analyses also establish capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. In similar analyses, feasibility analyses of new DSM options and/or continued growth in existing DSM options, are conducted.

The individual new resource options emerging from these feasibility options are then typically "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new resource needs are met. The creation of these competing resource plans is frequently carried out using dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs are identified.

Step 3: Determining the Total System Economics:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for comparing the system economics of these resource plans. In its 2006 resource planning work, FPL performed some of this work of combining resource options into resource plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI). The EGEAS model was also used to perform basic economic analyses of resource plans. For various analyses, including the analyses of the advanced technology coal option, FPL utilized the P-MArea production cost model and a Fixed Cost Spreadsheet to develop a more detailed perspective of costs for the various resource plans developed to analyze the advanced technology coal option. The P-MArea model is the model used by FPL to develop the Fuel Cost Budget and to conduct other production cost-related analyses.

In 2006, FPL also utilized several other models in its resource planning work. For DSM analyses, FPL used its DSM cost-effectiveness model; an FPL spreadsheet model utilizing the FPSC's approved methodology for analyzing the cost-effectiveness of individual DSM measures/programs, and its non-linear programming model for analyzing the potential for lowering system peak loads through additional load management capacity.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the intent of minimizing FPL's leveled system average rate (i.e., a Rate Impact Measure or RIM methodology). However, in cases in which the DSM contribution was assumed as a given and the only competing options were new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. Consequently, the competing options and plans were evaluated on a cumulative present value revenue requirement (CPVRR) basis.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps were used to develop the future generation plan. This plan is presented in the following section.

III.B Incremental Resource Additions

FPL's projected incremental generation capacity additions/changes for 2007 through 2016 are depicted in Table III.B.1 (the planned DSM additions through 2015 were shown previously in Table I.D.1). These capacity additions/changes result from a variety of actions including: changes to existing units (which are frequently achieved as a result of plant component replacements during major overhauls), changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, and by projected construction of new generating units.

As shown in Table III.B.1, the capacity additions are largely made up of committed new construction, new purchases, and proposed self-build alternatives. (The additional DSM MW are not presented in this table but have been accounted for prior to making these new capacity option projections.) FPL included its previously committed generation construction projects in its 2006 reliability assessment. These committed construction projects are the new 1,144 MW combined cycle (CC) unit at FPL's existing Turkey Point plant site (Turkey Point Unit #5) that will be placed into service in mid-2007, the new 1,219 MW CC unit at the West County Energy Center (WCEC) that is scheduled to be placed into service in mid-2009 (WCEC Unit #1), and a second 1,219 MW CC unit at WCEC (WCEC Unit #2) that is scheduled to be placed into service in mid-2010.

FPL also projects the construction of two new advanced technology coal units; one each by 2013 and 2014 at FPL's Glades Power Park (FGPP) site in Glades County. These two units will use ultra-supercritical pulverized coal (USCPC) technology in concert with advanced emissions controls to address FPL's resource needs for 2013 and 2014 and to maintain fuel diversity on FPL's system. FPL filed for FPSC approval of these two advanced technology coal units on February 1, 2007. The FPSC is expected to render its decision by July 2007.

These additions of the Turkey Point, WCEC, and FGPP units will meet a significant portion of FPL's projected resource needs through 2016 and will maintain fuel diversity on FPL's system. After accounting for these capacity additions, FPL projects a remaining small (167 MW) resource need in 2011 and more significant resource needs in 2012 (777 MW), 2013 (214 MW), 2015 (323 MW), and 2016 (1,327). No decisions are currently needed in regard to how FPL will meet those needs and FPL will consider additional cost-effective DSM, power purchases, enhancements to FPL's existing units, and new generation construction as options with which to meet those needs.

For purposes of this planning document, FPL projects short-term firm capacity purchases of 167 MW in 2011, 800 MW in 2012, and 200 MW in 2013 to meet the remaining capacity needs in those years. Also projected is the addition of a new 1,219 MW unsited CC unit (labeled as "South Florida CC") similar to the WCEC CC units in 2015 to meet the remaining capacity need in 2015 and 2016.

Table III.B.1: Projected Capacity Changes for FPL [1]

Projected Capacity Changes for FPL [1]		Net Capacity Changes (MW) Winter [2]	Net Capacity Changes (MW) Summer [3]
2007	Turkey Point Unit #5 [5]	---	1,144
	Changes to Existing Units	16	(2)
	Changes to Existing Purchases [4]	657	(387)
2008	Turkey Point Unit #5 [5]	1,181	---
	Changes to Existing Units	28	27
	Changes to Existing Purchases [4]	(836)	---
2009	West County Unit #1 [5]	---	1,219
	Changes to Existing Units	28	1
	Changes to Existing Purchases [4]	(326)	(482)
2010	West County Unit #1 [5]	1,335	---
	West County Unit #2 [5]	---	1,219
	Changes to Existing Purchases [4]	(512)	(405)
2011	West County Unit #2 [5]	1,335	---
	Power Purchase in 2011		167
	Changes to Existing Purchases [4]	(94)	(45)
2012	Changes to Existing Purchases [4]	---	(156)
	Changes to Power Purchase in 2011	---	(167)
	Power Purchase in 2012	---	800
2013	FGPP Unit # 1 [5]	---	980
	Changes to Power Purchase in 2012	---	(800)
	Power Purchase in 2013	---	200
	Changes to Existing Purchases [4]	(180)	---
2014	FGPP Unit # 1 [5]	990	---
	FGPP Unit # 2 [5]	---	980
	Changes to Power Purchase in 2013	---	(200)
2015	FGPP Unit # 2 [5]	990	---
	South Florida CC #1 [5]	---	1,219
2016	South Florida CC #1 [5]	1,335	---
	Changes to Existing Purchases [4]	(390)	(381)
	TOTALS =	5,557	4,931

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are values for January of year shown.
(3) Summer values are values for August of year shown.
(4) These are firm capacity and energy contracts with QF, Utilities and other purchases. See Table I.B.1 and Table I.B.2 for more details.
(5) All new unit additions are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

III.C Issues Impacting FPL's Recent Planning Work

FPL's 2006 and early 2007 planning efforts have continued to address two issues that were identified in previous Site Plans as being items of on-going importance. Those two issues are: (1) the need to maintain fuel diversity in the FPL system and (2) the need to address the imbalance between regional load and generating capacity located in Southeast Florida.

1. System Fuel Diversity

FPL's plans to add the two advanced technology coal FGPP units by 2013 and 2014, respectively, is a key and integral part of FPL's plan to maintain fuel diversity on FPL's system. After these coal units come on-line, the role of natural gas in FPL's projected fuel mix will be no greater than 61% through 2016.

FPL has also begun the process to review the prospect for new nuclear generation and the advisability of initiating significant financial commitments in the face of schedule, cost, and regulatory uncertainties to do so. FPL will be taking necessary and appropriate steps in the near future to preserve new nuclear generation as an option for the latter half of the next decade in order to maintain and enhance fuel diversity in the FPL system.

FPL also has been involved in activities to investigate adding or maintaining renewable resources as a part of its generation supply. One of these activities is a variety of discussions with existing facilities aimed at maintaining or extending current agreements. In addition, and as a direct result of FPL's Sunshine Energy® Program, photovoltaic installations are being made. These include a 250 kw photovoltaic site in Sarasota County as well other smaller installations throughout FPL's service territory. Additionally, FPL is actively investigating a site for a demonstration wind generation project in the 10 MW range.

FPL maintains its interest in new and developing technologies, such as solar photovoltaic, solar thermal, and ocean current turbine technology. It is possible that renewable technologies may become more cost-effective over the next ten years and may be feasible additions to provide some diversity to the system fuel supply. FPL shares, with others, the objective of fostering the development and operation of additional cost-effective renewable sources of generation. Based upon available information, however, FPL does not believe that renewable resources are likely to contribute more than a modest amount to satisfying the annual electric load growth in FPL's territory.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance fuel diversity in its capacity resource mix including purchasing power from coal-fired facilities when such power becomes available. FPL also plans to maintain the ability to utilize fuel oil at those existing units that have that capability, although cost factors currently limit the expected use of these facilities.

2. Southeast Florida Imbalance

There currently is an imbalance between regionally installed generation and peak load in Southeast Florida. A significant amount of energy required in the Southeast Florida region during peak periods is provided through the transmission system from plants located outside the region. Based on the forecast for continued load growth in this region, the imbalance between generation and load is projected to increase unless additional generation capacity is periodically located within this region.

FPL's prior planning work concluded that either additional installed capacity in this region, or transmission capacity capable of delivering additional electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location, Turkey Point Unit #5 and WCEC Units #1 and #2 were evaluated as the most cost-effective options to meet FPL's 2007 and 2009-2010 capacity needs, respectively. Adding Turkey Point Unit #5 and WCEC Units #1 and #2 will significantly reduce the imbalance between generation and load in Southeast Florida. Furthermore, the addition of the proposed FGPP units will also help address this imbalance by the addition of new transmission lines connecting Southeast Florida and the FGPP units.

Together these unit additions will help address the imbalance for at least much of the 2007-2016 reporting period addressed in this document. However, the Southeast Florida imbalance will remain a consideration in FPL's on-going resource planning work.

III.D Demand Side Management (DSM)

1. Currently Approved Programs and Goals:

FPL's currently approved DSM programs are summarized as follows:

Residential Conservation Service: This is an energy audit program designed to assist residential customers in understanding how to make their homes more energy-efficient through the installation of conservation measures/practices.

Residential Building Envelope: This program encourages the installation of energy-efficient ceiling insulation, reflective roofs, and roof membranes in residential dwellings that utilize whole-house electric air conditioning.

Duct System Testing and Repair: This program encourages demand and energy conservation through the identification of air leaks in whole-house air conditioning duct systems and by the repair of these leaks by qualified contractors.

Residential Air Conditioning: This is a program to encourage customers to purchase higher efficiency central cooling and heating equipment.

Residential Load Management (On-Call): This program offers load control of major appliances/household equipment to residential customers in exchange for monthly electric bill credits.

New Construction (BuildSmart): This program encourages the design and construction of energy-efficient homes that cost-effectively reduce coincident peak demand and energy consumption.

Residential Low Income Weatherization: This program addresses the needs of low-income housing retrofits by providing monetary incentives to various housing authorities, including weatherization agency providers (WAPS), non-weatherization agency providers (non-WAPS), and other providers approved by FPL. The incentives are used by these providers to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting.

Business Energy Evaluation: This program encourages energy efficiency in both new and existing businesses by identifying DSM opportunities and providing recommendations to business customers.

Business Heating, Ventilating and Air Conditioning: This program encourages the use of high-efficiency heating, ventilation, and air conditioning (HVAC) systems for business customers.

Business Efficient Lighting: This program encourages the installation of energy-efficient lighting measures for business customers.

Business Custom Incentive: This program encourages business customers to implement unique energy conservation measures or projects not covered by other FPL programs.

Commercial/Industrial Load Control: This program reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits. (This program was closed to new participants in 2000).

Commercial Demand Reduction: This program, which started in 2002, is similar to the Commercial/Industrial Load Control program mentioned above in continuing the objective to reduce peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits.

Business Building Envelope: This program encourages the installation of energy-efficient building envelope measures, such as roof/ceiling insulation, reflective roof coatings, and window treatments for business customers.

Business On Call: This program offers load control of central air conditioning units to both small non–demand-billed and medium demand-billed business customers in exchange for monthly electric bill credits.

Business Water Heating: This program encourages the installation of energy-efficient water heating equipment such as heat pump water heaters and heat recovery units for business customers.

Business Refrigeration: This program encourages the installation of qualifying controls and equipment that reduce electric strip heater usage in refrigeration equipment for business customers.

FPL's approved DSM Goals for Summer MW reduction from these programs are presented in Table III.D.1.

Year	Goal Cumulative Summer MW
2005	74
2006	142
2007	212
2008	287
2009	366
2010	448
2011	532
2012	619
2013	708
2014	802

Table III.D.1: FPL's Summer MW Reduction Goals for DSM (At the Meter)

Table III.D.1 reflects FPL's DSM Goals for 2005–2014 as approved by the Florida Public Service Commission in June, 2004. These annual cumulative values assume a 1/1/05 starting point.

2. Research and Development

FPL continues to support research and development activities. Historically, FPL has performed extensive DSM research and development. FPL will continue such activities, not only through its Conservation Research and Development program, but also through individual research projects. These efforts will examine a wide variety of technologies that build on prior FPL research where applicable and will expand the research to new and promising technologies as they emerge.

Conservation Research and Development Program

FPL's Conservation Research and Development Program is designed to evaluate emerging conservation technologies to determine which are worthy of pursuing for program development and approval. FPL has researched a wide variety of technologies such as condenser coil cleaner and coating, ultraviolet lights for evaporator coils, Energy Recovery Ventilators (ERV), fuel cell demonstrations, CO_2 ventilation control, two-speed air handlers, and duct plenum repair. Many of the technologies examined have resulted in enhancements to existing programs or the development of new programs such as Residential New Construction, Commercial/Industrial Building Envelope, and Business On Call.

On Call Incentive Reduction Pilot

In March 2003, FPL received FPSC approval to perform a pilot for its On Call Program. Under the pilot FPL is offering to new participants a residential load control service similar to the On Call Program at a reduced incentive level. The offering of this pilot is allowing FPL to test its market research data and gauge whether FPL can repackage its current residential load control service, minimize customer attrition, achieve current goals for residential load control, and, ultimately, change On Call incentive levels without damaging FPL system reliability.

3. Additional DSM Contributions

Since FPL's current DSM Goals were established, FPL has continued to evaluate the potential for additional cost-effective DSM. Increases in FPL's forecasted peak growth, and the corresponding increase in projected resource needs, has resulted in FPL increasing its projection of cost-effective DSM by 564 MW at the generator from 2006-2015, and by another 120 MW at the generator in 2016. Therefore, FPL projects the implementation of an additional 684 MW at the generator of cost-effective DSM beyond FPL's DSM Goals.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy for FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV bulk transmission lines that must be certified under the Transmission Line Siting Act.

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	St. Johns (1)	Pringle	26	Dec-08	230	759
FPL	Manatee	BobWhite	30	Dec-11	230	1190
FPL	Grove Area (TBD)	Sweatt	25	Jun-12	230	759

(1) Final order certifying the corridor was issued on April 21, 2006.

Table III.E.1: List of Proposed Power Lines

In addition, there will be transmission facilities needed to connect several of FPL's committed and projected capacity additions to the system transmission grid. These transmission facilities for the committed capacity additions at the Turkey Point and the WCEC sites, plus for the projected capacity additions at the FGPP site, are described on the following pages. Because the projected combined cycle capacity addition for 2015 is as-yet unsited, no transmission facilities information is provided for this unit.

III.E.1 Transmission Facilities for Turkey Point Unit #5

The work required to connect Turkey Point Unit #5 in 2007 with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 5 breakers to connect the four combustion turbines (CTs) and one steam turbine (ST).
2. Construct two string busses to connect the collector busses and main switchyard.
3. Add five main step-up transformers (4-225 MVA, 1-560 MVA), one for each CT and one for the ST.
4. Add a new two breaker bay to connect the collector bus at the Turkey Point switchyard.
5. Add a second two breaker bay at the Turkey Point switchyard to connect the other collector bus.
6. Add relays and other protective equipment.
7. Expand site and relay vault for two new line terminals at Turkey Point switchyard.

II. Transmission:

1. Upgrade the Turkey Point-Galloway Tap 230kV transmission line section to 1430 Amps.
2. Upgrade the Turkey Point–McGregor-Florida City 230kV transmission line section to 1495 Amps.
3. Upgrade the Turkey Point-Miller 230kV transmission line section to 1430 Amps.
4. Upgrade the Miller-Killian 230kV transmission line section to 1430 Amps.

III.E.2 Transmission Facilities for West County Energy Center (WCEC) Unit #1

The work required to connect West County Energy Center (WCEC) Unit #1 in 2009 with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 4 breakers to connect the three CTs and one ST.
2. Construct two string busses to connect the collector busses and main switchyard to Corbett 230 kV Substation.
3. Add four main step-up transformers (3-370 MVA, 1-580 MVA), one for each CT and one for the ST.
4. Add a new Bay #4 with 3 breakers at the Corbett 230 kV main switchyard. Connect one string buss from the collector yard and relocate the Alva 230 kV terminal from Bay #3 to new Bay #4.
5. Connect second collector string buss to Bay #3.
6. Add relays and other protective equipment.
7. Breaker replacements:
   Corbett Sub – Replace eight (8) 230 kV breakers
   Ranch Sub – Replace five (5) 138 kV breakers
   Midway Sub – Replace one (1) 230 kV breaker
   Levee Sub – Replace one (1) 230 kV breaker
   Dade Sub – Replace two (2) 138 kV breakers

II. Transmission:

1. No upgrades expected to be necessary at this time.

III.E.3 Transmission Facilities for West County Energy Center (WCEC) Unit #2

The work required to connect West County Energy Center (WCEC) Unit #2 in 2010 with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 4 breakers to connect the three CTs, and one ST.
2. Construct two string busses to connect the collector busses and main switchyard to Corbett 500kV Substation.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA) one for each CT, and one for the ST.
4. At Corbett Sub, install one breaker and relocate Martin #2 500 kV line from Bay 2S to Bay 2N. Install one West County 500 kv string bus into Bay 2S.
5. At Corbett Sub, install one breaker and second West County 500 kV string bus into Bay 1S.
6. Add relays and other protective equipment.
7. Breaker replacements:
   Dade Sub – Replace one (1) 138 kV breaker
   Levee Sub – Replace four (4) 230 kV breakers
   Midway Sub – Replace three (3) 230 kV breakers
   Ranch Sub – Replace one (1) 230 kV breaker

II. Transmission:

1. No upgrades expected to be necessary at this time.

III.E.4 Transmission Facilities for FGPP Unit #1

The work required to connect FGPP Unit #1 by 2013 with the FPL grid is projected to be as follows:

II. Substation:

1. Build new 500kV switchyard containing two bays with six breakers to connect the steam turbine and startup transformer.
2. Add two main step-up transformers (660 MVA each).
3. Build a new switching station with two 500kV bays, one 230kV bay, seven 500kV breakers and three 230kV breakers.
4. Add one 500/230kV, 750 MVA autotransformer bank.
5. Add relays and other protective equipment.

II. Transmission:

1. Build two 25 mile 500kV transmission lines connecting the switchyard to the switching station.
2. Build an additional 48 miles of 500kV transmission line to loop the existing Andytown-Orange River 500kV line into the new switching station.
3. Build an additional one mile of 230 kV transmission line to loop the Alva-Corbett 230 kV line into the new switching station.

III.E.5 Transmission Facilities for FGPP Unit #2

The work required to connect FGPP Unit #2 by 2014 with the FPL grid is projected to be as follows:

III. Substation:

1. Build new 500kV bay at the existing switchyard with 2 additional breakers to connect the coal unit and add a bus breaker to connect to connect the startup transformer.
2. Add two main step-up transformers (660 MVA each).
3. Build a new 500 kV bay at the existing switching station with two additional breakers to connect the new Levee 500 kV line
4. Andytown Substation – Remove the existing Levee #2 500 kV line terminal equipment
5. Add relays and other protective equipment.

II. Transmission:

1. Build an additional 74 miles of 500kV transmission line from the new switching station to Andytown 500kV station and disconnect the existing Andytown-Levee #2 500kV line from Andytown and connect to the new switching station.

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to utilize renewable energy technologies to meet its customers' current and future needs. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various technologies.

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970s in demonstrating the first residential solar photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-Kilowatt (kW) system was placed into operation in 1984. (The system was removed in 1990 to make room for substation expansion after the testing of this PV installation was completed.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. The FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's recent Green Pricing effort (which is discussed below).

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was no longer projected to be cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980's, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for 6 passive homes with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the Florida Public Service Commission to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test may be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, and various customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

More recently, FPL has analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach does not require all of its customers to bear PV's high cost, but allows customers who are interested in facilitating the use of renewable energy the means to do so. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund that FPL used to make PV purchases in bulk quantities. PV modules were then installed and delivered PV-generated electricity directly into the FPL grid. Thus, when sunlight is available, the PV-generated electricity displaces an equivalent amount of fossil fuel-generated electricity.

FPL's basic approach for this program, which has been termed Green Pricing, was initially discussed with the FPSC in 1994. FPL's efforts to implement this approach were then formally presented to the FPSC as part of FPL's DSM Plan in 1995 and FPL received approval from the FPSC in 1997 to proceed. FPL began the effort in 1998 and received approximately $89,000 in contributions (that significantly exceeded the goal of $70,000). FPL purchased the PV modules and installed them at FPL's Martin Plant site.

FPL initiated two new renewable efforts in 2000. FPL's first new initiative in 2000 was FPL's Photovoltaic Research, Development, and Education Project. This demonstration project's objectives were to: increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks (as well as the total annual energy capabilities of roof tile PV systems), and assess the homeowner's financial benefits and costs of PV roof tile systems. This project was completed in 2003.

The second effort initiated in 2000 was the Green Energy Project. The objectives of this Project were to: determine customer interest in an on–going renewable energy program, determine their price responsiveness and views on the different renewable technologies, and identify potential renewable energy supply sources that would meet the forecasted customer demand for this type of product. FPL conducted both customer research and issued a Request for Proposals (RFP) in 2001 to solicit proposals to potentially supply energy only from new renewable sources. This Project formed the basis for FPL's Green Power Pricing Research Project, and then led to FPL's Business Green Energy Research Project.

Both the Green Power Pricing Research Project and the Business Green Energy Research Project examined the feasibility of purchasing tradable renewable energy credits generated from new renewable resources including solar-powered technologies, biomass energy, landfill methane, wind energy, low impact hydroelectric energy, and/or other renewable sources. Customers who participate are charged higher premiums for purchasing the tradable renewable energy credits associated with electric energy generated by these sources.

Development of the Green Pricing Research Project was completed and filed with the FPSC in August 2003. As part of this process, a supply contract was put into place that allows FPL to match supply with demand for green energy. Tradable renewable energy credits are used to supply the renewable benefits required of this project. The FPSC approved the program on December 2, 2003 with program implementation during the first quarter of 2004. The project was marketed to customers as FPL's Sunshine Energy® program. As part of the project, FPL made a commitment that 150 kW of solar capacity would be put in place for every 10,000 program participants. The Business Green Energy Research Project focused on determining the interest and needs for business customers in this area. In 2006 FPL petitioned the FPSC for approval to make the Green Pricing Research Project a permanent program and expand eligibility to business customers. This approval was granted in the fourth quarter of 2006.

As of the end of 2006, FPL had 28,742 participants in the program. FPL has selected Rothenbach Park in Sarasota as the location to develop its first PV facility as a direct result of FPL's Sunshine Energy® renewable program. The 250 kilowatt FPL Solar Array at Rothenbach Park will be the largest solar facility in the state of Florida and one of the largest in the southeast.

The solar array will be mounted on the ground and will be visible from the road. The solar facility will be built with 1,200 photovoltaic solar panels and will be more than 28,000 square feet, about half the size of a football field. Each panel will be about 31 inches wide and 63 inches long. Construction on the new solar facility is scheduled to be completed in Summer 2007. FPL is currently investigating locations for additional solar sites when the next 150 kW PV commitment level in the Sunshine Energy® program is reached.

Several additional solar initiatives are currently under development. A residential community in the Naples/Ft Myers area is building 90 homes with 2 kW solar PV units on each home. A 2 kW demonstration site at the Miami Science Museum will be completed by 1st quarter 2007. In connection with SunSmart Schools, 2 kW PV systems are being installed in 4 schools by the end of March 2007. This activity is a continuation of previous FPL activities involving PV installations at schools. In 2003 as part of the State of Florida's PV for Schools program, FPL worked with three schools to install 4.8 kW PV systems. These schools were:

- A.D. Henderson Elementary & Middle School in Boca Raton
- Harlee Middle School in Bradenton
- Florida Gulf Coast University in Ft. Myers

FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy and as-available energy have been purchased by FPL from these developers. (Please refer to Tables I.B.1, I.B.2, and Table I.C.1). With recent legislative initiatives and new FPSC rules, FPL is seeing a renewed interest in the development of additional renewable energy projects and is actively working with developers on a number of potential projects.

Additionally, FPL is actively investigating a site for a demonstration wind generation project in Florida. FPL has conducted a survey of wind resources and is considering potential sites in both the Canaveral and Sarasota areas. The project size is estimated to be in the 10 MW range. FPL is also an active supporter of the recently established Center for Ocean Energy Engineering at Florida Atlantic University which aims to study the potential for ocean current energy conversion.

FPL has been investigating fuel cell technologies through monitoring of industry trends, discussions with manufacturers, and direct field trials. From 2002 through the end of 2005, FPL conducted field trials and demonstration projects of Proton Exchange Membrane (PEM) fuel cells with the objectives of serving customer end-uses while evaluating the technical performance, reliability, economics, and relative readiness of the PEM technology. The demonstration projects were conducted in partnership with customers and included 5 locations. The research projects were useful to FPL in identifying specific issues that can occur in field applications and the current commercial viability of this technology. FPL will continue to monitor the progress of these technologies and conduct additional field evaluations as significant developments in the fuel cell technologies occur.

In support of Florida Administrative Code Rule 25-6.065, Interconnection of Small Photovoltaic Systems, FPL works with customers to interconnect customer-owned PV systems. Through February 2007, 29 residential customer systems and 2 business customer systems have been interconnected. The total connect kW from these 31 systems is 108 kW. The residential customer average capacity per installation is 3.38 kW and the business customer average capacity per installation is 5.15 kW.

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fired generation. In the early 1980s FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership and additional purchases from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit #4 in 1989. Starting in 1997, petroleum coke was added to the fuel mix as a blend stock with coal at SJRPP.

The trend since the early 1990's has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective combined cycle generating units and the ready availability of natural gas. This planning document reflects an evolution in that trend in recognition that although efficient gas-fired generation continues to provide significant benefits to FPL's customers, adding natural gas-fired additions exclusively would, in the long term, create an unbalanced generation portfolio. FPL will add a new gas-fired CC unit in 2007 at Turkey Point and two new gas-fired CC units at the West County Energy Center in 2009 and 2010. These CC units will provide highly efficient generation that will benefit the entire FPL system by reducing transmission-related costs, mitigate the load-to-generation imbalance in Southeast Florida, and dramatically improve the overall system generation efficiency. However, FPL plans to complement these additions with two advanced technology coal units by 2013 and 2014, respectively. The addition of coal-fueled generation will maintain fuel supply diversity and assist in stabilizing fuel cost volatility through diversification.

FPL's future resource planning work will remain focused on identifying and evaluating alternatives that would maintain and/or enhance FPL's long-term fuel diversity. These fuel diverse alternatives may include: the purchase of power from new coal-based facilities, obtaining access to diversified sources of natural gas such as liquefied natural gas (LNG), preserving FPL's ability to utilize fuel oil at its existing units, and in the longer term, increased utilization of nuclear energy options. The evaluation of the feasibility and cost-effectiveness of these, and other possible alternatives, will be an ongoing part of future planning cycles.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2016 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

2. Fuel Price Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future generating capacity needs. FPL's forecasts are generally consistent with other published contemporary forecasts.

a) Fuel Price Forecast Methodology

Future oil and natural gas prices, and to a lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, coal, and petroleum coke. These drivers include: (1) current and projected worldwide demand for crude oil and petroleum products; (2) current and projected worldwide refinery capacity/production; (3) expected worldwide economic growth, in particular in China and the other Pacific Rim countries; (4) Organization of Petroleum Exporting Countries (OPEC) production and the availability of spare OPEC production capacity and the assumed growth in spare OPEC production capacity; (5) non-OPEC production and expected growth in non-OPEC production; (6) the geopolitics of the Middle East, West Africa, the Former Soviet Union, Venezuela, etc., as well as, the uncertainty and impact upon worldwide energy consumption related to U. S. and worldwide environmental legislation, politics, etc.; (7) current and projected North American natural gas demand; (8) current and projected U.S., Canadian, and Mexican natural gas production; (9) the worldwide supply and demand for LNG; and (10) the growth in solid fuel generation on a U. S. and worldwide basis.

The inherent uncertainty and unpredictability in these factors today and tomorrow clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal and petroleum coke) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed Low, Medium, and High price forecasts for oil, natural gas, and solid fuel, and a Shocked Medium (Shocked) price forecast for oil and natural gas which were used in the analyses of the FGPP advanced technology coal units.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology: (1) for 2006 through 2008, the methodology used the October 3, 2006 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil, and Henry Hub natural gas commodity prices; (2) for the next two years (2009 and 2010), FPL used a 50/50 blend of the October 3, 2006 forward curve and monthly projections from The PIRA Energy Group; (3) for the 2011 through 2020 period, FPL used the annual projections from The PIRA Energy Group, and (4) for the period beyond 2020, recognizing that prices cannot increase indefinitely and that significantly high prices have created, and will continue to create, technological and economic opportunities for commodity substitution in the energy markets, FPL applied the annual rate of increase in the delivered price of solid fuel to the commodity cost of oil and natural gas. In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach: (1) the price forecasts for Central Appalachian coal (CAPP), South American coal, and petroleum coke were provided by JD Energy; (2) the marine transportation rates from the loading port for coal and petroleum coke to an import terminal were also provided by JD Energy; (3) the Terminal Throughput Fee was based on a range of offers from comparable facilities throughout the Southeast U.S.; (4) the rail transportation rates from CAPP and from the import terminal facility to FGPP were based on the proposed rail transportation rates as of October 3, 2006. In order to achieve the maximum fuel supply diversity and delivery flexibility for FPL's customers, FPL assumed that the delivered price of solid fuel to the FGPP units would be a mix of 40% Central Appalachian coal, 40% South American coal, and 20% petroleum coke. The coal price forecast for FPL's existing coal plants at SJRPP and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for oil, natural gas, coal, and petroleum coke prices were based upon the historical relationship of prices realized by FPL's customers compared to the average for the 2000 through 2005 time frame. FPL developed these forecasts to account for the uncertainty which exists within each commodity as well as across commodities. These forecasts reflect a range of reasonable forecast outcomes.

The development of the Shocked Medium (Shocked) price forecast was based on the same methodology as the Low and High price forecasts described above. The shock was applied only to the oil and natural gas prices through 2016. In 2017, FPL averaged the Medium price forecast with the Shocked price forecast. From 2018 forward, all commodity prices are the same as in the Medium price forecast. FPL developed the Shocked price forecast as a sensitivity to show the impact of what a significant price increase in oil and natural gas could have on the evaluation of the FGPP advanced technology coal units.

FPL's four long-term oil, natural gas, coal, and petroleum coke price forecasts are reasonable and necessary for the analyses of the FGPP units. FPL's set of four fuel price forecasts bound the projected range of future forecast outcomes based on the actual range of prices realized by FPL's customers during the 2000 through 2005 period. During this period of time, all commodities showed significant variability, including periods of low and high prices, and periods of low and high price differentials between commodities, on both a domestic and worldwide basis.

Schedule 5
Fuel Requirements [1/]

		Actual 2/		Forecasted									
Fuel Requirements	Units	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1) Nuclear	Trillion BTU	235	258	254	273	269	268	273	270	268	273	269	269
(2) Coal	1,000 TON	3,098	3,367	4,034	3,668	3,986	3,686	3,972	3,806	5,454	8,259	9,400	9,428
(3) Residual (FO6)- Total	1,000 BBL	30,217	15,297	21,471	19,313	10,650	9,151	10,350	13,460	11,505	9,396	6,722	9,482
(4) Steam	1,000 BBL	30,217	15,297	21,471	19,313	10,650	9,151	10,350	13,460	11,505	9,396	6,722	9,482
(5) Distillate (FO2)- Total	1,000 BBL	344	40	0	4	210	1,827	2,289	2,753	2,535	1,891	1,057	1,949
(6) Steam	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7) CC	1,000 BBL	194	19	0	0	210	1798	2285	2753	2525	1889	1056	1947
(8) CT	1,000 BBL	150	21	0	4	0	28	4	0	10	2	1	2
(9) Natural Gas -Total	1,000 MCF	345,851	437,700	407,219	438,913	516,463	552,586	565,385	583,631	584,021	562,208	587,673	621,167
(10) Steam	1,000 MCF	44,167	91,555	23,856	24,583	32,439	36,804	25,072	36,944	34,937	28,802	27,683	30,608
(11) CC	1,000 MCF	296,076	341,229	380,475	410,978	480,782	514,915	539,599	544,474	548,261	532,856	559,390	588,753
(12) CT	1,000 MCF	5,608	4,916	2,888	3,352	3,242	867	714	2,213	823	549	601	1,806

1/ Reflects fuel requirements for FPL only.
2/ Source: A Schedules.

Note: As discussed on the preceding pages, FPL utilized four fuel cost forecasts in its 2006 and early 2007 resource planning work. The projected values shown on this form are based on one of these forecasts. For simplicity's sake, FPL is providing only one set of projected values in this document.

Schedule 6.1
Energy Sources

			Actual 1/		Forecasted									
	Energy Sources	**Units**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
(1)	Annual Energy Interchange 2/	GWH	10,221	10,440	11,285	11,294	11,267	10,967	10,768	10,815	10,783	10,784	10,388	7,677
(2)	Nuclear	GWH	21,406	23,533	22,754	24,455	24,110	24,042	24,467	24,192	24,043	24,467	24,121	24,114
(3)	Coal	GWH	5,765	6,168	7,610	6,953	7,530	7,011	7,504	7,223	11,885	19,793	23,014	23,084
(4)	Residual(FO6) -Total	GWH	19,069	9,586	14,328	12,890	7,081	6,071	6,852	8,909	7,612	6,214	4,445	6,269
(5)	Steam	GWH	19,069	9,586	14,328	12,890	7,081	6,071	6,852	8,909	7,612	6,214	4,445	6,269
(6)	Distillate(FO2) -Total	GWH	186	26	0	1	164	1,401	1,782	2,181	1,975	1,471	820	1,558
(7)	Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	123	9	0	0	164	1,393	1,781	2,181	1,971	1,470	820	1,558
(9)	CT	GWH	63	17	0	1	0	8	1	0	3	1	0	0
(10)	Natural Gas -Total	GWH	47,114	56,985	55,578	60,042	70,337	75,578	78,058	79,917	80,135	77,424	81,208	85,757
(11)	Steam	GWH	4,253	8,689	2,322	2,398	3,133	3,546	2,406	3,559	3,369	2,776	2,676	2,948
(12)	CC	GWH	42,422	47,871	52,941	57,281	66,850	71,953	75,585	76,152	76,690	74,596	78,476	82,640
(13)	CT	GWH	439	424	315	363	354	79	67	206	77	51	57	169
(14)	Other 3/	GWH	7,541	6,399	5,995	6,390	5,781	5,430	5,335	5,802	5,946	6,105	6,296	6,096
	Net Energy For Load 4/	GWH	111,301	113,137	117,551	122,024	126,270	130,499	134,766	139,038	142,379	146,257	150,291	154,556

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecst of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
4/ Net Energy For Load is also shown in Schedule 2.3.

Note: As discussed on the preceding pages, FPL utilized four fuel cost forecasts in its 2006 and early 2007 resource planning work. The projected values shown on this form are based on one of these forecasts. For simplicity's sake, FPL is providing only one set of projected values in this document.

Schedule 6.2
Energy Sources % by Fuel Type

	Energy Source	Units	Actual 1/ 2005	2006	Forecasted 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	Annual Energy Interchange 2/	%	9.2	9.2	9.6	9.3	8.9	8.4	8.0	7.8	7.6	7.4	6.9	5.0
(2)	Nuclear	%	19.2	20.8	19.4	20.0	19.1	18.4	18.2	17.4	16.9	16.7	16.0	15.6
(3)	Coal	%	5.2	5.5	6.5	5.7	6.0	5.4	5.6	5.2	8.3	13.5	15.3	14.9
(4)	Residual (FO6) -Total	%	17.1	8.5	12.2	10.6	5.6	4.7	5.1	6.4	5.3	4.2	3.0	4.1
(5)	Steam	%	17.1	8.5	12.2	10.6	5.6	4.7	5.1	6.4	5.3	4.2	3.0	4.1
(6)	Distillate (FO2) -Total	%	0.2	0.0	0.0	0.0	0.1	1.1	1.3	1.6	1.4	1.0	0.5	1.0
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CC	%	0.1	0.0	0.0	0.0	0.1	1.1	1.3	1.6	1.4	1.0	0.5	1.0
(9)	CT	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	42.3	50.4	47.3	49.2	55.7	57.9	57.9	57.5	56.3	52.9	54.0	55.5
(11)	Steam	%	3.8	7.7	2.0	2.0	2.5	2.7	1.8	2.6	2.4	1.9	1.8	1.9
(12)	CC	%	38.1	42.3	45.0	46.9	52.9	55.1	56.1	54.8	53.9	51.0	52.2	53.5
(13)	CT	%	0.4	0.4	0.3	0.3	0.3	0.1	0.0	0.1	0.1	0.0	0.0	0.1
(14)	Other 3/	%	6.8	5.7	5.1	5.2	4.6	4.2	4.0	4.2	4.2	4.2	4.2	3.9
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules.
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

Note: As discussed on the preceding pages, FPL utilized four fuel cost forecasts in its 2006 and early 2007 resource planning work. The projected values shown on this form are based on one of these forecasts. For simplicity's sake, FPL is providing only one set of projected values in this document.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1) Year	(2) Total Installed Capacity [1/] MW	(3) Firm Capacity Import MW	(4) Firm Capacity Export MW	(5) Firm QF MW	(6) Total Capacity Available [2/] MW	(7) Total Peak [3/] Demand MW	(8) DSM [4/] MW	(9) Firm Summer Peak Demand MW	(10) Reserve Margin Before Maintenance [5/] MW	(11) Reserve Margin Before Maintenance [5/] % of Peak	(12) Scheduled Maintenance MW	(13) Reserve Margin After Maintenance [6/] MW	(14) Reserve Margin After Maintenance [6/] % of Peak
2007	22,123	2,255	0	738	25,116	22,259	1,768	20,491	4,625	23	0	4,625	22.6
2008	22,150	2,255	0	738	25,143	22,770	1,908	20,862	4,281	21	0	4,281	20.5
2009	23,370	1,824	0	687	25,881	23,435	2,034	21,401	4,480	21	0	4,480	20.9
2010	24,589	1,467	0	640	26,696	24,003	2,146	21,857	4,839	22	0	4,839	22.1
2011	24,589	1,634	0	595	26,818	24,612	2,264	22,348	4,470	20	0	4,470	20.0
2012	24,589	2,111	0	595	27,295	25,115	2,388	22,727	4,568	20	0	4,568	20.1
2013	25,569	1,511	0	595	27,675	25,590	2,516	23,074	4,601	20	0	4,601	19.9
2014	26,549	1,311	0	595	28,455	26,100	2,651	23,449	5,006	21	0	5,006	21.3
2015	27,768	1,311	0	595	29,674	26,772	2,790	23,982	5,692	24	0	5,692	23.7
2016	27,768	930	0	595	29,293	27,410	2,910	24,500	4,793	20	0	4,793	19.6

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. All values are Summer net MW.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the 2006 load forecast without DSM.

4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2006-on for use with the 2006 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed [1/] Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available [2/] MW	Total Peak [3/] Demand MW	DSM [4/] MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance [5/] MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance [6/] MW	% of Peak
2006/07	22,294	3,124	0	738	26,156	22,247	1,555	20,692	5,464	26.4	0	5,464	26.4
2007/08	23,503	2,288	0	738	26,529	22,627	1,649	20,978	5,551	26.5	0	5,551	26.5
2008/09	23,531	1,962	0	738	26,231	23,115	1,750	21,365	4,866	22.8	0	4,866	22.8
2009/10	24,866	1,501	0	687	27,054	23,587	1,814	21,773	5,281	24.3	0	5,281	24.3
2010/11	26,201	1,500	0	595	28,296	24,047	1,883	22,164	6,132	27.7	0	6,132	27.7
2011/12	26,201	1,500	0	595	28,296	24,498	1,954	22,544	5,752	25.5	0	5,752	25.5
2012/13	26,201	1,320	0	595	28,116	24,952	2,028	22,924	5,192	22.6	0	5,192	22.6
2013/14	27,191	1,320	0	595	29,106	25,416	2,106	23,310	5,796	24.9	0	5,796	24.9
2014/15	28,181	1,320	0	595	30,096	26,048	2,188	23,860	6,236	26.1	0	6,236	26.1
2015/16	29,516	930	0	595	31,041	26,692	2,264	24,428	6,613	27.1	0	6,613	27.1

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the 2006 load forecast without DSM.

4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2006-on for use with the 2006 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2007														
Cape Canaveral	1	Brevard County	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	402,050	5	3	OT
Cape Canaveral	2	Brevard County	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	402,050	5	3	OT
Cutler	5	Miami Dade County	ST	NG	No	PL	No	Unknown	Jun-07	Unknown	75,000	(2)	(3)	OT
Cutler	6	Miami Dade County	ST	NG	No	PL	No	Unknown	Jun-07	Unknown	161,500	(29)	(32)	OT
Ft. Myers	2	Lee County	CC	NG	No	PL	No	Unknown	Jun-07	Unknown	1,701,890	11	1	OT
Ft. Myers	3	Lee County	CT	NG	FO2	PL	PL	Unknown	Jun-07	Unknown	376,380	8	2	OT
Lauderdale	4	Broward County	CC	NG	FO2	PL	PL	Unknown	Jun-07	Unknown	526,250	(2)	(8)	OT
Lauderdale	5	Broward County	CC	NG	FO2	PL	PL	Unknown	Jun-07	Unknown	526,250	(2)	(8)	OT
Port Everglades	1	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	247,775	(2)	(1)	OT
Port Everglades	2	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	247,775	(2)	(1)	OT
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	402,050	7	6	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	402,050	6	3	OT
Riveria	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	310,420	(2)	(1)	OT
Riveria	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	310,420	(5)	(4)	OT
Manatee	1	Manatee County	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	863,300	1	6	OT
Manatee	2	Manatee County	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	863,300	1	6	OT
Manatee	3	Manatee County	CC	NG	No	PL	No	Unknown	Jun-07	Unknown	1,224,510	7	10	OT
Martin	1	Martin County	ST	FO6	NG	PL	PL	Unknown	Jun-07	Unknown	934,500	(4)	(1)	OT
Martin	2	Martin County	ST	FO6	NG	PL	PL	Unknown	Jun-07	Unknown	934,500	(5)	(8)	OT
Martin	3	Martin County	CC	NG	No	PL	No	Unknown	Jun-07	Unknown	612,000	(20)	(18)	OT
Martin	4	Martin County	CC	NG	No	PL	No	Unknown	Jun-07	Unknown	612,000	(19)	(17)	OT
Martin	8	Martin County	CC	NG	FO2	PL	PL	Unknown	Jun-07	Unknown	1,224,510	25	11	OT
Putnam	1	Putnam County	CC	NG	FO2	PL	WA	Unknown	Jun-07	Unknown	290,004	3	–	OT
Putnam	2	Putnam County	CC	NG	FO2	PL	WA	Unknown	Jun-07	Unknown	290,004	3	–	OT
Sanford	3	Volusia County	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	156,250	2	–	OT
Sanford	4	Volusia County	CC	NG	No	PL	No	Unknown	Jun-07	Unknown	1,188,900	(8)	8	OT
Sanford	5	Volusia County	CC	NG	No	PL	No	Unknown	Jun-07	Unknown	1,188,900	(2)	14	OT
SJRPP	1	Duval County	BIT	BIT	Pet	RR	WA	Unknown	Jun-07	Unknown	135,918	5	2	OT
SJRPP	2	Duval County	BIT	BIT	Pet	RR	WA	Unknown	Jun-07	Unknown	135,918	5	2	OT
Scherer	4	Monroe, GA	BIT	BIT	No	RR	No	Unknown	Jun-07	Unknown	680,368	14	12	OT
Turkey Point	1	Miami Dade County	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	402,050	3	2	OT
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	Unknown	Jun-07	Unknown	402,050	9	8	OT
Turkey Point CC	5	Miami Dade County	CC	NG	FO2	PL	PL	Jan-05	Jun-07	Unknown	1,223,000	–	1,144	V
									2007 Changes/Additions Total:			16	1,142	
2008														
Cape Canaveral	1	Brevard County	ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	(1)	(1)	OT
Cape Canaveral	2	Brevard County	ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	(1)	(1)	OT
Cutler	5	Miami Dade County	ST	NG	No	PL	No	Unknown	Nov-54	Unknown	75,000	3	3	OT
Cutler	6	Miami Dade County	ST	NG	No	PL	No	Unknown	Jul-55	Unknown	161,500	21	21	OT
Martin	3	Martin County	CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	12	11	OT
Martin	4	Martin County	CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	12	11	OT
Riviera	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	(2)	(3)	OT
Scherer	4	Monroe, GA	BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	680,368	(10)	(10)	OT
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	(6)	(4)	OT
Turkey Point CC	5	Miami Dade County	CC	NG	FO2	PL	PL	Jan-05	Jun-07	Unknown	1,223,000	1,181	–	V
									2008 Changes/Additions Total:			1,209	27	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All other MW will be picked up in the following year.

Note 2: Changes shown include different ratings than shown in Schedule 1 due solely to ambient temperature consistent with those in FPL 's peak load forecast to maintain consistency in Reserve Margin calculation.

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2009														
Cutler	5	Miami Dade County	ST	NG	No	PL	No	Unknown	Nov-54	Unknown	75,000	(1)	–	OT
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	3	–	OT
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	1	–	OT
Martin	1	Martin County	ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	5	–	OT
Martin	2	Martin County	ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	5	–	OT
Martin	3	Martin County	CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	1	1	OT
Manatee	1	Manatee County	ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	7	–	OT
Manatee	2	Manatee County	CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	7	–	OT
West County Combined Cycle	1	Palm Beach County	CC	NG	FO2	PL	PL	Jan-07	Jun-09	Unknown	Unknown	—	1,219	U
									2009 Changes/Additions Total:			28	1,220	
2010														
West County Combined Cycle	1	Palm Beach County	CC	NG	FO2	PL	PL	Jan-07	Jun-09	Unknown	Unknown	1,335	—	U
West County Combined Cycle	2	Palm Beach County	CC	NG	FO2	PL	PL	Jan-08	Jun-10	Unknown	Unknown	—	1,219	U
									2010 Changes/Additions Total:			1,335	1,219	
2011														
West County Combined Cycle	2	Palm Beach County	CC	NG	FO2	PL	PL	Jan-08	Jun-10	Unknown	Unknown	1,335	—	U
									2011 Changes/Additions Total:			1,335	0	
2012														
									2012 Changes/Additions Total:			0	0	
2013														
Glades Power Park	1	Glades County	BIT	BIT	No	RR	No	Jan-09	Jun-13	Unknown	Unknown	—	980	P
									2013 Changes/Additions Total:			0	980	
2014														
Glades Power Park	1	Glades County	BIT	BIT	No	RR	No	Jan-09	Jun-13	Unknown	Unknown	990	—	P
Glades Power Park	2	Glades County	BIT	BIT	No	RR	No	Jan-10	Jun-14	Unknown	Unknown	—	980	
									2014 Changes/Additions Total:			990	980	
2015														
Glades Power Park	2	Glades County	BIT	BIT	No	RR	No	Jan-10	Jun-14	Unknown	Unknown	990	—	P
South Florida 3x1 G CC	1	Unknown	CC	NG	FO2	PL	PL	Jan-13	Jun-15	Unknown	Unknown	—	1,219	P
									2015 Changes/Additions Total:			0	1,219	
2016														
South Florida 3x1 G CC	1	Unknown	CC	NG	FO2	PL	PL	Jan-13	Jun-15	Unknown	Unknown	1,335	—	P
									2016 Changes/Additions Total:			1,335	0	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All other MW will be picked up in the following year.

Note 2: Changes shown include different ratings than shown in Schedule 1 due solely to ambient temperature consistent with those in FPL 's peak load forecast to maintain consistency in Reserve Margin calculation.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point Combined Cycle Unit # 5

(2) **Capacity**
a. Summer 1,144 MW
b. Winter 1,181 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2005
b. Commercial In-service date: 2007

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 11,000 Acres

(9) **Construction Status:** V Under Construction, more than 50% complete

(10) **Certification Status:** Certified

(11) **Status with Federal Agencies:** Certified

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 97%	(First Base OperationYear)
Average Net Operating Heat Rate (ANOHR):	6,835	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2007 $/kW):	507	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2007 $kW-Yr)	10.06	
Variable O&M ($/MWH): (2007 $/MWH)	0.13	
K Factor:	1.5699	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit # 1

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2007
b. Commercial In-service date: 2009

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** U (Under construction, less than or equal to 50% complete)

(11) **Status with Federal Agencies:** U (Under construction, less than or equal to 50% complete)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 97%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2009 $/kW):	565	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2009 $kW-Yr)	11.65	
Variable O&M ($/MWH): (2009 $/MWH)	0.138	
K Factor:	1.5834	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit # 2

(2) **Capacity ***
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2008
b. Commercial In-service date: 2010

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complet

(10) **Certification Status:** U (Under construction, less than or equal to 50% complet

(11) **Status with Federal Agencies:** U (Under construction, less than or equal to 50% complet

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 94%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data **,*****

Book Life (Years):	25	years
Total Installed Cost (2010 $/kW):	519	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2010 $kW-Yr)	10.11	
Variable O&M ($/MWH): (2010 $/MWH)	0.138	
K Factor:	1.5873	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.
(Note: Costs shown are based on the constuction of Unit 1 first.)

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** FGPP Unit # 1

(2) **Capacity**
a. Summer 980 MW
b. Winter 990 MW

(3) **Technology Type:** Ultra-Supercritical Steam Generator

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2008
b. Commercial In-service date: 2013

(5) **Fuel**
a. Primary Fuel: Coal
b. Alternate Fuel: Up to 20% Petroleum Coke

(6) **Air Pollution and Control Strategy:** Low No_x Burners, Over-fired Air, SCR, Baghouse Wet Flue Gas Desulfurization, Wet Electric Static Precipatator

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 4,900 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	5.0%
Forced Outage Factor (FOF):	3.0%
Equivalent Availability Factor (EAF):	92%
Resulting Capacity Factor (%):	Approx. 90% (First Year Operation)
Average Net Operating Heat Rate (ANOHR):	8,800 Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	40 years
Total Installed Cost (2013 $/kW):	3,526
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2013 $kW-Yr)	35.61
Variable O&M ($/MWH): (2013$/MWH)	1.744
K Factor:	1.6017

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes transmission interconnection and transmission integration,escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** FGPP Unit # 2

(2) **Capacity**
a. Summer 980 MW
b. Winter 990 MW

(3) **Technology Type:** Ultra-Supercritical Steam Generator

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2008
b. Commercial In-service date: 2014

(5) **Fuel**
a. Primary Fuel: Coal
b. Alternate Fuel: Up to 20% Petroleum Coke

(6) **Air Pollution and Control Strategy:** Low No_x Burners, Over-fired Air, SCR, Baghouse Wet Flue Gas Desulfurization, Wet Electric Static Precipatator

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 4,900 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	5.0%
Forced Outage Factor (FOF):	3.0%
Equivalent Availability Factor (EAF):	92%
Resulting Capacity Factor (%):	Approx. 90% (First Year Operation)
Average Net Operating Heat Rate (ANOHR):	8,800 Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	40 years
Total Installed Cost (2014 $/kW):	2,290
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2014 $kW-Yr)	26.42
Variable O&M ($/MWH): (2014 $/MWH)	1.76
K Factor:	1.5955

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes transmission interconnection and transmission integration,escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** South Florida (unsited) Combined Cycle #1

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2013
b. Commercial In-service date: 2015

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Distillate

(6) **Air Pollution and Control Strategy:** Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	
Resulting Capacity Factor (%):	Approx. 97%	(First Year Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2015 $/kW):	746	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2015 $kW-Yr)	11.11	
Variable O&M ($/MWH): (2015 $/MWH)	0.52	
K Factor:	1.543	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes transmission interconnection and transmission integration,escalation, and AFUDC.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Combined Cycle Unit #5

The new Turkey Point CC unit that is scheduled to come in-service in 2007 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

West County Energy Center Unit #1

The new West County Energy Center Unit #1 that is scheduled to come in-service in 2009 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

West County Energy Center Unit #2

The new West County Energy Center Unit #2 that is scheduled to come in-service in 2010 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

FGPP Unit #1 by 2013

(1)	Point of Origin and Termination:	New switchyard – New switching station
(2)	Number of Lines:	2
(3)	Right-of-way	FPL Owned & New acquisitions
(4)	Line Length:	25 miles each
(5)	Voltage:	500 kV
(6)	Anticipated Construction Timing:	Start date: March 2009 End date: November 2011
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$200,881,000
(8)	Substations:	New switchyard and new switching station
(9)	Participation with Other Utilities:	None

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(1)	Point of Origin and Termination:	Andytown-Orange River – New switching station
(2)	Number of Lines:	2
(3)	Right-of-way	FPL Owned & New acquisitions
(4)	Line Length:	24 miles each
(5)	Voltage:	500 kV
(6)	Anticipated Construction Timing:	Start date: March 2009 End date: November 2011
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$172,566,000
(8)	Substations:	Andytown 500kV, Orange River 500kV and new 500kV switching station
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

FGPP Unit #2 by 2014

(1)	Point of Origin and Termination:	New switchyard – Levee 500kV
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned & New acquisitions
(4)	Line Length:	74 miles
(5)	Voltage:	500 kV
(6)	Anticipated Construction Timing:	Start date: March 2009 End date: November 2012
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$96,020,000
(8)	Substations:	Andytown 500kV, Levee 500kV and new 500kV switching station
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Unsited South Florida Combined Cycle Unit in 2015

No projection of a new transmission line(s) can be made until a site is selected for this unit.

Schedule 11.1

Existing FIRM and NON-FIRM Capacity and Energy by Primary Fuel Type
Actuals for the Year 2006

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				Net Energy For Load	
	Generation by Primary Fuel	Summer (MW)	Summer (%)	Winter (MW)	Winter (%)	GWH	%
(1)	Coal	896	3.7%	902	3.5%	6,168	5.5%
(2)	Nuclear	2,939	12.1%	3,014	11.8%	23,533	20.8%
(3)	Residual	6,818	28.0%	6,876	27.0%	9,586	8.5%
(4)	Distillate	660	2.7%	781	3.1%	26	0.0%
(5)	Natural Gas	9,668	39.6%	10,706	42.0%	56,985	50.4%
(6)	*FPL Existing Units Total:*	*20,981*	*86.0%*	*22,279*	*87.4%*	*96,298*	*85.1%*
(7)	Renewables (Purchases)- Firm	157.6	0.6%	157.6	0.6%	1,253	1.1%
(8)	Renewables (Purchases)- Non-Firm	As Available		As Available		393	0.3%
(9)	Renewable (Owned)		0.0%		0.0%		0.0%
(10)	*Renewable Total:*	*157.6*	*0.6%*	*157.6*	*0.6%*	*1,646*	*1.5%*
(11)	*Purchases Other:*	*3,249.0*	*13.3%*	*3,047.0*	*12.0%*	*15,193*	*13.4%*
(12)	*Total*	*24,387.6*	*100.0%*	*25,483.6*	*100.0%*	*113,137*	*100.0%*

Note:
(1) FPL Existing Units Total matches Total System found on Schedule 1.
(2) "Renewable Purchases" - Firm are broken down in Schedule 11.2
(3) "Renewable Purchases" - Non-Firm are broken down in Schedule 11.3
(4) Net Energy for Load MWH matches Schedule 6.1

Schedule 11.2

Existing FIRM Renewable Report by Fuel Type
Actuals for the Year 2006

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Gross (MW) Capability				Net Energy For Load	
	Renewable Fuel Type	Summer (MW)	Summer (%)	Winter (MW)	Winter (%)	GWH	%
1	Biomass	157.6	100.0%	157.6	100.0%	1,253	100.0%
2	Landfill Gas						
3	Hydro						
4	Geothermal						
5	Biofuels						
6	Solar						
7	Ocean Energy						
8	Wind						
9	Other						
10	Total	157.6	100.0%	157.6	100.0%	1,253	100.0%

Note:
(1) Col (2) matches Row (7) on Schedule 11.1.
(2) Col (6) total matches Row (7) on Schedule 11.1.

Schedule 11.3

Existing NON-FIRM Renewable Report by Fuel Type
Actuals for the Year 2006

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Gross (MW) Capability				Net Energy For Load	
	Renewable Fuel Type	Summer (MW)	Summer (%)	Winter (MW)	Winter (%)	GWH	%
1	Biomass	As Available		As Available		375.5	95.5%
2	Landfill Gas	As Available		As Available		17.8	4.5%
3	Hydro						
4	Geothermal						
5	Biofuels						
6	Solar						
7	Ocean Energy						
8	Wind						
9	Other						
10	Total					393.3	100.0%

Note:
(1) Col (6) total needs to match Row (8) on Schedule 11.1.

Schedule 11.4

Existing NON-FIRM Self-Service Renewable Generation Facilities
Actuals for the Year 2006

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Facility Name	**Unit No.**	**Gross MW**	**Net MW**	**Fuel Type**	**Self-Service MW**	**Self-Service MWh**	**In-Service Date**
Customer owned PV< 10 kw (est)	N/A	0.100	Unk	SUN	0.100	70.8	2002 - 2006
FPL Martin PV (est)	N/A	0.011	0.0	SUN	0.011	14.4	
FPL estimates there are 42,861 solar water heaters in our system				SUN			
FPL estimates there are 34,358 solar pool heaters in our system				SUN			

Notes
(1) Provide as much data available for facilities/resources "behind the meter" (as data permits).
(2) A 'Facility Name' may include an aggregated quantity (i.e., Pool Heaters, Solar-Powered Interstate Call Boxes, Photovoltaic Lighting, etc.).
(3) Self-Service MW and MWh pertains to power and energy consumed by the entity, whether it be a named facility or aggregated quantity.

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered plant and animal species. Population growth in FPL's service area is continuing, which heightens competition for air, land, and water resources that are necessary to meet the increased demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

FPL has been recognized for many years as one of the leaders among utilities for its commitment to the environment. FPL's environmental leadership has been heralded by many outside organizations. In 2004, FPL Group earned a first place ranking among U.S. power companies and second globally in a report from the World Wildlife Fund for voluntary commitments to limit CO_2 emissions. This commitment was made to support initiatives to better manage utility impacts on climate change through use of greenhouse gas emission reductions and improvements in energy efficiency. The report stated that this was "primarily due to the company's leadership in developing wind energy and their commitment to dramatically improve their efficiency". In January 2007, FPL joined with a diverse group of U.S. based business market leaders and leading non-governmental organizations to form the U.S. Climate Action Partnership (USCAP) in recognition of the need for a national policy framework on climate change. USCAP has called upon the federal government to formulate mandatory economy-wide policies to reduce CO_2 emissions. As a further demonstration of FPL's efforts in sustainability, the EPA and the Department of Energy awarded FPL for its Sunshine Energy® program which allows customers who choose to participate to pay a premium for their electricity that is used to purchase tradable renewable energy credits associated with electric energy generated from renewable energy sources. FPL Group, the parent corporation of Florida Power & Light was also recently awarded its fourth number one rating of major electric utilities surveyed in an environmental assessment conducted by Innovest, an independent advisory group. This rating was in recognition of FPL Group's success in executing a strategy to become a clean energy provider harnessing primarily clean and renewable fuels while also boosting shareholder value. FPL Group was named one of the world's most Sustainable Corporations in Global 100 and was one of only two utilities to be so named in the United States.

FPL was awarded Edison Electric Institute's National Land Management Award for its stewardship of 25,000 acres surrounding its Turkey Point Plant. FPL won the Council for Sustainable Florida's award for its sea turtle conservation and education programs at its St. Lucie Plant. In 2001, FPL was awarded the 2001 Waste Reduction and Pollution Prevention Award from the Solid Waste Association of North America. FPL received the 2001 Program Champion Award from the Environmental Protection Agency's Wastewise Program. The Florida Department of Environmental Protection named FPL a "Partner for Ecosystem Protection" for its emission-reducing "repowering" projects at its Fort Myers and Sanford Plants. Finally, FPL has been recognized by numerous federal and state agencies for its innovative endangered species programs which include such species as manatees, crocodiles, and sea turtles.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Statement in 1992 to clearly define its position. This statement reflects how FPL incorporates environmental values into all aspects of its activities and serves as a framework for new environmental initiatives throughout the company. FPL's Environmental Statement is:

It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:

- Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
- Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
- Encourage the wise use of energy to minimize the impact on the environment.
- Communicate effectively on environmental issues.
- Conduct periodic self-evaluations, report performance, and take appropriate actions.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an environmental management system to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program that is discussed below. Other components include: executive management support and commitment, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident/emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to evaluate environmental performance, verify compliance with Corporate policy as well as with legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and Company policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2006 environmental outreach activities are noted in Table IV.E.1.

Table IV.E.1: 2006 FPL Environmental Outreach Activities

Activity	# of Participants
Visitors to Energy Encounter	20,000
Visitors to Manatee Park	150,000
Number of visits to FPL's Environmental Website	258,000
Number of pieces of Environmental literature distributed	>120,000

(All numbers are approximations.)

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified three Preferred Sites and eight Potential Sites for future generation additions. Preferred Sites are those locations where FPL has conducted significant reviews and taken action to site generation. Potential Sites are those sites that have attributes that support the siting of generation and are under consideration as a location for future generation. Some of these sites are currently in use as existing generation sites and some are not. The identification of a Potential Site does not indicate that FPL has made a definitive decision to pursue generation (or generation expansion in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of a generator has been determined. These Preferred Sites and Potential Sites are discussed in separate sections below.

IV.F.1 Preferred Sites

FPL identifies three Preferred Sites in this Site Plan: the existing Turkey Point plant site, the West County Energy Center (WCEC) adjacent to the existing Corbett FPL substation, and the FPL Glades Power Park (FGPP) located northwest of the city of Moore Haven in Glades County. The Turkey Point site is the location for a capacity addition that FPL will make in mid-2007. The West County Energy Center site is the location for capacity additions FPL will make in 2009 and 2010. The FGPP site is the projected location for advanced technology coal capacity additions by 2013 and 2014.

The capacity additions at the Turkey Point site and the WCEC site have been approved by the FPSC and by the Governor and Siting Board. FPL petitioned the FPSC for approval of the FGPP advanced technology coal units in January 2007. A decision is expected by the FPSC by July 2007.

The three Preferred Sites are discussed below.

Preferred Site # 1: Turkey Point Plant, Miami-Dade County

The Turkey Point Plant site is located on the west side of Biscayne Bay, 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. Public access to the plant site is limited due to the nuclear units located there. The land surrounding the site is owned by FPL and acts as a buffer zone. The site is comprised of two nuclear units and two conventional boiler, fossil units, the cooling canals, an FPL-maintained natural wildlife area, and wetlands that have been set aside as the Everglades Mitigation Bank (EMB).

Units #1 and #2 are fossil fuel generating plants with approximate generating capacity of 400 MW each. Unit #1 was completed in 1967 and Unit #2 in 1968. Units #3 and #4 are nuclear generating units with approximate generating capacity of 700 MW each. Unit #3 was completed in 1972 and Unit #4 in 1973. Turkey Point also has five diesel peaking units that, in total, produce approximately 12 MW. These units are primarily used to provide emergency power, but occasionally run during the Summer to provide power during peak load demands.

The site for the new Turkey Point Unit #5, a "4-on-1" combined cycle electrical generating unit, is within the existing FPL Turkey Point facility property. The site is adjacent to the existing fossil Units #1 and #2, and includes the existing parking lot and storage areas immediately northwest of Units #1 and #2 as well as mangrove wetlands north of the facility.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Turkey Point plant site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the Turkey Point Unit #5 generating facility at the site is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a self-contained cooling canal system that supplies water to condense steam used by the existing units' turbine generators. The canal system consists of 36 interconnected canals each five miles long, 200 feet wide and approximately four feet deep. The remaining developed area of the site is where the two fossil steam generating units and 5 diesel generators are located. South of, and adjacent to, the fossil plant are the two nuclear generating units. Further to the south, wetlands have been set aside as part of the Everglades Mitigation Bank (EMB) in an effort to restore these areas to historical plant communities and hydrological function.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site was undeveloped dwarf red mangrove swamp that is tidally inundated with waters from Biscayne Bay. Along with the dominant red mangroves, buttonwood is a common canopy component, along with occasional white mangrove. Only a few individual black mangroves were observed within the site. Biscayne Bay is a shallow, subtropical bay supporting seagrasses, sponges, coral reefs, and a variety of marine life.

2. Listed Species

The construction and operation of Unit #5 is not expected to adversely affect any rare, endangered, or threatened species. Listed species known to occur in the nearby Biscayne National Park that could potentially utilize the site include the peregrine falcon (Falco peregrinus), wood stork (Mycteria americana), American crocodile (Crocodylus acutus), mangrove rivulus (Rivulus marmoratus), roseate spoonbill (Ajaja ajaja), limpkin (Aramus guarauna), little blue heron (Egretta caerulea), snowy egret (Egretta thula), American oystercatcher (Haematopus palliates), least tern (Sterna antillarum), brown pelican (Pelicanus occidentalis), the white ibis (Eudocimus albus), and bald eagle (Haliaeetus leucocephalus). No bald eagle nests are known to exist in the vicinity of the site. The federally listed, endangered American Crocodile thrives at the Turkey Point site, primarily in and around the southern end of the cooling canals which lie south of the project area. The entire site is considered crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American crocodile. A project-specific crocodile management plan was developed for construction of Unit #5.

3. **Natural Resources of Regional Significance Status**

Significant features in the vicinity on the site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park, comprised of several miles of shoreline north of the Turkey Point facility extending offshore approximately 12 nautical miles. Biscayne National Park contains 180,000 acres, approximately 95% of which is open water interspersed with over 40 keys. The Biscayne National Park headquarters is located approximately 2 miles north of the Turkey Point plant and is adjacent to the Miami-Dade County Homestead Bayfront Park which contains a marina and day use recreational facilities.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

Additional generating capacity is being added to the site for operation beginning in mid-2007. The new generating unit will consist of four new combustion turbines (CT) and four new heat recovery steam generators (HRSG) and a new steam turbine that will comprise Turkey Point Unit #5. Natural gas delivered via the existing pipeline is the primary fuel type for this unit (with ultra low sulfur light oil serving as a backup fuel).

Mitigation for unavoidable wetland impacts related to construction of Unit #5 includes: on-site hydrologic improvements to enhance existing wetlands, restoration and preservation of areas overgrown with exotic plant species, creation of an on-site lagoon, transfer of some mangrove-dominated lands to South Florida Water Management District and Biscayne National Park, and the purchase of mitigation credits from the EMB that is in the same drainage basin. The use of a cooling tower will minimize thermal discharges to the cooling canals. The facility already encompasses several preserved areas where wildlife is abundant.

g. Local Government future Land Use Designations

Local government future land use plan designates most of the site as IU-3 "Industrial, Unlimited Manufacturing District." There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. Site Selection Criteria Process

For the past several years, a number of FPL's existing power plant sites have been considered as potentially suitable sites for new or repowered generation. The Turkey Point plant has been selected as a Preferred site due to consideration of various factors including system load, an imbalance in the Southeast Florida region between load and generating capacity, and economics. Environmental issues are an important factor at this site and FPL will minimize environmental impacts and mitigate where impacts are unavoidable.

i. Water Resources

Unique to Turkey Point plant site is the self-contained cooling canal system that supplies water to condense steam used by the plant's turbine generators. The canal system consists of 36 interconnected canals each five miles long, 200 feet wide, and approximately four feet deep. The system performs the same function as a giant radiator. The water is circulated through the canals in a two-day journey, ending at the plant's intake pumps. During the slow journey down the canals, the water cools as much as 15 degrees

j. Geological Features of Site and Adjacent Areas

FPL's Turkey Point site is underlain by approximately 13,000 feet of sedimentary rock strata. The strata that extends to approximately 500 feet forms the Biscayne Aquifer. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily of marine origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, or clay. The Tamiami formation is named for deposits composed principally of white cream-colored calcareous sandstone, sandy limestone, and beds and pockets of quartz sand. In the Turkey Point area, Key Largo limestone is present.

The Floridan Aquifer, located approximately 1,100 feet below the land surface, is a confined aquifer. The Floridan Aquifer system is composed entirely of carbonate rocks except for minor evaporates. The water in the carbonate rock aquifer is more highly mineralized.

k. Projected Water Quantities for Various

The additional quantity of water for industrial processing will be approximately 294 gallons per minute (gpm) for plant process and service water. Water for this type of use would be supplied by an existing county water system. A new water treatment plant is installed to provide treated water for the new unit. Cooling water for new Unit #5 will be processed through a cooling tower. FPL will use approximately 14 million gallons per day (mgd) of water from the Floridan Aquifer as the source of makeup water used by the cooling tower.

l. Water Supply Sources and Type

This additional capacity at the site will utilize the cooling tower for the dissipation of heat from the cooling water. A new water treatment system will be installed to provide treated water for Unit #5. The Floridan Aquifer will supply the makeup cooling water.

m. Water Conservation Strategies

The plant will implement a Water Conservation Plan including physical features, procedures, and employee training to conserve water resources. Features in the plant's water systems design will include, when practical:

- Automatic shutoff valves
- Use of flow restrictors
- Use of low volume sanitary facilities
- Low maintenance landscaping design

An awareness program will be implemented for employees that operate the plant. The awareness program will educate employees on water conservation methods, techniques, and procedures. Procedures will be reviewed on an annual basis with the first review occurring in approximately June 2008, one year after the expected commercial operation date. The Water Conservation Plan will be updated as necessary.

n. Water Discharges and Pollution Control

Heated water discharges are dissipated using the existing once-through cooling water system and the cooling canal system. Unit #5 cooling water will be processed through a cooling tower which will dissipate the heat prior to discharge to the cooling canal system. Storm water runoff is collected and used to recharge the surficial aquifer via a storm water management system. Design elements have been included to capture suspended sediments. Various facility permits mandate various sampling and testing activities that provide indication of any pollutant discharges.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by multiple fuel delivery facilities. There is currently a pipeline that supplies natural gas to the facility. The facility also has oil capabilities through on-site storage tanks and accessibility to barge deliveries. Unit #5 will utilize the existing pipeline with the addition of a compression system(s). An aboveground storage tank for the ultra-low sulfur light oil backup fuel will be added. The backup fuel for Unit #5 will be delivered to the site by truck.

p. Air Emissions and Control Systems

The use of natural gas and ultra-low sulfur light oil and combustion controls will minimize air emissions from this unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using the ultra-low sulfur light oil as backup fuel. These design alternatives constitute the Best Available Control Technology for air emissions and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of Turkey Point Unit

#5 will incorporate features that will make it one of the most efficient and cleanest power plants in the State of Florida.

q. **Noise Emissions and Control Systems**

A field survey and impact assessment of noise expected to be caused by unit construction at the site indicated that construction noise would be below current noise levels for the residents nearest the site. Noise from the operation of the new unit will also be within allowable levels. Similar natural gas-fired facilities in Broward, Manatee, and Martin counties have been constructed and operated without exceeding allowable noise levels.

r. **Status of Applications**

FPL filed the Site Certification Application (SCA) for the Turkey Point Plant Unit #5 with the Florida Department of Environmental Protection (FDEP) on November 14, 2003, and received Site Certification by the Governor and Cabinet in February 2005. The U.S. Army Corps of Engineers issued a federal Dredge and Fill permit in February 2005. FDEP issued the Prevention of Significant Deterioration (PSD) air permit in February 2005. FPL acquired all permits and authorizations needed, and commenced construction in Spring 2005 with an anticipated, in-service date of mid-2007.

Preferred Site # 2: West County Energy Center, Palm Beach County

FPL has identified the property adjacent to the existing Corbett Substation property in unincorporated western Palm Beach County as a Preferred Site for the addition of new generating capacity. The site was selected for the addition of a new greenfield combined cycle natural gas power plant project with ultra-low sulfur oil as a backup fuel. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections. The proposed facility would use natural gas as the primary fuel and state-of-the-art combustion controls.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the West County Energy Center (WCEC) plant site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the WCEC generating facilities at the site is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The land on the site is currently inactive but was previously dedicated to industrial and agricultural use. The site has been excavated, back-filled, and totally re-graded to an elevation approximately 10 ft. above surrounding land surface. No structures are present on the site and vegetation is virtually non-existent.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The plant site has been significantly altered by the construction and operation of a limestone mine where vegetation had been cleared and removed. The surrounding land use is predominantly sugar cane agriculture and limestone mining. FPL's existing Corbett substation is located north of the site. The Arthur R. Marshall Loxahatchee National Wildlife Refuge is located to the south of the proposed site.

2. Listed Species

Construction and operation of new units at the site is not expected to affect any rare, endangered, or threatened species. Wildlife utilization of the property is minimal as a result of the mining activities. Common wading birds can be observed on areas adjacent to and occasionally within the property. The property is adjacent to areas that have been identified as potential habitat for wood stork.

3. Natural Resources of Regional Significance Status

The construction and operation of a gas-fired combined cycle generating facility at the proposed location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands including the Arthur R. Marshall Loxahatchee National Wildlife Refuge. It is not anticipated that construction will result in wetland impacts under federal, state, or local agency permitting criteria.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design option is to construct two new 1,200 MW (approximate) units each consisting of three new combustion turbines (CT) and three new heat recovery steam generators (HRSG) and a new steam turbine. These two new units are scheduled to be in-service in mid-2009 and mid-2010, respectively. Natural gas delivered via pipeline is the primary fuel type for this unit with ultra-low sulfur light oil serving as a backup fuel.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the project site is "Rural Residential" according to the Palm Beach County Future Land Use Map. Designations for the area under the Palm Beach County Unified Land Development Code classified the project site and surrounding area as Special Agricultural District. The site has been granted conditional use for electrical power facilities under a General Industrial zoning district.

h. **Site Selection Criteria Process**

The site has been selected as a Preferred Site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues.

i. **Water Resources**

Water from the Floridan Aquifer and surface water from the L10/L12 canal will be used for cooling, service, and process water. Water from the surficial aquifer will be treated and used for potable water.

j. **Geological Features of Site and Adjacent Areas**

The site is underlain by approximately 13,000 feet of sedimentary rock strata. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine in origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, clay, and phosphate grains. The deepest formation in Palm Beach County on which significant published data are available is the Eocene Age Avon Park. Limited information is available from wells penetrating the underlying Oldsmar formation. The published information on the sediments comprising the formations below the Avon Park Limestone is based on projections from deep wells in Okeechobee, St. Lucie, and Palm Beach Counties.

k. <u>Projected Water Quantities for Various Uses</u>

The estimated quantity of water required for industrial processing for both units is approximately 450 gallons per minute (gpm) for uses such as process water and service water. Approximately 15 million gallons per day (mgd) in total of cooling water for the two generating units would be cycled through the addition of cooling towers. Water quantities needed for other uses such as potable water are estimated to be approximately 35,000 gallons per day (gpd).

l. <u>Water Supply Sources by Type</u>

The generating units will use available surface or ground water as the source of cooling water for the cooling towers. The cooling towers will also act as a heat sink for the facility process water. Such needs for cooling and process water will comply with the existing South Florida Water Management District (SFWMD) regulations for consumptive water use.

m. <u>Water Conservation Strategies Under Consideration</u>

Impacts on the surficial aquifer would be minimized and used only for potable water. Water from the Floridan Aquifer or the L10/L12 canal will be used for cooling purposes and cooling towers will be utilized. In addition, captured stormwater will be reused in the cooling tower whenever feasible. Stormwater captured in the stormwater ponds will also recharge the surficial aquifer.

n. <u>Water Discharges and Pollution Control</u>

Heat will be dissipated in the cooling towers. Blowdown water from the cooling towers, along with other wastestreams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Storm water runoff will be collected and used to recharge the surficial aquifer via a storm water management system. Design elements will be included to capture suspended sediments. In addition, captured stormwater will be reused in the cooling towers whenever feasible The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is not located near an existing natural gas transmission pipeline that is capable of providing a sufficient quantity of gas. Upgrades of existing pipelines and/or lateral connections to other pipelines will be made for supply of natural gas. Ultra-low sulfur light fuel oil would be received by truck and stored in above-ground storage tanks to serve as backup fuel for the new units.

p. Air Emissions and Control Systems

The use of natural gas and ultra-low sulfur light fuel oil and combustion controls will minimize air emissions from these units and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of the West County Energy Center units will incorporate features that will make them among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site. Noise from the operation of the new unit will be within allowable levels.

r. Status of Applications

A Site Certification Application (SCA) for the construction and operation of the West County Energy Center project under the Florida Electrical Power Plant Siting Act was filed on April 14, 2005 and received Site Certification by the Governor and Cabinet on December 26, 2006. Palm Beach County Planning Zoning and Building department issued approval for the project on June 28, 2006. FDEP issued a Class I Underground Injection Control Exploratory Well permit on January 11, 2006 and a Class V Exploratory Well Permit on December 6, 2006. FDEP issued a Prevention of Significant Deterioration (PSD) air permit on January 10, 2007. After acquiring these permits and authorizations, FPL initiated construction in February 2007 and anticipates an in-service date for the first unit of mid-2009. An application for the final Underground Injection Control (UIC) system permit will be submitted once the exploratory well construction is completed.

Preferred Site # 3: FPL Glades Power Park (FGPP), Glades County

FPL has identified a 4,900 acre property in unincorporated Glades County as a Preferred Site for the addition of 1,960 MW of new generating capacity. The site boundary is located approximately 2.3 miles northwest of Moore Haven, Florida. The Preferred Site was selected for the addition of a new advanced technology coal project. The existing site is adjacent to a rail line that can be used for fuel delivery. In addition, the facility can be designed to beneficially use excess storm water from the region as one of the sources of cooling water. New transmission lines in Glades and Hendry Counties, as well as a new substation in Hendry County will be required to interconnect the facility to the FPL power grid. The proposed facility would use a combination of domestic coal and/or foreign coal with up to 20% petroleum coke. The proposed generation process is a highly efficient, ultra-supercritical pulverized coal technology. The facility will feature advanced, state-of-the-art pollution control equipment to minimize emissions.

a. U.S. Geological Survey (USGS) Map

A USGS map of the FPL Glades Power Park (FGPP) site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the proposed generating facilities at the site is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The site is comprised of active sugar cane fields, pasture, and undeveloped land. Unpaved farm roads and irrigation ditches related to the sugar cane operations are also prevalent throughout much of the site. Land uses immediately surrounding the site are active sugar cane fields, open pasture, and undeveloped land.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The plant will be developed on approximately 4,000 acres of the 4,900 acre site, with the balance of the site being preserved. The area to be developed has been significantly altered by agricultural activities. Specifically, the natural topography, soils, and hydrology has been altered to create an area favorable for the production of sugar cane. Natural surface water drainage features have been modified through the construction of a network of irrigation ditches. The undeveloped portion of the site will be preserved.

Nicodemus Slough is located to the north of the site. Lake Okeechobee is located approximately 1.5 miles east of the site. The Fisheating Creek Wildlife Management Area is located approximately 4 miles north of the site.

2. Listed Species

Construction and operation of new units at the site is not expected to adversely affect any rare, endangered, or threatened species. Wildlife utilization of the property is minimal as a result of the agricultural activities. The majority of the site is comprised of active sugar cane fields which are unsuitable habitat for most species due to the lack of native vegetation and the amount and frequency of human disturbance. However, wading birds and alligators do utilize the irrigation canals and opportunistic wildlife forage in areas of heavy machinery. Brazilian pepper/willow and marsh wetlands within the sugar can fields also provide habitat for avian species and common herpetofauna.

Three federally listed species have been observed at the site, including the wood stork, the crested caracara, and the Everglades snail kite. State-listed species observed at the site include the little blue heron, snowy egret, white ibis, tri-color heron, wood stork, sand hill crane, and American alligator. The site does not provide any critical wildlife habitat.

3. **Natural Resources of Regional Significance Status**

Construction and operation of the advanced technology coal generating facility at the proposed location is not expected to have adverse impacts on parks, recreation areas, or environmentally sensitive lands. Construction will impact approximately 300 acres of man-made irrigation/drainage ditches and 248 acres of low quality wetlands dominated by exotic vegetation. The irrigation/drainage ditches are vegetated by nuisance/exotic species of vegetation, receive agricultural runoff, and do not provide high quality aquatic habitat for fish and wildlife.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design option is to construct two new nominal 980 MW net advanced technology coal units with state-of-the-art pollution control equipment. These units are planned to be in-service no later than mid-2013 and mid-2014,respectively. Domestic and/or imported coal along with up to 20% petroleum coke delivered via rail is the fuel type for these units. The extensive array of pollution control equipment will make this one of the cleanest coal facilities in the U.S.

Proposed mitigation for unavoidable wetland impacts related to construction of the units includes will be accomplished through a combination of onsite freshwater marsh and forested wetland creation within the pasture portion of the site and preservation of the highest quality marsh, wet prairie, wetland scrub, and mature upland live oak/cabbage palm habitat at the site.

g. **Local Government Future Land Use Designations**

The site is located in unincorporated Glades County and is designated as Agricultural/Open on the Glades County Future Land Use Map.

The site is located in the Open Use Agriculture (OUA) zoning district. Power plants and ancillary facilities are listed as a permitted use in the Glades County Table of Zoning District Uses.

The use of the site for the plant and directly associated facilities is consistent with the existing land use plans and zoning ordinances.

h. **Site Selection Criteria Process**

The site has been selected as a Preferred Site due to consideration of various factors including, but not limited to: site size, proximity to rail service, water resources, and environmental condition of the site (already disturbed).

i. **Water Resources**

A number of water sources are available for plant use at this location, including: recycled stormwater, Floridan Aquifer water, excess stormwater from the C-43/Caloosahatchee River, surficial aquifer water, and reclaimed water from the City of Moore Haven Publicly Owned Treatment Works (POTW).

j. **Geological Features of Site and Adjacent Areas**

The site is underlain by undifferentiated surficial sands and clays, Calooshatchee and Fort Thompson Formations, Tamiami Formation, and the Peace River Formation of the Hawthorne Group. Regionally, geologic features that are encountered within 1,000 feet of the land surface in Glades County include the Avon Park Formation, Ocala Group, Suwannee Limestone, Hawthorne Group, Tamiami, Caloosahatchee, and Fort Thompson Formations, and undifferentiated surficial sediments.

k. **Projected Water Quantities for Various Uses**

The total water requirement for the FGPP units is expected to average about 26 million gallons per day (mgpd) for process water, service water, and cooling water. The cooling water for the two proposed units would be cycled through the addition of mechanical draft cooling towers. Potable water will be provided by the City of Moore Haven and/or surficial aquifer wells.

l. **Water Supply Sources by Type**

The proposed units will use recycled stormwater, available surface or ground water, and reclaimed water as sources of cooling water for the cooling towers. The cooling towers will also act as a heat sink for the facility process water. Such needs for cooling and process water will comply with the existing South Florida Water Management District (SFWMD) regulations for consumptive water use.

m. Water Conservation Strategies Under Consideration

Impacts on the surficial aquifer would be minimized since it will only serve small water needs (i.e., service water). When available, excess stormwater will be used with the remainder of the water being obtained from the Floridan Aquifer for the source of cooling water. In addition, the entire plant site will capture and reuse stormwater and process water.

n. Water Discharges and Pollution Control

Heated water discharges will be dissipated in the cooling towers. Blowdown water from the cooling towers will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Industrial discharges will be minimized by treating and recycling equipment wash water, boiler blowdown water, and equipment area runoff. Storm water runoff will be collected and recycled in plant processes.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Fuel will be transported to the site by rail lines located adjacent to the site. The fuel will be transferred on site to a transfer tower where the fuel is unloaded into the active and inactive storage areas. The active storage area will maintain sufficient fuel for about 7 days of full operation by both units and the inactive storage area will maintain sufficient fuel for about 60 days of full operation by both units. The inactive storage area will be sealed.

The plant will produce recyclable byproducts that can be used in cement and wallboard manufacturing and other industries (fly ash, bottom ash, and synthetic gypsum). It is the intent to market all of these byproducts for beneficial reuse. However, as a contingency, the project will include construction of a synthetically lined byproduct storage area equipped with a leachate collection system where the byproducts can be routed in the event that market conditions do not enable recycling of some or all of the byproducts.

Only small quantities of other solid wastes will be generated by the FGPP units. These wastes will be managed in accordance with all local, state, and federal regulations.

p. **Air Emissions and Control Systems**

The use combustion controls and state-of-the-art pollution control equipment will minimize air emissions from these units and ensure compliance with applicable emission limiting standards. Combustion controls minimize the formation of nitrogen oxides (NO_x), and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. Post-combustion NO_x emissions will be controlled using selective catalytic reduction (SCR). Emissions of SO_2 will be controlled using wet limestone flue gas desulfurization (FGD). Particulate matter will be controlled using a fabric filter (FF). A wet electrostatic precipitator (wet ESP) will be used to control fine particulates and sulfuric acid mist. These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Further, each of these pollution controls will enhance or remove mercury. In addition, sorbent injection technology will be used to further enhance mercury removal. Taken together, the design of the FGPP units will incorporate features that will make them among the most efficient and cleanest coal-fired units in the State of Florida and the U.S.

q. **Noise Emissions and Control Systems**

A field survey and impact assessment of noise expected to be caused by construction activities at the site was conducted. Predicted noise levels are not expected to result in adverse noise impacts in the vicinity of the site during construction or operation of the facility.

r. **Status of Applications**

A Site Certification Application (SCA) for the construction and operation of the FPL Glades Power Park project under the Florida Electrical Power Plant Siting Act was filed on December 22, 2006. A Prevention of Significant Deterioration (PSD) permit application and an Underground Injection Control permit application were submitted to the Florida Department of Environmental Protection (FDEP) on December 19, 2006. A petition for approval of a Determination of Need for these units was filed with the FPSC on February 1, 2007 and a decision by the FPSC is expected by July 2007.

IV.F.2 Potential Sites for Generating Options

Eight (8) sites are currently identified as Potential Sites for near-term future generation additions to meet FPL's capacity needs.[3] These sites have been identified as Potential Sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies.

Each of these Potential Sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that will require further definition and attention. For the purpose of estimating water requirements for each site, it was assumed that either one dual-fuel (natural gas and light oil) simple cycle combustion turbine (CT) or a natural gas-fired combined cycle unit (CC) would be constructed at the Potential Sites. A simple cycle CT would require approximately 50 gallons per minute (gpm) for both process and cooling water (assuming air cooling). A CC unit would require approximately 150 gpm for service and process water and approximately 14 million gallons per day (mgd) for cooling water.

Permits are presently considered to be at least theoretically obtainable for all of these sites. No significant environmental constraints are currently known for any of these sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time FPL considers each site to be equally viable.

Potential Site # 1: Andytown Substation, Broward County

FPL has identified the Andytown Substation property in western unincorporated Broward County as a potential site for the addition of new generating capacity. Current facilities on-site include an electric substation. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections.

a. U.S. Geological Survey (USGS) Map

A USGS map of the site has been included at the end of this chapter.

[3] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites.

b. **Land Uses**

The land uses for the potential site were designated as industrial or agricultural use.

c. **Environmental Features**

Extensive low-quality wetlands are adjacent to the site. Construction and operation of a new facility on this site would not be expected to adversely affect any rare, endangered, or threatened species.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

Groundwater from the shallow aquifer or a local source of gray water have been identified as potential water sources. The Floridan Aquifer has also been identified as a potential cooling water source.

Potential Site # 2: Cape Canaveral Plant, Brevard County

This site is located on the FPL Cape Canaveral Plant property in unincorporated Brevard County. The city of Port St. Johns is located less than a mile away. The site has direct access to a four-lane highway (US 1). A rail line is located near the plant. The existing facility consists of two 400 MW (approximate) steam boiler type generating units.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site is found at the end of this chapter.

b. **Land Uses**

The land is primarily dedicated to industrial use; i.e., FPL's existing Cape Canaveral power plant Units #1 and #2. It is surrounded by grassy areas and a few acres of remnant pine forest. The land adjacent to the site is dedicated to light commercial and residential use.

c. **Environmental Features**

There are no significant environmental features on the site.

d. Water Quantities

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. Supply Sources

Existing on-site wells, reclaimed water, public supply water, and the existing once-through cooling water system are potential water supply sources.

Potential Site # 3: Desoto County Greenfield Site

This site is a "Greenfield" undeveloped site located on a 13,515 acre property in unincorporated Desoto County. The site is adjacent to portions of the Peace River and lies on both the east and west sides of US Hwy 17 approximately 3 to 5 miles north of the City of Arcadia. There are currently no facilities on the site.

a. U.S. Geological Survey (USGS) Map

A USGS map of the site is found at the end of this chapter.

b. Land Uses

The land on the site is currently dedicated to agricultural use (sod farming, cattle grazing, and truck crops).

c. Environmental Features

Developed portions of the adjacent properties are primarily agricultural (sod farms, citrus groves, and cattle grazing). Undeveloped portions include mixed scrub with some hardwoods and a few small isolated wetlands.

d. Water Quantities

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. Supply Sources

Groundwater from the upper and lower Floridan Aquifer, or if available and practicable, a local source of gray water are potential water sources.

Potential Site # 4: Fort Myers Plant Site, Lee County

This site is located on FPL's existing 460-acre Fort Myers property. The existing facilities on the site include one 1,440 MW (approximate) combined cycle unit, 12 gas turbines, each with an approximate capacity of 54 MW, and 2 combustion turbines, each with an approximate capacity of 160 MW.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the Fort Myers plant site is found at the end of this chapter.

b. **Land Uses**

The land on the site is currently dedicated to industrial use with surrounding grassy and landscaped areas. Much of the site has been used in recent years for direct plant construction activities. The adjacent land uses include light commercial and retail to the east of the property, plus some residential areas located toward the west.

c. **Environmental Features**

Mixed scrub with some hardwoods can be found to the east and further south.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

The available water source is the Caloosahatchee River and the available groundwater source is the sandstone aquifer.

Potential Site # 5: Lauderdale Plant, Broward County

The Lauderdale site is located in Eastern Broward County approximately 5 miles inland from Dania Beach and less than 2 miles west of Ft. Lauderdale International Airport. The site is bounded on the south by Dania Cutoff Canal, the east by SW 30th Avenue, and the North by I-595.

The existing approximately 1,700 MW of generating capacity at FPL's Lauderdale site occupies a portion of the approximately 210 acres that are wholly owned by FPL. The generating capacity is made up of two combined cycle units (Units #4 and #5), and 24 simple cycle gas turbine (GT) units.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site is found at the end of this chapter.

b. **Land Uses**

The existing power plant facilities are located on approximately 130 acres. The existing site has been in use since the 1920s and is adjacent to a county resource recovery project.

c. **Environmental Features**

To the north of the power plant is an area of mixed uplands with a scattering of small wetlands.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

Existing groundwater or the municipal water supply are potential water sources.

Potential Site # 6: Martin Plant, Martin County

The Martin site is located approximately 40 miles northwest of West Palm Beach, 5 miles east of Lake Okeechobee, and 7 miles northwest of Indiantown in Martin County, Florida. The site is bounded on the west by the Florida East Coast Railway (FEC) and the adjacent South Florida Water Management District (SFWMD) L-65 Canal, on the south by the St. Lucie Canal (C-44 or Okeechobee Waterway), and on the northeast by SR 710 and the adjacent CSX Railroad.

The existing approximately 3,700 MW of generating capacity at FPL's Martin site occupies a portion of the approximately 11,300 acres that are wholly owned by FPL. The generating capacity is made up of two steam units (Units #1 and #2), plus three combined cycle units (Units #3, #4, and #8). The site includes a 6,800-acre cooling pond (6,500 acres of water surface and 300 acres of dike area) and approximately 300 acres for the existing power plant units and related facilities.

a. **U.S. Geological Survey (USGS) Map**

A USGS map for the site is found at the end of this chapter.

b. **Land Uses**

A major portion of the site consists of a 6,800-acre cooling pond. The existing power plant facilities are located on approximately 300 acres.

c. **Environmental Features**

To the east of the power plant there is an area of mixed pine flat wood with a scattering of small wetlands. To the north of the cooling pond there is a 1,200-acre area which has been set aside as a mitigation area. There is a peninsula of wetland forest on the West Side of the reservoir that is named the Barley Barber Swamp. The Barley Barber Swap encompasses 400 acres and is preserved as a natural area. There is also a 10-kilowatt (kW) photovoltaic energy facility at the south end of this site.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

Surface water resources currently used at the Martin facility include the cooling pond which takes its water from the St. Lucie canal. The available ground water resource is the surficial aquifer system which is used as a source of potable and service water.

Potential Site # 7: Port Everglades Plant, Broward County

This site is located on the 94-acre FPL Port Everglades plant site in Port Everglades, Broward County. The site has convenient access to State Road (SR) 84 and I- 595. Rail line is located near the plant. The existing plant consists of four steam boiler generating units: two 200 MW (approximate) and two 400 MW (approximate) sized units. The four steam boilers are capable of firing residual fuel oil, natural gas, or a combination of both. The site also is home to twelve simple cycle gas turbine (GT) peaking units of 30 MW (approximate) each. The GT's are part of the Gas Turbine Power Park that is made up of 24 GT's at the Lauderdale Plant site and the twelve GTs at the Port Everglades site. The GT's are capable of firing either natural gas or liquid fuel.

a. U.S. Geological Survey (USGS) Map

A map of the site is found at the end of this chapter.

b. Land Uses

The land on this site is primarily industrial. The adjacent land uses are port facilities and associated industrial activities, oil storage, cruise ships, and light commercial.

c. Environmental Features

The shoreline of the intake and discharge canal banks are vegetated with fringing mangrove, with some open, maintained grass areas on the side.

d. Water Quantities

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. Supply Sources

Existing groundwater or the municipal water supply could be used for industrial process and makeup water. Industrial cooling water needs could be met using the existing one-through cooling water system. We believe these sources would provide sufficient water for either simple cycle or combined cycle generation.

Potential Site # 8: Riviera Plant, Palm Beach County

This site is located on the FPL Riviera Plant property in Riviera Beach, Palm Beach County. The site has direct access to a four-lane highway, US 1, and barge access is available. A rail line is located near the plant. The facility currently houses two operational 300 MW (approximate) steam boiler generating units and one retired 50 MW generating unit.

a. U.S. Geological Survey (USGS) Map

A USGS map of the site is found at the end of this chapter.

b. Land Uses

The land on the site is primarily covered by the existing generation facilities. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development.

c. Environmental Features

The site is located on the Intra-coastal waterway near the Lake Worth Inlet which provides a warm water refugia for manatees during cold winter days. The plant property contains some open, maintained grass area.

d. Water Quantities

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. Supply Sources

The existing municipal water supply could be used for industrial processing water. Industrial cooling water needs could be met using the existing once-through cooling water system. For once-through cooling water, FPL could use Lake Worth as a source of water. We believe these sources would provide sufficient water for either simple cycle or combined cycle generation.

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Environmental and Land Use Information: Supplemental Information

Preferred Site: Turkey Point

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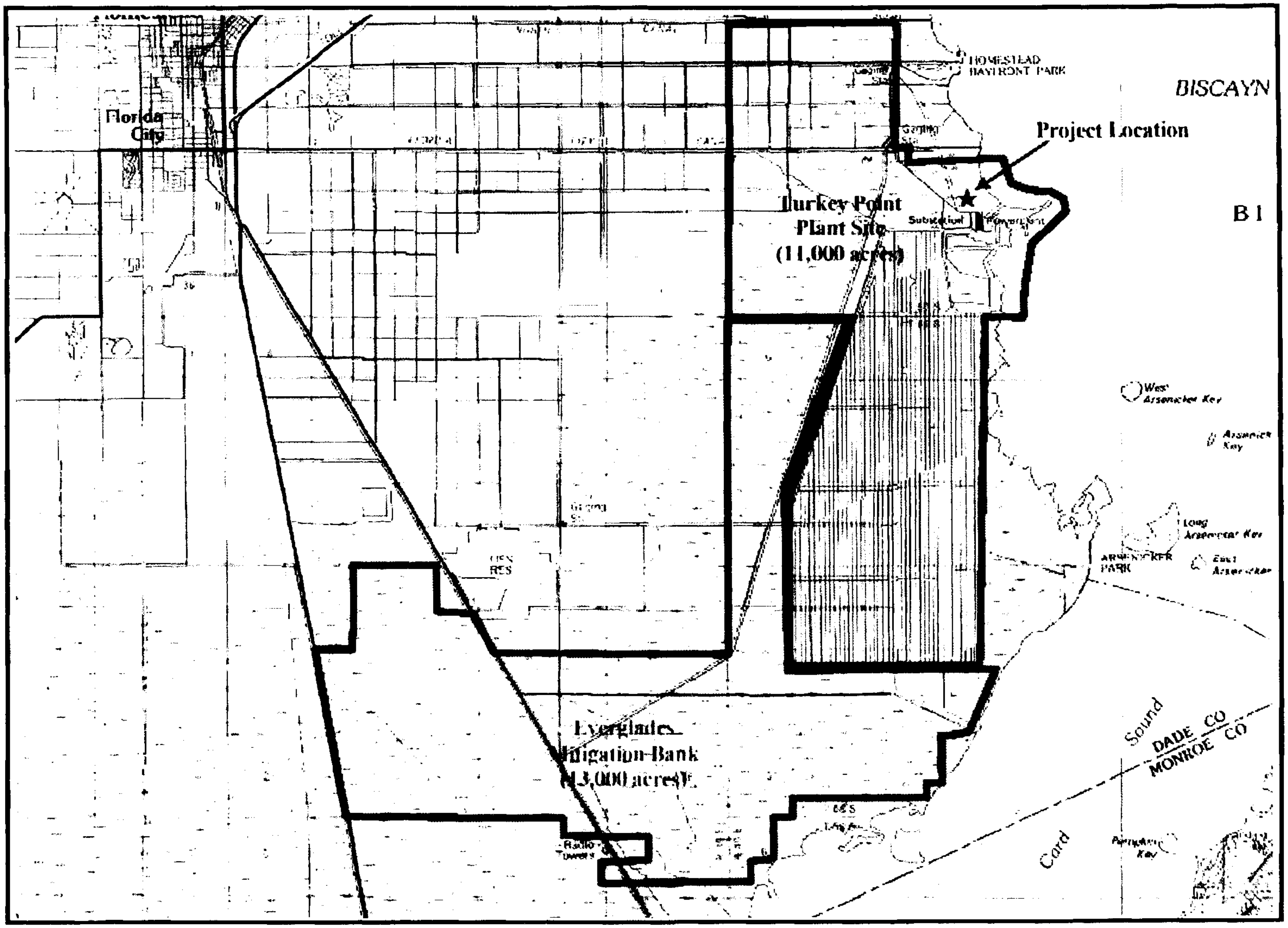
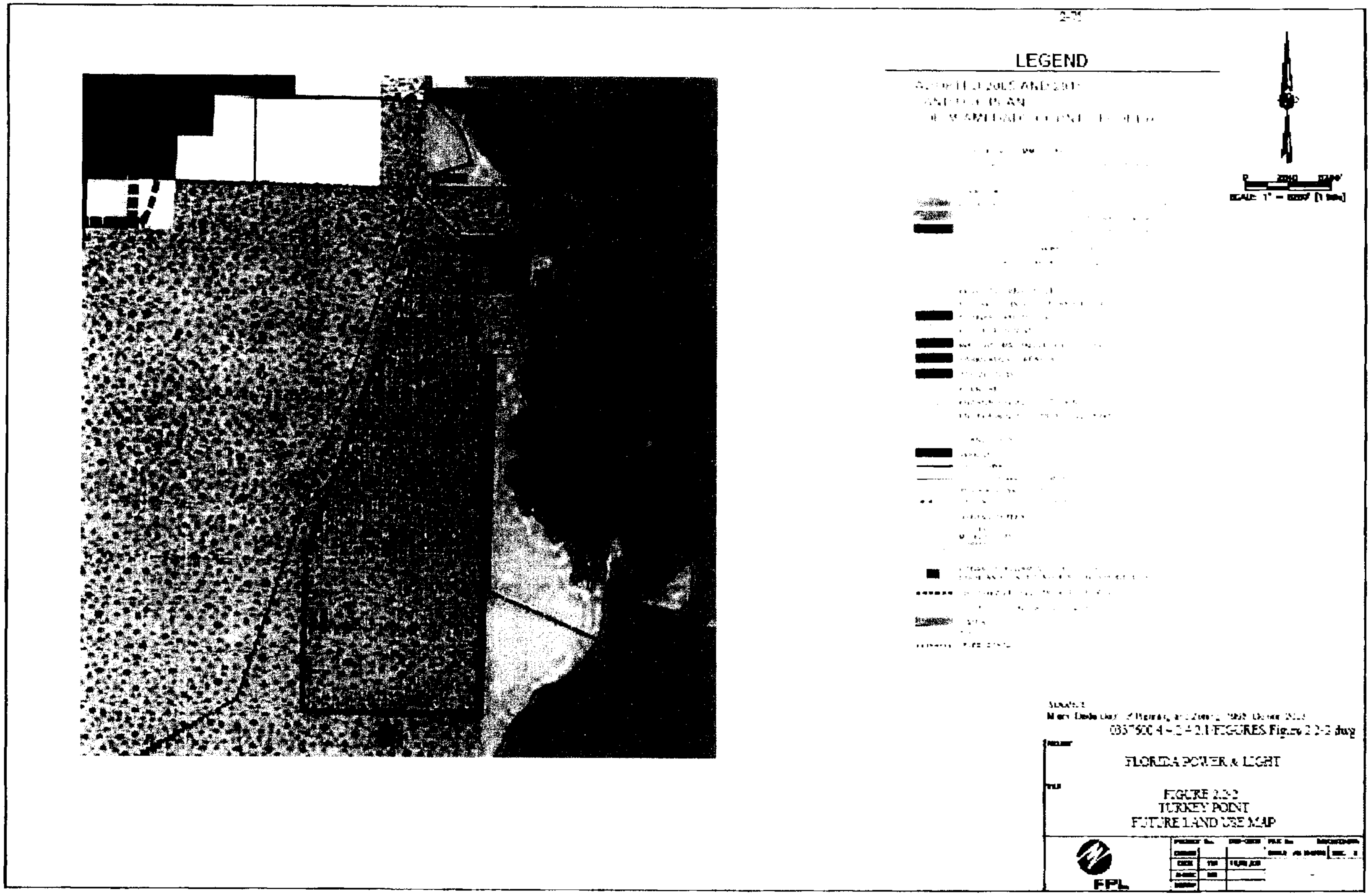
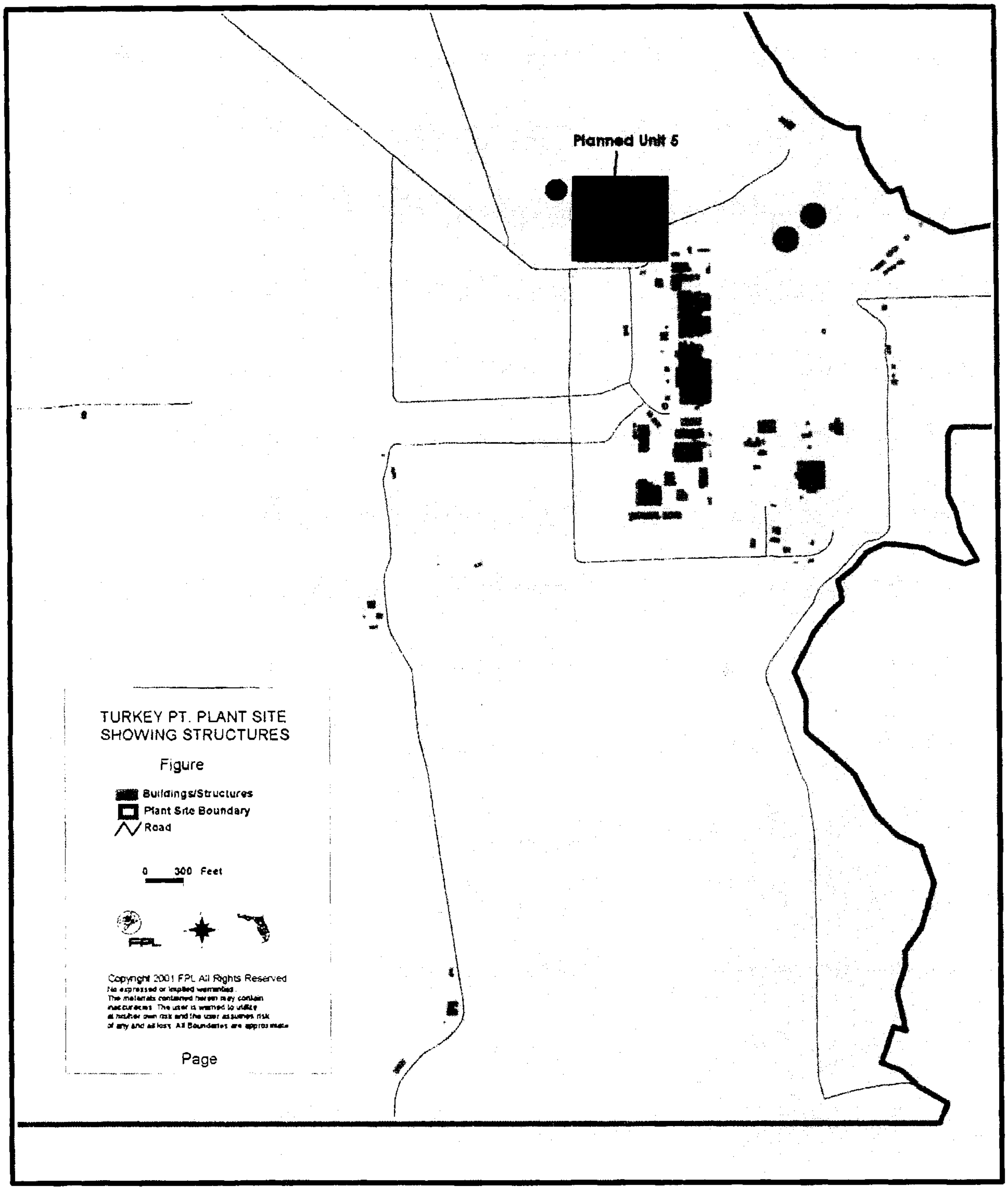

Florida City
HOMESTEAD BAYFRONT PARK
BISCAYN
Project Location
Turkey Point Plant Site (11,000 acres)
B 1
Everglades Mitigation Bank (13,000 acres)
DADE CO
MONROE CO
Card
Sound


LEGEND
FLORIDA POWER & LIGHT
FIGURE 2.2-2
TURKEY POINT
FUTURE LAND USE MAP
FPL


Planned Unit 5
TURKEY PT. PLANT SITE
SHOWING STRUCTURES
Figure
Buildings/Structures
Plant Site Boundary
Road
0 300 Feet
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Environmental and Land Use Information: Supplemental Information

Preferred Site: West County Energy Center

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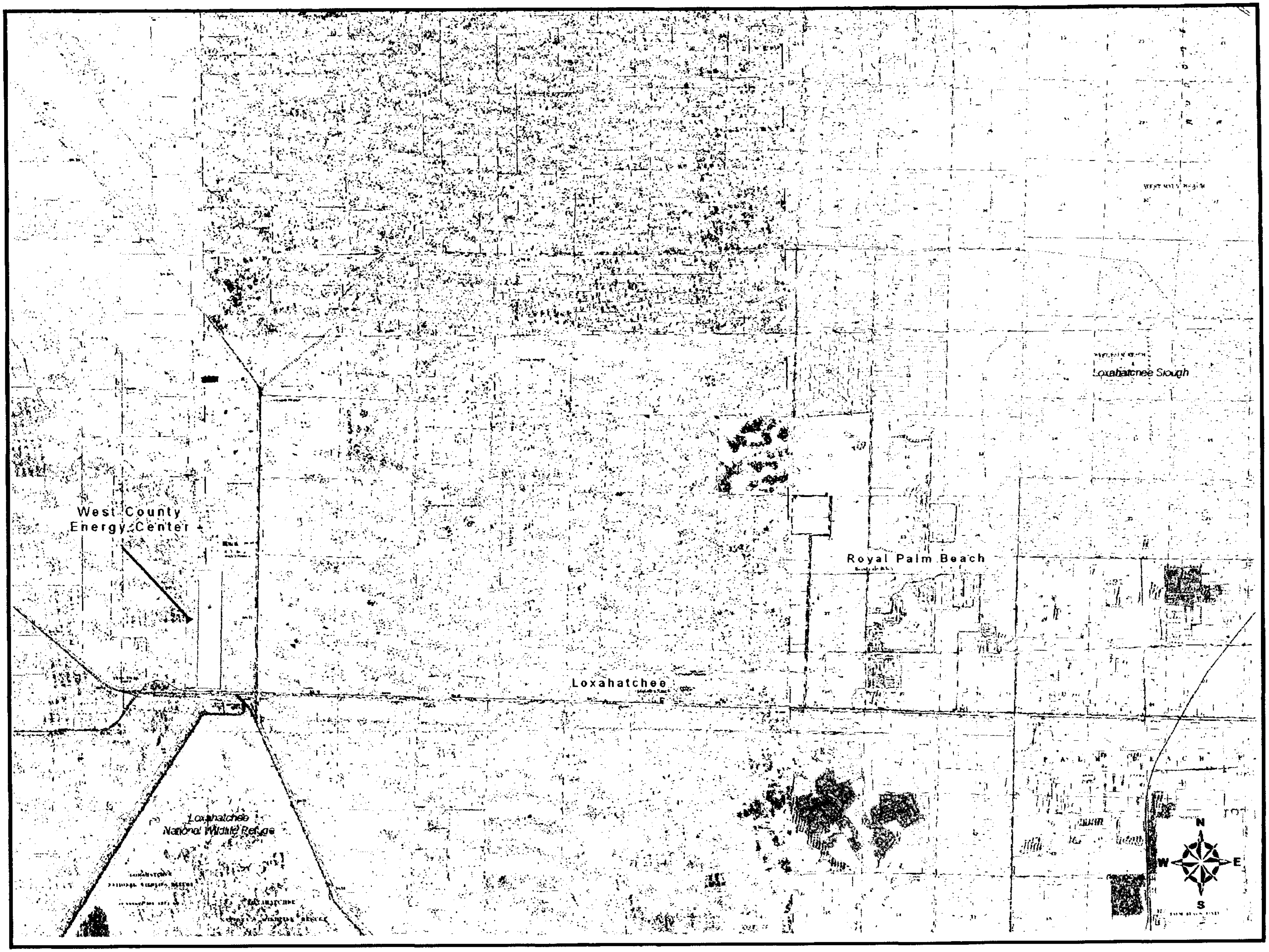
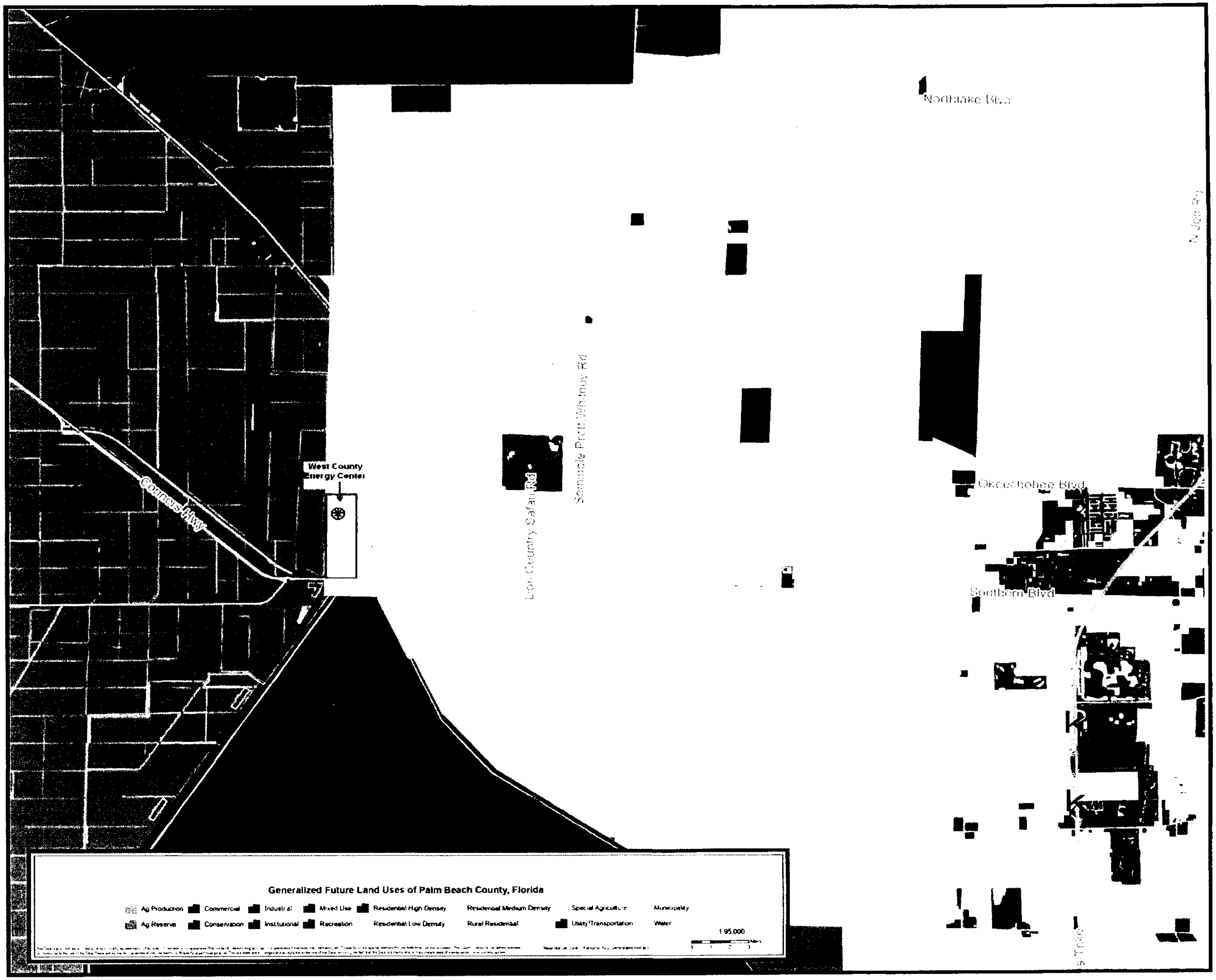
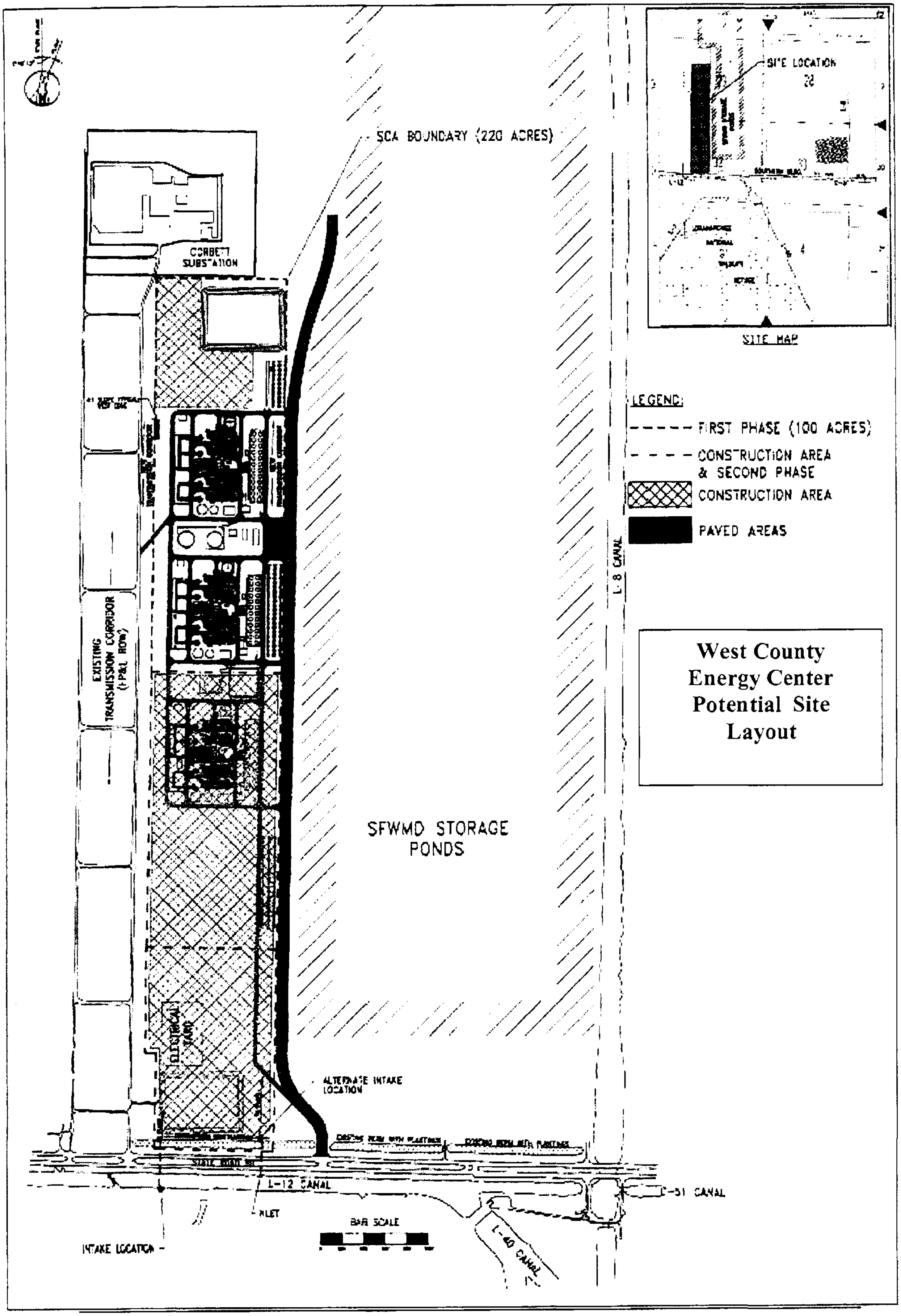

West County
Energy Center
Royal Palm Beach
Loxahatchee
Loxahatchee Slough
Loxahatchee
National Wildlife Refuge
N
W
E
S


Northlake Blvd
Okeechobee Blvd
Southern Blvd
Conners Hwy
Lion Country Safari Rd
Seminole Pratt Whitney Rd
West County Energy Center
Generalized Future Land Uses of Palm Beach County, Florida
Ag Production
Commercial
Industrial
Mixed Use
Residential High Density
Residential Medium Density
Special Agriculture
Municipality
Ag Reserve
Conservation
Institutional
Recreation
Residential Low Density
Rural Residential
Utility/Transportation
Water



West County Energy Center Potential Site Layout

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Environmental and Land Use Information: Supplemental Information

Preferred Site: FPL Glades Power Park

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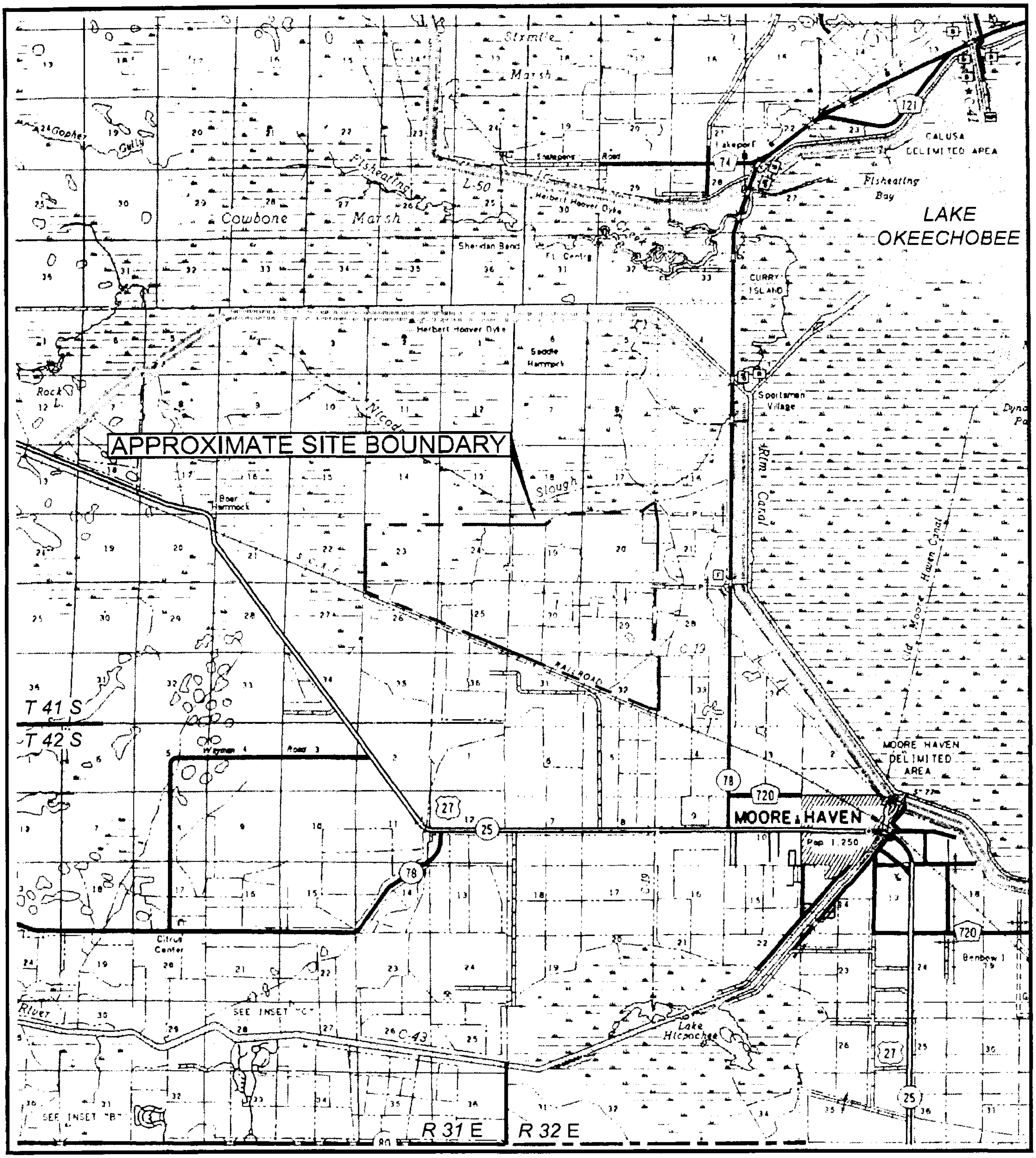
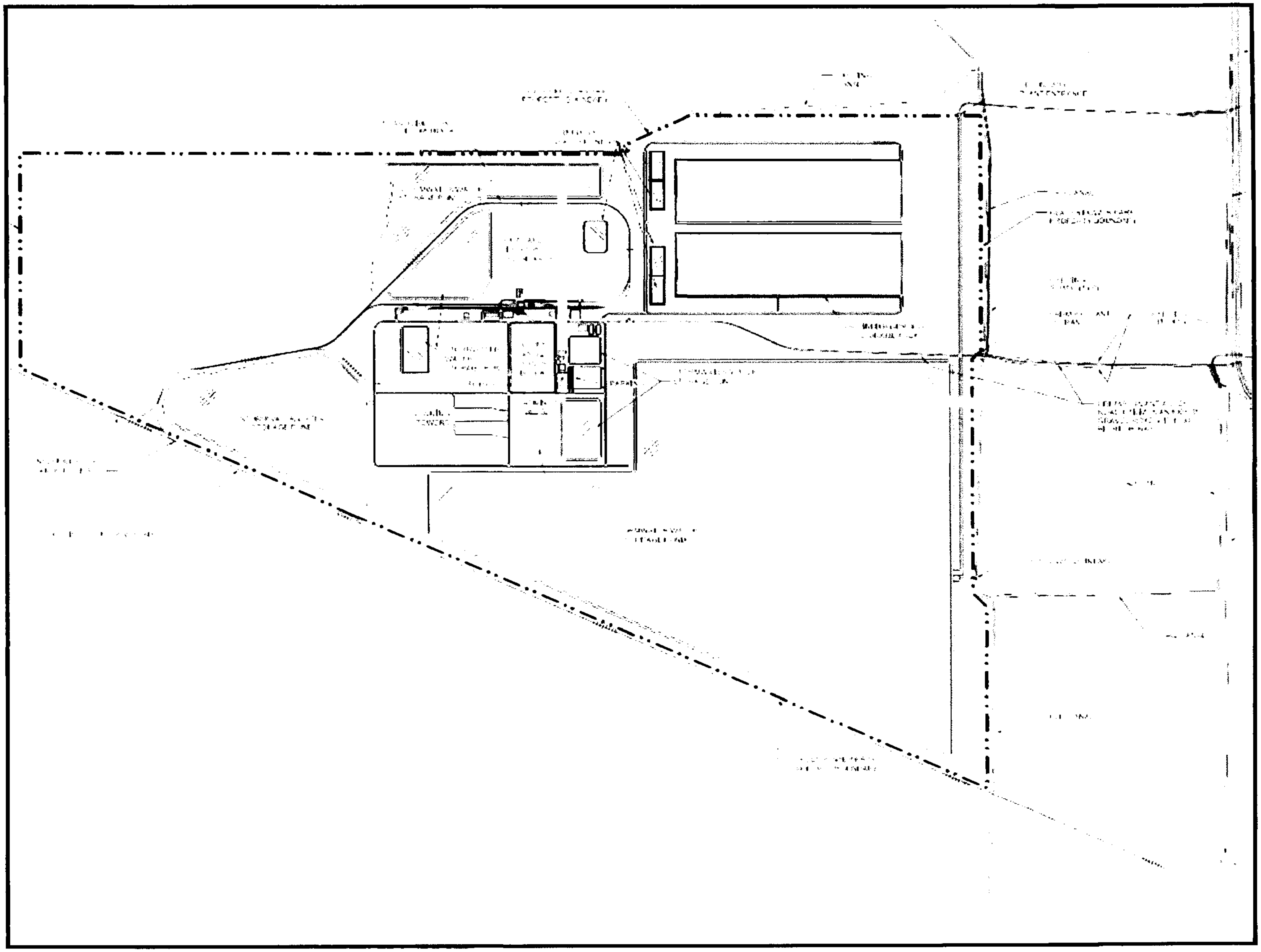

APPROXIMATE SITE BOUNDARY
LAKE
OKEECHOBEE
MOORE HAVEN
Pop. 1,250
MOORE HAVEN
DELIMITED
AREA
CALUSA
DELIMITED AREA
Fisheating
Bay
Cowbone
Marsh
Fisheating
L-50
Herbert Hoover Dyke
Lakeport
CURRY
ISLAND
Sportsman
Village
Rim Canal
Slough
Boar
Hammock
Saddle
Hammock
Citrus
Center
SEE INSET "C"
SEE INSET "B"
C-43
River
Lake
Hicpochee
Old Moore Haven Canal
RAILROAD
T 41 S
T 42 S
R 31 E
R 32 E
Gopher
Gully
Rock
L.
Strmile
Marsh
Sheridan Bend
Ft. Centre
Benbow


FPL Glades Power Park
Site



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Environmental and Land Use Information: Supplemental Information

Potential Site: Andytown

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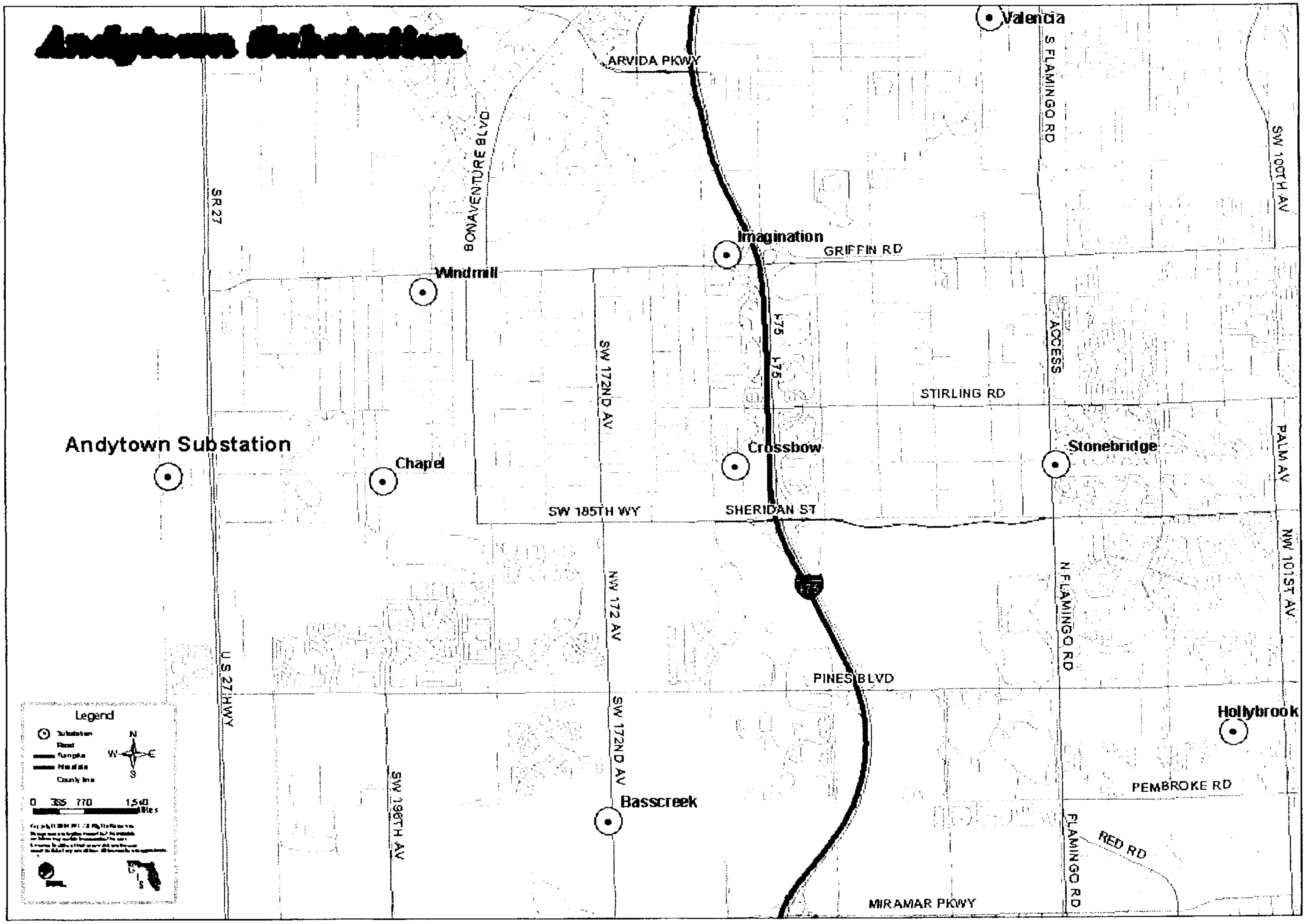
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SR 27
Imagination
GRIFFIN RD
Windmill
I-75
ACCESS
SW 172ND AV
STIRLING RD
PALM AV
Andytown Substation
Chapel
Crossbow
Stonebridge
SW 185TH WY
SHERIDAN ST
NW 101ST AV
N FLAMINGO RD
NW 172 AV
US 27 HWY
PINES BLVD
SW 172ND AV
Hollybrook
SW 196TH AV
PEMBROKE RD
Basscreek
RED RD
FLAMINGO RD
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Environmental and Land Use Information: Supplemental Information

Potential Site: Cape Canaveral

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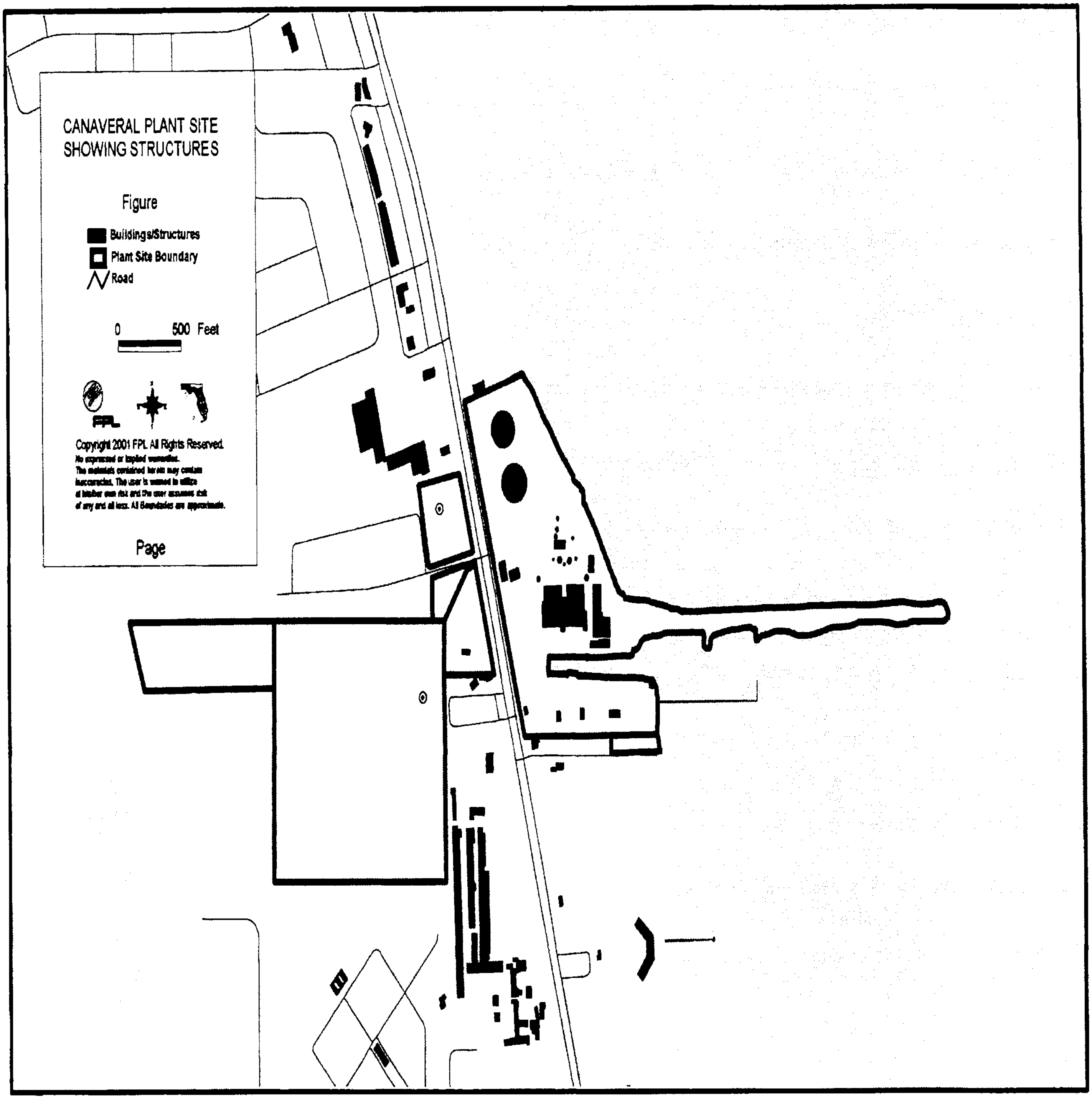
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Figure
Buildings/Structures
Plant Site Boundary
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Environmental and Land Use Information: Supplemental Information

Potential Site: Desoto

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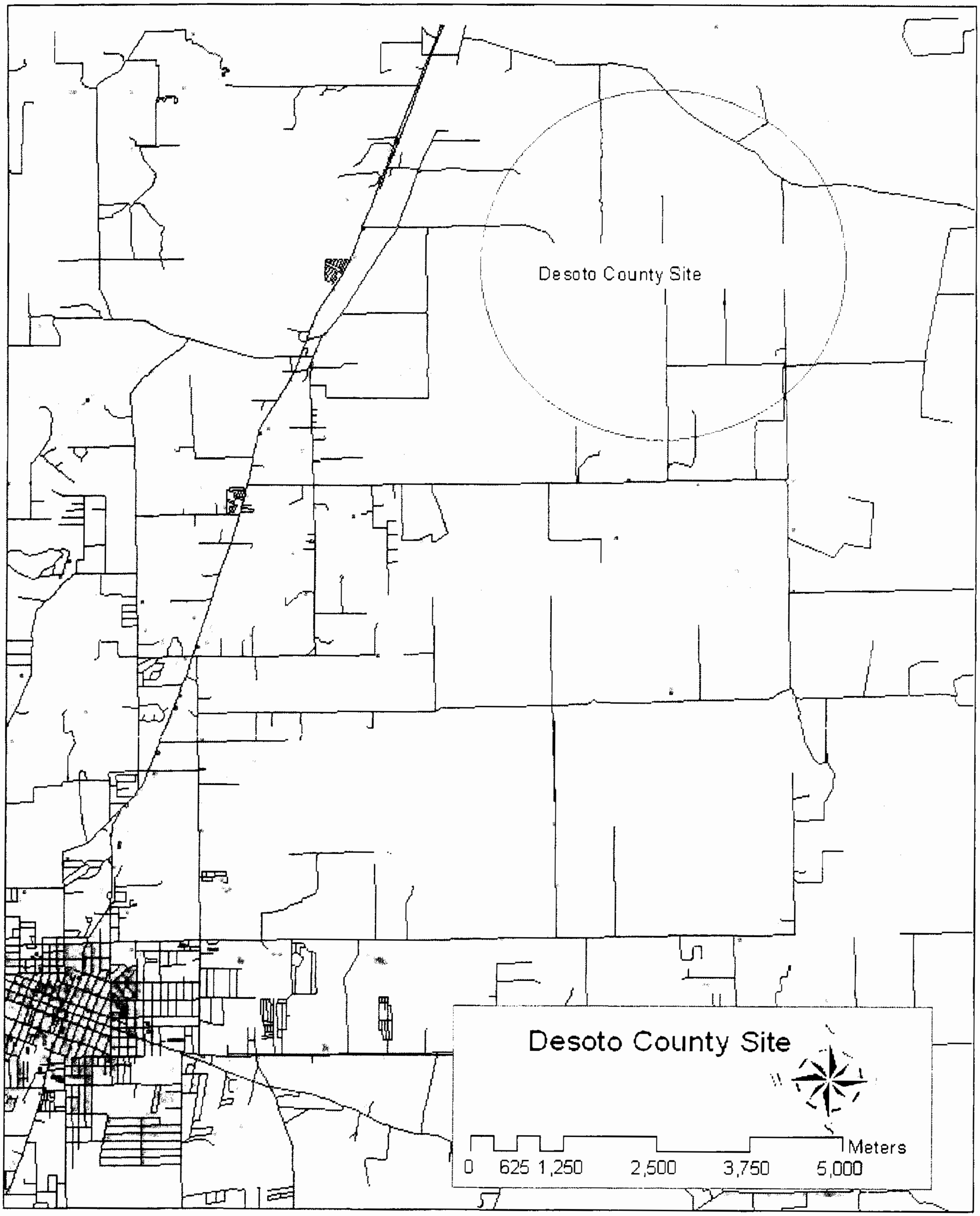
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Environmental and Land Use Information: Supplemental Information

Potential Site: Ft. Myers

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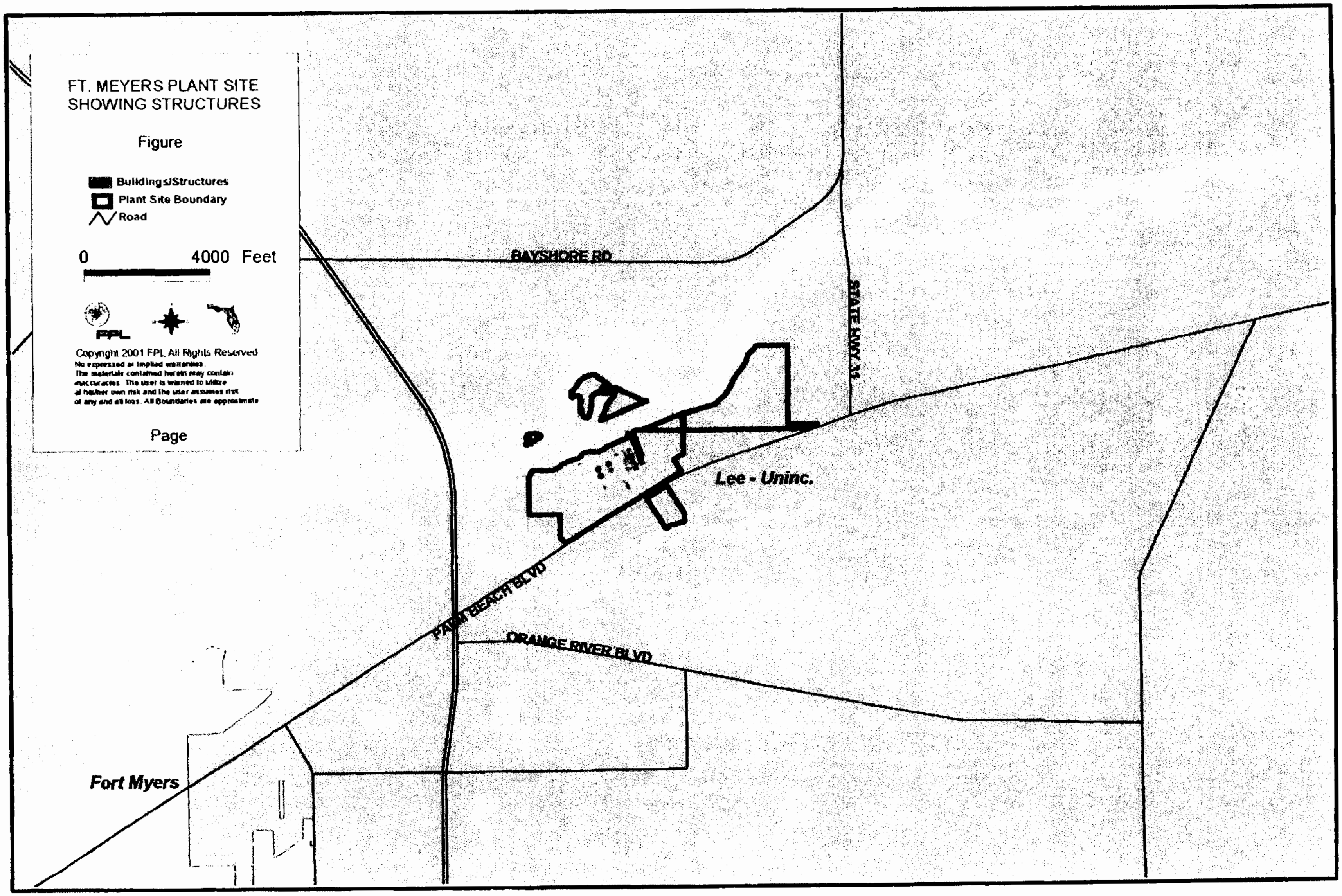
FT. MEYERS PLANT SITE
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Buildings/Structures
Plant Site Boundary
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Page
BAYSHORE RD
STATE HWY 31
Lee - Uninc.
PALM BEACH BLVD
ORANGE RIVER BLVD
Fort Myers

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Environmental and Land Use Information: Supplemental Information

Potential Site: Lauderdale

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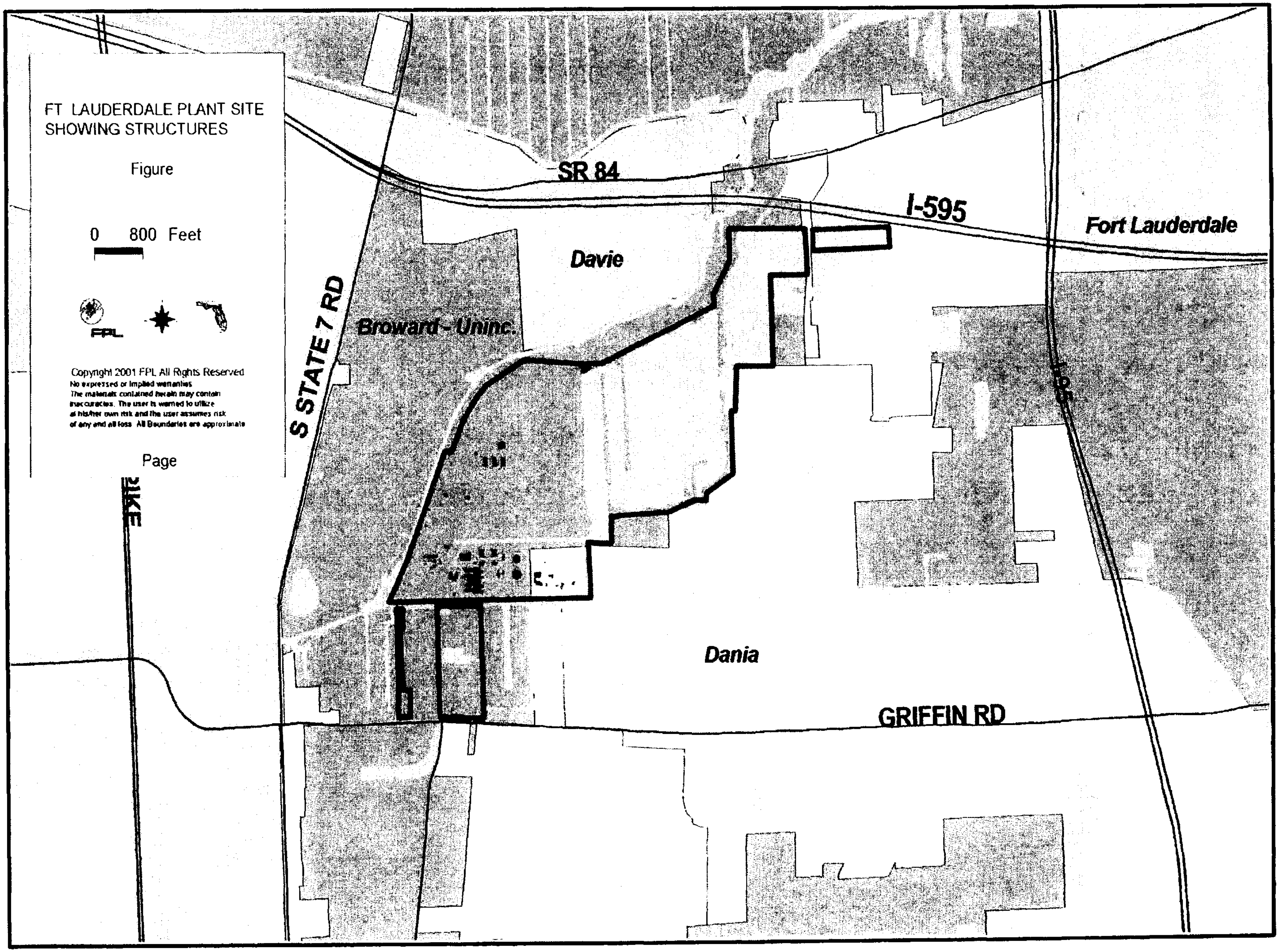
Florida Power & Light Company



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Environmental and Land Use Information: Supplemental Information

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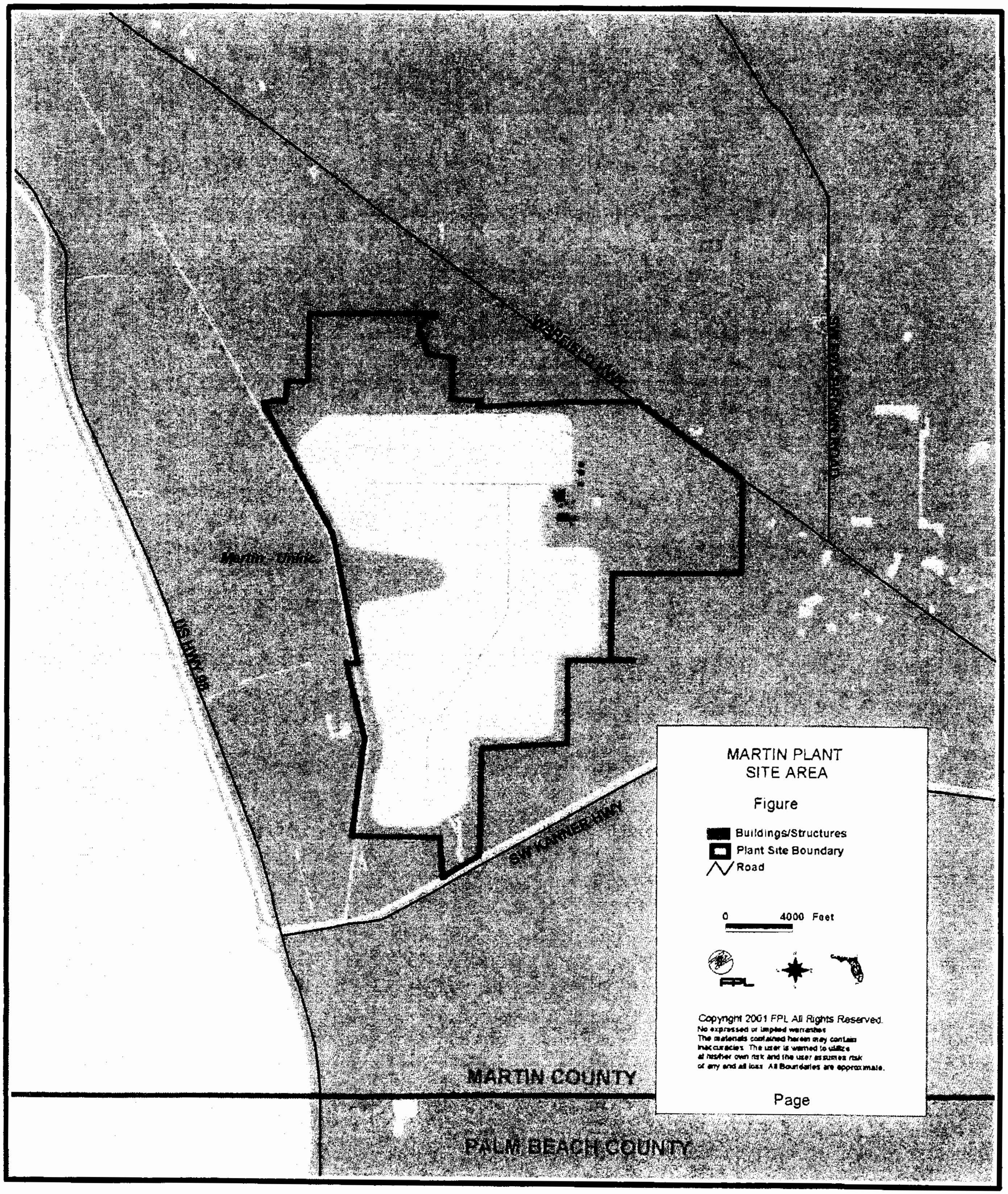
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SW KANNER HWY
MARTIN COUNTY
PALM BEACH COUNTY
MARTIN PLANT
SITE AREA
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Buildings/Structures
Plant Site Boundary
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Environmental and Land Use Information: Supplemental Information

Potential Site: Port Everglades

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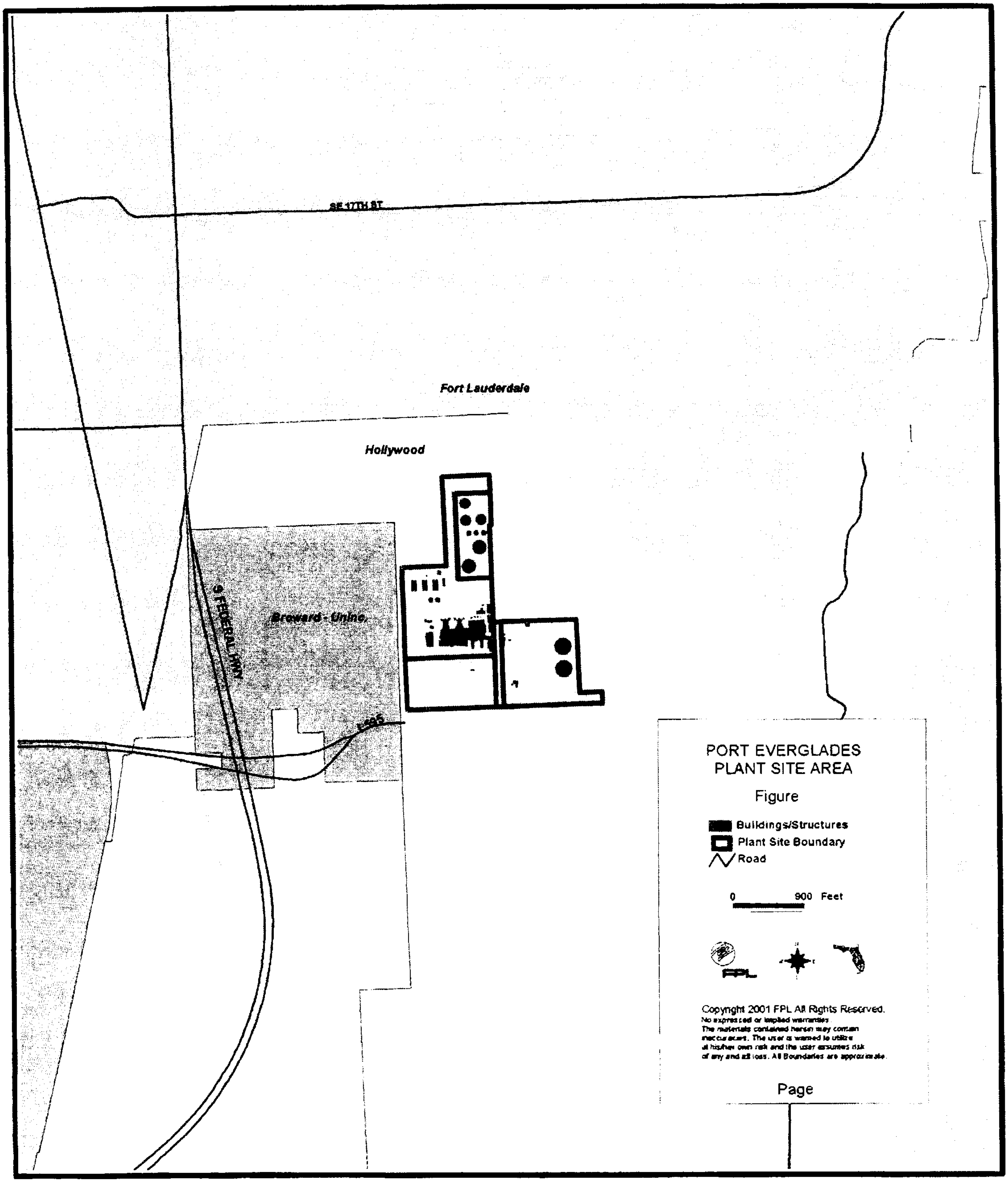
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Fort Lauderdale
Hollywood
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Broward - Uninc.
PORT EVERGLADES
PLANT SITE AREA
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Buildings/Structures
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Environmental and Land Use Information: Supplemental Information

Potential Site: Riviera Plant

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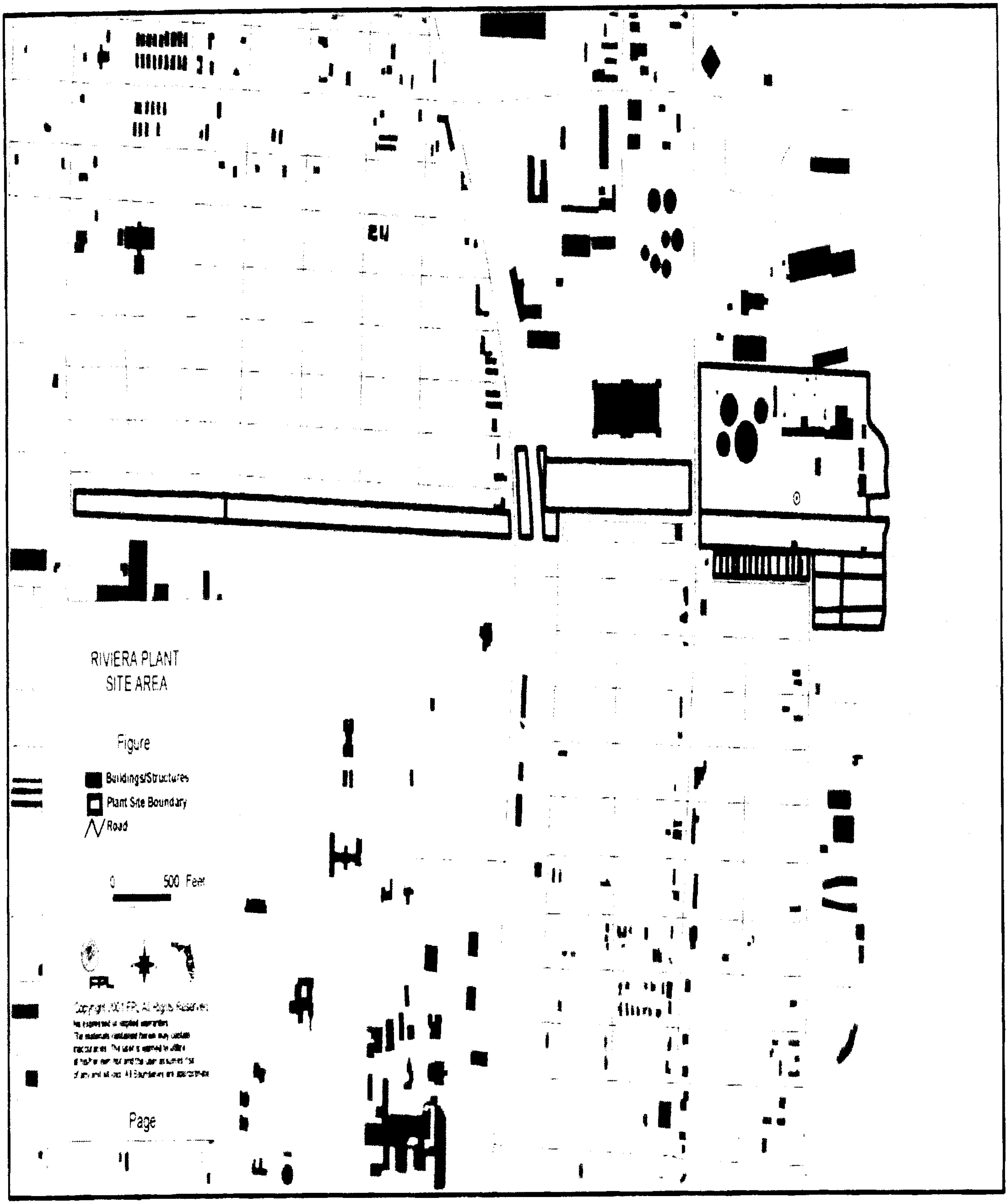
RIVIERA PLANT
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CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information". These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important since they affect the development of assumptions for the amount of external assistance which is available to the FPL system and the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new units that may not adversely impact such limitations. The internal transmission limitations are also addressed by developing the direct costs for siting new units at different locations and by evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system. Both site- and system-related transmission costs are developed for each different unit/unit location option or groups of options.

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's planned transmission facilities to interconnect and integrate FPL's resource plans and those that must be certified under the Transmission Line Siting Act are presented in Section III.E.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements for the FPL system.[4]

In its 2006 reserve planning work, FPL utilized an updated load forecast. No sensitivity tests to this updated load forecast were utilized.

[4] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis, the lowest rate basis and the lowest system revenue requirements basis are identical. In such cases FPL evaluates options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its fuel price forecasts are discussed in Chapter III of this document. FPL's 2006 resource planning work utilized four different fuel cost forecasts (and four different environmental compliance cost forecasts). A detailed discussion of these forecasts, and their impacts on the generation expansion plan, are presented in FPL's Petition To Determine Need for FPL's Glades Power Park Units #1 and #2 Electrical Power Plant filed February 1, 2007.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item #3, FPL used four fuel forecasts in the comparative economic analysis of clean coal generation. While these forecasts did not represent a constant cost differential between oil/gas and coal, four different costs differentials were represented in these forecasts.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 and Schedule 8 present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options which were considered in the resource planning work. A summary of this information for the new capacity options FPL projects to add over the planning horizon is presented on the Schedule 9 forms.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

The key financial assumptions used in FPL's most recent resource planning work were a 44.2% debt and 55.8% equity FPL capital structure, projected debt cost of 7.2%, and an equity return of 12.3%. These assumptions resulted in a weighted average cost of capital of 10.05% and an after-tax discount rate of 8.82%. FPL did not test the sensitivity of its resource plan to varying financial assumptions.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item #2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective are identical when DSM levels are unchanged between competing plans. Therefore, in planning work in which DSM levels were unchanged, the equivalent cumulative present value of revenue requirements perspective was utilized.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses two system reliability criteria in its resource planning work. One of these is a minimum 20% Summer and Winter reserve margin. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the reliability standards established by the North American Electric Reliability Council (NERC) in its *Reliability Standards*. FPL has applied these planning criteria in a manner consistent with prudent utility practice. The *NERC Reliability Standards* are available on the internet (http://www.nerc.com).

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Transmission Facility Rating Methodology* document that are also available on the internet (http://floasis.siemens-asp.com/OASIS/FPL/INFO.HTM).

The normal voltage criteria for FPL stations is given below:

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09

There may be isolated cases for which FPL may determine it prudent to deviate from the general criteria stated above. The overall potential impact on customers and the probability of an outage actually occurring, as well as other factors, would influence the decision in such cases.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The impact of FPL's DSM Programs on demand and energy consumption is revised periodically. Engineering models, calibrated with field-metered data, are updated when significant efficiency changes occur in the marketplace. Participation trends are tracked for all of the FPL DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants.

Survey data is collected from non-participants in order to establish the baseline efficiency. Participant data is compared against non-participant data to establish the demand and energy saving benefits of the utility program versus what would be installed in the absence of the program. Finally, FPL is careful to claim only program savings for the average life of the installed efficiency measure. For these DSM measures which involve the utilization of load management, FPL conducts periodic tests of the load control equipment to ensure that it is functioning correctly.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

Among the strategic factors FPL typically considers when choosing between resource options are the following: (1) fuel diversity; (2) technology risk; (3) environmental risk, and (4) site feasibility. The consideration of these factors may include both economic and non-economic aspects.

Fuel diversity relates to two concepts, the diversity of sources of fuel (e.g., coal vs. oil vs. natural gas), and the diversity of supply for a single fuel source (for example alternative pipeline suppliers for natural gas). All other factors being equal, supply options that increase diversity in fuel source and/or supply would be favored over those that do not.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology which has not achieved general commercial acceptance has a higher risk than a technology in wide use and, therefore, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the FPL system, including environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for a plan are those which minimize environmental impacts through highly efficient fuel use and state of the art controls (e.g., advanced technology coal technologies versus conventional pulverized coal).

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decisions, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As has been previously discussed, elements of FPL's capacity additions include the construction of new generating capacity at an existing site; Turkey Point and at a new site; West County Energy Center. These generation construction projects were selected after evaluating competing bids received in response to Requests for Proposals (RFP) issued by FPL. The FPSC subsequently approved FPL's decision to construct these new combined cycle units in Determination of Need dockets.

In 2006 FPL sought, and was granted by the FPSC, a waiver from the RFP requirement of the Bid Rule in order to seek approval for advanced technology coal generation as early as possible. FPL filed its Need petition for two advanced technology coal units with the FPSC on February 1, 2007.

The construction capacity addition decisions projected in this document for 2015 and beyond are expected to be conducted in a manner consistent with the Commission's Bid Rule.

Identification of self-build options beyond those units already approved by the FPSC and Governor and Siting Board, or units for which FPL is currently seeking approval, in FPL's Site Plan is not an indication that FPL has pre-judged any capacity solicitation it may conduct. The identification of future capacity units is required of FPL and represents those alternatives that appear to be FPL's best, most cost-effective self-build options at this time. FPL reserves the right to refine its planning analyses and to identify other self-build options. Such refined analyses have the potential to yield a variety of self-build options, some of which might not require an RFP. If an RFP is issued for supply-side resources, FPL reserves the right to choose the best alternative for its customers, even if that option is not an FPL self-build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

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(1) FPL has identified the need for a new 230kV transmission line (by December 2008) that requires certification under the Transmission Line Siting Act. The new line will connect FPL's St. Johns Substation to FPL's proposed Pringle Substation (also shown on Table III.E.1). The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

(2) FPL has identified the need for a new 230kV transmission line (by December 2011) that requires certification under the Transmission Line Siting Act. The new line will connect FPL's Manatee Substation to FPL's proposed BobWhite Substation (also shown on Table III.E.1). The construction of this line is necessary to serve existing and future customers in the Manatee and Sarasota areas in a reliable and effective manner.

(3) Additionally, FPL has identified the need for a new 230kV transmission line (by June 2012) that requires certification under the Transmission Line Siting Act. The new line will connect a future FPL substation in the Grove Area (TBD) to FPL's Sweatt Substation (also shown on Table III.E.1). The construction of this line is necessary to serve existing and future customers in the Okeechobee and St. Lucie areas in a reliable and effective manner.

FPL

April 1, 2008

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COMMISSION CLERK

VIA HAND DELIVERY

Ms. Ann Cole
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

080000

Re: 2008 – 2017 Ten Year Site Plan

Dear Ms. Cole:

In accordance with Chapter 186 (Section 186.801 – Ten Year Plans) of the Florida Statues, enclosed for filing are twenty-five (25) copies of Florida Power & Light Company's 2008 – 2017 Ten Year Power Plant Site Plan.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Sabrina Spradley
Senior Regulatory Affairs Analyst
(305) 552-4416

SS:ec
Enclosures

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 43
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-H

DOCUMENT NUMBER-DATE
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FPSC-COMMISSION CLERK

Ten Year Power Plant Site Plan
2008 – 2017

FPL

FPL

Ten Year Power Plant Site Plan

2008-2017

Submitted To:

**Florida Public
Service Commission**

**Miami, Florida
April 2008**

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Table of Contents

List of Figures and Tables

Potential Sites

List of Schedules

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Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan. This plan includes an estimate of the utility's electric power generating needs, a projection of how those needs will be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. This information is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

This Ten Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) integrated resource planning (IRP) analyses that were carried out in 2007 and that were on-going in the first quarter of 2008. The forecasted information presented in this plan addresses the 2008–2017 time frame.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information, especially for the latter years of the ten-year time horizon, and is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, based on FPL's IRP work in 2007 and

early 2008.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as preferred and potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve “discussion items” which pertain to additional information that is to be included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	***Abbreviation***	***Definition***
Unit Type	BIT	Bituminous Coal
	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	IC	Internal Combustion
	NP	Nuclear Power
	ST	Steam Unit
Fuel Type	UR	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	P	Planned Unit
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete

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Executive Summary

Florida Power & Light Company's (FPL) 2008 Ten Year Power Plant Site Plan (Site Plan) presents FPL's current plans to increase its electric generation capability (owned or purchased) as part of its efforts to meet its projected incremental resource needs for the 2008-2017 time period. By design, the primary focus of this document is on supply side additions; i.e., electric generation capability. The supply side additions discussed in this document are resources projected to be needed after accounting for FPL's extensive demand side management (DSM) additions.

The resource plan that is presented in FPL's 2008 Site Plan contains some similarities to the resource plan presented in FPL's 2007 Site Plan, especially for the early years of the ten-year period. However, there are also some significant changes in the current resource plan.

I. Similarities to the Resource Plan Presented in the 2007 Site Plan:

There are two key similarities in the current resource plan presented in this document compared to the resource plan presented in the 2007 Site Plan. One similarity is the addition of new generating units in 2009 and 2010. In each of these years, FPL will be adding one 1,219 MW (Summer) combined cycle (CC) unit in western Palm Beach County. The site for these units is named the West County Energy Center (WCEC) and these units are identified as West County Energy Center Units 1 and 2 (WCEC 1 and 2). Both of these CC units were approved by the Florida Public Service Commission (FPSC) in June 2006. FPL's applications for site certification for these units under the Florida Electric Power Plant Siting Act were approved by the Governor and the Cabinet serving as the Siting Board in December 2006.

The other key similarity to the resource plan presented in the 2007 Site Plan is FPL's continuing significant efforts to implement cost-effective demand side management (DSM). These efforts include meeting FPL's approved DSM Goals through 2014, implementing additional cost-effective DSM through 2014 that was identified by FPL after the DSM Goals were established, and a projection of continued DSM additions in 2015 through 2017 at an annual implementation rate commensurate with that in the years leading up to 2014. These DSM efforts are projected to add approximately 1,539 MW of cost-effective DSM from August 2006 through August 2017. These 1,539 MW of additional DSM will avoid the need for approximately 1,847 MW of additional generating capacity that otherwise would be needed to continue to meet FPL's 20% reserve margin planning criterion. Through these DSM efforts FPL will continue to build upon its industry-leading position in both energy efficiency DSM programs and overall DSM achievement, as reported annually by the U.S. Department of Energy.

II. Changes From the Resource Plan Presented in the 2007 Site Plan:

There are three primary factors that caused FPL to change its resource plan from the one presented in the 2007 Site Plan. These three factors, and the changes in the resource plan that result from these factors, are briefly described below and are addressed in more detail in Chapters II and III of this document.

The first factor that is driving changes in the current resource plan is FPL's new load forecast. FPL now projects a lower rate of population growth than forecasted in the 2007 Site Plan for the next several years. However, FPL's current load forecast also reflects its plan to serve a portion of the load and energy requirements of Lee County Electric Co-Operative (Lee County) starting in 2010, and to serve the full load and energy requirements of Lee County starting in 2014. FPL's current projection of peak loads compared to that presented in the 2007 Site Plan is for lower peaks through 2013, but higher peaks for 2014 through 2017.

Although the timing of growth in peak load has changed, significant growth in both peaks and annual energy is still projected through 2017 and this growth will necessitate significant increases in generating capacity. In addition, because of the slower growth in peak load projected for the earlier years, FPL will have an opportunity to consider upgrades to its existing generating units, including the possible repowering of one or more units.

The second factor is that new advanced coal technology power plants are no longer seen as viable options in Florida over the ten-year reporting period for this Site Plan. Concerns over greenhouse gas emissions have resulted in advanced technology coal power plants being removed from FPL's list of generation options currently under consideration. The primary consequence is that the only type of generating unit that can be considered as a large-scale resource option to meet the growing needs of FPL's customers in the ten year reporting period is a natural gas-fired combined cycle unit.

The third factor that is driving change in FPL's resource plan is the Executive Orders issued by Florida's Governor Crist in July 2007 that, in part, called for a significant reduction in greenhouse gas emissions in Florida and for an increase in the amount of energy provided by renewable, non-emitting sources. The consequence of this factor is to reinforce FPL's on-going efforts to increase the production of electricity from nuclear energy and renewable energy options in the future, and to seek to increase the efficiency of its non-nuclear generating units.

The development of the resource plan presented in this document has taken these three factors, and other concerns, into account. As a result, the current resource plan has changed from the resource plan presented in the 2007 Site Plan in the following ways:

- **Increased Nuclear Generating Capacity:** On January 7, 2008, the Florida Public Service Commission approved FPL's request to uprate, by 414 MW, the generating capacity of FPL's four existing nuclear generating units – Turkey Point Nuclear Units 3 & 4 and St. Lucie Nuclear Units 1 & 2. The capacity of each unit will increase between 103 or 104 MW. The in-service dates for the uprates are: December 2011 for St. Lucie 1, May 2012 for Turkey Point 3, June 2012 for St. Lucie 2, and December 2012 for Turkey Point 4. In addition, although not specifically presented in this document due to the fact that the reporting period ends in 2017, FPL has filed with the FPSC for a Determination of Need for two new nuclear units at its existing Turkey Point power plant site. One of these units is projected to come in-service in 2018 and the other is projected to come in-service in 2020. The FPSC voted to approve the need for these two new nuclear units on March 18, 2008 and the FPSC is expected to issue the final order by mid-April 2008. Increased nuclear capacity is projected to result in economic savings to FPL's customers while making significant contributions to both greater system fuel diversity and lower greenhouse gas emissions.

- **Increased Renewable Energy Contribution:** FPL issued a renewable energy-only Request for Proposals (RFP) in 2007 and will be issuing another one in April 2008. FPL is also directly pursuing renewable energy through several other efforts. FPL's plans include building a wind energy generation facility totaling up to approximately 13.8 MW at FPL's existing St. Lucie nuclear power plant site. The wind energy facility is expected to go in-service starting in 2009. In addition, several FPL solar thermal and/or photovoltaic (PV) facilities are being evaluated that could go in-service in the 2009 – 2012 time frame. FPL is also currently assuming, for planning purposes, that contract extensions and/or new contracts will be reached with several existing renewable energy suppliers whose contracts with FPL are set to expire within this ten-year period. In addition, FPL's resource plan reflects its intent to obtain additional capacity and/or energy from the Renewable RFP solicitations or its own renewable energy development efforts.

For purposes of this planning document, FPL is assuming that 269 MW of firm capacity from renewable facilities will be added to FPL's system in the ten-year reporting period. It is currently assumed that other renewable energy additions will likely be added and that these additions would serve FPL's customers as intermittent, as-available energy resources, not as resources that provide firm capacity. As actual operating data at system peak hours for these renewable energy facilities becomes available, the potential of these renewable facilities to provide firm capacity will be better known. Any cost-effective renewable resources that FPL can add to its system will help FPL increase fuel diversity and reduce greenhouse gas emissions.

- **2011 Addition of WCEC 3:** FPL issued a capacity Request for Proposals (RFP) in December 2007 that solicited firm capacity proposals with in-service dates in the June 2011 to June 2012 time frame. A total of 3 proposals were received in response to the RFP. These proposals have been compared to FPL's next planned generating unit, a three-on-one combined cycle unit at the West County Energy Center (WCEC) site that is identical in technology and size to the WCEC 1 & 2 units. After an evaluation of these options by FPL and an Independent Evaluator, the WCEC 3 unit, proposed to be placed in-service in June 2011, was selected as the best option for FPL and its customers. FPL plans to submit a petition to the FPSC in April 2008 for approval of a Determination of Need for WCEC 3. Not only will the addition of WCEC 3 in 2011 result in significant economic savings to FPL's customers, its addition in June of 2011 also provides an opportunity for FPL to consider repowering one or more of its existing plants.

In fact, adding WCEC 3 in 2011 is necessary for FPL to have the option of repowering one or more of its existing plants by 2013 or 2014 in place of adding new generation at a "greenfield" site in that timeframe. Repowering could effectively transform as much as approximately 1,400 MW of relatively inefficient, existing steam generation into 2,438 MW of new, highly efficient, state-of-the-art, environmentally benign advanced combined cycle units. It is anticipated that such repowerings would result in economic savings to FPL's customers and reduced system emissions, including CO_2 emissions. As a result, repowering these plants by 2013 or 2014 could enable FPL to comply with the 2017 CO_2 emission targets proposed in 2007 by Governor Crist. FPL has initiated a thorough evaluation of this repowering alternative to determine its costs and quantify its benefits relative to those of other alternatives before it can make a decision to proceed with repowering. However, because repowering existing plants would initially require removal of approximately 1,400 MW of existing generating capacity from service in 2011, it is necessary to add WCEC 3 in 2011 to offset the loss of existing capacity and maintain a 20% reserve margin, thereby preserving the repowering option.

Finally, for long-term planning purposes, this document shows unsited combined cycle units similar in technology and design to those being added at the WCEC site being added to meet capacity needs for 2014 through 2017. However, no decision regarding these capacity options needs to be made, or has been made, at this time.[1]

As previously mentioned, the reduction of greenhouse gas emissions, particularly carbon dioxide (CO_2), has become a major factor in FPL's resource planning work. FPL already has a relatively low CO_2 emission rate (CO_2 tons per MWh generated) compared to other utilities due to its four existing nuclear units, the high efficiency of its combined cycle generating units, a number of renewable capacity and energy contracts, and its strong on-going DSM efforts. In addition, changes in FPL's 2008 resource plan, compared to that presented in its 2007 Site Plan, will result in a further lowering of FPL's CO_2 emission rate. Specifically, the nuclear capacity uprates, the addition of new, highly efficient combined cycle units, potential renewable resource additions, and significant on-going DSM efforts are projected to not only lower FPL's CO_2 emission rate, but also temporarily lower FPL's total annual CO_2 emissions.

However, despite this reduction in FPL's system CO_2 emission rate, significant load growth driven primarily by projected increases in population will cause total annual CO_2 emissions to increase at least until the two proposed new nuclear units at Turkey Point come in-service in 2018 and 2020, respectively.

As previously mentioned, FPL's peak load is projected to continue to increase at a still significant pace over the ten-year period. At present, FPL projects that it will need 3,625 MW of additional capacity through 2017 after the proposed addition of WCEC 3. Consequently, FPL's total generation capability is projected to significantly increase during the 2008-2017 time period as shown in Table ES.1. The table reflects FPL's current planned changes to existing generation units (due to scheduled unit overhauls, etc.), projected changes in the delivered amounts of purchased power, assumed capacity increases from certain renewable facilities, the capacity uprates of its existing nuclear units, and the planned additions of new generating units. Note that this table focuses solely on changes in capacity purchases and generating units. As such, it does

[1] Repowering at existing FPL sites remains an alternative to construction at new sites and FPL will continue to examine this option. In addition, both other generating options and DSM options will continue to be evaluated. FPL will be filing for approval of new DSM Goals in 2009 that will address DSM for the time frame of 2010 through 2019.

not directly address FPL's significant DSM efforts, but these DSM contributions have been incorporated prior to making a projection of new generating unit additions. Likewise, because FPL will be projecting the contribution of a number of new renewable resources as non-firm, energy-only resources at least until actual operating data at the facilities' specific sites are available, a number of the new renewable resources currently being considered, as discussed above and in Chapter III, are not included in Table ES.1.

FPL's ongoing resource planning efforts will continue to be influenced by the three driving factors discussed above (i.e., a new load forecast, advanced coal technology no longer being a viable option, and the Governor's Executive Orders)and by several other items FPL refers to as system concerns. These system concerns include: (1) maintaining/enhancing fuel diversity in the FPL system and (2) maintaining a balance between load and generating capacity in Southeastern Florida. In addition, FPL's resource planning work will seek opportunities to further enhance the operating efficiency of its existing generation fleet.

Table ES.1: Projected Capacity Changes and Reserve Margins for FPL

Projected Capacity Changes and Reserve Margins for FPL (1)		Net Capacity Changes (MW)		FPL Reserve Margin (%)	
		Winter (2)	Summer (3)	Winter	Summer
2008	Changes to Existing Units	41	14	28.4%	23.0%
	Changes to Existing Purchases (4)	(836)	---		
2009	West County Unit #1 (5)	---	1,219	25.0%	24.9%
	Changes to Existing Units	28	1		
	Changes to Existing Purchases (4)	(326)	(431)		
2010	West County Unit #1 (5)	1,335	---	25.4%	25.2%
	West County Unit #2 (5)	---	1,219		
	Extension Renewable Capacity Purchases	98	98		
	Changes to Existing Purchases (4)	(559)	(455)		
2011	West County Unit #2 (5)	1,335	---	28.9%	27.9%
	West County Unit # 3 (5)	---	1,219		
	New Renewable Capacity Purchases	---	32		
	Extension Renewable Capacity Purchases	45	45		
	Changes to Existing Purchases (4)	(46)	(45)		
2012	Changes to Existing Purchases (4)	---	(156)	33.3%	26.0%
	West County Unit # 3 (5)	1,335	---		
	New Renewable Capacity Purchases	126	94		
	Changes to Existing Nuclear Units	103	310		
2013	Changes to Existing Nuclear Units	311	104	31.5%	24.0%
	Changes to Existing Purchases (4)	(180)	---		
2014	Unsited 3 x 1 CC #1 (5)	---	1,219	24.7%	23.8%
2015	Unsited 3 x 1 CC #1 (5)	1,335	---	27.1%	21.1%
2016	Unsited 3x1 CC # 2 (5)	---	1,219	20.2%	22.9%
	Unsited 3x1 CC # 3 (5)	---	1,219		
	Changes to Existing Purchases (4)	(930)	(1,311)		
2017	Unsited 3x1 CC # 2 (5)	1,335	---	25.9%	20.1%
	Unsited 3x1 CC # 3 (5)	1,335	---		
	Changes to Existing Purchases (4)	(390)	---		
	TOTALS =	5,495	5,614		

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are values for January of year shown.
(3) Summer values are values for August of year shown.
(4) These are firm capacity and energy contracts with QF, Utilities and other purchases. See Table I.B.1 and Table I.B.2 for more details.
(5) All new unit additions are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

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CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 8.7 million people. FPL served an average of 4,496,589 customer accounts in thirty-five counties during 2007. These customers were served from a variety of resources including: FPL-owned fossil and nuclear generating units, non-utility owned generation, demand side management (DSM), and interchange/purchased power.

I.A. FPL-Owned Resources

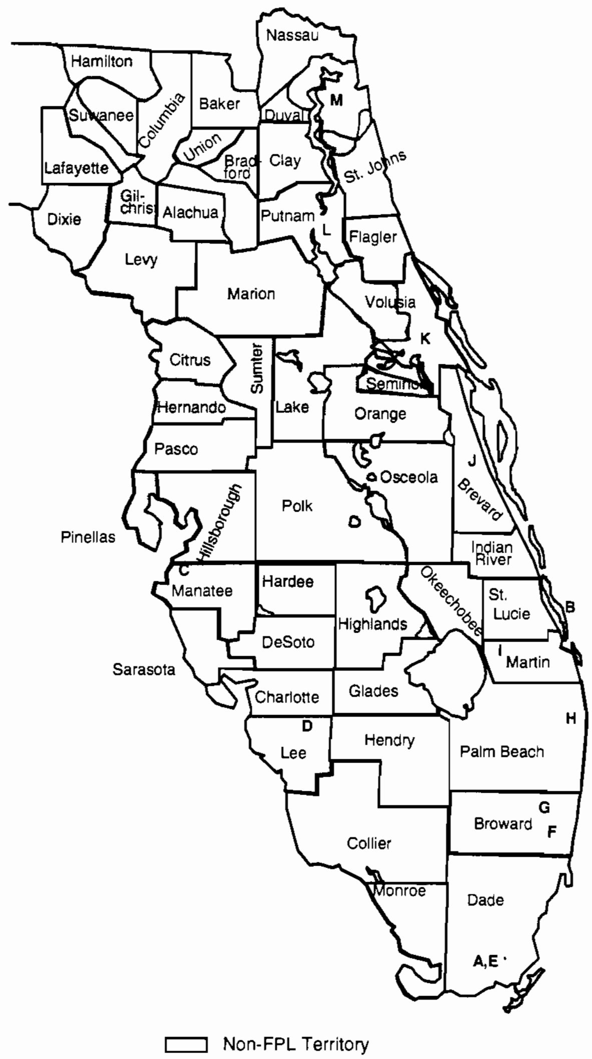
The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory and also include partial ownership of one unit located in Georgia and two units located in Jacksonville, Florida. The current generating facilities consist of four nuclear units, three coal units, twelve combined cycle units, seventeen fossil steam units, forty eight combustion gas turbines, one simple cycle combustion turbine, and five diesel units. The location of these ninety generating units is shown on Figure I.A.1 and in Table I.A.1.

FPL's bulk transmission system is comprised of 6,640 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 573 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3 shows FPL's interconnection ties with other utilities.

FPL Generating Resources by Location

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	5	3,318
B	St. Lucie *	2	1,553
C	Manatee	3	2,742
D	Fort Myers	2	1,764
E	Cutler	2	205
F	Lauderdale	2	872
G	Port Everglades	4	1,219
H	Riviera	2	565
I	Martin	5	3,738
J	Cape Canaveral	2	792
K	Sanford	3	2,054
L	Putnam	2	498
M	SJRPP **	2	250
	Scherer ***	1	646
	Gas Turbines	48	1,908
	Internal Combustion Turbines	5	12
	FPL Generation =	**90**	**22,135**



* Represents FPL's ownership share: St Lucie nuclear: 100% unit 1, 85% unit 2: St. Johns River: 20% of two units.

** SJRPP = St. John's River Power Park

*** The Scherer unit is located in Georgia and is not shown on this map.

Figure I.A.1: Capacity Resources by Location (as of December 31, 2007)

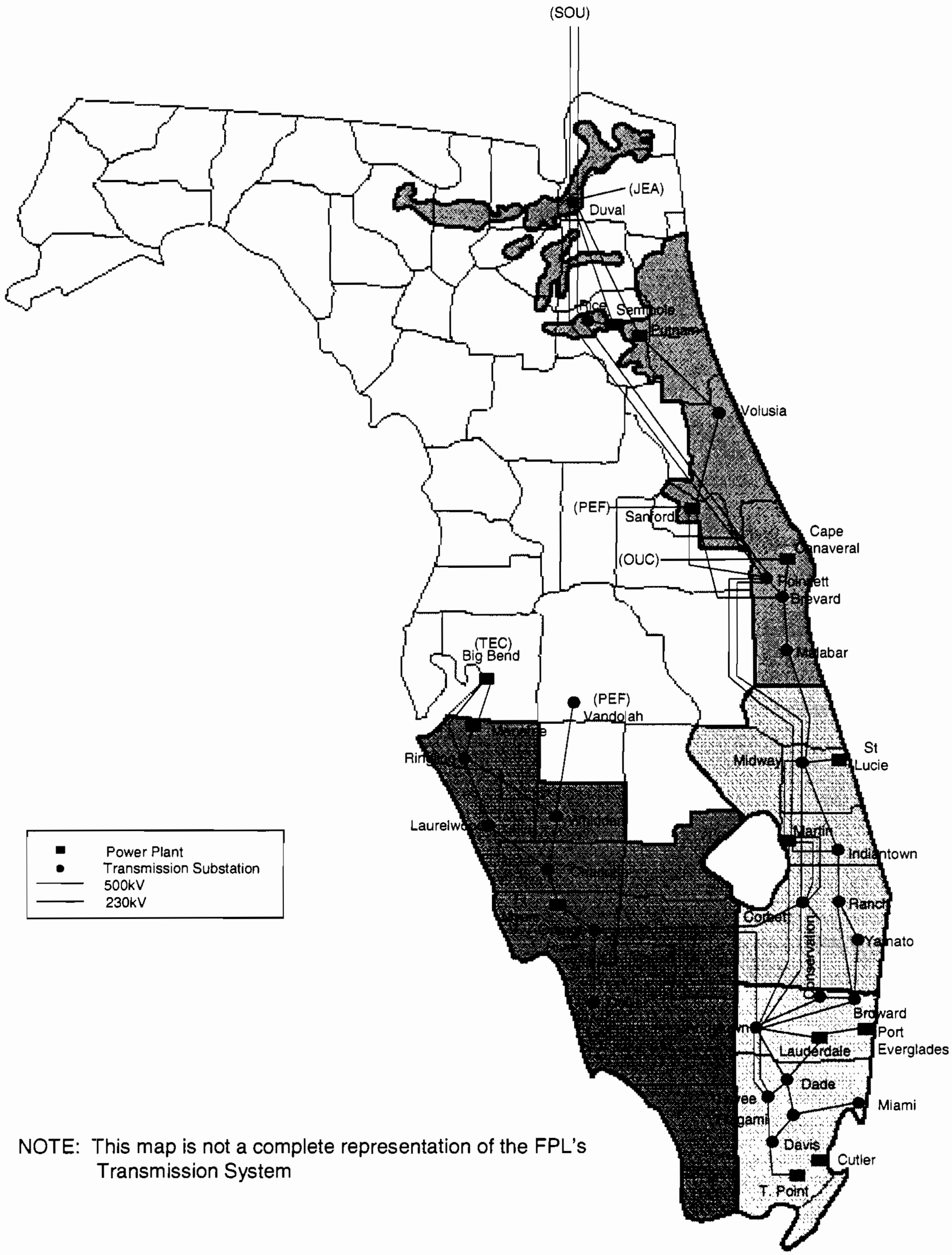
Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2007)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Combined-Cycle				
Lauderdale	Dania, FL	2	Gas/Oil	872
Martin	Indiantown,FL	2	Gas	956
Martin	Indiantown,FL	1	Gas/Oil	1,104
Sanford	Lake Monroe, FL	2	Gas	1,916
Putnam	Palatka, FL	2	Gas/Oil	498
Fort Myers	Fort Myers, FL	1	Gas	1,440
Manatee	Parrish,FL	1	Gas	1,104
Turkey Point	Florida City, FL	1	Gas	1,144
Total Combined Cycle		**12**		**9,033**
Combustion Turbines				
Fort Myers *	Fort Myers, FL	1	Gas/Oil	324
Total Combustion Turbines		**1**		**324**
Nuclear				
Turkey Point	Florida City, FL	2	Nuclear	1,386
St. Lucie **	Hutchinson Island, FL	2	Nuclear	1,553
Total Nuclear		**4**		**2,939**
Coal Steam				
SJRPP ***	Jacksonville, FL	2	Coal	250
Scherer	Monroe County, Ga	1	Coal	646
Total Coal Steam		**3**		**896**
Oil/Gas Steam				
Cape Canaveral	Cocoa, FL	2	Oil/Gas	792
Cutler	Miami, FL	2	Gas	205
Manatee	Parrish, FL	2	Oil/Gas	1,638
Martin	Indiantown,FL	2	Oil/Gas	1,678
Port Everglades	Port Everglades, FL	4	Oil/Gas	1,219
Riviera	Riviera Beach, FL	2	Oil/Gas	565
Sanford	Lake Monroe, FL	1	Oil/Gas	138
Turkey Point	Florida City, FL	2	Oil/Gas	788
Total Oil/Gas Steam		**17**		**7,023**
Gas Turbines(GT)/Diesels(IC)				
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Turkey Point (IC)	Florida City, FL	5	Oil	12
Total Gas Turbines/Diesels		**53**		**1,920**
Total Units:		**90**		
Total Net Generating Capability:				**22,135**

* The consists of two combustion turbines.

** Total capability of each unit is 853/839 MW. FPL's ownership share of St. Lucie 1 and 2 is 100%(853/839) and 85% (714/726) above. respectively as shown. Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.

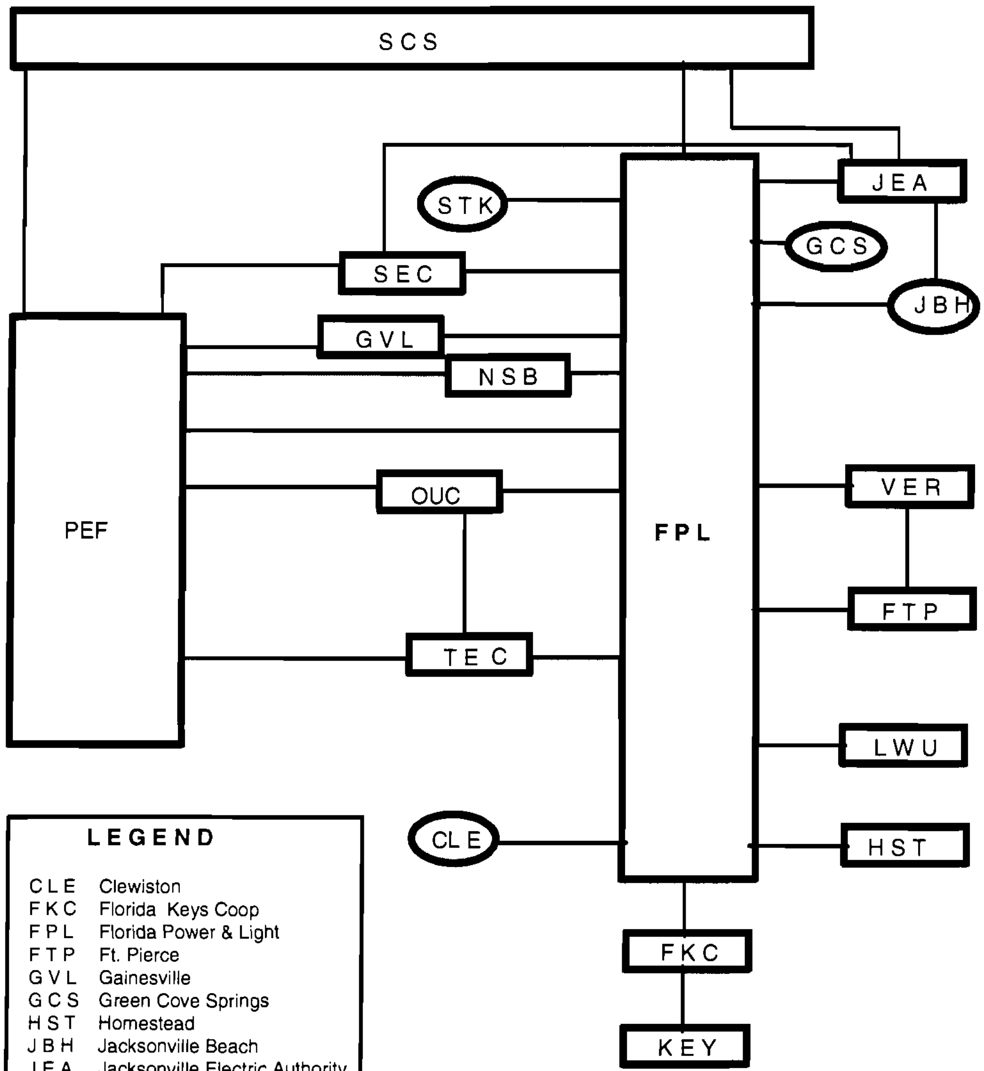
*** Represents FPL's ownership share: SJRPP coal: 20% of two units



NOTE: This map is not a complete representation of the FPL's Transmission System

Figure I.A.2 FPL Substation and Transmission System Configuration

FPL Interconnection Diagram



LEGEND

C L E	Clewiston
F K C	Florida Keys Coop
F P L	Florida Power & Light
F T P	Ft. Pierce
G V L	Gainesville
G C S	Green Cove Springs
H S T	Homestead
J B H	Jacksonville Beach
J E A	Jacksonville Electric Authority
K E Y	Key West
L W U	Lake Worth
N S B	New Smyrna Beach
O U C	Orlando Utilities Commission
P E F	Progress Energy Florida
S E C	Seminole Electric Cooperative
S C S	Southern Companies
S T K	Starke
T E C	Tampa Electric Company
V E R	Vero Beach

Figure I.A.3: FPL Interconnection Diagram

I.B Firm Capacity Power Purchases

Purchases from Qualifying Facilities (QF):

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has contracts with five qualifying facilities; i.e., cogeneration/small power production facilities, to purchase firm capacity and energy.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

Purchases from Utilities:

FPL has a Unit Power Sales (UPS) contract to purchase 931 MW, with a minimum of 381 MW, of coal-fired generation from the Southern Company (Southern) through May 2010. An additional contract with Southern will result in FPL receiving 930 MW from June 2010 through the end of December 2015. This capacity will be supplied by Southern from a mix of gas-fired and coal-fired units.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 381 MW (Summer) and 390 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. Due to Internal Revenue Service (IRS) regulations, the total amount of energy that FPL may receive from this purchase is limited. FPL currently assumes, for planning purposes, that this limit will be reached at the end of April 2016. (FPL also has ownership interest in these units. The ownership amount is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.)

Other Purchases:

FPL has other firm capacity purchase contracts with a variety of Non-QF suppliers. These purchases are generally near-term in nature. Table I.B.1 and I.B.2 present the Summer and Winter MW, respectively, resulting from all firm purchased power contracts discussed above through the year 2017. For planning purposes, FPL assumes an additional 269 MW of firm capacity will be supplied from renewable energy sources. This firm capacity is expected to be provided through a variety of sources including: contract extensions and/or new contracts with existing renewable facilities currently under contract with FPL but whose contracts are set to expire in 2009 – 2010, proposals received in response to a new Renewable RFP that FPL plans to issue in April 2008, and/or FPL's own renewable development efforts.

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1. Broward South	4/1/1991	8/1/2009 *	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
2. Broward South	1/1/1993	12/31/2026	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
3. Broward South	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
4. Broward South	1/1/1997	12/31/2026	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
5. Broward North	4/1/1992	12/31/2010 *	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
6. Broward North	1/1/1993	12/31/2026	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
7. Broward North	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
8.Broward North	1/1/1997	12/31/2026	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
9. Cedar Bay Generating Co.	1/25/1994	12/31/2024	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
10. Indiantown Cogen., LP	12/22/1995	12/1/2025	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
11. Palm Beach SWA	4/1/1992	3/31/2010 *	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5
		QF Purchases Sub Total:	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1. UPS from Southern Co.	7/20/1988	5/31/2010	931	931	0	0	0	0	0	0	0	0
2. UPS Replacement	6/1/2010	12/31/2015	0	0	930	930	930	930	930	930	0	0
3. SJRPP	4/2/1982	10/31/2015	381	381	381	381	381	381	381	381	0	0
		Utility Purchases Sub Total:	**1312**	**1312**	**1311**	**1311**	**1311**	**1311**	**1311**	**1311**	**0**	**0**

III. Other Purchases:

	Contract Start Date	Contract End Date	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1. Reliant/Indian River	1/1/2006	12/31/2009	576	250	0	0	0	0	0	0	0	0
2. Oleander (Extension)	6/1/2007	5/31/2012	156	156	156	156	0	0	0	0	0	0
3. Williams	3/1/2006	12/31/2009	106	106	0	0	0	0	0	0	0	0
4. Progress Energy Ventures	4/1/2006	3/31/2009	105	0	0	0	0	0	0	0	0	0
5. Additional Renewable Firm Capacity	6/1/2011	varies	0	0	0	32	126	126	126	126	126	126
		Other Purchases Sub Total	**943**	**512**	**156**	**188**	**126**	**126**	**126**	**126**	**126**	**126**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Summer Firm Capacity Purchases Total MW:	**2993**	**2562**	**2205**	**2237**	**2175**	**2175**	**2175**	**2175**	**864**	**864**

* For planning purpose, the contracts for these renewable capacity purchases are assumed to be extended. New contractual arrangement have not yet been developed.

Table I.B.2: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1. Broward South	04/01/91	8/1/2009 *	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
2. Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
3. Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
4. Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
5. Broward North	04/01/92	12/31/2010 *	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
6. Broward North	01/01/93	12/31/26	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
7. Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
8.Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
9. Cedar Bay Generating Co.	01/25/94	12/31/24	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
10. Indiantown Cogen., LP	12/22/95	12/01/25	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
11. Palm Beach SWA	04/01/92	3/31/2010 *	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5
		QF Purchases Sub Total:	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1. UPS from Southern Co.	07/20/88	05/31/10	931	931	931	0	0	0	0	0	0	0
2. UPS Replacement	06/01/10	12/31/15	0	0	0	930	930	930	930	930	0	0
3. SJRPP	04/02/82	04/01/16	390	390	390	390	390	390	390	390	390	0
		Utility Purchases Sub Total:	**1321**	**1321**	**1321**	**1320**	**1320**	**1320**	**1320**	**1320**	**390**	**0**

III. Other Purchases:

	Contract Start Date	Contract End Date	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1. Reliant/Indian River	01/01/06	12/31/09	576	250	0	0	0	0	0	0	0	0
2. Oleander (Extension)	06/01/07	05/31/12	180	180	180	180	180	0	0	0	0	0
3. Williams	03/01/06	12/31/09	106	106	0	0	0	0	0	0	0	0
4. Progress Energy Ventures	04/01/06	03/31/09	105	105	0	0	0	0	0	0	0	0
5. Additional Renewable Firm Capacity	6/1/2011	varies	0	0	0	0	126	126	126	126	126	126
		Other Purchases Sub Total	**967**	**641**	**180**	**180**	**306**	**126**	**126**	**126**	**126**	**126**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Winter Firm Capacity Purchases Total MW:	**3026**	**2700**	**2239**	**2238**	**2364**	**2184**	**2184**	**2184**	**1254**	**864**

* For planning purpose, the contracts for these renewable capacity purchases are assumed to be extended. New contractual arrangement have not yet been developed.

I.C Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. Table I.C.1 shows the amount of energy purchased in 2007 from these facilities.

Table I.C.1: As Available Energy Purchases From Non-Utility Generators in 2007

Project	*County*	*Fuel*	*In-Service Date*	*Energy (MWH) Delivered to FPL in 2007*
Tropicana	Manatee	Natural Gas	2/90	19,067
Elliot	Palm Beach	Natural Gas	7/05	297
US Sugar-Bryant	Palm Beach	Bagassee	2/80	1,432
Okeelanta	Palm Beach	Bagassee/Wood	11/95	265,475
Georgia Pacific	Putnam	Paper by-product	2/94	3,415
Tomoka Farms	Volusia	Landfill Gas	7/98	20,500
Rothenbach Park	Sarasota	PV	10/07	48
Customer Owned PV	Various	PV	Various	60

I.D. Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include a number of conservation/energy-efficiency and load management initiatives. FPL's DSM efforts through 2007 have resulted in a cumulative Summer peak reduction of approximately 3,958 MW at the generator and an estimated cumulative energy saving of approximately 42,301 Gigawatt Hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2007 have eliminated the need to construct the equivalent of approximately 12 new 400 MW generating units.

Table I.D.1 presents FPL's DSM projections. This projection captures: FPL's DSM Goals approved by the Florida Public Service Commission through 2014, additional cost-effective DSM identified by FPL after the DSM Goals were established, and a projection of continued DSM implementation for 2015 – 2017 at an implementation rate commensurate with the projected annual rate of implementation for the years immediately preceding 2014.

Table I.D.1. : FPL's DSM Goals and Additional DSM: 2006 – 2017 (Summer MW)

Projected Incremental FPL DSM: 2006 - 2017

Year	DSM Projected by FPL (Summer MW at Generator) (1)
2006	1,491
2007	1,768
2008	1,908
2009	2,034
2010	2,146
2011	2,264
2012	2,388
2013	2,516
2014	2,651
2015	2,790
2016	2,910
2017	3,030
Incremental DSM MW from 2006 through 2017 =	1,539

Notes: (1) The DSM Summer MW shown are from column (8) in Schedule 7.1 and reflect projected DSM signups from 8/2006 through 8/2020. These values reflect FPL's DSM Goals through 2014 plus additional DSM through 2015 identified as cost-effective after the DSM Goals were established. These values also include a projected continuation of DSM signups for 2015 - 2017.

Schedule 1

Existing Generating Facilities
As of December 31, 2007

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW
Cape Canaveral		Brevard County 19/24S/36F									804,100	796	792
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	398	396
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	398	396
Cutler		Miami Dade County 27/55S/40E									236,500	207	205
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	75,000	69	68
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	161,500	138	137
Fort Myers		Lee County 35/43S/25E									2,895,890	2,740	2,412
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,775,390	1,599	1,440
	3A & B		CT	NG	FO2	PL	PL	Unknown	Jun-03	Unknown	376,380	372	324
	1-12		GT	FO2	No	PL	No	Unknown	May-74	Unknown	744,120	769	648
Lauderdale		Broward County 30/50S/42E									1,873,968	1,946	1,712
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	464	436
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	464	436
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	509	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,734	509	420
Manatee		Manatee County 18/33S/20E									2,951,110	2,859	2,742
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	831	819
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	831	819
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,197	1,104

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Martin		Martin County 29/29S/38E									4,317,510	3,874	3,738
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	844	839
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	844	839
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	503	478
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	503	478
	8*		CC	NG	FO2	PL	PL	Unknown	Jun-05	Unknown	1,224,510	1,180	1,104
Port Everglades		City of Hollywood 23/50S/42E									1,710,384	1,736	1,639
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	247,775	222	220
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	247,775	222	220
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	389	387
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	394	392
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	509	420
Putnam		Putnam County 16/10S/27E									580,008	566	498
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,004	283	249
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,004	283	249
Riviera		City of Riviera Beach 33/42S/43E									620,840	571	565
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	280	277
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	291	288
Sanford		Volusia County 16/19S/30E									2,533,970	2,267	2,054
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	156,250	140	138
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,860	1,067	958
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	1,060	958

1/ These ratings are peak capability.
* Martin 8 A and B combustion turbine units went into service on 6/14/2001 and the conversion to Combined Cycle went into service 6/30/2005.

Schedule 1

Existing Generating Facilities
As of December 31, 2007

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW
Scherer 2/		Monroe, GA									680,368	652	646
	4		BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	680,368	652	646
St. Johns River Power Park 3/		Duval County 12/15/28E (RPC4)									271,836	250	250
	1		BIT	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	125	125
	2		BIT	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	125	125
St. Lucie		St. Lucie County 16/36S/41E									1,573,775	1,579	1,553
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	850,000	853	839
	2	4/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	723,775	726	714
Turkey Point		Miami Dade County 27/57S/40E									3,560,548	3,451	3,330
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	398	396
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	394	392
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	759,900	717	693
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	759,900	717	693
	5		CC	NG	No	PL	No	Unknown	May-07	Unknown	1,224,510	1213	1,144
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	12,138	12	12
Total System as of December 31, 2007 =												**23,494**	**22,135**

1/ These ratings are peak capability.
2/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.
3/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No. 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80%.
4/ Total capability of each unit is 853/839 MW. FPL's ownership share of St. Lucie 1 and 2 is 100%(853/839) and 85% (714/726) respectively as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.

CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

II. A. Overview of the Load Forecasting Process

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are typically developed on an annual basis for resource planning work at FPL and new forecasts were developed by FPL in February 2008. These forecasts are a key input to the models used to develop FPL's Integrated Resource Plan. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

Consistent with past forecasts, the primary drivers to develop these forecasts are demographic trends, weather, economic conditions, and prices of electricity. In addition, the resulting forecasts are an integration of economic evaluations, inputs of local economic development boards, weather assessments from the National Oceanic and Atmospheric Administration (NOAA), and inputs from FPL's own customer service planning areas. In the area of demographics, population trends, plus housing characteristics such as housing starts, housing sizes, and vintage of homes, are assessed.

The projections for the national and Florida economies are obtained from Global Insight. Population projections are obtained from the Bureau of Economic and Business Research (BEBR) of the University of Florida. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects FPL's energy sales and peak demand. Two sets of weather variables are developed and used in FPL's forecasting models:

1. Cooling and Heating Degree-Hours are used to forecast energy sales.
2. Temperature data is used to forecast Summer and Winter peaks.

The Cooling and Heating Degree-Hours are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. A composite temperature hourly profile is derived using hourly temperatures across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained. In developing the composite hourly profile these regional temperatures are weighted by regional energy sales. This composite temperature is used to derive Cooling and Heating Degree-Hours which are based, respectively, on starting point temperatures of 72°F and 66°F degrees. Similarly, composite temperature and hourly profile of temperatures are used for the Summer and Winter peak models.

II. B. Comparison of FPL's Current and Previous Load Forecasts

FPL's current load forecast is significantly changed from the load forecast presented in its 2007 Site Plan. Two significant factors have been the primary factors in this change in the current load forecast compared to the load forecast presented in the 2007 Ten Year Site Plan. First, FPL has utilized the November 2007 population projections issued by BEBR, which are lower than the projections utilized in the load forecasts presented in the 2007 Site Plan. Second, Lee County Electric Co-Operative (Lee County) has contracted with FPL to serve a portion of its load starting in 2010 and to serve its full load beginning in 2014.

The net effects of these two factors is that FPL's load, compared to the load forecast presented in the 2007 Site Plan, is projected to grow at a somewhat slower rate for 2008 through 2013. Then, due in large part to the fact that FPL will begin serving Lee County's full load in 2014, the load is projected to be higher in 2014 through 2017.

Although the projected growth pattern of FPL's load has changed; somewhat less growth in 2008 through 2013, followed by higher growth in 2014 through 2017, the total growth projected by FPL for the ten-year reporting period of this document is still significant.

II.C. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for each revenue class for the forecasting period of 2008-2026 and are adjusted to match the Net Energy for Load (NEL) forecast. The results of these sales forecasts for the years 2008-2017 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and NEL forecast are outlined below.

1. <u>Residential Sales</u>

Residential electric usage per customer is estimated by using a regression model which contains the real residential price of electricity, Florida Real Personal Income, Cooling and Heating Degree-Hours as explanatory variables, as well as a dummy variable for hurricanes and other outliers. The price of electricity plays a role in explaining electric usage since electricity, like all other goods and services, will be used in greater or lesser quantities depending upon its price. To capture economic conditions, the model includes Florida's Real Personal Income. The degree of economic prosperity can, and does, affect residential electricity sales. The impact of weather is captured by the Heating Degree-Hours and Cooling Degree-Hours. Residential energy sales are forecast by multiplying the residential use per customer forecast by the number of residential customers forecasted.

2. Commercial Sales

The commercial sales forecast is also developed using a regression model. Commercial sales are a function of the following variables: Florida Non-Agricultural Employment, commercial real price of electricity, Cooling Degree-Hours, as well as dummy variable for hurricanes. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. Cooling Degree-Hours are used to capture weather-sensitive load in the commercial sector.

3. Industrial Sales

Industrial sales were forecasted using a linear multiple regression model. The linear multiple regression model utilizes the following variables: Florida Housing Starts, Cooling Degree-Hours, and several dummy variables for outliers, hurricanes, and months. The Cooling Degree-Hour term is used to capture the weather-sensitive load in the industrial class.

4. Railroad & Railways Sales and Street and Highway Sales

The forecast for street and highway sales is developed using historical usage patterns and multiplying these usage levels by the number of forecasted customers. The forecast of sales to railroad & railways is developed using an econometric model with the Florida population as the primary driver and several monthly dummy variables to capture seasonality. This class consists solely of the Miami-Dade County's Metrorail system.

5. Other Public Authority Sales

The sales for other public authority sales are developed using historical usage patterns.

6. **Total Sales to Ultimate Customer**

Sales forecasts by revenue class are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, an expansion factor is applied to generate a forecast of annual NEL.

7. **Sales for Resale**

Sales for resale (wholesale) customers are composed of municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers.

Currently, there are three customers in this class: the Florida Keys Electric Cooperative (Florida Keys), City Electric System of the Utility Board of Key West, Florida (City of Key West), and Miami-Dade County. However, starting in January 2010, Lee County will also be a customer in this class.

Sales to the City of Key West are forecasted using a regression model. Forecasted sales to the Florida Keys are based on assumptions regarding their contract demand and expected load factor. Miami-Dade County sells 60 MW to Progress Energy. Line losses associated with this sale are billed to Miami-Dade under a wholesale contract. Lee County has contracted for FPL to supply a portion of their load beginning in January 2010 and for FPL to supply their total load beginning in January 2014 through December 2033. Forecasted sales to Lee County are based on assumptions regarding their contract demand and expected load factor.

II.D. Net Energy for Load (NEL)

An econometric model is developed to produce an NEL forecast. The key inputs to the model are: the real price of electricity, Heating and Cooling Degree-Hours, and Florida Real Personal Income.

Once the NEL forecast is obtained using the above-mentioned methodology, the results are then compared for reasonableness to the NEL forecast generated using the total sales forecast. The sales by class forecasts previously discussed are then adjusted to match the NEL from the annual NEL model.

The forecasted NEL values for 2008 – 2017 are presented in Schedule 3.3 that appears at the end of this chapter.

II.E. System Peak Forecasts

The rate of absolute growth in FPL system peak load has been a function of a growing customer base, varying weather conditions, continued economic growth, changing patterns of customer behavior (including an increased stock of electricity-consuming appliances), and more efficient heating and cooling appliances. FPL developed the peak forecast models to capture these behavioral relationships. In addition, as previously discussed, the introduction of the Lee County load beginning in January 2010 is a new factor in FPL's 2008 load forecast that is addressed in the forecast models.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2008–2017 are presented in Schedules 3.1 and 3.2 as well as in Schedules 7.1 and 7.2.

1. System Summer Peak

The Summer peak forecast is developed using an econometric regression model. This econometric model utilizes the following explanatory variables: total average customers, the real price of electricity, Florida Real Personal Income, average temperature on peak day, and a heat buildup weather factor consisting of the sum of the Cooling Degree -Hours during the peak day and three prior days.

2. System Winter Peak

The Winter peak forecast is developed using the same econometric regression methodology as is used for Summer peak forecasts. The Winter peak model is a per customer model which contains the following explanatory variables: the square of the minimum temperature on the peak day and Heating Degree-Hours for the prior day as well as for the morning of the Winter peak day. The model also includes an economic variable: Florida Real Personal Income.

3. Monthly Peak Forecasts

Monthly peaks are forecasted to provide information for the scheduling of maintenance for power plants and fuel budgeting. The forecasting process is basically the same as for the monthly NEL forecast and consists of the following actions:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to seasonal peaks (Summer = April-October, Winter = November-March.)

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.F. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2008-2026 are produced using a System Load Forecasting "shaper" program. This model uses sixteen years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population 1/	Members per Household	GWH 2/	Average 3/ No. of Customers	Average KWH Consumption Per Customer	GWH 2/	Average 3/ No. of Customers	Average KWH Consumption Per Customer
1998	7,249,627	2.22	45,482	3,266,011	13,926	34,618	396,749	87,255
1999	7,412,744	2.22	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,603,964	2.23	46,320	3,414,002	13,568	37,001	415,295	89,096
2001	7,754,846	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,898,628	2.21	50,865	3,566,167	14,263	40,029	435,313	91,955
2003	8,079,316	2.21	53,485	3,652,663	14,643	41,425	444,650	93,163
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,620,855	2.21	54,570	3,906,201	13,970	44,487	478,930	92,889
2007	8,729,806	2.19	55,138	3,981,451	13,849	45,921	493,130	93,121
2008	8,861,063	2.19	57,243	4,038,555	14,174	47,382	499,843	94,794
2009	8,994,454	2.19	59,323	4,101,036	14,465	48,862	511,028	95,615
2010	9,151,644	2.19	61,420	4,170,352	14,728	50,568	521,289	97,006
2011	9,322,534	2.20	64,016	4,246,852	15,074	52,364	531,779	98,469
2012	9,484,655	2.20	66,564	4,320,532	15,407	54,096	541,819	99,841
2013	9,635,901	2.19	69,483	4,390,441	15,826	55,638	551,197	100,940
2014	9,784,007	2.19	71,587	4,459,223	16,054	57,062	560,814	101,749
2015	9,933,270	2.19	73,170	4,528,735	16,157	58,498	570,634	102,514
2016	10,087,189	2.19	75,147	4,599,061	16,340	59,963	580,654	103,269
2017	10,242,968	2.19	77,121	4,670,181	16,514	61,426	590,870	103,959

1/ Population represents only the area served by FPL. Does not include any Wholesale customers.
2/ Actual energy sales include the impacts of existing conservation. Forecasted energy sales do not include the impact of incremental conservation.
3/ Average No. of Customers is the annual average of the twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial					Other	Total
		Average 3/	Average KWH	Railroads &	Street & Highway	Sales to Public	Sales to Ultimate
		No. of	Consumption	Railways	Lighting	Authorities	Consumers
Year	GWH 2/	Customers	Per Customer	GWH	GWH 2/	GWH	GWH 4/
1998	3,951	15,126	261,206	81	373	625	85,130
1999	3,948	16,040	246,135	79	473	465	84,676
2000	3,768	16,410	229,616	81	408	381	87,960
2001	4,091	15,445	264,875	86	419	67	90,212
2002	4,057	15,533	261,186	89	420	63	95,523
2003	4,004	17,029	235,128	93	425	64	99,496
2004	3,964	18,512	214,139	93	413	58	99,095
2005	3,913	20,392	191,873	95	424	49	102,296
2006	4,036	21,216	190,232	94	422	49	103,659
2007	3,774	18,732	201,499	91	437	53	105,415
2008	3,923	14,129	277,667	93	444	52	109,137
2009	3,931	13,245	296,769	93	456	50	112,715
2010	3,940	13,447	292,976	93	468	49	116,537
2011	3,947	14,116	279,616	93	481	48	120,948
2012	3,950	14,857	265,856	93	493	46	125,243
2013	3,952	15,463	255,565	93	506	46	129,718
2014	3,953	15,978	247,423	93	518	46	133,260
2015	3,955	16,389	241,307	93	530	46	136,293
2016	3,955	16,722	236,525	93	543	46	139,747
2017	3,955	16,917	233,767	93	555	46	143,196

2/ Actual energy sales include existing conservation. Forecasted energy sales do not include the impact of incremental conservation.

3/ Average No.of Customers is the annual average of the twelve month values.

4/ GWH Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(17)	(18)	(19)	(20)	(21)
Year	Sales for Resale GWH	Utility Use & Losses GWH	Net 5/ Energy For Load GWH 2/	Average 3/ No. of Other Customers	Total Average 3/,6/ Number of Customers
1998	1,326	6,206	92,662	2,584	3,680,470
1999	953	5,829	91,458	2,605	3,756,009
2000	970	7,059	95,989	2,694	3,848,401
2001	970	7,222	98,404	2,722	3,935,281
2002	1,233	7,443	104,199	2,792	4,019,805
2003	1,511	7,386	108,393	2,879	4,117,221
2004	1,531	7,464	108,091	3,029	4,224,509
2005	1,506	7,498	111,301	3,157	4,321,896
2006	1,569	7,909	113,137	3,216	4,409,563
2007	1,499	7,401	114,315	3,276	4,496,589
2008	903	8,316	118,357	3,353	4,555,881
2009	903	8,233	121,852	3,435	4,628,744
2010	1,871	8,596	127,004	3,515	4,708,603
2011	2,001	8,913	131,862	3,597	4,796,344
2012	2,047	9,581	136,871	3,682	4,880,891
2013	2,089	9,567	141,374	3,770	4,960,871
2014	5,450	10,042	148,752	3,857	5,039,871
2015	5,919	10,283	152,495	3,942	5,119,700
2016	6,098	10,538	156,384	4,028	5,200,465
2017	6,251	10,799	160,246	4,114	5,282,082

2/ Actual energy sales include existing conservation. Forecasted energy sales do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

3/ Average No.of Customers is the annual average of the twelve month values.

5/ GWH Col. (19) = Col. (16) + Col. (17) + Col. (18). Actual NEL include the impacts of existing conservation and agrees to Col. (8) on schedule 3.3.

6/ Total Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1998	17,897	426	17,471	0	628	526	458	385	16,811
1999	17,615	169	17,446	0	673	592	452	420	16,490
2000	17,808	161	17,647	0	719	645	467	451	16,622
2001	18,754	169	18,585	0	737	697	488	481	17,529
2002	19,219	261	18,958	0	770	755	489	517	17,960
2003	19,668	253	19,415	0	781	799	577	554	18,310
2004	20,545	258	20,287	0	783	847	588	578	19,174
2005	22,361	264	22,097	0	790	895	600	611	20,971
2006	21,819	256	21,563	0	809	948	635	640	18,787
2007	21,962	261	21,701	0	954	982	715	683	18,628
2008	22,356	162	22,195	0	966	129	738	75	20,448
2009	22,792	162	22,630	0	997	174	760	103	20,758
2010	23,554	361	23,193	0	1016	221	776	133	21,408
2011	24,191	368	23,823	0	1037	270	791	166	21,927
2012	24,837	373	24,463	0	1,059	322	806	201	22,449
2013	25,414	380	25,034	0	1,083	375	822	236	22,898
2014	26,576	1,076	25,500	0	1,110	430	837	274	23,925
2015	27,241	1,106	26,136	0	1,139	486	852	312	24,452
2016	27,932	1,135	26,797	0	1,164	535	867	345	25,021
2017	28,621	1,165	27,456	0	1,189	583	880	378	25,591

Historical Values (1998 - 2007):

Col. (2) - Col. (4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) for 1997 through 2006 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC) and Commercial /Industrial Demand Reduction (CDR). Col.(5) - Col.(9) for year 2004 are "estimated actuals" and are August values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula:Col. (10) = Col.(2) - Col.(6) - Col.(8).

Projected Values (2008 - 2017):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2004 are incorporated into the load forecast.

Col. (5) - Col. (9) represent all incremental conservation and cumulative load control. These values are projected August values and the conservation values are based on projections with a 1/2006 starting point for use with the 2006 load forecast.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
1998/99	16,802	149	16,653	0	692	404	446	164	15,664
1999/00	17,057	142	16,915	0	741	434	438	176	15,878
2000/01	18,199	150	18,049	0	791	459	448	183	16,960
2001/02	17,597	145	17,452	0	811	500	457	196	16,329
2002/03	20,190	246	19,944	0	847	546	453	206	18,890
2003/04	14,752	211	14,541	0	857	570	532	230	13,363
2004/05	18,108	225	17,883	0	862	583	542	233	16,704
2005/06	19,683	225	19,458	0	870	600	550	240	18,263
2006/07	16,815	223	16,592	0	894	620	577	249	15,344
2007/08	18,055	225	17,830	0	879	644	635	279	15,618
2008/09	22,755	137	22,617	0	935	54	644	17	21,105
2009/10	23,454	138	23,316	0	972	82	670	27	21,704
2010/11	23,971	374	23,597	0	989	109	678	38	22,157
2011/12	24,487	381	24,105	0	1,009	137	686	51	22,604
2012/13	24,976	387	24,588	0	1,030	166	694	65	23,022
2013/14	26,290	394	25,895	0	1,052	194	702	79	24,262
2014/15	26,979	1,226	25,753	0	1,077	224	711	95	24,873
2015/16	27,690	1,260	26,430	0	1,105	253	719	112	25,502
2016/17	28,418	1,296	27,122	0	1,131	280	726	127	26,154
2017/18	29,178	1,332	27,846	0	1,154	305	733	141	26,844

Historical Values (1998 - 2007):

Col. (2) - Col. (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col.(9) for 1996/97 through 2005/06 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC) and Commercial/Industrial Demand Reduction (CDR).Col.(5) - Col.(9) for year 2004/05 are "estimated actuals" and are January values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (6) - Col. (8).

Projected Values (2008 - 2017):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2004 are incorporated into the load forecast.

Col. (5) - Col.(9) represent all incremental conservation and cumulative load control. These values are projected January values and the conservation values are based on projections with a 1/2004 starting point for use with the 2004 load forecast.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.3

History of Annual Net Energy for Load - GWH: Base Case

(All values are "at the generator"value)

(1) Year	(2) = (5) + (3) + (4) Total Net Energy For Load without DSM	(3) Residential Conservation	(4) C/I Conservation	(5) **Actual** Net Energy For Load	(6) Sales for Resale GWH	(7) Utility Use & Losses	(8) = (5) - (6) - (7) **Actual** Total Billed Retail Energy Sales (GWH)	(9) Load Factor(%)
1998	95,318	1,374	1,282	92,662	1,326	6,206	85,130	59.1%
1999	94,365	1,542	1,365	91,458	953	5,829	84,676	59.3%
2000	99,097	1,674	1,434	95,989	970	7,059	87,960	61.4%
2001	101,739	1,789	1,545	98,404	970	7,222	90,212	59.9%
2002	107,755	1,917	1,639	104,199	1,233	7,443	95,523	61.9%
2003	112,160	2,008	1,759	108,393	1,511	7,386	99,496	62.9%
2004	112,031	2,106	1,834	108,091	1,531	7,464	99,095	59.9%
2005	115,440	2,205	1,934	111,301	1,506	7,498	102,296	56.8%
2006	117,490	2,312	2,041	113,137	1,569	7,909	103,659	59.2%
2007	118,894	2,373	2,206	114,315	1,499	7,401	105,415	59.4%

Historical Values (1998 - 2007):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5).

Col.(3) & Col.(4) for 1998 through 2007 are DSM values starting in January 1988 and are annual (12-month) values.Col. (3) and Col. (4) for 2007 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWH reductions actually experienced each year .

Col. (5) is the **actual** Net Energy for Load (NEL) for years 1998 - 2007.

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7).

Col. (9) is calculated using Col. (5) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (5)*1000) / ((Col.(2) * 8760)

Forecast of Annual Net Energy for Load - GWH: Base Case

(All values are "at the generator"value)

(1) Year	(2) **Forecasted** Net Energy For Load without DSM	(3) Residential Conservation	(4) C/I Conservation	(5) = (2) - (3) - (4) Net Energy For Load Adjusted for DSM	(6) Sales for Resale GWH	(7) Utility Use & Losses	(8) = (2) - (6) - (7) **Forecasted** Total Billed Retail Energy Sales (GWH) without DSM	(9) Load Factor(%)
2008	118,357	91	41	118,225	903	8,316	109,137	60.3%
2009	121,852	181	86	121,586	903	8,233	112,715	61.0%
2010	127,004	275	133	126,595	1,871	8,596	116,537	61.6%
2011	131,862	373	184	131,305	2,001	8,913	120,948	62.2%
2012	136,871	475	238	136,158	2,047	9,581	125,243	62.7%
2013	141,374	580	294	140,500	2,089	9,567	129,718	63.5%
2014	148,752	688	354	147,710	5,450	10,042	133,260	63.9%
2015	152,495	797	413	151,285	5,919	10,283	136,293	63.9%
2016	156,384	894	510	154,979	6,098	10,538	139,747	63.7%
2017	160,246	991	608	158,647	6,251	10,799	143,196	63.9%

Forecasted Values (2008 - 2017):

Col. (2) represents Forecasted Net Energy for Load w/o DSM values. The values are extracted from Schedule 2.3, Col. (19).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation and are mid-year (6-month) values. The effects of conservation implemented prior to 2006 are incorporated into the load forecast.

Col. (5) is the forecasted Net Energy for Load (NEL) with DSM for years 2008 - 2017.

Col. (8) is the Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7).

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of
Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2007 ACTUAL		2008* FORECAST		2009* FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	15,619	8,458	22,332	8,579	22,755	9,051
FEB	16,815	7,476	18,409	7,938	18,757	8,154
MAR	16,450	8,427	17,369	8,964	17,698	9,216
APR	17,623	8,775	18,612	9,089	18,974	9,370
MAY	19,004	9,319	20,648	9,982	21,050	10,292
JUN	20,560	10,593	21,488	10,763	21,907	11,055
JUL	21,732	10,979	21,900	11,599	22,326	11,883
AUG	21,962	11,978	22,356	11,573	22,792	11,911
SEP	21,808	11,283	21,701	11,529	22,124	11,776
OCT	19,876	10,293	20,191	10,217	20,585	10,506
NOV	16,484	8,434	18,853	9,289	19,238	9,518
DEC	16,043	8,300	19,247	8,833	19,639	9,121
TOTALS		114,315		118,357		121,852

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation and are consistent with values shown in Col. (19) of Schedule 2.3 and Col (2) of Schedule 3.3.

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CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990s and has since utilized the process to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of potential new power plants, the primary subjects of this document, are determined as part of the IRP process work. This section discusses how FPL applied this process in its 2007 and early 2008 resource planning work.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental "steps" to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Evaluate the competing options and resource plans in regard to system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

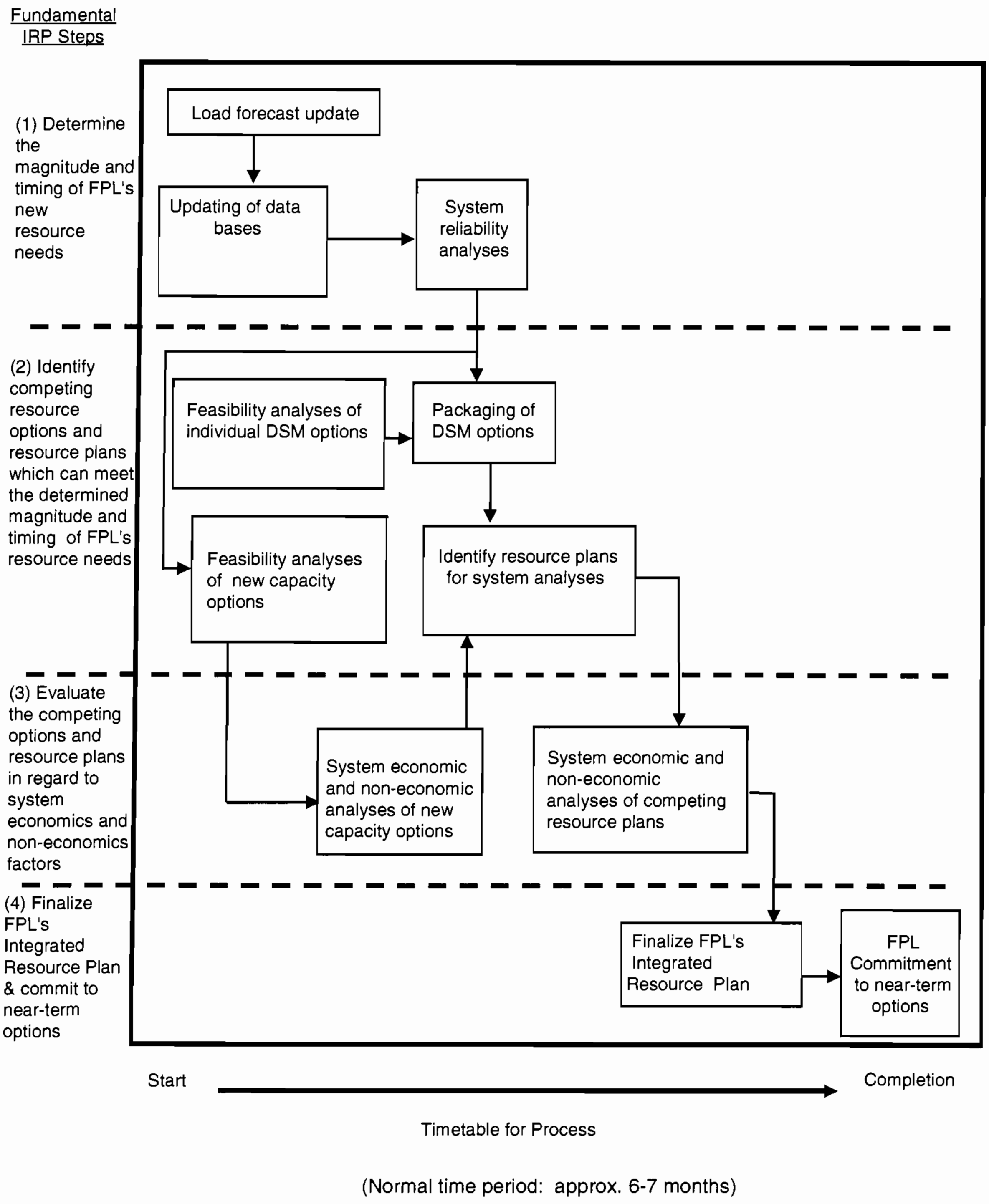

Figure III.A.1: Overview of FPL's IRP Process

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of these four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed. Also determined in this step is when the MW are needed to meet FPL's planning criteria. This step is often referred to as a reliability, or resource adequacy, assessment for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include: delivered fuel price projections, current financial and economic assumptions, and power plant capability and reliability assumptions. FPL also includes key assumptions regarding three specific resource areas: (1) near-term construction capacity additions, (2) firm capacity power purchases, and (3) DSM implementation.

The first of these assumptions is based on FPL's ongoing engineering and construction activities to add near-term capacity. These construction activities include two new combined cycle (CC) units at FPL's West County Energy Center (WCEC) site scheduled to come in-service by mid-2009 and mid-2010 respectively. FPL selected these CC units, designated as WCEC 1 & 2, after conducting a Request for Proposals (RFP) solicitations and evaluating the options received in response to the RFP. The need for these additions was approved by the FPSC, and the Governor and Cabinet, acting as the Siting Board, approved FPL's Site Certification Application for the units.

The second of these assumptions involves firm capacity power purchases. These firm capacity purchases are from a combination of utility and independent power producers. Details, including the annual total capacity values for these purchases are presented in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's recent resource planning work.

The third of these assumptions involves DSM. Since 1994, FPL's resource planning work has assumed that the DSM MW called for in FPL's approved DSM Goals will be achieved per plan as has historically been the case. This was again the case in FPL's most recent planning work as its new DSM Goals that address the years 2005 through 2014, and that were approved by the FPSC in August 2004, are assumed to be achieved per plan. In addition, FPL's resource planning also incorporated a significant amount of additional cost-effective DSM through 2014 that FPL identified after FPL's DSM Goals had been set. In addition, FPL is also assuming continued DSM implementation in 2015 - 2017 at annual implementation rates commensurate with DSM implementation rates projected for the years immediately preceding 2014. In total, these projected DSM efforts will result in FPL implementing approximately 1,539 MW of cost-effective DSM from August 2006 through August 2017 beyond the significant amount of DSM previously achieved by FPL. These additional MWs of DSM were also accounted for prior to making projections of new resource needs.

These key assumptions, plus the other updated information, are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's resource needs. This determination is accomplished by system reliability analyses which are typically based on a dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry.

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the generation resource adequacy of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss–of-load probability or LOLP. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of the "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

The result of the first fundamental step of resource planning is a projection of how many new MW of resources are needed to meet both reserve margin and LOLP criteria, and thus maintain system reliability, and of when the MW are needed. Information regarding the timing and magnitude of these resource needs is used in the second fundamental step: identifying resource options and resource plans that can meet the determined magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, feasibility analyses of new capacity options are conducted to determine which new capacity options appear to be the most competitive on FPL's system. These analyses also establish capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. In similar analyses, feasibility analyses of new DSM options and/or continued growth in existing DSM options are conducted.

The individual new resource options emerging from these feasibility options are then typically "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet and/or dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans in Regard to System Economics and Non-Economic Factors:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for evaluating these resource options and resource plans. In 2007, once the resource plans were developed, FPL utilized the P-MArea production cost model and a Fixed Cost Spreadsheet to perform the economic analyses. The P-MArea model is the model used by FPL to develop the Fuel Cost Budget and to conduct other production cost-related analyses.

FPL also utilized several other models in the economic evaluation portion of its resource planning work. For DSM analyses, FPL used its DSM cost-effectiveness model; an FPL spreadsheet model utilizing the FPSC's approved methodology for analyzing the cost-effectiveness of individual DSM measures/programs, and its non-linear programming model for analyzing the potential for lowering system peak loads through additional load management capacity.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the intent of minimizing FPL's leveled system average rate (i.e., a Rate Impact Measure or RIM methodology). However, in cases in which the DSM contribution was assumed as a given and the only competing options were new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. Consequently, the competing options and plans were evaluated on a cumulative present value revenue requirement (CPVRR) basis.

Other factors are also included in FPL's evaluation of resource options and resource plans. While these factors may have an economic component or impact, they are often discussed in quantitative, but non-economic terms, such as percentages, etc. rather than in terms of dollars. These factors are often referred to by FPL as "system concerns" that include maintaining/enhancing fuel diversity in the FPL system, maintaining a regional imbalance between load and generating capacity, particularly in Southeastern Florida, and moving in the direction of lowering system carbon dioxide (CO_2) emissions. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL's system, both the economic and non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps were used to develop the future generation plan. This plan is presented in the following section.

III.B Incremental Resource Additions

FPL's projected incremental generation capacity additions/changes for 2008 through 2017 are depicted in Table III.B.1 (the planned DSM additions through 2017 were shown previously in Table I.D.1). These capacity additions/changes result from a variety of actions including: changes to existing units (which are frequently achieved as a result of plant component replacements during major overhauls), changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, increases in generating capacity at FPL's four existing nuclear units, and by construction of both committed and proposed new generating units.

As shown in Table III.B.1, the capacity additions are largely made up of committed new construction, new purchases, and proposed self-build alternatives. (The additional DSM MW are not presented in this table but have been accounted for prior to making these new capacity option projections.) In 2009, the table shows previously committed generation additions: the new 1,219 MW CC unit at the West County Energy Center (WCEC) that is scheduled to be placed into service in June 2009 (WCEC Unit 1), and a second 1,219 MW CC unit at WCEC (WCEC Unit 2) that is scheduled to be placed into service in June 2010.

FPL is also currently assuming, for planning purposes, that contract extensions and/or new contracts will be reached with several existing renewable energy suppliers whose contracts with FPL are set to expire within this ten-year period. In addition, FPL's resource plan reflects its intent to obtain additional capacity and/or energy from the Renewable RFP solicitations or its own renewable energy development efforts.

For purposes of this planning document, FPL is assuming that 269 MW of firm capacity from renewable facilities will be added to FPL's system in the ten-year reporting period. This is discussed further in Section III.F.

In addition, FPL will be adding approximately 414 MW of proposed capacity uprates to FPL's four existing nuclear units in the 2011 and 2012 time period. Three uprates are projected to come in-service in December 2011, May 2012, and June 2012, respectively. Therefore, the 310 MW of capacity from these three units is accounted for in Summer reserve margin calculations beginning with the Summer of 2012. The fourth uprate is projected to come in-service in December 2012. Therefore, its 104 MW of capacity is accounted for in Summer reserve margin calculations beginning with the Summer of 2013.

Also projected is the proposed addition of a third new 1,219 MW unsited CC unit at the West County Energy Center site (WCEC 3) similar to the WCEC 1 & 2 units. This proposed new unit would have a June 2011 in-service date.

For purposes of this planning document, FPL also projects the construction of one unsited CC in 2014, and two unsited CC in 2016 to meet its remaining capacity needs through 2017. As an alternative to the 2014 unsited CC unit, FPL is currently evaluating the repowering of existing plants that would be completed in 2013 and 2014. The potential repowering projects are not shown in the table because FPL is currently analyzing these potential additions at the time the 2008 Site Plan is being prepared.

Table III.B.1: Projected Capacity Changes for FPL [1]

Projected Capacity Changes and Reserve Margins for FPL [1]			
		Net Capacity Changes (MW)	
		Winter [2]	Summer [3]
2008	Changes to Existing Units	41	14
	Changes to Existing Purchases [4]	(836)	---
2009	West County Unit #1 [5]	---	1,219
	Changes to Existing Units	28	1
	Changes to Existing Purchases [4]	(326)	(431)
2010	West County Unit #1 [5]	1,335	---
	West County Unit #2 [5]	---	1,219
	Extension Renewable Capacity Purchases	98	98
	Changes to Existing Purchases [4]	(559)	(455)
2011	West County Unit #2 [5]	1,335	---
	West County Unit # 3 [5]	---	1,219
	New Renewable Capacity Purchases	---	32
	Extension Renewable Capacity Purchases	45	45
	Changes to Existing Purchases [4]	(46)	(45)
2012	Changes to Existing Purchases [4]	---	(156)
	West County Unit # 3 [5]	1,335	---
	New Renewable Capacity Purchases	126	94
	Changes to Existing Nuclear Units	103	310
2013	Changes to Existing Nuclear Units	311	104
	Changes to Existing Purchases [4]	(180)	---
2014	Unsited 3 x 1 CC #1 [5]	---	1,219
2015	Unsited 3 x 1 CC #1 [5]	1,335	---
2016	Unsited 3x1 CC # 2 [5]	---	1,219
	Unsited 3x1 CC # 3 [5]	---	1,219
	Changes to Existing Purchases [4]	(930)	(1,311)
2017	Unsited 3x1 CC # 2 [5]	1,335	---
	Unsited 3x1 CC # 3 [5]	1,335	---
	Changes to Existing Purchases [4]	(390)	---
	TOTALS =	**5,495**	**5,614**

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are values for January of year shown.
(3) Summer values are values for August of year shown.
(4) These are firm capacity and energy contracts with QF, Utilities and other purchases. See Table I.B.1 and Table I.B.2 for more details.
(5) All new unit additions are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

III.C Issues Impacting FPL's Resource Planning Work

FPL's 2007 and early 2008 planning efforts have continued to address two issues, or system concerns, that were identified in previous Site Plans as being items of on-going importance. Those two system concerns are: (1) the need to maintain fuel diversity in the FPL system and (2) the need to address the imbalance between regional load and generating capacity located in Southeastern Florida.

In addition, a third factor affecting resource planning was introduced in 2007: Florida Governor Crist's Executive Orders. These Orders addressed a number of issues including two of particular interest to electric utilities. The first of these was a goal to provide 20% of the energy produced by electric utilities from renewable, non-emitting sources. The second was to move in the direction of significantly reducing greenhouse gas emissions by 2017 and in later years.

1. **System Fuel Diversity**

FPL is working to increase system fuel diversity in variety of ways. In 2007, FPL sought approval from the FPSC to add two new advanced technology coal units to its system. These two new units would have been placed in-service in 2013 and 2014. However, due to concerns over greenhouse gas emissions, FPL was unable to obtain approval for these units. Consequently, FPL does not believe that new advanced technology coal units are viable generation options for the ten-year reporting period of this Site Plan.

FPL also sought approval for increased nuclear generation capacity in 2007 in two filings with the FPSC. The first filing was to increase capacity at each of FPL's four existing nuclear units by 103 or 104 MW. These capacity "uprates", that in total will add 414 MW to the FPL system in the 2011/2012 time period, were approved by the FPSC in January 2008. The second filing was for approval for FPL to proceed with plans and expenditures for two new nuclear units at FPL's existing Turkey Point site. These two new nuclear units are projected to add 2,200 to 3,040 MW to FPL's system, with the MW value dependent upon the technology eventually selected by FPL. The first of these units is projected to come in-service in 2018 (i.e., outside of the ten-year reporting period of this document) and the second unit to come in-service in 2020. The FPSC voted to approve the need for these two new nuclear units on March 18, 2008 and the FPSC is expected to issue the final order approving the units by mid-April 2008.

FPL also has been involved in activities to investigate adding or maintaining renewable resources as a part of its generation supply. One of these activities is a variety of discussions with existing facilities aimed at maintaining or extending current agreements that are scheduled to end during the ten-year reporting period of this document. Another activity is to attempt to solicit cost-effective new renewable projects. FPL issued a Request for Proposals (RFP) for new renewable energy capacity and energy in 2007 and plans to issue another one in April 2008, Other efforts to utilize renewable energy are discussed in Section III.F.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance fuel diversity in its capacity resource mix. FPL also plans to maintain the ability to utilize fuel oil at those existing units that have that capability, although cost factors currently limit the expected use of these facilities.

2. **Southeastern Florida Imbalance**

In recent years an imbalance had developed between regionally installed generation and peak load in Southeastern Florida. A significant amount of energy required in the Southeastern Florida region during peak periods was being provided through the transmission system from plants located outside the region. FPL's prior planning work concluded that either additional installed capacity in this region, or transmission capacity capable of delivering additional electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location, three recent capacity additions: Turkey Point 5, WCEC Units 1 & 2, were evaluated as the most cost-effective options to meet FPL's 2007, 2009, and 2010 capacity needs, respectively. Adding these units will significantly reduce the imbalance between generation and load in Southeastern Florida.

In addition, FPL is proposing to add the WCEC 3 unit in 2011, and will be adding the already approved plans to increase capacity at FPL's existing two nuclear units at Turkey Point in 2011/2012. The result of these committed and proposed generating unit additions in Southeastern Florida are expected to address the imbalance for most, if not all, of the 2008-2017 reporting period addressed in this document. However, the Southeastern Florida imbalance will remain a consideration in FPL's on-going resource planning work.

3. **Governor Crist's Executive Orders**

The Executive Orders, particularly the portions directing significant increases in renewable, non-emitting energy and decreases in greenhouse gas emissions, are being addressed by FPL in a variety of ways. In regard to renewable energy, FPL's efforts to procure capacity from renewable energy sources, and to build its own renewable energy facilities, is discussed in detail in Section III.F.

These renewable energy efforts have the potential to help lower greenhouse gas emissions. In addition, significant reductions (particularly of carbon dioxide, CO_2) will be accomplished by the approved capacity uprates at FPL's existing nuclear units and the proposed two nuclear units at FPL's existing Turkey Point site. Further reductions in greenhouse gas emissions are also expected from increasing the overall fuel efficiency of FPL's system through the addition of the approved new generating units WCEC 1 & 2, and proposed new WCEC 3 unit. FPL will also continue to look for cost-effective ways to further improve the efficiency of its system that will lead to even more greenhouse gas emission reductions.

Another important potential strategy that could help achieve these objectives is "repowering" one or more of FPL's existing generating plants. The repowering plan consists, in part, of replacing an existing steam plant with a heat rate of about 10,000 Btu/kWh, with a new state-of-the-art advanced combined cycle unit that uses natural gas as the primary fuel, with a heat rate of less than 6,600 Btu/kWh. In addition, this new, highly efficient, repowered unit would result in a net increase in generating capacity.

The principal advantage of repowering is that, in addition to providing a net increase in generating capacity to meet growing demand, in a manner that is cost-competitive with adding a new generating unit, the repowering also converts a significant amount of existing, low efficiency, steam generation that utilizes fuel oil as much as, if not more than, natural gas, into an equivalent amount of highly efficient, low emission, gas-fueled, advanced combined cycle generation and thereby reduces fuel use and air emissions, including CO_2 emissions. As a result, such a repowering strategy could enable FPL to economically reduce, by 2017, CO_2 emissions to the level of CO_2 emissions in 2000, consistent with the 2017 CO_2 emissions target proposed in 2007 by Governor Crist, while still meeting FPL customers' electricity needs.

Before FPL can take concrete steps aimed at implementing a repowering strategy, it must complete a detailed evaluation of all aspects of repowering in order to ensure that its implementation would be beneficial to FPL's customers.

FPL's system CO_2 emission rate (amount of CO_2 emitted per MWh of electricity generated) is already relatively low due in large part to the overall efficiency of FPL's system. The efforts described above have the potential not only to continue the trend of steadily lowering FPL's already low CO_2 emission rate, but also to begin to lower total system CO_2 emissions despite increasing population growth.

III.D Demand Side Management (DSM)

FPL offers a wide variety of cost-effective DSM programs and a DSM-based renewable energy option to its customers. In addition, FPL is actively engaged in DSM research and development. These DSM efforts are discussed in the remainder of this section.

RESIDENTIAL DSM PROGRAMS

1. **Residential Building Envelope:** Offers incentives to residential customers to install energy efficient roof and ceiling insulation measures. FPL offers a maximum incentive of $1,676 per summer kW for ceiling insulation, a maximum incentive of $706 per summer kW for reflective roofs, and $1,518 per summer kW for other roofing technologies.

2. **Duct System Testing and Repair:** Provides reduced cost duct system testing to identify leaks in air conditioning duct systems, and encourages the repair of those leaks by qualified contractors. Incentives are offered for duct system repair. The maximum incentive is $466 per summer kW reduction.

3. **Residential Air Conditioning:** Offers incentives to customers to purchase higher efficiency heating, ventilating, and air conditioning equipment with incentive levels at a maximum of $1,429 and $1,643 per summer kW reduction for straight cooling and heat pumps, respectively. The program includes additional incentives for: 1) plenum repair measure, with a maximum incentive level of $412 per summer kW reduction; 2) air handler units with electronically commutated motors with a maximum incentive of $208 per summer kW; and, 3) units properly sized using FPL approved sizing software with a maximum incentive of $272 per summer kW.

4. **Residential Load Management (On Call Program):** Offers load control of major appliances/household equipment to residential customers in exchange for monthly electric bill credits. Direct load control equipment is installed on selected customer end-use equipment, allowing FPL to control these customer loads as needed. Qualifying equipment (and applicable monthly credits) includes central electric air conditioners ($3.00 for cycle units, and $9.00 for shed units), central electric heaters ($2.00 for cycle, and $4.00 for shed), conventional electric water heaters ($1.50), and swimming pool pumps ($3.00).

5. **Residential New Construction (BuildSmart):** Encourages the design and construction of energy efficient homes by offering education to contractors on energy efficiency measures, and providing construction design reviews and home inspections.

6. **Residential Low Income Weatherization:** Combines energy audits and incentives to encourage low income housing administrators to retrofit homes with energy efficiency measures. The housing authorities include: weatherization agency providers (WAPS), non-weatherization agency providers (non-WAPS), and other providers approved by FPL. The incentives are used by these providers to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting. FPL offers incentives for HVAC maintenance ($45), reduced air infiltration measures ($60), and room air conditioning replacement ($25).

7. **Residential Conservation Service:** Offers a walk-through energy audit, a computer generated Class A audit, and a customer-assisted energy audit. For customer-assisted energy audits, a mail-in, phone, and Internet audit option may be offered. FPL does not apply demand and energy savings from this program towards its DSM Goals.

BUSINESS DSM PROGRAMS

1. **Business Heating, Ventilating, and Air Conditioning (HVAC):** Offers business customers financial incentives to upgrade to higher efficiency HVAC equipment that exceed the minimum efficiencies mandated by the U.S. Department of Energy. The current FPL program includes: 1) a maximum thermal storage incentive up to $898 per summer kW reduction; 2) a maximum incentive for chillers up to $99 per summer kW; 3) incentives for energy recovery ventilator units with a maximum incentive up to $417 per summer kW reduction; 4) incentives for direct expansion (DX) units up to $168 per summer kW reduction and up to $498 per summer kW for efficient air conditioning room units; 5) a maximum incentive of $627 per summer kW for demand control ventilation systems including kitchen hood control; and 6) a maximum incentive of $102 per summer kW for electrically commutated motors for air conditioning systems.

2. **Business Efficient Lighting:** Offers business customers financial incentives to install high efficiency lighting measures at the time of replacement. The FPL current program offers an incentive of $0.65 to $2 per lamp on linear fluorescent plus a schedule of incentives for other efficient lighting technologies.

3. **Business Building Envelope:** Offers financial incentives to business customers to install high efficiency building envelope measures such as roof/ceiling insulation and reflective roof coatings. The current incentive structure offers incentives for summer kW reductions with a maximum incentive of $185 for ceiling insulation, $219 for roof insulation, $579 for reflective roofs, and $429 for window treatments.

4. **Business Custom Incentive:** Serves as a "catch-all" program for cost-effective business efficiency measures which are not included in other FPL programs. DSM measures must reduce or shift at least 25 kW during peak hours, have verifiable demand and energy savings, and pass FPL's cost-effectiveness testing.

5. **Business On Call:** Offers load control of central air conditioning units to both small non–demand-billed, and medium demand-billed, business customers in exchange for monthly electric bill credits. FPL offers incentive payments of $2.00 per ton.

6. **Commercial Industrial Demand Reduction (CDR):** Reduces peak demand by allowing the direct control of customer loads of 200 kW or greater during periods of extreme demand or capacity shortages. Participants contract for a firm demand level which may not be exceeded during load control periods. In return, participants receive a monthly credit of $4.68 per kW used during a specified controllable rating period, less their contracted firm demand. Any kW used in excess of the contracted firm demand level is re-billed at $4.68 per kW, plus a $0.99 penalty charge per kW of excess kW for each month of rebilling. Participants must provide a 5-year termination notice to discontinue service under this rider.

7. **Business Energy Evaluation:** Offers free standard level energy evaluations on-site and on-line. More detailed evaluations are available through this audit program with costs shared between FPL and the participating customer. Participation in FPL's other business DSM programs is promoted through this program.

8. **Commercial/Industrial Load Control:** Reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits. (This program was closed to new participants in 2000).

9. **Business Water Heating:** Encourages the installation of energy-efficient heat recovery units or heat pump water heaters. A maximum incentive of $881 per summer kW reduction is available.

10. **Business Refrigeration:** Encourages the installation of controls and equipment to reduce the usage of electric strip heat for defrosting purposes. FPL offers a maximum incentive of $80 per summer kW reduction.

11. **Cogeneration and Small Power Production:** Facilitates FPL compliance with all regulatory requirements concerning qualifying facilities and small power producers. One role of the program is to assist customers in the evaluation of potential cogeneration

projects, including self-generation. FPL does not project demand and energy savings from this program towards its DSM Goals.

RENEWABLE ENERGY PROGRAM

Green Power Program (marketed as the *Sunshine Energy* ® program): A voluntary program providing interested residential and business customers with the opportunity to support renewable energy development. The program includes a special tariff, under which participating customers voluntarily pay a $9.75 monthly premium. In exchange, FPL purchases a 1,000 kWh block of tradable renewable energy credits. For every 10,000 residential customers participating in the program, FPL will cause to be developed 150 kW of solar capacity in Florida.

RESEARCH AND DEVELOPMENT PROGRAMS

Conservation Research and Development Program (CRD): An umbrella research project under which new DSM technologies are analyzed. Several FPL DSM programs have emerged from the CRD program, including the business Building Envelope, Business On Call, and Residential New Construction programs. The program has also resulted in the addition of cost-effective measures to existing programs, such as the proposed inclusion of Energy Recovery Ventilators to the Business HVAC Program. FPL operates the CRD program based on DSM Plan approval, or for 6 years, whichever occurs first, with a spending cap of $2,500,000 for the period.

Residential Thermostat Load Control Pilot Project: On June 15, 2007 FPL filed a petition with the Commission for the Residential Thermostat Load Control Pilot Project. A typical barrier to customer acceptance of utility load control programs is reluctance to surrender control of heating and air conditioning appliances. Consequently, for an initial 24-month period, FPL is proposing to evaluate whether the benefits of the existing On-Call Program can be expanded through use of a new generation of communication and control technologies that put residential customers in charge of decisions that could lower energy costs, while allowing customers to override FPL control of their heating and air conditioning appliances. The Commission approved FPL's request on August 14, 2007, and issued Consummating Order 07-0719 TRF-EG on September 28, 2007.

DSM SUMMARY:

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include both conservation initiatives and load management. FPL's DSM efforts through 2007 have resulted in a cumulative Summer peak reduction of approximately 3,958 MW at the generator and an estimated cumulative energy saving of approximately 42,301 Gigawatt Hour (GWh) at the generator. Accounting for reserve margin requirements, FPL's DSM efforts through 2007 have eliminated the need to construct the equivalent approximately 12 new 400 MW generating units.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy for FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV bulk transmission lines that must be certified under the Transmission Line Siting Act.

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	St. Johns [1/]	Pringle	25	Dec-08	230	759
FPL	Manatee	BobWhite	30	Dec-11	230	1190

1/ Final order certifying the corridor was issued on April 21, 2006. This project will be completed in two phases. Phase I consists of 4 miles of new 230kV line (Pringle to Pellicer) and is scheduled to be completed by Dec-2008. Phase II consists of 21 miles of new 230kV line (St. Johns to Pellicer) and is scheduled to be completed by Jun-2011.

Table III.E.1: List of Proposed Power Lines

In addition, there will be transmission facilities needed to connect several of FPL's committed and proposed capacity additions to the system transmission grid. These transmission facilities for the committed capacity additions at the WCEC site; WCEC 1 & 2, and the proposed capacity addition at the WCEC site, WCEC 3, are described on the following pages.

III.E.1 Transmission Facilities for West County Energy Center (WCEC) Unit 1

The work required to connect West County Energy Center (WCEC) Unit 1 in 2009 with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 4 breakers to connect the three combustion turbines (CT) and one steam turbine (ST).
2. Construct two string busses to connect the collector busses and main switchyard to Corbett 230 kV Substation.
3. Add four main step-up transformers (3-370 MVA, 1-580 MVA), one for each CT, and one for the ST.
4. Add a new Bay #4 with 3 breakers at the Corbett 230 kV main switchyard. Connect one string buss from the collector yard and relocate the Alva 230 kV terminal from Bay #3 to new Bay #4.
5. Connect second collector string buss to Bay #3.
6. Add relays and other protective equipment.
7. Breaker replacements:
   Corbett Sub – Replace eight (8) 230 kV breakers
   Ranch Sub – Replace five (5) 138 kV breakers
   Midway Sub – Replace one (1) 230 kV breaker
   Levee Sub – Replace one (1) 230 kV breaker
   Dade Sub – Replace two (2) 138 kV breakers

II. Transmission:

1. No upgrades expected to be necessary at this time.

III.E.2 Transmission Facilities for West County Energy Center (WCEC) Unit 2

The work required to connect West County Energy Center (WCEC) Unit 2 in 2010 with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 4 breakers to connect the three combustion turbines (CT), and one steam turbine (ST).
2. Construct two string busses to connect the collector busses and main switchyard to Corbett 500kV Substation.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. At Corbett Sub, install one breaker and relocate Martin #2 500 kV line from Bay 2S to Bay 2N. Install one West County 500 kv string bus into Bay 2S.
5. At Corbett Sub, install one breaker and second West County 500 kV string bus into Bay 1S.
6. Add relays and other protective equipment.
7. Breaker replacements:
   Dade Sub – Replace one (1) 138 kV breaker
   Levee Sub – Replace four (4) 230 kV breakers
   Midway Sub – Replace three (3) 230 kV breakers
   Ranch Sub – Replace one (1) 230 kV breaker

II. Transmission:

1. No upgrades expected to be necessary at this time.

III.E.3 Transmission Facilities for West County Energy Center (WCEC) Unit 3

The work required to connect the proposed West County Energy Center (WCEC) Unit 3 in 2011 with the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with 4 breakers to connect the three combustion turbines (CT), and one steam turbine (ST).
2. Build new Sugar 230 kV substation on WCEC site.
3. Construct two string busses to connect the collector busses and main switchyard to Sugar 230kV Substation.
4. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
5. At Corbett Sub relocate Germantown 230 kV line terminal from Corbett to Sugar Sub.
6. At Corbett Sub relocate Broward/Yamato 230 kV line terminal from Corbett to Sugar Sub.
7. At Corbett Sub install new Sugar 230 kV line terminal in Bay 2W
8. At Corbett Sub, install one 5-ohm reactor on the 230 kV side of the 500/230 kV autotransformer.
9. Add relays and other protective equipment Corbett, Sugar, Rainberry, Broward, Yamato, and Marlin Subs

II. Transmission:

1. Relocate Germantown 230 kV line from Corbett to Sugar.
2. Relocate Broward/Yamato 230 kV line from Corbett to Sugar.
3. Construct one (1) mile 230 kV 1190 MVA line from Sugar to Corbett

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to utilize renewable energy technologies to meet its customers' current and future needs. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. For purposes of discussing FPL's renewable energy efforts in this document, those efforts will be placed into five categories.

1) **Early Research & Development Efforts:**

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970s in demonstrating the first residential solar photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-kilowatt (kW) system was placed into operation in 1984. (The system was removed in 1990 to make room for substation expansion after the testing of this PV installation was completed.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. The FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's recent Green Pricing effort (which is discussed below).

2) **Demand Side & Customer Efforts:**

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was no longer cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for 6 passive homes with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the Florida Public Service Commission to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test were deemed to be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, and various customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

FPL then analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach did not require all of its customers to bear PV's high cost, but facilitated the use of renewable energy by customers who were interested. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund that FPL used to make PV purchases in bulk quantities. PV modules were then installed and deliver PV-generated electricity directly into the FPL grid, thus displacing an equivalent amount of fossil fuel-generated electricity.

FPL's basic approach for this program, which has been termed Green Pricing, was initially discussed with the FPSC in 1994. FPL's efforts to implement this approach were then formally presented to the FPSC as part of FPL's DSM Plan in 1995 and FPL received approval from the FPSC in 1997 to proceed. FPL began the effort in 1998 and received approximately $89,000 in contributions (that significantly exceeded the goal of $70,000). FPL purchased the PV modules and installed them at FPL's Martin Plant site.

FPL initiated two new renewable efforts in 2000. FPL's first new initiative in 2000 was FPL's Photovoltaic Research, Development, and Education Project. This demonstration project's objectives were to: increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks (as well as the total annual energy capabilities of roof tile PV systems), and assess the homeowner's financial benefits and costs of PV roof tile systems. This project was completed in 2003.

The second effort initiated in 2000 was the Green Energy Project. The objectives of this Project were to: determine customer interest in an on–going renewable energy program, determine their price responsiveness and views on the different renewable technologies, and identify potential renewable energy supply sources that would meet the forecasted customer demand for this type of product. This Project formed the basis for FPL's Green Power Pricing Research Project, and then led to FPL's Business Green Energy Research Project.

Both the Green Power Pricing Research Project and the Business Green Energy Research Project examined the feasibility of purchasing tradable renewable energy credits generated from renewable resources including solar-powered technologies, biomass energy, landfill methane, wind energy, low impact hydroelectric energy, and/or other renewable sources. Customers who participate are charged a premium for purchasing the tradable renewable energy credits associated with electric energy generated by these sources.

Development of the Green Pricing Research Project was completed and filed with the FPSC in August 2003. As part of this process, a supply contract was put into place that allows FPL to match supply with demand for green energy. Tradable renewable energy credits are used to supply the renewable benefits required of this project. The FPSC approved the program on December 2, 2003 with program implementation during the first quarter of 2004. The project was offered to customers as FPL's Sunshine Energy® program. As part of the project, FPL made a commitment that 150 kW of solar capacity would be put in place for every 10,000 program participants. The Business Green Energy Research Project focused on determining the interest and needs for business customers in this area. In 2006 FPL petitioned the FPSC for approval to make the Green Pricing Research Project a permanent program and expand eligibility to business customers. This approval was granted in the fourth quarter of 2006.

As of the end of 2007, FPL had 36,918 participants in the program. The Rothenbach Park solar array in Sarasota was commissioned as the first large scale PV facility as a direct result of FPL's Sunshine Energy® renewable program. The 250 kilowatt solar array at Rothenbach Park is the largest solar facility in the state of Florida and one of the largest in the Southeastern United States. Construction on the new solar facility was completed in October 2007.

Several additional solar initiatives have also been developed through the Sunshine Energy program including support for schools. The Sunshine Energy program support of installing PV at schools is a continuation of previous FPL renewable activities involving schools. In 2003, as part of the State of Florida's PV for Schools program, FPL worked with three schools to install 4.8 kW PV systems.

FPL has also been investigating fuel cell technologies through monitoring of industry trends, discussions with manufacturers, and direct field trials. From 2002 through the end of 2005, FPL conducted field trials and demonstration projects of Proton Exchange Membrane (PEM) fuel cells with the objectives of serving customer end-uses while evaluating the technical performance, reliability, economics, and relative readiness of the PEM technology. The demonstration projects were conducted in partnership with customers and included 5 locations. The research projects were useful to FPL in identifying specific issues that can occur in field applications and the current commercial viability of this technology. FPL will continue to monitor the progress of these technologies and conduct additional field evaluations as significant developments in the fuel cell technologies occur.

In addition, FPL assists customers who are interested in installing PV equipment at their facilities. In support of Florida Administrative Code Rule 25-6.065, Interconnection of Small Photovoltaic Systems, FPL works with customers to interconnect these customer-owned PV systems. Through February 2008, approximately 110 customer systems (predominantly residential but with a few business systems) have been interconnected.

3) **Supply Side Efforts – Power Purchases:**

FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy and as-available energy have been purchased by FPL from these types of facilities. (Please refer to Tables I.B.1, I.B.2, and Table I.C.1).

FPL is seeking out cost-effective Power Purchase Agreements (PPAs) with any and all potential renewable energy providers. FPL issued a Renewable Request for Proposals (RFP) in 2007 that solicited proposals that offered capacity and/or energy from new renewable energy facilities. FPL plans to issue another Renewable Energy RFP in April 2008.

In regard to certain of the existing contracts that are currently scheduled to end in the near-term, and proposals resulting from the RFP process, FPL has assumed that some of this firm capacity will be available during the ten-year reporting period of this document through extended and/or new contracts. Firm renewable energy capacity from these sources, and from the FPL development activities discussed below, are assumed for planning purposes to provide 269 MW through this reporting period.

4) **Supply Side Efforts – FPL Facilities:**

FPL is in the process of developing a wind generation project on South Hutchinson Island, in St. Lucie County known as the "St. Lucie Wind project" which may consist of up to six (6) wind turbine generators (i.e., that do not use water or emit pollutants of any kind) capable of generating up to approximately 13.8 MW of wind generation. In addition, other wind development efforts are currently underway on Florida's coastline. FPL's goal is to start construction on the St. Lucie Wind project in 2008 with completion in 2009.

FPL is in the process of developing three large scale proposed solar thermal and/or photovoltaic generation facilities, with plans to install up to 350 MW of overall solar capacity by 2012. All of the solar generation facilities will be constructed within FPL's service territory. FPL is in the process of locating sites for these three solar projects. The first solar project is being designed to deliver up to 10 MW of solar generation to FPL's customers. One potential location for this project is at NASA's Kennedy Space Center in Brevard County Florida, where FPL and NASA are actively engaged in studies to determine if the Kennedy Space Center property may be feasible. The second solar project is being designed to deliver up to 20 MW. The third solar project is being designed for up to 50 MW of solar energy to FPL's customers and the existing Martin plant site is being considered as a potential location for the project. FPL is in the process of locating and/or finalizing sites for these three solar projects. FPL's goal is to start construction on all three solar projects mentioned in 2008 with completion in 2009/2010. FPL is also in the process of identifying the feasibility of technologies, locating sites and potential equipment suppliers for the remaining portion of the projected 350 MW of solar generation.

FPL is currently in the process of evaluation to determine each project's costs, impacts to the community and the environment as part of the overall development analysis. For those projects it determines to be both technically and economically viable, FPL plans to seek approval for the projects and recovery of the associated costs from the FPSC.

For planning purposes, FPL expects that the energy delivered from these proposed renewable facilities to be "as available", non-firm energy. This is due to the intermittent nature of these renewable resources. Once site-specific operating data has been gathered for an appropriate amount of time, FPL will then re-evaluate the actual output from each renewable facility to determine what portion, if any, of this output can be projected as firm capacity in its resource planning work.

5) **<u>Ongoing Research & Development Efforts:</u>**

FPL has developed alliances with several Florida Universities to promote development of emerging technologies. For example, an alliance as been established with the newly formed Center of Excellence in Ocean Energy Technology at Florida Atlantic University (FAU), which will focus on the commercialization of ocean current, ocean thermal (i.e., energy conversion as well as cold water air conditioning) and hydrogen technologies. FPL has been taking the lead in assisting FAU with the discussions being held with the U.S. Department of the Interior's Minerals Management Service Department (MMS). MMS is working to establish the permitting process for ocean energy development on the outer continental shelf.

FPL has also developed an alliance with the University of Florida to support their studies of biomass renewable potential and wind studies in the state. In addition, FPL has partnered with Florida Institute of Technology on fuel cell technology.

FPL has also been in discussion with several private companies on several emerging technology initiatives including ocean current, ocean thermal, hydrogen, fuel cell technology, biomass, biofuels and energy storage.

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fired generation. In the early 1980s FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership and additional purchases from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit 4 in 1989. Starting in 1997, petroleum coke was added to the fuel mix as a blend stock with coal at SJRPP.

The trend since the early 1990s has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective combined cycle generating units and the ready availability of natural gas. This planning document reflects an evolution in that trend in recognition that, although efficient gas-fired generation continues to provide significant benefits to FPL's customers, adding natural gas-fired additions exclusively would, in the long term, create an unbalanced generation portfolio. FPL has committed to add two new gas-fired CC units at the West County Energy Center (WCEC) site in 2009 and 2010, and is proposing to add a third CC unit at the WCEC site in 2011. These CC units will provide highly efficient generation that will benefit the entire FPL system by reducing transmission-related costs, mitigate the load-to-generation imbalance in Southeastern Florida, and dramatically improve the overall system generation efficiency.

FPL's future resource planning work will remain focused on identifying and evaluating alternatives that would maintain and/or enhance FPL's long-term fuel diversity. These fuel diverse alternatives may include: the purchase of power from renewable energy facilities, addition of FPL-owned renewable energy facilities, obtaining access to diversified sources of natural gas such as liquefied natural gas (LNG), preserving FPL's ability to utilize fuel oil at its existing units, and increased utilization of nuclear energy. (As previously discussed in the Executive Summary of this document, new advanced technology coal generating units are not considered as viable options in Florida in the ten-year reporting period of this document due to concerns over greenhouse gas emissions.) The evaluation of the feasibility and cost-effectiveness of these, and other possible alternatives, will be an ongoing part of future planning cycles.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2017 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

2. Fossil Fuel Price Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future generating capacity needs. FPL's forecasts are generally consistent with other published contemporary forecasts.

a) Fossil Fuel Price Forecast Methodology

Future oil and natural gas prices, and to a lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, coal, and petroleum coke. These drivers include: (1) current and projected worldwide demand for crude oil and petroleum products; (2) current and projected worldwide refinery capacity/production; (3) expected worldwide economic growth, in particular in China and the other Pacific Rim countries; (4) Organization of Petroleum Exporting Countries (OPEC) production and the availability of spare OPEC production capacity and the assumed growth in spare OPEC production capacity; (5) non-OPEC production and expected growth in non-OPEC production; (6) the geopolitics of the Middle East, West Africa, the Former Soviet Union, Venezuela, etc., as well as, the uncertainty and impact upon worldwide energy consumption related to U. S. and worldwide environmental legislation, politics, etc.; (7) current and projected North American natural gas demand; (8) current and projected U.S., Canadian, and Mexican natural gas production; (9) the worldwide supply and demand for LNG; and (10) the growth in solid fuel generation on a U. S. and worldwide basis.

The inherent uncertainty and unpredictability in these factors today and tomorrow clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal and petroleum coke) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed and utilized Low, Medium, and High price forecasts for oil, natural gas, and solid fuel in much of its 2007 and early 2008 resource planning work.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology: (1) for 2007 through 2009, the methodology used the July 31,2007 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil, and Henry Hub natural gas commodity prices; (2) for the next two years (2010 and 2011), FPL used a 50/50 blend of the July 31, 2007 forward curve and projections from The PIRA Energy Group; (3) for the 2012 through 2020 period, FPL used the annual projections from The PIRA Energy Group, and (4) for the period beyond 2020, FPL used the real rate of escalation provided in the Energy Information Administration (EIA) *Annual Energy Outlook 2007* publication. FPL assumed a 2.5% annual rate of escalation to convert real prices to nominal prices. In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach: (1) the price forecasts for Central Appalachian coal (CAPP), South American coal, and petroleum coke were provided by JD Energy; (2) the marine transportation rates from the loading port for coal and petroleum coke to an import terminal were also provided by JD Energy; (3) the Terminal Throughput Fee was based on a range of offers from comparable facilities throughout the Southeast U.S.. The coal price forecast for FPL's existing coal plants at SJRPP and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for oil, natural gas, coal, and petroleum coke prices were based upon the historical relationship of prices realized by FPL's customers compared to the average for the 2000 through 2006 time frame. FPL developed these forecasts to account for the uncertainty which exists within each commodity as well as across commodities. These forecasts reflect a range of reasonable forecast outcomes.

3. <u>Nuclear Fuel Cost Forecast</u>

This section reviews the various steps needed to fabricate nuclear fuel for delivery to the nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel costs.

a) Steps Required for Nuclear Fuel to be Delivered to FPL's Plants

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

Step (1) - Mining: Uranium is produced in many countries such as Canada, Australia, Khazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mine, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U3O8 (sometimes referred to as yellowcake).

Step (2) - Conversion: During the second step, the U3O8 is chemically converted into UF6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

Step (3) - Enrichment: The third step is called enrichment. Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 3% to as high as 5%). The output of this enrichment process is enriched uranium in the form of UF6.

Step (4) - Fabrication: During the last step, fuel fabrication, the enriched UF6 is changed to a UO2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) Mining: There is a significant volatility in the current uranium market. Demand is rather stable but inventory sales are a significant source of supply to complement outputs from production facilities. To the extent that source of supply can be restricted and inventories held from the market, price will rise significantly. The following are the current major contributors to this uranium price volatility:

- Hedge funds have been purchasing a significant amount of uranium, reducing availability of uranium.
- The large inventory from DOE is being withheld from the market due to political pressure.
- The Russians have announced that they would not supply down-blended weapons material to the U.S. government after 2013, for sales in the U.S. market.
- The U.S. Department of Commerce (DOC) has imposed restrictions on the import of nuclear fuel from France and Russia.

However, FPL expects these issues to be addressed within the next few years, returning price behavior to be more consistent with market fundamentals. A number of lawsuits have determined that DOC is illegally restricting the import of nuclear fuels. FPL expects the hedge funds to significantly reduce their activities, once supply starts outpacing demand. The high market price has led to significant investment to increase supply of uranium.

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert firms. There is a current shortage of uranium, which has pushed the current spot market price up. On the other hand, these higher market prices have motivated additional production expected to come on line over the next few years, which should bring uranium prices back to a level consistent with market fundamentals.

(2) Conversion: FPL's price forecast considers the construction of new nuclear units. Just like for raw uranium, an increase in demand for conversion services would result from this need. Insufficient planned production is currently forecast after 2013 to meet the higher demand scenario. As with additional raw uranium production, supply will expand beyond current level once more firm commitments are made to building new nuclear units.

(3) Enrichment: With no new production capacity, and if the current restrictions on imports of enrichment services from Russia and France continue, the current tight market supply for economically produced enrichment services will continue. A high projection of new nuclear unit construction shows a shortage of enrichment services, starting in 2010. Fortunately, there are a number of new facilities coming on line in that time frame and the current restrictions will be lifted, at least partially if not totally. In addition, as with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the Nuclear Regulatory Commission (NRC), not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply/demand is expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast

The calculations for the nuclear fuel costs are performed consistent with the method currently used for FPL's Fuel Clause filings, including the assumption of a fuel lease and the assumption of refueling outages every 18 months. The costs for each step to fabricate the nuclear fuels are added and capitalized to come up with the total costs of the fresh fuel to be loaded at each refueling (capitalized acquisition costs). The capitalized acquisition cost for each group of fresh fuel assemblies are then amortized over the energy produced by each group of fuel assemblies, and carrying costs are also added on the total un-recovered costs to come up with the total fuel costs to be charged to customers. FPL also adds 1 mill per kilowatt hour net to reflect payment to DOE for spent fuel disposal.

Schedule 5
Fuel Requirements [1/]

			Actual 2/		Forecasted									
	Fuel Requirements	Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	Nuclear	Trillion BTU	258	240	273	269	252	261	280	304	309	305	305	309
(2)	Coal	1,000 TON	3,367	2,961	3,668	3,986	3,686	3,972	3,806	3,794	3,795	3,793	3,805	3,791
(3)	Residual (FO6)- Total	1,000 BBL	15,297	15,524	8,580	6,083	6,074	1,653	1,847	2,471	1,951	2,727	1,989	1,794
(4)	Steam	1,000 BBL	15,297	15,524	8,580	6,083	6,074	1,653	1,847	2,471	1,951	2,727	1,989	1,794
(5)	Distillate (FO2)- Total	1,000 BBL	40	114	0	20	1,518	0	0	1	1	1	4	0
(6)	Steam	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)	CC	1,000 BBL	19	64	0	10	1513	0	0	1	0	1	0	0
(8)	CT	1,000 BBL	21	50	0	10	5	0	0	0	1	0	4	0
(9)	Natural Gas -Total	1,000 MCF	437,700	447,353	474,527	496,322	549,764	613,218	626,260	638,207	685,761	705,665	777,390	799,950
(10)	Steam	1,000 MCF	91,555	66,914	81,613	32,933	32,032	29,227	30,282	33,256	37,187	33,140	37,691	32,689
(11)	CC	1,000 MCF	341,229	370,039	392,775	463,148	517,479	583,991	595,978	604,938	648,434	671,785	738,734	765,830
(12)	CT	1,000 MCF	4,916	10,401	140	241	252	0	0	13	140	740	966	1,432

1/ Reflects fuel requirements for FPL only.
2/ Source: A Schedules.

Schedule 6.1
Energy Sources

			Actual 1/		Forecasted									
	Energy Sources	Units	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	Annual Energy Interchange 2/	GWH	10,440	10,688	11,294	11,267	9,191	6,370	6,435	6,748	6,923	7,070	832	0
(2)	Nuclear	GWH	23,533	21,899	24,455	24,110	22,617	23,376	25,150	27,276	27,751	27,353	27,355	27,751
(3)	Coal	GWH	6,168	6,856	6,953	7,530	7,011	7,504	7,223	7,201	7,202	7,198	7,222	7,195
(4)	Residual(FO6) -Total	GWH	9,586	9,651	5,740	4,030	4,018	1,094	1,221	1,634	1,290	1,803	1,316	1,186
(5)	Steam	GWH	9,586	9,651	5,740	4,030	4,018	1,094	1,221	1,634	1,290	1,803	1,316	1,186
(6)	Distillate(FO2) -Total	GWH	26	27	0	11	1,172	0	0	0	0	1	1	0
(7)	Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	9	6.7	0	8	1,171	0	0	0	0	1	0	0
(9)	CT	GWH	17	20	0	3	1	0	0	0	0	0	1	0
(10)	Natural Gas - Total	GWH	56,985	59,300	63,415	68,568	76,891	86,832	88,901	90,421	97,355	100,621	111,387	115,379
(11)	Steam	GWH	8,689	6,205	8,059	3,208	3,114	2,853	2,954	3,239	3,631	3,231	3,677	3,188
(12)	CC	GWH	47,871	52,717	55,343	65,337	73,754	83,979	85,948	87,180	93,711	97,320	107,619	112,055
(13)	CT	GWH	424	378	13	22	24	0	0	1	13	70	91	136
(14)	Other 3/	GWH	6,399	5,893	6,500	6,337	6,103	6,687	7,940	8,094	8,232	8,450	8,272	8,736
	Net Energy For Load 4/	GWH	113,137	114,315	118,357	121,852	127,004	131,862	136,871	141,374	148,752	152,495	156,384	160,246

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecst of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
4/ Net Energy For Load is also shown in Schedule 2.3.

Schedule 6.2
Energy Sources % by Fuel Type

	Energy Source	Units	Actual 1/ 2006	2007	Forecasted 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	Annual Energy Interchange 2/	%	9.2	9.3	9.5	9.2	7.2	4.8	4.7	4.8	4.7	4.6	0.5	0.0
(2)	Nuclear	%	20.8	19.2	20.7	19.8	17.8	17.7	18.4	19.3	18.7	17.9	17.5	17.3
(3)	Coal	%	5.5	6.0	5.9	6.2	5.5	5.7	5.3	5.1	4.8	4.7	4.6	4.5
(4)	Residual (FO6) -Total	%	8.5	8.4	4.8	3.3	3.2	0.8	0.9	1.2	0.9	1.2	0.8	0.7
(5)	Steam	%	8.5	8.4	4.8	3.3	3.2	0.8	0.9	1.2	0.9	1.2	0.8	0.7
(6)	Distillate (FO2) -Total	%	0.0	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CC	%	0.0	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	50.4	51.9	53.6	56.3	60.5	65.9	65.0	64.0	65.4	66.0	71.2	72.0
(11)	Steam	%	7.7	5.4	6.8	2.6	2.5	2.2	2.2	2.3	2.4	2.1	2.4	2.0
(12)	CC	%	42.3	46.1	46.8	53.6	58.1	63.7	62.8	61.7	63.0	63.8	68.8	69.9
(13)	CT	%	0.4	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
(14)	Other 3/	%	5.7	5.2	5.5	5.2	4.8	5.1	5.8	5.7	5.5	5.5	5.3	5.5
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules.
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1) Year	(2) Total Installed [1/] Capacity MW	(3) Firm Capacity Import MW	(4) Firm Capacity Export MW	(5) Firm QF MW	(6) Total Capacity Available [2/] MW	(7) Total Peak [3/] Demand MW	(8) DSM [4/] MW	(9) Firm Summer Peak Demand MW	(10) Reserve Margin Before Maintenance [5/] MW	(11) Reserve Margin Before Maintenance [5/] % of Peak	(12) Scheduled Maintenance MW	(13) Reserve Margin After Maintenance [6/] MW	(14) Reserve Margin After Maintenance [6/] % of Peak
2008	22,149	2,255	0	738	25,142	22,356	1,908	20,448	4,694	23.0	0	4,694	23.0
2009	23,369	1,824	0	738	25,931	22,792	2,034	20,758	5,173	24.9	0	5,173	24.9
2010	24,588	1,467	0	738	26,793	23,554	2,146	21,408	5,385	25.2	0	5,385	25.2
2011	25,807	1,499	0	738	28,044	24,191	2,264	21,927	6,117	27.9	0	6,117	27.9
2012	26,117	1,437	0	738	28,292	24,837	2,388	22,449	5,843	26.0	0	5,843	26.0
2013	26,221	1,437	0	738	28,396	25,414	2,516	22,898	5,498	24.0	0	5,498	24.0
2014	27,440	1,437	0	738	29,615	26,576	2,651	23,925	5,690	23.8	0	5,690	23.8
2015	27,440	1,437	0	738	29,615	27,241	2,790	24,451	5,164	21.1	0	5,164	21.1
2016	29,878	126	0	738	30,742	27,932	2,910	25,022	5,720	22.9	0	5,720	22.9
2017	29,878	126	0	738	30,742	28,621	3,030	25,591	5,151	20.1	0	5,151	20.1

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. All values are Summer net MW.
2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).
3/ These forecasted values reflect the 2008 load forecast without DSM. This load does include load from Lee County
4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2006-on for use with the 2008 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.
5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)
6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed [1/] Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available [2/] MW	Total Peak [3/] Demand MW	DSM [4/] MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance [5/] MW	Reserve Margin Before Maintenance [5/] % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance [6/] MW	Reserve Margin After Maintenance [6/] % of Peak
2007/08	23,535	2,288	0	738	26,561	22,332	1,649	20,683	5,878	28.4	0	5,878	28.4
2008/09	23,563	1,962	0	738	26,263	22,755	1,750	21,005	5,258	25.0	0	5,258	25.0
2009/10	24,898	1,501	0	738	27,137	23,454	1,814	21,640	5,497	25.4	0	5,497	25.4
2010/11	26,233	1,500	0	738	28,471	23,971	1,883	22,088	6,383	28.9	0	6,383	28.9
2011/12	27,671	1,626	0	738	30,035	24,487	1,954	22,533	7,502	33.3	0	7,502	33.3
2012/13	27,982	1,446	0	738	30,166	24,976	2,028	22,948	7,218	31.5	0	7,218	31.5
2013/14	27,982	1,446	0	738	30,166	26,290	2,106	24,184	5,982	24.7	0	5,982	24.7
2014/15	29,317	1,446	0	738	31,501	26,979	2,188	24,791	6,710	27.1	0	6,710	27.1
2015/16	29,317	516	0	738	30,571	27,690	2,264	25,426	5,145	20.2	0	5,145	20.2
2016/17	31,987	126	0	738	32,851	28,418	2,334	26,084	6,767	25.9	0	6,767	25.9

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.
2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).
3/ These forecasted values reflect the 2007 load forecast without DSM. This load does include load from Lee County
4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2007-on for use with the 2007 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.
5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)
6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2008														
Cape Canavaral	1	Brevard County	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	402,050	4	2	OT
Cape Canaveral	2	Brevard County	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	402,050	4	2	OT
Cutler	5	Miami Dade County	ST	NG	No	PL	No	Jan-08	Jun-08	Unknown	75,000	1	---	OT
Cutler	6	Miami Dade County	ST	NG	No	PL	No	Jan-08	Jun-08	Unknown	161,500	(8)	(11)	OT
Ft. Myers	2	Lee County	CC	NG	No	PL	No	Jan-08	Jun-08	Unknown	1,775,390	11	1	OT
Ft. Myers	3	Lee County	CT	NG	FO2	PL	PL	Jan-08	Jun-08	Unknown	376,380	8	2	OT
Lauderdale	4	Broward County	CC	NG	FO2	PL	PL	Jan-08	Jun-08	Unknown	526,250	(2)	(8)	OT
Lauderdale	5	Broward County	CC	NG	FO2	PL	PL	Jan-08	Jun-08	Unknown	526,250	(2)	(8)	OT
Port Everglades	1	City of Hollywood	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	247,775	(2)	(1)	OT
Port Everglades	2	City of Hollywood	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	247,775	(2)	(1)	OT
Port Evergladas	3	City of Hollywood	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	402,050	7	6	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	402,050	6	3	OT
Manatee	1	Manatee County	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	863,300	1	6	OT
Manatee	2	Manatee County	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	863,300	1	6	OT
Manatea	3	Manatee County	CC	NG	No	PL	No	Jan-08	Jun-08	Unknown	1,224,510	7	10	OT
Martin	1	Martin County	ST	FO6	NG	PL	PL	Jan-08	Jun-08	Unknown	934,500	(4)	(1)	OT
Martin	2	Martin County	ST	FO6	NG	PL	PL	Jan-08	Jun-08	Unknown	934,500	(5)	(8)	OT
Martin	3	Martin County	CC	NG	No	PL	No	Jan-08	Jun-08	Unknown	612,000	(8)	(7)	OT
Martin	4	Martin County	CC	NG	No	PL	No	Jan-08	Jun-08	Unknown	612,000	(7)	(6)	OT
Martin	8	Martin County	CC	NG	FO2	PL	PL	Jan-08	Jun-08	Unknown	1,224,510	25	11	OT
Putnam	1	Putnam County	CC	NG	FO2	PL	WA	Jan-08	Jun-08	Unknown	290,004	3	---	OT
Putnam	2	Putnam County	CC	NG	FO2	PL	WA	Jan-08	Jun-08	Unknown	290,004	3	---	OT
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	310,420	(2)	(1)	OT
Riviera	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	310,420	(7)	(7)	OT
Sanford	3	Volusia County	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	156,250	2	---	OT
Sanford	4	Volusia County	CC	NG	No	PL	No	Jan-08	Jun-08	Unknown	1,188,860	(8)	8	OT
Sanford	5	Volusia County	CC	NG	No	PL	No	Jan-08	Jun-08	Unknown	1,188,860	(5)	4	OT
St. Johns River Power Park	1	Duval County	BIT	BIT	Pet	RR	WA	Jan-08	Jun-08	Unknown	135,918	5	2	OT
St. Johns Rivar Power Park	2	Duval County	BIT	BIT	Pet	RR	WA	Jan-08	Jun-08	Unknown	135,918	5	2	OT
Scharer	4	Monroe, GA	BIT	BIT	No	RR	No	Jan-08	Jun-08	Unknown	680,368	4	2	OT
Turkey Point	1	Miami Dade County	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	402,050	3	2	OT
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	Jan-08	Jun-08	Unknown	402,050	3	4	OT
									2008 Changes/Additions Total:			**41**	**14**	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achievad by June. All other MW will be picked up in the following year.

Note 2: Changes shown include different ratings than shown in Schedule 1 due solely to ambient temperature consistent with those in FPL 's peak load forecast to maintain consistency in Reserve Margin calculation.

Schedule 8

Planned And Prospective Generating Facility Additions And Changes

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(5) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Const. Start Mo./Yr.	(10) Comm. In-Service Mo./Yr.	(11) Expected Retirement Mo./Yr.	(12) Gen. Max. Nameplate KW	(13) Net Capability Winter MW	(14) Net Capability Summer MW	(15) Status
ADDITIONS/ CHANGES														
2009														
Cutler	5	Miami Dade County	ST	NG	No	PL	No	Jan-09	Jun-09	Unknown	75,000	(1)	---	OT
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	402,050	3	---	OT
Martin	1	Martin County	ST	FO6	NG	PL	PL	Jan-09	Jun-09	Unknown	934,500	5	---	OT
Martin	2	Martin County	ST	FO6	NG	PL	PL	Jan-09	Jun-09	Unknown	934,500	5	---	OT
Martin	3	Martin County	CC	NG	No	PL	No	Jan-09	Jun-09	Unknown	612,000	1	1	OT
Manatee	1	Manatee County	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	863,300	7	---	OT
Manatee	2	Manatee County	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	863,300	7	---	OT
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	310,420	1	---	OT
West County Combined Cycle	1	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-09	Unknown	Unknown	---	1,219	U
											2009 Changes/Additions Total:	**28**	**1,220**	
2010														
West County Combined Cycle	1	Palm Beach County	CC	NG	FO2	PL	PL	Jan-07	Jun-09	Unknown	Unknown	1,335	---	U
West County Combined Cycle	2	Palm Beach County	CC	NG	FO2	PL	PL	Jan-08	Jun-10	Unknown	Unknown	---	1,219	U
											2010 Changes/Additions Total:	**1,335**	**1,219**	
2011														
West County Combined Cycle	2	Palm Beach County	CC	NG	FO2	PL	PL	Jan-08	Jun-10	Unknown	Unknown	1,335	---	U
West County Combined Cycle	3	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	Unknown	---	1,219	P
											2011 Changes/Additions Total:	**1,335**	**1,219**	
2012														
West County Combined Cycle	3	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	Unknown	1,335	—	P
St. Lucie Uprates	1	St. Lucie County	NP	UR	No	TK	No	See Note 3	Dec-11	Unknown	850,000	103	103	T
St. Lucie Uprates	2	St. Lucie County	NP	UR	No	TK	No	See Note 3	Jun-12	Unknown	723,775	—	103	T
Turkey Point Uprates	3	Miami Dade County	NP	UR	No	TK	No	See Note 3	May-12	Unknown	759,900	—	104	T
											2012 Changes/Additions Total:	**1,438**	**310**	
2013														
St. Lucie Uprates	2	St. Lucie County	NP	UR	No	TK	No	See Note 3	Jun-12	Unknown	723,775	103	---	T
Turkey Point Uprates	3	Miami Dade County	NP	UR	No	TK	No	See Note 3	May-12	Unknown	759,900	104	---	T
Turkey Point Uprates	4	Miami Dade County	NP	UR	No	TK	No	See Note 3	Dec-12	Unknown	759,900	104	104	T
											2013 Changes/Additions Total:	**311**	**104**	
2014														
Unsited 3x1 CC #1	1	Unknown	CC	NG	FO2	PL	PL	Jan-12	Jun-14	Unknown	Unknown	---	1219	P
											2014 Changes/Additions Total:	**0**	**1,219**	
2015														
Unsited 3x1 CC #1	1	Unknown	CC	NG	FO2	PL	PL	Jan-12	Jun-14	Unknown		1,335	---	P
											2015 Changes/Additions Total:	**1,335**	**0**	
2016														
Unsited 3x1 CC #2	2	Unknown	CC	NG	FO2	PL	PL	Jan-13	Jun-16			---	1219	P
Unsited 3x1 CC #3	*3*	*Unknown*	*CC*	*NG*	FO2	PL	PL	Jan-14	*Jun-16*	*Unknown*	*Unknown*	---	*1,219*	*P*
											2016 Changes/Additions Total:	**0**	**2,438**	
2017														
Unsited 3x1 CC #2	2	Unknown	CC	NG	FO2	PL	PL	Jan-14	Jun-16	Unknown	Unknown	1,335	---	P
Unsited 3x1 CC #3	3	Unknown	CC	NG	FO2	PL	PL	Jan-15	Jun-16	Unknown	Unknown	1,335	---	P
											2017 Changes/Additions Total:	**2,670**	**0**	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring later in the year will be picked up for reporting/planning purposes in the following year.

Note 2: Changes shown include different ratings than shown in Schedule 1 due solely to ambient temperature consistent with those in FPL 's peak load forecast to maintain consistency in Reserve Margin calculations.

Note 3: The nuclear uprates will be performed during the scheduled refueling outages for each unit.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit 1

(2) **Capacity**

a. Summer	1,219	MW
b. Winter	1,335	MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2007
b. Commercial In-service date:	2009

(5) **Fuel**

a. Primary Fuel	Natural Gas
b. Alternate Fuel	Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** U (Under construction, less than or equal to 50% complete)

(11) **Status with Federal Agencies:** U (Under construction, less than or equal to 50% complete)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2009 $/kW):	565	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2009 $kW-Yr)	11.65	
Variable O&M ($/MWH): (2009 $/MWH)	0.138	
K Factor:	1.5834	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit 2

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2008
b. Commercial In-service date: 2010

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** U (Under construction, less than or equal to 50% complete)

(11) **Status with Federal Agencies:** U (Under construction, less than or equal to 50% complete)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 88%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data **,*****

Book Life (Years):	25	years
Total Installed Cost (2010 $/kW):	519	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2010 $kW-Yr)	10.11	
Variable O&M ($/MWH): (2010 $/MWH)	0.138	
K Factor:	1.5873	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit 3

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2009
b. Commercial In-service date: 2011

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 93%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data **,*****

Book Life (Years):	25	years
Total Installed Cost (2011 $/kW):	715	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	72	
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2011 $kW-Yr)	11.63	
Variable O&M ($/MWH): (2011 $/MWH)	0.480	
K Factor:	1.4699	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** St. Lucie 1 Nuclear Uprate

(2) **Capacity**
a. Summer 103 MW (Incremental)
b. Winter 103 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2010
b. Commercial In-service date: 2011

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data** *

Book Life (Years):	25	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	3,054	(See Note (1) for explanation.)
Direct Construction Cost:	3,054	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) This value does not include a plant-specific portion of the early recovery of approx. $353 million of capital carrying costs in total associated with the uprates at the four existing nuclear units, nor a plant-specific portion of a projected $45 million in total for transmission costs associated with the uprates at the four existing nuclear units.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Turkey Point 3 Nuclear Uprate	
(2)	**Capacity**		
	a. Summer	104	MW (Incremental)
	b. Winter	104	MW (Incremental)
(3)	**Technology Type:**	Nuclear	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2010	
	b. Commercial In-service date:	2012	
(5)	**Fuel**		
	a. Primary Fuel	Uranium	
	b. Alternate Fuel	---	
(6)	**Air Pollution and Control Strategy:**		No change from existing unit
(7)	**Cooling Method:**		No change from existing unit
(8)	**Total Site Area:**		No change from existing unit
(9)	**Construction Status:**	T	(Regulatory approval received, but not under construction)
(10)	**Certification Status:**	T	(Regulatory approval received, but not under construction)
(11)	**Status with Federal Agencies:**	T	(Regulatory approval received, but not under construction)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		No change from existing unit
	Forced Outage Factor (FOF):		No change from existing unit
	Equivalent Availability Factor (EAF):		No change from existing unit
	Resulting Capacity Factor (%):		No change from existing unit
	Average Net Operating Heat Rate (ANOHR):		No change from existing unit
	Base Operation 75F,100%		No change from existing unit
(13)	**Projected Unit Financial Data** *		
	Book Life (Years):	20	years (Matches the current operating license period.)
	Total Installed Cost ($/kW): **	3,580	(See Note (1) for explanation.)
	Direct Construction Cost ($/kW):	3,580	(See Note (1) for explanation.)
	AFUDC Amount ($/kW):		(See Note (2) for explanation.)
	Escalation ($/kW):		(See Note (3) for explanation.)
	Fixed O&M ($/kW -Yr.):		There is no additional O&M impact from this project.
	Variable O&M ($/MWH):		There is no additional O&M impact from this project.
	K Factor:		(See Note (2) for explanation.)

NOTE:

(1) This value does not include a plant-specific portion of the early recovery of approx. $353 million of capital carrying costs in total associated with the uprates at the four existing nuclear units, nor a plant-specific portion of a projected $45 million in total for transmission costs associated with the uprates at the four existing nuclear units.

(2) Not applicable due to early recovery of capital carrying costs.

(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.

** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** St. Lucie 2 Nuclear Uprate

(2) **Capacity**
a. Summer 103 MW (Incremental)
b. Winter 103 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2010
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data *,****

Book Life (Years):	31	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	3,271	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	3,271	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) This value does not include a plant-specific portion of the early recovery of approx. $353 million of capital carrying costs in total associated with the uprates at the four existing nuclear units, nor a plant-specific portion of a projected $45 million in total for transmission costs associated with the uprates at the four existing nuclear units.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point 4 Nuclear Uprate

(2) **Capacity**
a. Summer 104 MW (Incremental)
b. Winter 104 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2011
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data *,****

Book Life (Years):	22	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	3,630	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	3,630	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) This value does not include a plant-specific portion of the early recovery of approx. $353 million of capital carrying costs in total associated with the uprates at the four existing nuclear units, nor a plant-specific portion of a projected $45 million in total for transmission costs associated with the uprates at the four existing nuclear units.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Combined Cycle

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2012
b. Commercial In-service date: 2014

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	
Resulting Capacity Factor (%):	Approx. 92%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2014 $/kW):	994	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2014 $kW-Yr)	14.74	
Variable O&M ($/MWH): (2014 $/MWH)	0.80	
K Factor:	1.481	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Combined Cycle

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2014
b. Commercial In-service date: 2016

(5) **Fuel**
a. Primary Fuel — Natural Gas
b. Alternate Fuel — Distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	
Resulting Capacity Factor (%):	Approx. 92%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2016 $/kW):	1,044	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2016 $kW-Yr)	15.49	
Variable O&M ($/MWH): (2016 $/MWH)	0.84	
K Factor:	1.481	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

West County Energy Center Unit 1

The new West County Energy Center Unit 1 that is scheduled to come in-service in 2009 does not require any “new” transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

West County Energy Center Unit 2

The new West County Energy Center Unit 2 that is scheduled to come in-service in 2010 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

WCEC Unit 3 by 2011

(1)	Point of Origin and Termination:	New Sugar Substation – Corbett Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	1 mile
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: May 2009 End date: November 2010
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$11,300,000
(8)	Substations:	New Sugar Substation and Corbett Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

St. Lucie 1 Nuclear Uprate

The St. Lucie 1 Nuclear Uprate that is scheduled to come in-service in 2011 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point 3 Nuclear Uprate

The Turkey Point 3 Nuclear Uprate that is scheduled to come in-service in 2012 does not require any “new” transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

St. Lucie 2 Nuclear Uprate

The St. Lucie 2 Nuclear Uprate that is scheduled to come in-service in 2012 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point 4 Nuclear Uprate

The Turkey Point 3 Nuclear Uprate that is scheduled to come in-service in 2012 does not require any "new" transmission lines.

Schedule 11.1

Existing FIRM and NON-FIRM Capacity and Energy by Primary Fuel Type
Actuals for the Year 2007

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	Summer (MW)	Summer (%)	Winter (MW)	Winter (%)	GWH	%
(1)	Coal	896	3.6%	902	3.3%	6,856	6.0%
(2)	Nuclear	2,939	11.7%	3,013	11.0%	21,899	19.2%
(3)	Residual	6,818	27.1%	6,876	25.1%	9,651	8.4%
(4)	Distillate	660	2.6%	781	2.9%	27	0.0%
(5)	Natural Gas	10,822	43.1%	11,922	43.6%	59,300	51.9%
(6)	***FPL Existing Units Total:***	***22,135***	***88.1%***	***23,494***	***85.9%***	***97,733***	***85.5%***
(7)	Renewables (Purchases)- Firm	157.6	0.6%	157.6	0.6%	1,201	1.1%
(8)	Renewables (Purchases)- Non-Firm	Not Applicable		Not Applicable		291	0.3%
(9)	***Renewable Total:***	***157.6***	***0.6%***	***157.6***	***0.6%***	***1,492***	***1.3%***
(10)	***Purchases Other:***	***2,835.0***	***11.3%***	***3,704.0***	***13.5%***	***15,090***	***13.2%***
(11)	***Total***	***25,127.6***	***100.0%***	***27,355.6***	***100.1%***	***114,315***	***100.0%***

Note:
(1) FPL Existing Units Total matches Total System found on Schedule 1.
(2) Net Energy for Load MWH matches Schedule 6.1

Schedule 11.2

Existing NON-FIRM Self-Service Renewable Generation Facilities
Actuals for the Year 2007

(1)	(2)	(3)	(4)	(5) = (3) - (4)
Type of Facility	**Installed Capacity (MW)**	**Projected Annual Output (MWH)**	**Annual Energy Sold to FPL (MWH)**	**Projected Annual Energy Used by Customer (MWH)**
Customer-Owned PV (less than 10 kw)	0.27	277.19	57.59	219.60

Notes:

(1) There were approximately 110 customer-owned operating PV facilities interconnected with FPL during this year.
(2) The Installed Capacity value is the sum of the nameplate ratings (AC kw) for all of the customer-owned PV facilities.
(3) The Projected Annual Output value is based on NREL's PV Watts program and the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.
(4) The Annual Energy Sold to FPL is an actual value from FPL's metered data for this year.
(5) The Projected Annual Energy Used by Customers is a projected value that is the difference between the Projected Annual Output value in column (2) and the actual Annual Energy Sold to FPL in column (4).

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered plant and animal species. Population growth in FPL's service area is continuing, which heightens competition for air, land, and water resources that are necessary to meet the increased demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

FPL has been recognized for many years as one of the leaders among electric utilities for its commitment to the environment. FPL's environmental leadership has been heralded by many outside organizations as demonstrated by a few recent examples. In 2004, FPL Group earned a first place ranking among U.S. power companies and second globally in a report from the World Wildlife Fund for voluntary commitments to limit CO_2 emissions. This commitment was made to support initiatives to better manage utility impacts on climate change through use of greenhouse gas emission reductions and improvements in energy efficiency. The report stated that this was "primarily due to the company's leadership in developing wind energy and their commitment to dramatically improve their efficiency." In January 2007, FPL joined with a diverse group of U.S.-based business market leaders and leading non-governmental organizations to form the U.S. Climate Action Partnership (USCAP) in recognition of the need for a national policy framework on climate change. USCAP has called upon the federal government to formulate mandatory economy-wide policies to reduce CO_2 emissions.

As a further demonstration of FPL's efforts in sustainability, the EPA and the Department of Energy gave an award to FPL for its Sunshine Energy® program which allows customers, who voluntarily choose to participate, to pay a premium for their electricity that is used to purchase renewable energy credits associated with electric energy generated from renewable energy sources. FPL Group, the parent corporation of FPL was also recently awarded its fourth number one rating of major electric utilities surveyed in an environmental assessment conducted by Innovest, an independent advisory group. This rating was in recognition of FPL Group's success in executing a strategy to become a clean energy provider harnessing primarily clean and renewable fuels while also boosting shareholder value. FPL Group was named one of the world's most Sustainable

Corporations in Global 100 and was one of only two utilities to be so named in the United States.

FPL has also been the recipient of earlier environmental awards and recognition. In 2001, FPL was awarded Edison Electric Institute's National Land Management Award for its stewardship of 25,000 acres surrounding its Turkey Point Plant. In 2001, FPL was awarded the 2001 Waste Reduction and Pollution Prevention Award from the Solid Waste Association of North America. FPL received the 2001 Program Champion Award from the Environmental Protection Agency's Wastewise Program. The Florida Department of Environmental Protection named FPL a "Partner for Ecosystem Protection" in 2001 for its emission-reducing "repowering" projects at its Fort Myers and Sanford Plants. FPL won the Council for Sustainable Florida's award in 2002 for its sea turtle conservation and education programs at its St. Lucie Plant. Finally, FPL has been recognized by numerous federal and state agencies for its innovative endangered species protection programs which include such species as manatees, crocodiles, and sea turtles.

As mentioned above, FPL Group has taken a leadership role to address climate change and the call for action for a national climate change policy. The decision to step into the forefront of this issue goes hang-in-hand with FPL Group's longtime commitment to managing operations with sensitivity to the environment.

FPL is taking action now in Florida to address climate change with a number of actions. According to the U.S. Department of Energy (DOE), FPL is the nation's leader among electric utilities for its energy efficiency/conservation achievement and is also ranked number three nationally in load management achievement. FPL's nationally recognized leadership in the implementation of demand side management (DSM) within its system has avoided the need to build the equivalent of 12 medium-sized power plants as discussed in Chapter III of this document. Also discussed in Chapter III are FPL's plans for adding a significant amount of renewable energy resources. FPL is also the nation's leader in "repowering," significantly increasing the efficiency of a number of its existing power plants while reducing FPL system emissions. In addition, FPL's future generation plans include nuclear uprates and two new nuclear units that are projected to significantly reduce air emissions in Florida.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Statement in 1992 to clearly define its position. This statement reflects how FPL incorporates environmental values into all aspects of its activities and serves as a framework for new environmental initiatives throughout the company. FPL's Environmental Statement is:

It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:

- Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
- Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
- Encourage the wise use of energy to minimize the impact on the environment.
- Communicate effectively on environmental issues.
- Conduct periodic self-evaluations, report performance, and take appropriate actions.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an environmental management system to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program that is discussed below. Other components include: executive management support and commitment, a dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to evaluate environmental performance, verify compliance with corporate policy as well as with legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and FPL policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2006 environmental outreach activities are noted in Table IV.E.1.

Table IV.E.1: 2007 FPL Environmental Outreach Activities

Activity	***# of Participants***
Visitors to Energy Encounter	20,000
Visitors to Manatee Park	150,000
Number of visits to FPL's Environmental Website	300,000
Number of pieces of Environmental literature distributed	>120,000

(All numbers are approximations.)

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified three Preferred Sites and eight Potential Sites for future generation additions. Preferred Sites are those locations where FPL has conducted significant reviews and has either taken action, or is planning to take action, to site new generation capacity. Potential Sites are those sites that have attributes that support the siting of generation and are under consideration as a location for future generation. Some of these sites are currently in use as existing generation sites and some are not. The identification of a Potential Site does not indicate that FPL has made a definitive decision to pursue generation (or generation expansion in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of a generator has been determined. The Preferred Sites and Potential Sites are discussed in separate sections below.

IV.F.1 Preferred Sites

FPL identifies three Preferred Sites in this Site Plan: the West County Energy Center (WCEC) adjacent to the existing Corbett FPL substation, the existing St. Lucie plant site, and the existing Turkey Point plant site. The West County Energy Center site is the location for combined cycle capacity additions FPL will make in 2009 and 2010, and is proposing to make in 2011. The St. Lucie site is the location for nuclear capacity additions that FPL will make in 2011 and 2012, and the plant site is also the location for a proposed wind generation addition that is proposed for 2009. The Turkey Point site is the location for nuclear capacity additions that FPL will make in 2012.

In regard to the WCEC site, combined cycle (CC) capacity additions, WCEC units 1 & 2, have been approved by the FPSC and by the Governor and Cabinet acting as the Siting Board. FPL is planning to file a need petition for the WCEC unit 3 combined cycle unit in April 2008.

In regard to the St. Lucie and Turkey Point sites, FPL petitioned the FPSC for approval of capacity uprates for the two existing nuclear units at each of these sites in September 2007. The FPSC approved the need and issued a Need Order for both Uprates in January 2008.

The existing Turkey Point plant site is also the proposed site for two new nuclear units, Turkey Point units 6 & 7. These two new nuclear units are proposed for 2018 and 2020, respectively. FPL filed for approval of a determination of need for these two new nuclear units with the FPSC in the second half of 2007. The FPSC voted to approve this request on March 18, 2008, and is expected to issue a final order approving the units in April 2008. These new nuclear units are not discussed in detail in this Site Plan because the units' projected in-service dates, fall outside of the 2008-2017 time period covered in this document.

The three Preferred Sites are discussed below.

Preferred Site # 1: West County Energy Center , Palm Beach County

FPL has identified the property adjacent to the existing Corbett Substation property in unincorporated western Palm Beach County as a Preferred Site for the addition of new generating capacity. The site was selected for the addition of two new combined cycle natural gas power plants with ultra-low sulfur light fuel oil (distillate) as a backup fuel. These units, WCEC 1 & 2, have been approved by both the FPSC and the Governor and Cabinet acting as the Siting Board. The units are scheduled to come in-service in 2009 and 2010, respectively. In addition, the site has also been selected as the location for a proposed third combined cycle unit, WCEC 3, projected to come in-service in 2011 if approved. FPL plans to file for FPSC approval of a determination of need for this unit in April 2008. If approved, all three combined cycle units will be identical in regard to technology and capacity.

The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections. The approved and proposed facilities would use natural gas as the primary fuel and state-of-the-art combustion controls.

a. U.S. Geological Survey (USGS) Map

A USGS map of the West County Energy Center (WCEC) plant site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the WCEC generating facilities at the site is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The site was inactive until February 2007 when construction of WCEC 1 & 2 was initiated. The site was previously dedicated to industrial and agricultural use. The site had been excavated, back-filled, and totally re-graded to an elevation approximately 10 feet. above the surrounding land surface. Prior to initiation of power plant construction, no structures were present on the site and vegetation was virtually non-existent. Structures are now being built on the site for work associated with WCEC 1 & 2.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The plant site had been significantly altered by the construction and operation of a limestone mine where vegetation had been cleared and removed. The surrounding land use is predominantly sugar cane agriculture and limestone mining. FPL's existing Corbett substation is located north of the site. The Arthur R. Marshall Loxahatchee National Wildlife Refuge is located to the south of the site.

2. Listed Species

Construction and operation of new units at the site is not expected to affect any rare, endangered, or threatened species. Wildlife utilization of the property is minimal as a result of the prior mining activities. Common wading birds can be observed on areas adjacent to, and occasionally within, the property. The property is adjacent to areas that have been identified as potential habitat for wood stork.

3. Natural Resources of Regional Significance Status

The construction and operation of gas-fired combined cycle generating facilities at this location are not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands including the Arthur R. Marshall Loxahatchee National Wildlife Refuge. Construction will not result in any onsite wetland impacts under federal, state, or local agency permitting criteria.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design of both the two approved units and the one proposed unit is a new 1,219 MW (Summer capacity) unit with each unit consisting of three new combustion turbines (CT) and three new heat recovery steam generators (HRSG) and a new steam turbine. Natural gas delivered via pipeline is the primary fuel type for this facility with ultra-low sulfur light fuel oil (distillate) serving as a backup fuel.

g. Local Government Future Land Use Designations

Local government future land use designation for the project site is "Rural Residential" according to the Palm Beach County Future Land Use Map. Designations for the area under the Palm Beach County Unified Land Development Code classified the project site and surrounding area as Special Agricultural District. The site has been granted conditional use for electrical power facilities under a General Industrial zoning district.

h. Site Selection Criteria Process

The site has been selected as a Preferred Site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues.

i. Water Resources

In regard to the two approved units, water from the Floridan Aquifer and surface water from the L10/L12 canal will be used for cooling, service, and process water. Water from the surficial aquifer will be treated and used for potable water unless water is available for purchase from Palm Beach County water municipality.

In regard to the proposed third unit, the primary water source for the project will be reclaimed (reuse) water that will come from Palm Beach County Water Utilities Department. FPL will obtain the necessary approvals to also supply Units 1 & 2 using reclaimed water after obtaining the necessary approvals for Unit 3. The Floridan and L10/L12 will remain as back up water supplies for the site. Reclaimed water will be used for cooling, service, and process water. Back-up water sources include utilizing the Floridan Aquifer allocation permitted for WCEC 1 & 2, potable water from Palm Beach County, and the L10/L12 canal when made available by the SFWMD. Water from the surficial aquifer will be treated and used for potable water unless water is available for purchase from Palm Beach County.

j. Geological Features of Site and Adjacent Areas

The site is underlain by approximately 13,000 feet of sedimentary rock strata. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine in origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, clay, and phosphate grains. The deepest formation in Palm Beach County on which significant published data are available is the Eocene Age Avon Park. Limited information is available from wells penetrating the underlying Oldsmar formation. The published information on the sediments comprising the formations below the Avon Park Limestone is based on projections from deep wells in Okeechobee, St. Lucie, and Palm Beach Counties.

Testing during construction of Exploratory Well 2 (EW-2) demonstrated the presence of a highly permeable zone (Boulder Zone) below a depth of 2,790 feet below pad level (bpl) overlain by a thick confining interval from approximately 2,000 to 2,790 feet bpl. The base of the Underground Source of Drinking Water (USDW) was identified between the depths of 1,932 and 1,959 feet bpl through interpretation of packer tests water quality data and geophysical logs. These conditions suggest that the hydrogeology of the EW-2 site is favorable for disposal of fluids via a deep injection well system.

k. Projected Water Quantities for Various Uses

In regard to the two approved units, the estimated quantity of water required for industrial processing for both units is approximately 450 gallons per minute (gpm) for uses such as process water and service water. Approximately 15 million gallons per day (mgd) in total of cooling water for the two generating units would be cycled through the addition of cooling towers.

In regard to the proposed third unit, the estimated quantity of water required for industrial processing is approximately 225 gallons per minute (gpm) for uses such as process water and service water. Approximately 7.5 million gallons per day (mgd) in total of cooling water for the one generating unit would be cycled through the addition of a cooling tower. Water quantities needed for other uses such as potable water are estimated to be approximately 35,000 gallons per day (gpd) for the entire WCEC site.

l. Water Supply Sources by Type

The two approved generating units will use available surface or ground water as the source of cooling water for the cooling towers. The cooling towers will also act as a heat sink for the facility process water. Such needs for cooling and process water will comply with the existing South Florida Water Management District (SFWMD) regulations for consumptive water use.

In regard to the proposed third unit, it will use reclaimed water as the primary source of cooling water for the cooling tower. The cooling tower will also act as a heat sink for the facility process water. Such needs for cooling and process water will comply with the existing SFWMD regulations for consumptive water use. In addition, reclaimed water used by WCEC 3 must meet all relevant requirements of Chapter 62-610, F.A.C., Part III, for use in the cooling tower.

m. **Water Conservation Strategies Under Consideration**

The use of reclaimed water is a water conservation strategy because it is a beneficial use of wastewater. Impacts on the surficial aquifer would be minimized and used only for potable water. Water from the Floridan Aquifer or the L10/L12 canal will be used for cooling purposes as a backup water source and cooling towers will be utilized. In addition, captured stormwater will be reused in the cooling tower whenever feasible. Stormwater captured in the stormwater ponds will also recharge the surficial aquifer.

n. **Water Discharges and Pollution Control**

Heat will be dissipated in the cooling towers. Blowdown water from the cooling towers, along with other wastestreams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Storm water runoff will be collected and used to recharge the surficial aquifer via a storm water management system. Design elements will be included to capture suspended sediments. In addition, captured stormwater will be reused in the cooling towers whenever feasible The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

The site is not located near an existing natural gas transmission pipeline that is capable of providing a sufficient quantity of gas. Upgrades of existing pipelines and/or lateral connections to other pipelines will be made for supply of natural gas. Ultra-low sulfur light fuel oil (distillate) would be received by truck and stored in above-ground storage tanks to serve as backup fuel for the new units.

p. **Air Emissions and Control Systems**

The use of natural gas and ultra-low sulfur light fuel oil (distillate) and combustion controls will minimize air emissions from these units and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil (distillate) as backup fuel. These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of the West County Energy Center units will incorporate features that will make them among the most efficient and cleanest power plants in the State of Florida.

q. **Noise Emissions and Control Systems**

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site. Noise from the operation of the new units will be within allowable levels.

r. **Status of Applications**

In regard to the two approved units, a Site Certification Application (SCA) for the construction and operation of the West County Energy Center project under the Florida Electrical Power Plant Siting Act was filed on April 14, 2005 and received Site Certification by the Governor and Cabinet, acting as the Siting Board, on December 26, 2006. Palm Beach County Planning Zoning and Building department issued approval for the project on June 28, 2006. FDEP issued an Underground Injection Control Exploratory Well permit on January 11, 2006 and another Exploratory Well Permit on December 6, 2006. FDEP issued a Prevention of Significant Deterioration (PSD) air permit on January 10, 2007. After acquiring these permits and authorizations, FPL initiated construction in February 2007 and anticipates an in-service date for the first unit of mid-2009. FDEP is in the process of issuing the Final UIC permit.

In regard to the proposed third unit, a Site Certification Application (SCA) for the construction and operation of WCEC 3 under the Florida Electrical Power Plant Siting Act was filed on December 6, 2007 and is currently undergoing review. Palm Beach County Planning Zoning and Building department issued initial approval on November 29, 2007, and final approval on December 5, 2007, for an increase in total generating capacity for the project. A Prevention of Significant Deterioration (PSD) air permit was filed on December 6, 2007. After acquiring these permits and authorizations, FPL proposes to initiate construction in June 2009 and anticipates an in-service date of mid-2011. WCEC 3 plans to utilize the UIC system being permitted for the entire site.

Preferred Site # 2: St. Lucie Plant, St. Lucie County

FPL's St. Lucie Plant is located in St. Lucie County on Hutchinson Island on an FPL-owned 1,130-acre site. The plant site is bordered by the Atlantic Ocean to the east and the Indian River Lagoon to the west. Located on the site are two nuclear powered generating units, St. Lucie Units 1 & 2, that have been in operation since 1976 and 1983, respectively. The St. Lucie site has been selected as a Preferred Site for the addition of two types of new generating capacity.

The first type of generating capacity addition is an increase in the capacity of the two existing nuclear generating units by approximately 103 to 104 MW each. This work will involve changes to several existing main components within the existing facilities to increase their capability to produce steam for the generation of electricity. No new or expanded facilities are required as part of this capacity "uprate." This capacity uprate, along with a similar capacity uprate of FPL's existing Turkey Point nuclear units, was approved by the FPSC in January 2008. The capacity uprates at St. Lucie for the two nuclear units sited there are projected to be in-service in late 2011 and 2012, respectively.

The second type of generating capacity addition is the proposed installation of FPL wind generation turbines at the plant site by 2009. Six wind turbines are being proposed that, in total, would have a maximum output of approximately 13.8 MW.

a. U.S. Geological Survey (USGS) Map

A USGS map of the FPL St. Lucie Nuclear site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the proposed generating facilities at the site is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

St. Lucie Units 1 & 2 are pressurized water reactors, each having two steam generators. The prominent structures, enclosed facilities, and equipment associated with St. Lucie Units 1 & 2 include the containment building, the turbine generator building, the auxiliary building, and the fuel handling building.

Prominent features beyond the power block area include the intake and discharge canals, switchyard, spent-fuel storage facilities, technical and administrative support facilities, and public education facilities (Energy Encounter Exhibit and the Marine Education Facility). Significant features surrounding the St. Lucie Units 1 & 2 are predominately undeveloped land and water bodies including; Big Mud Creek, the Atlantic Ocean, Herman's Bay and Indian River Lagoon.

In regard to the nuclear capacity uprates, the only changes will be modifications to the existing power generation facilities within the power block area. None of the other existing facilities at the plant will change as a result of the uprates. No changes to the nuclear power generation facilities are currently projected as a result of the proposed wind turbine additions.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

FPL's St. Lucie Plant is located in St. Lucie County on Hutchinson Island on an FPL-owned 1,130-acre site. The St. Lucie Plant includes the reactor buildings, turbine buildings, access/security building, auxiliary building, maintenance facilities, and miscellaneous warehouses and other buildings associated with the operation of Units 1 & 2. The site includes adjacent undeveloped mangrove areas. As a result of the approved capacity uprates, the site characteristics will not change.

The proposed wind turbines are also located on the FPL-owned site. Impacts to the site characteristics are projected to be minimal from the proposed wind turbines.

2. **Listed Species**

Some listed species known to occur in the area of the plant location are atlantic sturgeon, smalltooth sawfish, loggerhead sea turtle (*Caretta caretta*), green sea turtle (*Chelonia mydas)*, leatherback sea turtle (*Dermochelys coriacea*), hawksbill sea turtle (*Eretmochelys imbriccata*), gopher tortoise (*Gopherus polyphemus*), kemp's ridley (*Lepidochelys kempi*) sea turtle, wood stork (*Mycteria americana*), black skimmer (*Rynchops niger*), and least tern (*Sterna antillarum*).

In regard to the capacity uprates, neither the development work, nor the continued operation of the two nuclear units after the uprate work has been completed, are expected to adversely affect any rare, endangered, or threatened species. No changes in wildlife populations at the adjacent undeveloped areas are anticipated, including listed species. Noise and lighting impacts will not change and it is expected that wildlife will continue to use the undeveloped areas within the St. Lucie Plant boundary.

In regard to the wind turbines, some changes to the adjacent undeveloped areas are anticipated, excluding listed species. Noise and lighting impacts will not change and the wind turbines are not anticipated to deter the continued use by wildlife of the undeveloped areas within the St. Lucie Plant boundary or any adjacent areas.

3. **Natural Resources of Regional Significance Status**

Significant features surrounding the St. Lucie Units 1 & 2 are predominately undeveloped land and water bodies including; Big Mud Creek, the Atlantic Ocean, Herman's Bay and Indian River Lagoon.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. It is a once-through system. The effects of the discharge of cooling water via these discharge structures were evaluated and mixing zones were established to allow compliance with thermal water quality standards as a part of the Plant's NPDES (Permit No. FL0002208). These mixing zones include the volume of water beyond the discharge structures, at the edge of which, the water temperature is no greater than 17°F above the ambient temperature of the intake water.

In regard to the nuclear capacity uprates, the once-through system will continue to be used for the nuclear units. In regard to the wind turbines, no water will be used.

g. <u>Local Government Future Land Use Designations</u>

St. Lucie Units 1 & 2 are located in unincorporated St. Lucie County, Florida. The County has adopted a comprehensive plan, which is updated on a periodic basis. The County Comprehensive Plan incorporates a map that depicts the future land use categories of all property falling within the unincorporated portions of the County. The St. Lucie Plant has a Future Land Use category of Transportation/Utilities (T/U) according to the St. Lucie County Future Land Use Map. The T/U category is described in the St. Lucie County Comprehensive Plan Future Land Use Element Future Land Use.

h. <u>Site Selection Criteria Process</u>

The site has been selected as a Preferred Site for the nuclear capacity uprates because it is an existing nuclear plant site and, therefore, offers the opportunity for increased nuclear capacity. The site has been selected as a Preferred Site for the wind turbines because of the available wind resource at that location.

i. <u>Water Resources</u>

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. The once-through system flow will not change as a result of the nuclear capacity uprates. There will be no water used to operate the wind turbines. Due to the existing nature of the St. Lucie Plant, surrounding surface waters will not be adversely affected by either of the generation capacity additions. Stormwater will be handled by the existing facilities and no new areas will be impacted. Wetlands, groundwater, and nearby surface waters will not be impacted.

j. <u>Geological Features of Site and Adjacent Areas</u>

Beneath the land surface, there is a peat layer 4 to 6 feet thick. Below this layer is the Anastasia Formation, a sedimentary rock formation composed of clay lenses, sandy limestone, and silty fine to medium sand with fragmented shells. This highly permeable stratum extends 35 to 90 feet below mean sea level (msl). Underlying this stratum there is a semi-permeable zone, The Hawthorn Formation, consisting of slightly clayey and very fine silt which extends 600 feet below msl.

The original surficial deposits at the St. Lucie Plant were excavated to a depth of 60 feet and backfilled with Category I or II fill. The fill is underlain by the Anastasia formation, a sequence of partially cemented sand and sandy limestone, which extend to an average depth of about 145 feet. The Anastasia is underlain to an depth of about 600 to 700 feet by the partially cemented and indurated sands, clays, and sandy limestones of The Hawthorn Formation. Underlying these surface strata are about 13,000 feet of Jurassic through Tertiary Formations, primarily carbonate rocks. These formations have a relatively gentle slope to the southeast.

k. Projected Water Quantities for Various Uses

In regard to the nuclear capacity uprates, no change is expected in the quantity or characteristics of industrial wastewaters generated by the facility. Therefore, no change in that compliance achievement status is expected. The capacity uprates will not cause any changes in hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow. The St. Lucie Plant does not directly withdraw groundwater under its current operations and it will not withdraw groundwater after the uprates work is completed. The use of water supplied by the City of Fort Pierce, which does withdraw groundwater, will remain unchanged and there will be no changes to the groundwater discharges. There will be no quality, quantity, or hydrological changes, either by withdrawal or discharge to a drinking water source. Therefore, there will be no impacts on drinking water.

The wind turbines will not require water for operations and will not cause any changes in the hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow.

l. Water Supply Sources by Type

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. General plant service water, fire protection water, process water, and potable water are obtained from City of Fort Pierce. Process water uses include demineralizer regeneration, steam cycle makeup, and general service water use for washdowns.

The existing St. Lucie Plant water use is projected to be unchanged from that for the existing facility as a result of the nuclear capacity uprates. The wind turbines will not require water for operations.

m. Water Conservation Strategies Under Consideration

The existing water resources will not change as a result of the nuclear capacity uprates. The wind turbines will not require water for operations.

n. Water Discharges and Pollution Control

St. Lucie Units 1 & 2 use once-through cooling water from the Atlantic Ocean to remove heat from the main (turbine) condensers via the Circulating Water System (CWS), and to remove heat from other auxiliary equipment via the Auxiliary Equipment Cooling Water System (AECWS). The great majority of this cooling water is used for the CWS.

Under emergency conditions, water can be withdrawn from Big Mud Creek via the Emergency Intake Canal through two 54-inch pipe assemblies in the barrier wall that separates the Creek from the Canal. FPL does not use this intake during normal operations, but does test this system semi-annually.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

The wind turbines will not require water for operations. Consequently, there will be no water discharge as a result of these turbines.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

St. Lucie Units 1 & 2 are licensed for uranium-dioxide fuel that is slightly enriched uranium-235. The uranium-dioxide fuel is in the form of pellets contained in Zircaloy tubes with welded end plugs to confine radionuclides. The tubes are fabricated into assemblies designed for loading into the reactor core. Each reactor core includes 217 fuel assemblies.

FPL currently replaces approximately one-third of the fuel assemblies in each reactor at intervals of approximately 18 months. FPL operates the reactors such that the average fuel usage by the reactors is approximately 47,000 megawatt-days per metric ton uranium. In regard to the nuclear capacity uprates, more nuclear fuel will be used due to the increased capacity of each unit. No changes in the fuel-handling facilities are required. The addition of the wind turbines will have no fuel-related impact; i.e., no impacts from fuel delivery, storage, waste, or pollution control.

Diesel fuel is used in a number of emergency generators that include four main plant generators, two building generators, and various general purpose diesel engines. The main plant emergency generators will not be changed as a result of either of the two types of generation capacity additions. These emergency generators are for standby use only and only tested to assure reliability and for maintenance. Diesel fuel is delivered to the St. Lucie Plant by truck as needed, and stored in tanks with secondary containment.

p. Air Emissions and Control Systems

The St. Lucie Plant is classified as a minor source of air pollution, since FDEP has issued a Federally Enforceable State Operating Permit (FESOP) to keep emissions less than 100 tons per year for any air pollutant regulated under the Clean Air Act.

The applicable units at the St. Lucie Plant in regard to air emissions consist of eight large main plant diesel engines, two smaller diesel engines, and various general-purpose diesel engines. The air emissions from these engines are limited by the use of 0.05-percent sulfur diesel fuel and good combustion practices. Best Available Control Technology (BACT) is not applicable to these existing emission units.

Nitrogen oxide (NOx) emissions from the operation of the diesel engines comprise the limiting pollutant for these diesel units at the St Lucie Plant. The FDEP FESOP limits NOx emissions to 99.4 tons, which includes fuel use limits on the large main plant emergency diesel engines of 97,000 gallons in any 12-month consecutive period and the smaller building and general purpose diesel engines of 190,000 gallons in any 12-month consecutive period. Also, the Plant may choose to combine the diesel units' fuel-tracking, which then limits the NOx totals for a 12-month consecutive period to a maximum of 80 tons. There will be no change in the operation or emissions of the diesel engines resulting from either the nuclear capacity uprates or the wind turbines. In addition, neither of these types of generation capacity additions will result in an increase of carbon dioxide (CO_2) or other greenhouse gas emissions. In fact, both of these increases in generation capacity are projected to result in decreased FPL system emissions of CO_2 and other greenhouse gases.

q. Noise Emissions and Control Systems

A field survey and impact assessment of noise expected to be caused by construction activities at the site was conducted in regard to both types of generation capacity additions. Predicted noise levels are not expected to result in adverse noise impacts in the vicinity of the site during construction or operation of either generating capacity additions.

r. Status of Applications

In regard to the nuclear capacity uprates, a Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act was filed on December 13, 2007. The FPSC voted to approve the need for the St. Lucie (and Turkey Point) uprates and the final order approving the need for these units was issued on January 7, 2008. In regard to the wind turbines, a Site Certification Application is not required.

Preferred Site # 3: Turkey Point Plant, Miami-Dade County

The Turkey Point Plant site is located on the west side of Biscayne Bay, 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. Public access to the plant site is limited due to the nuclear units located there. The land surrounding the site is owned by FPL and acts as a buffer zone. The site is comprised of two nuclear units (Units 3 & 4) and two natural gas/oil conventional boiler units (Units 1 & 2), one combined cycle natural gas unit (Unit 5), the cooling canals, an FPL-maintained natural wildlife area, and wetlands that have been set aside as the Everglades Mitigation Bank (EMB).

Turkey Point Units 3 & 4 have been in operation since 1972 and 1973, respectively. The Turkey Point site has been selected as a Preferred Site for the increase in the capacity of its two existing nuclear generating units by approximately 103 to 104 MW each. This work will involve changes to several existing main components within the existing facilities to increase their capability to produce steam for the generation of electricity. No new or expanded facilities are required as part of this capacity "uprate." This capacity uprate, along with a similar capacity uprate of FPL's existing St. Lucie nuclear units, was approved by the FPSC in January 2008. The capacity uprates at Turkey Point are projected to be in-service in 2012.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Turkey Point plant site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the Turkey Point Units 3 & 4 generating facility at the site is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The five existing power generation units and support facilities occupy approximately 150 acres of the 11,000-acre Turkey Point Plant. Support facilities include service buildings, an administration building, fuel oil tanks, water treatment facilities, circulating water intake and outfall structures, wastewater treatment basins, and a system substation. The cooling canal system occupies approximately 5,900 acres. The two 400-megawatt (MW) (nominal) fossil fuel-fired steam electric generation units at the Turkey Point Plant have been in service since 1967 (Unit 1) and 1968 (Unit 2). These units currently burn residual fuel oil and/or natural gas with a maximum equivalent sulfur content of 1 percent. The two 700-MW (nominal) nuclear units have been in service since 1972 (Unit 3) and 1973 (Unit 4). Turkey Point Units 3 & 4 are pressurized water reactor (PWR) units. Turkey Point Unit 5 is a nominal 1,150-MW combined cycle unit that began operation in 2007. Significant features in the vicinity of the site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The prominent structures and enclosed facilities and equipment associated with Units 3 & 4 include: the containment building, which contains the nuclear steam supply system, including the reactor, steam generators, reactor coolant pumps, and related equipment; the turbine generator building, where the turbine generator and associated main condensers are located; the auxiliary building, which contains waste management facilities, engineered safety components, and other facilities; and the fuel handling building, where the spent fuel storage pool and storage facilities for new fuel are located. Prominent features beyond the power block area include the intake system, cooling canal system, switchyard, spent fuel storage facilities, and technical and administrative support facilities.

2. **Listed Species**

The construction during the uprating of the units, and operation of the units after the capacity uprating is completed, are not expected to adversely affect any rare, endangered, or threatened species. Listed species known to occur in the nearby Biscayne National Park that could potentially utilize the site include the peregrine falcon *(Falco peregrinus)*, wood stork *(Mycteria americana)*, American crocodile *(Crocodylus acutus)*, mangrove rivulus *(Rivulus marmoratus)*, roseate spoonbill *(Ajaja ajaja)*, limpkin *(Aramus guarauna),* little blue heron *(Egretta caerulea),* snowy egret *(Egretta thula),* American oystercatcher *(Haematopus palliates),* least tern *(Sterna antillarum)*, the white ibis *(Eudocimus albus)*, and bald eagle *(Haliaeetus leucocephalus)*. No bald eagle nests are known to exist in the vicinity of the site. The federally listed, endangered American Crocodile thrives at the Turkey Point site, primarily in and around the southern end of the cooling canals which lie south of the project area. The entire site is considered crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American crocodile.

3. **Natural Resources of Regional Significance Status**

Significant features in the vicinity on the site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park. Biscayne National Park contains 180,000 acres, approximately 95% of which is open water interspersed with over 40 keys. The Biscayne National Park headquarters is located approximately 2 miles north of the Turkey Point plant and is adjacent to the Miami-Dade County Homestead Bayfront Park which contains a marina and day use recreational facilities.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

Turkey Point Units 3 & 4 uses cooling water from a closed-cycle cooling canal system to remove heat from the main (turbine) condensers, and to remove heat from other auxiliary equipment. The existing cooling canals will accommodate the increase in heat load that is associated with the increased capacity from the uprates. The maximum predicted increase in water temperature entering the cooling canal system from the units resulting from the uprates is predicted to be about 2.5°F, from 106.1 to 108.6°F. The associated maximum increase in water temperature returning to the units is about 0.9°F, from 91.9 to 92.8°F.

g. <u>Local Government future Land Use Designations</u>

Local government future land use plan designates most of the site as IU-3 "Industrial, Unlimited Manufacturing District." There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. <u>Site Selection Criteria Process</u>

The site has been selected as a Preferred Site for the nuclear capacity uprates because it is an existing nuclear plant site and, therefore, offers the opportunity for increased nuclear capacity.

i. <u>Water Resources</u>

Unique to Turkey Point plant site is the self-contained cooling canal system that supplies water to condense steam used by the plant's turbine generators. The canal system consists of 36 interconnected canals each five miles long, 200 feet wide, and approximately four feet deep. The system performs the same function as a giant radiator. The water is circulated through the canals in a two-day journey, ending at the plant's intake pumps.

j. <u>Geological Features of Site and Adjacent Areas</u>

The Turkey Point Plant lies upon the Floridian Plateau, a partly-submerged peninsula of the continental shelf. The peninsula is underlain by approximately 4,000 to 15,000 feet of sedimentary rocks consisting of limestone and associated formations that range in age from Paleozoic to Recent. Little is known about the basement complex of Paleozoic igneous and metamorphic rocks due to their great depth.

Generally in Miami-Dade County, the surficial aquifer (Biscayne Aquifer) consists of a wedge-shaped system of porous clastic and carbonate sedimentary materials, primarily limestone and sand deposits of the Miocene to late Quaternary age. The Biscayne Aquifer is thickest along the eastern coast and varies in thickness from 80 to 200 feet thick. The surficial aquifer is typically composed of Pamlico Sand, Miami Limestone (Oolite), the Fort Thompson and Anastasia Formations (lateral equivalents), Caloosahatchee Marl, and the Tamiami formation. The lower confining layers below the surficial aquifer range in thickness from 350 to 600 feet and are composed of the Hawthorn Group. Beneath the Hawthorn Group, the Floridan Aquifer System (FAS) ranges from 2,800 to 3,400 feet thick and consists of Suwannee Limestone, Avon Park Limestone, and the Oldsmar Formations.

k. Projected Water Quantities for Various

The addition of nuclear generating capacity as a result of the uprates will not cause any changes in the quantity or characteristics of industrial wastewaters generated by the facility; therefore, no change in that compliance achievement status is expected. The uprates will not cause any changes in hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow. The Turkey Point Plant does not directly withdraw groundwater under its current operations and it will not do so after the capacity uprates. Locally, groundwater is present beneath the Site in the surficial or Biscayne Aquifer and in deeper aquifer zones that are part of the Floridan Aquifer System. There will be no effects on those deeper aquifer zones from the capacity uprates.

l. Water Supply Sources and Type

The source of cooling water for Turkey Point Units 3 & 4 is the cooling canal system. There will be no increase in the amount of water withdrawn as a result of the capacity uprates. General plant service water, fire protection water, process water, and potable water are obtained from Miami-Dade County. Process water uses include demineralizer regeneration, steam cycle makeup, and general service water use for washdowns. The water use for the facility will not change as a result of the capacity uprates.

m. Water Conservation Strategies

The existing water resources will not change as a result of the uprates.

n. Water Discharges and Pollution Control

Heated water discharges are dissipated using the existing closed cooling water system and the cooling canal system.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Turkey Point Units 3 & 4 utilize uranium-dioxide fuel that is slightly enriched uranium-235. The uranium-dioxide fuel is in the form of pellets contained in Zircaloy tubes with welded end plugs to confine radionuclides. The tubes are fabricated into assemblies designed for loading into the reactor core.

FPL currently replaces approximately one-third of the fuel assemblies in each reactor at intervals of approximately 18 months. FPL operates the reactors such that the average fuel usage by the reactors is approximately 45,000 megawatt-days per metric ton of uranium. Following completion of the uprates, more nuclear fuel will be used to increase the capacity of each unit. No changes in the fuel handling facilities are required.

Diesel fuel is used in a number of emergency generators that include four main emergency generators, five smaller emergency generators and various general purpose diesel engines. The emergency generators will not be changed as a result of the capacity uprates. These emergency generators are for stand-by use only and only operated for testing purposes to assure reliability and for maintenance. Diesel fuel for the emergency generators is delivered to the Turkey Point Plant by truck as needed, and stored in tanks with secondary containment.

p. Air Emissions and Control Systems

The normal operation of Turkey Point Units 3 & 4 does not create fossil fuel-related air emissions. However, there are nine emergency generators associated with Units 3 & 4. Four main plant emergency generators are rated at 2.5 MW. Five smaller emergency generators are associated with the security system. In addition, various general purpose diesel are used as needed for Units 3 & 4.

Turkey Point Plant Units 3 & 4's associated emergency generators and diesel engines, together with Units 1, 2, and 5, are classified as a major source of air pollution. FDEP has issued a separate Title V Air Operating Permit for the Turkey Point Nuclear Plant (Permit Number 0250003-004-AV). There are no operating limits for the emergency generators or diesel engines. NOx emissions are regulated under Reasonably Available Control Technology (RACT) requirements in Rule 62-296.570(4)(b)7 F.A.C., which limit NOx emissions to 4.75 lb/MMBtu. The use of 0.5 percent sulfur diesel fuel and good combustion practices serve to keep NOx emissions under this limit.

q. Noise Emissions and Control Systems

A field survey and impact assessment of noise expected to be caused by activities associated with the uprates was conducted. Predicted noise levels are not expected to result in adverse noise impacts in the vicinity of the site..

r. Status of Applications

A Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act was filed on January 18, 2008. The FPSC voted to approve the need for the Turkey Point (and St. Lucie) uprates and the final order approving the need for these units was issued on January 7, 2008.

IV.F.2 Potential Sites for Generating Options

Eight (8) sites are currently identified as Potential Sites for near-term future generation additions to meet FPL's capacity and energy needs[2]. These sites have been identified as Potential Sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies.

Each of these Potential Sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that will require further definition and attention. Solely for the purpose of estimating water requirements for each site, it was assumed that either one dual-fuel (natural gas and light oil) simple cycle combustion turbine (CT) or a natural gas-fired combined cycle unit (CC) would be constructed at the Potential Sites. A simple cycle CT would require approximately 50 gallons per minute (gpm) for both process and cooling water (assuming air cooling). A CC unit would require approximately 150 gpm for service and process water and approximately 14 million gallons per day (mgd) for cooling water depending upon the water source and associated water quality. If an existing power plant site is ultimately selected for repowering of an existing unit(s), the water requirements discussed above for a CC unit would be approximately correct for the repowered unit. If a renewable energy generating

[2] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other greenfield sites.

technology, such as photovoltaic and solar thermal, is ultimately selected for one of these sites, the water requirements would be less than those for CT or CC facilities.

Permits are presently considered to be obtainable for each of these sites. No significant environmental constraints are currently known for any of these sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time FPL considers each site to be equally viable.

Potential Site # 1: West Broward, Broward County

FPL has identified the Andytown Substation property in western unincorporated Broward County as a potential site for the addition of new generating capacity and FPL refers to this potential site as the West Broward site. Current facilities on-site include an electric substation. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site has been included at the end of this chapter.

b. **Land Uses**

The land uses for the potential site were designated as agricultural use.

c. **Environmental Features**

Extensive low-quality wetlands are present on the site. Construction and operation of a new facility on this site would not be expected to adversely affect any rare, endangered, or threatened species.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

Groundwater from the shallow aquifer or a local source of reclaimed (reuse) water has been identified as potential water sources. The Floridan Aquifer has also been identified as a potential cooling water source.

Potential Site # 2: Cape Canaveral Plant, Brevard County

The FPL Cape Canaveral Plant property is located in unincorporated Brevard County. The city of Port St. Johns is located less than a mile away. The site has direct access to a four-lane highway (U.S. 1). A rail line is located near the plant. The existing facility consists of two 400 MW (approximate) steam boiler type generating units.

a. U.S. Geological Survey (USGS) Map

A USGS map of the site is found at the end of this chapter.

b. Land Uses

The land is primarily dedicated to industrial use; i.e., FPL's existing Cape Canaveral power plant Units 1 & 2. It is surrounded by grassy areas and a few acres of remnant pine forest. The land adjacent to the site is dedicated to light commercial and residential use.

c. Environmental Features

The site is located on the Intra-coastal waterway which provides warm water refugia for manatees during cold winter days.

d. Water Quantities

As previously discussed, if additional water is needed beyond the currently permitted amount, then the water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. Supply Sources

Existing on-site wells, reclaimed (reuse) water, public supply water, and the existing once-through cooling water system are potential water supply sources.

Potential Site # 3: Desoto County Greenfield Site

This site is a "Greenfield" undeveloped site located on a 13,515 acre property in unincorporated Desoto County. The site is adjacent to portions of the Peace River and lies on both the east and west sides of U.S. Highway 17 approximately 3 to 5 miles north of the City of Arcadia. There are currently no utility facilities on the site.

a. U.S. Geological Survey (USGS) Map

A USGS map of the site is found at the end of this chapter.

b. Land Uses

A portion of the land on the site is currently dedicated to agricultural use (sod farming, cattle grazing, and truck crops). The remaining land is undeveloped.

c. Environmental Features

Developed portions of the adjacent properties are primarily agricultural (sod farms, citrus groves, and cattle grazing). Undeveloped portions include mixed scrub with some hardwoods and a few small isolated wetlands.

d. Water Quantities

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. Supply Sources

Groundwater from the upper and lower Floridan Aquifer, or if available and practicable, a local source of reclaim (reuse) water are potential water sources.

Potential Site # 4: Fort Myers Plant Site, Lee County

FPL's existing 460-acre Fort Myers property is located just east of Interstate 75 in Lee County and is adjacent to the Caloosahatchee River. The existing facilities on the site include one 1,440 MW (approximate) combined cycle unit, 12 gas turbines, each with an approximate capacity of 54 MW, and 2 combustion turbines, each with an approximate capacity of 160 MW.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Fort Myers plant site is found at the end of this chapter.

b. Land Uses

The land on the site is currently dedicated to industrial use with surrounding grassy and landscaped areas. Much of the site has been used in recent years for direct plant construction activities. The adjacent land uses include light commercial and retail to the east of the property, plus some residential areas located toward the west.

c. **Environmental Features**

Mixed scrub with some hardwoods can be found to the east and further south.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

The available water source is the Caloosahatchee River and the available groundwater source is the sandstone aquifer.

Potential Site # 5: Lauderdale Plant, Broward County

The Lauderdale site is located in Eastern Broward County approximately 5 miles inland from Dania Beach and less than 2 miles west of Ft. Lauderdale International Airport. The site is bounded on the south by Dania Cutoff Canal, the east by S.W. 30th Avenue, and the North by I-595.

The existing approximately 1,700 MW of generating capacity at FPL's Lauderdale site occupies a portion of the approximately 210 acres that are wholly owned by FPL. The generating capacity is made up of two combined cycle units (Units 4 & 5), and 24 simple cycle gas turbine (GT) units.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site is found at the end of this chapter.

b. **Land Uses**

The existing power plant facilities are located on approximately 130 acres. The existing site has been in use since the 1920s and is adjacent to a county resource recovery project.

c. **Environmental Features**

To the north of the power plant is an area of mixed uplands with a scattering of small wetlands.

d. Water Quantities

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. Supply Sources

Existing groundwater or the municipal water supply are potential water sources.

Potential Site # 6: Martin Plant, Martin County

The Martin site is located approximately 40 miles northwest of West Palm Beach, 5 miles east of Lake Okeechobee, and 7 miles northwest of Indiantown in Martin County, Florida. The site is bounded on the west by the Florida East Coast Railway (FEC) and the adjacent South Florida Water Management District (SFWMD) L-65 Canal, on the south by the St. Lucie Canal (C-44 or Okeechobee Waterway), and on the northeast by SR 710 and the adjacent CSX Railroad.

The existing approximately 3,700 MW of generating capacity at FPL's Martin site occupies a portion of the approximately 11,300 acres that are wholly owned by FPL. The generating capacity is made up of two steam units (Units 1 & 2), plus three combined cycle units (Units 3, 4, & 8). In addition, a 10 kilowatt (kw) photovoltaic (PV) facility also in operation at the south end of the site. The site includes a 6,800-acre cooling pond (6,500 acres of water surface and 300 acres of dike area) and approximately 300 acres for the existing power plant units and related facilities.

a. U.S. Geological Survey (USGS) Map

A USGS map for the site is found at the end of this chapter.

b. Land Uses

A major portion of the site consists of a 6,800-acre cooling pond. The existing power plant facilities are located on approximately 300 acres.

c. Environmental Features

To the east of the power plant there is an area of mixed pine flat wood with a scattering of small wetlands. To the north of the cooling pond there is a 1,200-acre area which has been set aside as a mitigation area. There is a peninsula of wetland forest on the West Side of the reservoir that is named the Barley Barber Swamp. The Barley Barber Swap encompasses 400 acres and is preserved as a natural area. There is also a 10-kilowatt (kW) photovoltaic energy facility at the south end of this site.

d. Water Quantities

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. Supply Sources

Surface water resources currently used at the Martin facility include the cooling pond which takes its water from the St. Lucie canal. The available ground water resource is the surficial aquifer system which is used as a source of potable and service water.

Potential Site # 7: Port Everglades Plant, Broward County

The 94-acre FPL Port Everglades plant site is located at Port Everglades in Broward County. The site has convenient access to State Road (S.R.) 84 and I-595. Rail line is located near the plant. The existing plant consists of four steam boiler generating units: two 200 MW (approximate) and two 400 MW (approximate) sized units. The four steam boilers are capable of firing residual fuel oil, natural gas, or a combination of both. The site also is home to 12 simple cycle gas turbine (GT) peaking units of 30 MW (approximate) each. The GT units are part of the Gas Turbine Power Park that is made up of 24 GTs at the Lauderdale Plant site and the 12 GTs at the Port Everglades site. The GTs are capable of firing either natural gas or liquid fuel.

a. U.S. Geological Survey (USGS) Map

A map of the site is found at the end of this chapter.

b. Land Uses

The land on this site is primarily industrial. The adjacent land uses are port facilities and associated industrial activities, oil storage, cruise ships, and light commercial.

c. **Environmental Features**

The shoreline of the intake and discharge canal banks are vegetated with fringing mangrove, with some open, maintained grass areas on the side.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

Existing groundwater or the municipal water supply could be used for industrial process and makeup water. Industrial cooling water needs could be met using the existing once-through cooling water system.

Potential Site # 8: Riviera Plant, Palm Beach County

The FPL Riviera Plant property is located in Riviera Beach in Palm Beach County. The site has direct access to a four-lane highway, U.S. 1, and barge access is available. A rail line is located near the plant. The facility currently houses two operational 300 MW (approximate) steam boiler generating units and one retired 50 MW generating unit.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site is found at the end of this chapter.

b. **Land Uses**

The land on the site is primarily covered by the existing generation facilities. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development. The plant property contains some open, maintained grass area.

c. **Environmental Features**

The site is located on the Intra-coastal waterway near the Lake Worth Inlet which provides warm water refugia for manatees during cold winter days.

d. **Water Quantities**

As previously discussed, if additional water is needed beyond the currently permitted amount, then water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. Supply Sources

The existing municipal water supply could be used for industrial processing water. Industrial cooling water needs could be met using the existing once-through cooling water system from Lake Worth.

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Environmental and Land Use Information: Supplemental Information

Preferred Site: West County Energy Center

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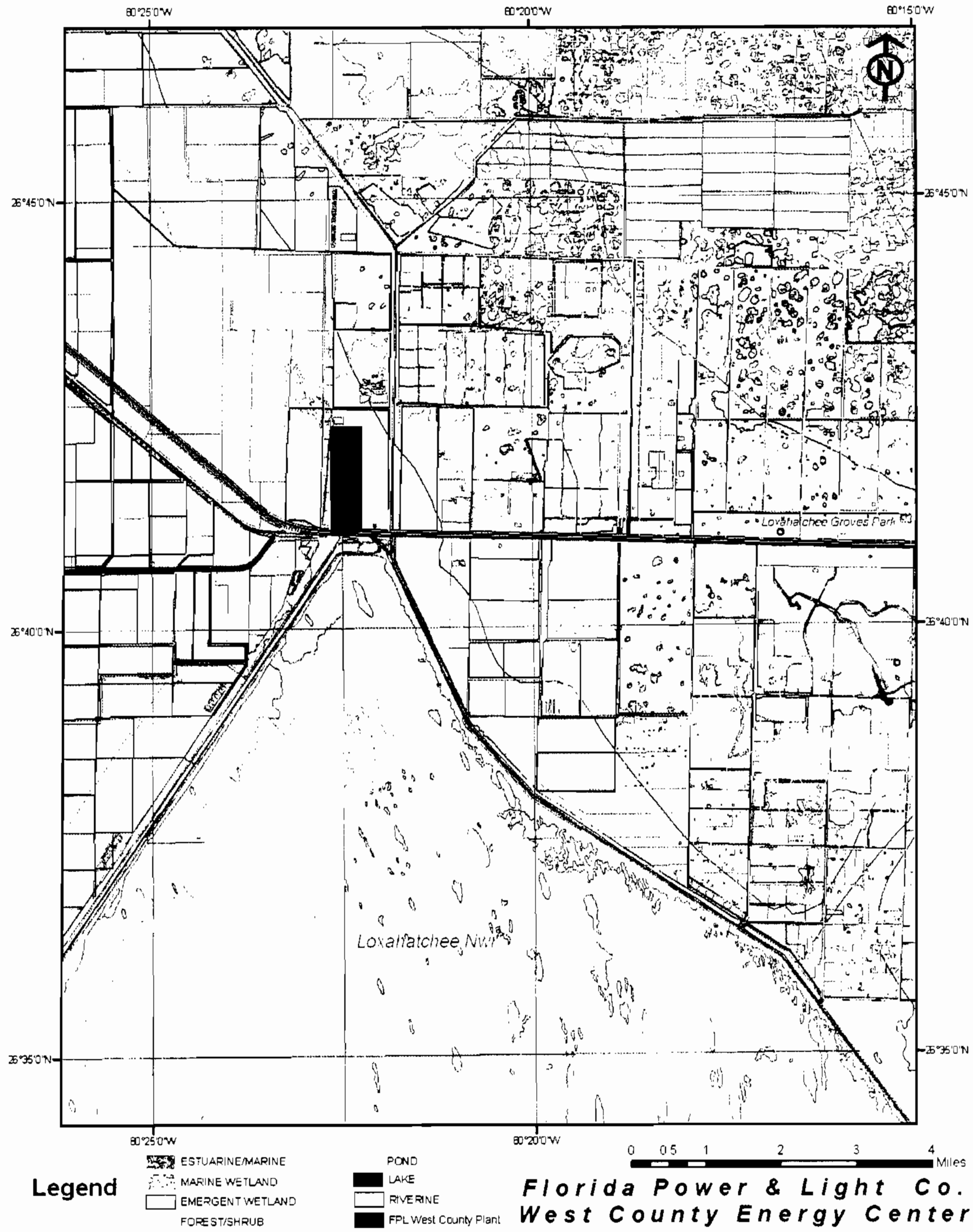
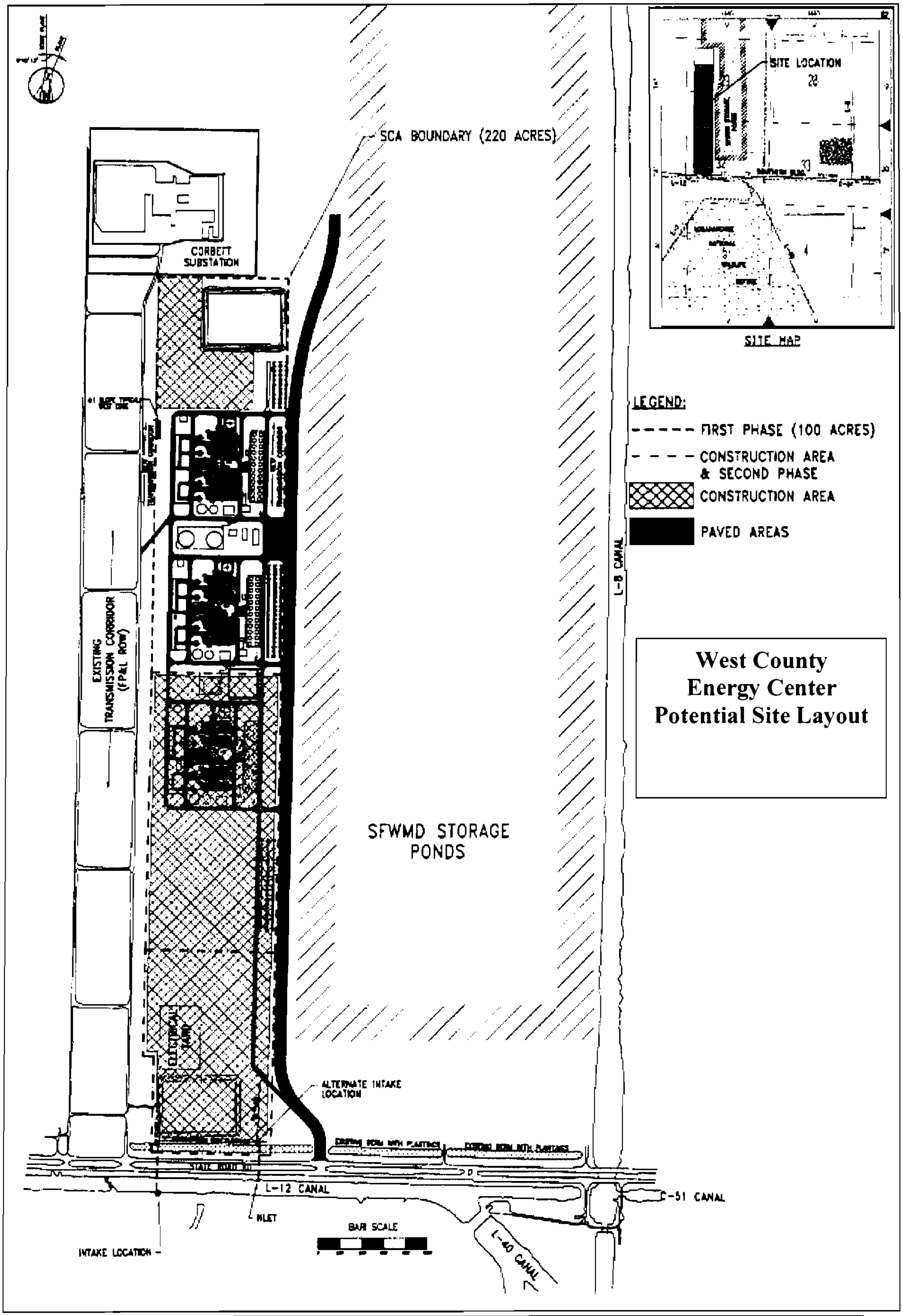
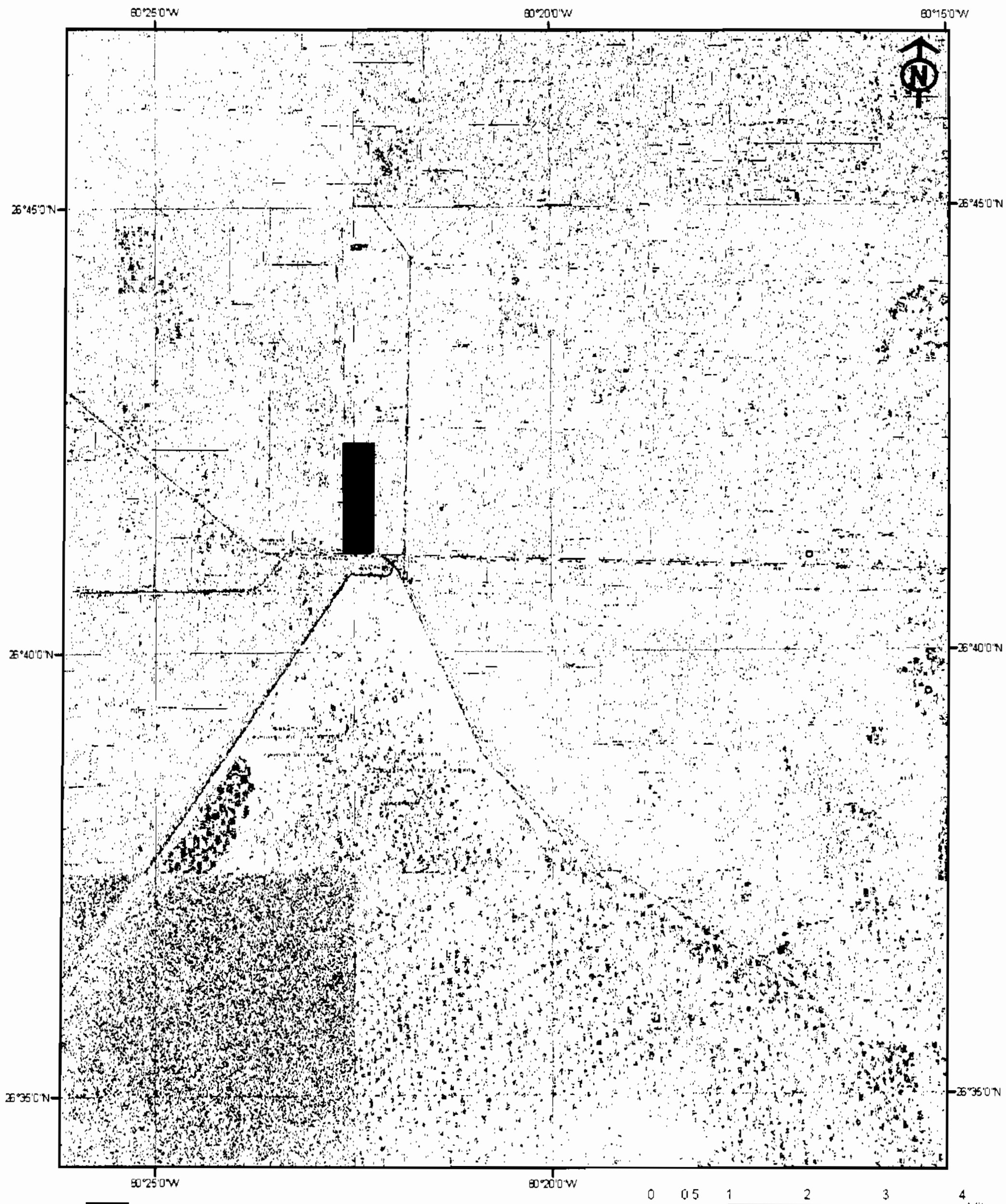

80°25'0"W
80°20'0"W
80°15'0"W
26°45'0"N
26°40'0"N
26°35'0"N
N
Loxahatchee Groves Park
Loxahatchee Nwr
0 0.5 1 2 3 4
Miles
Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL West County Plant
Florida Power & Light Co.
West County Energy Center



West County Energy Center Potential Site Layout



FPL West County Energy Center Site

Florida Power & Light Co.
West County Energy Center

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Environmental and Land Use Information: Supplemental Information

Preferred Site: St. Lucie Plant

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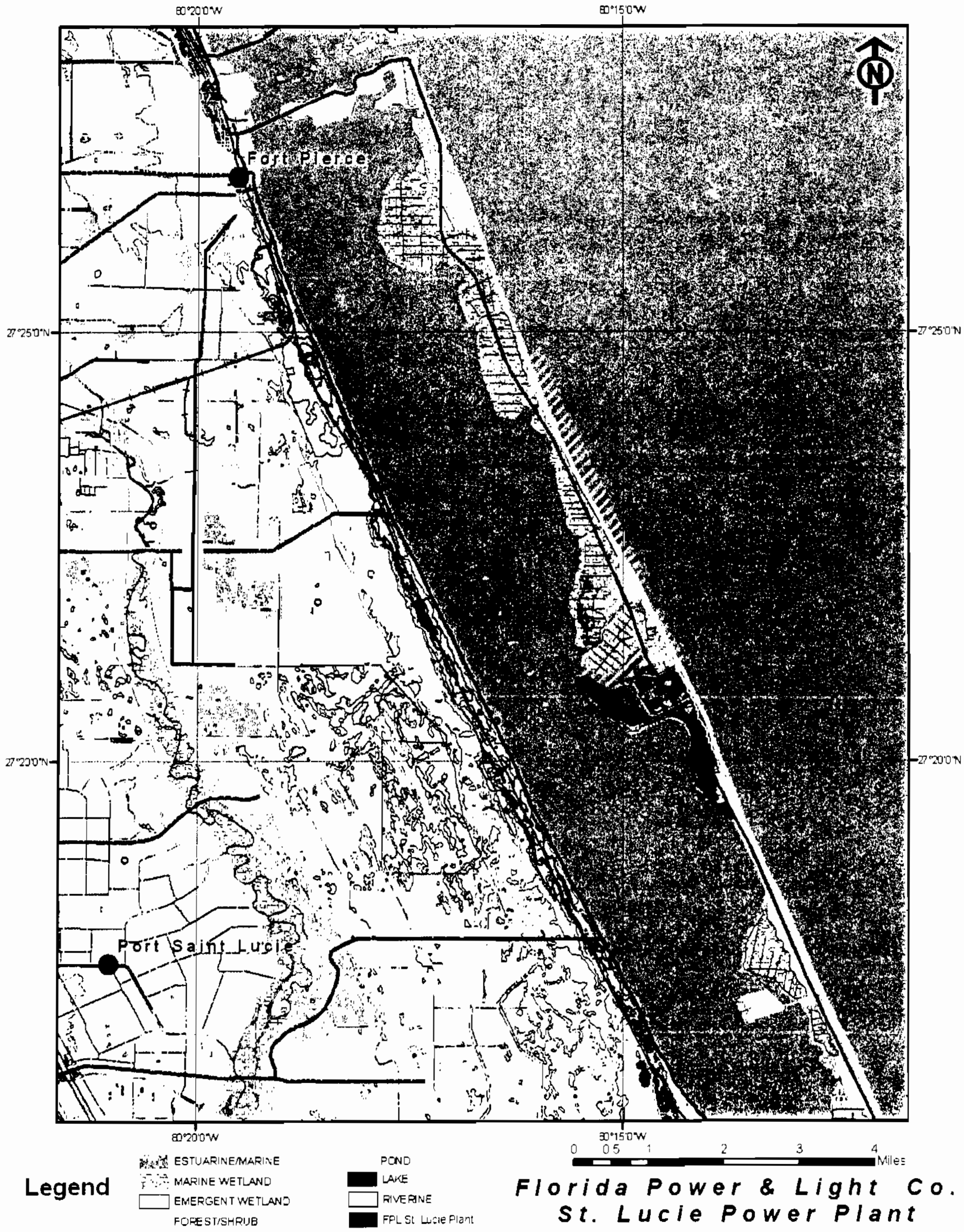
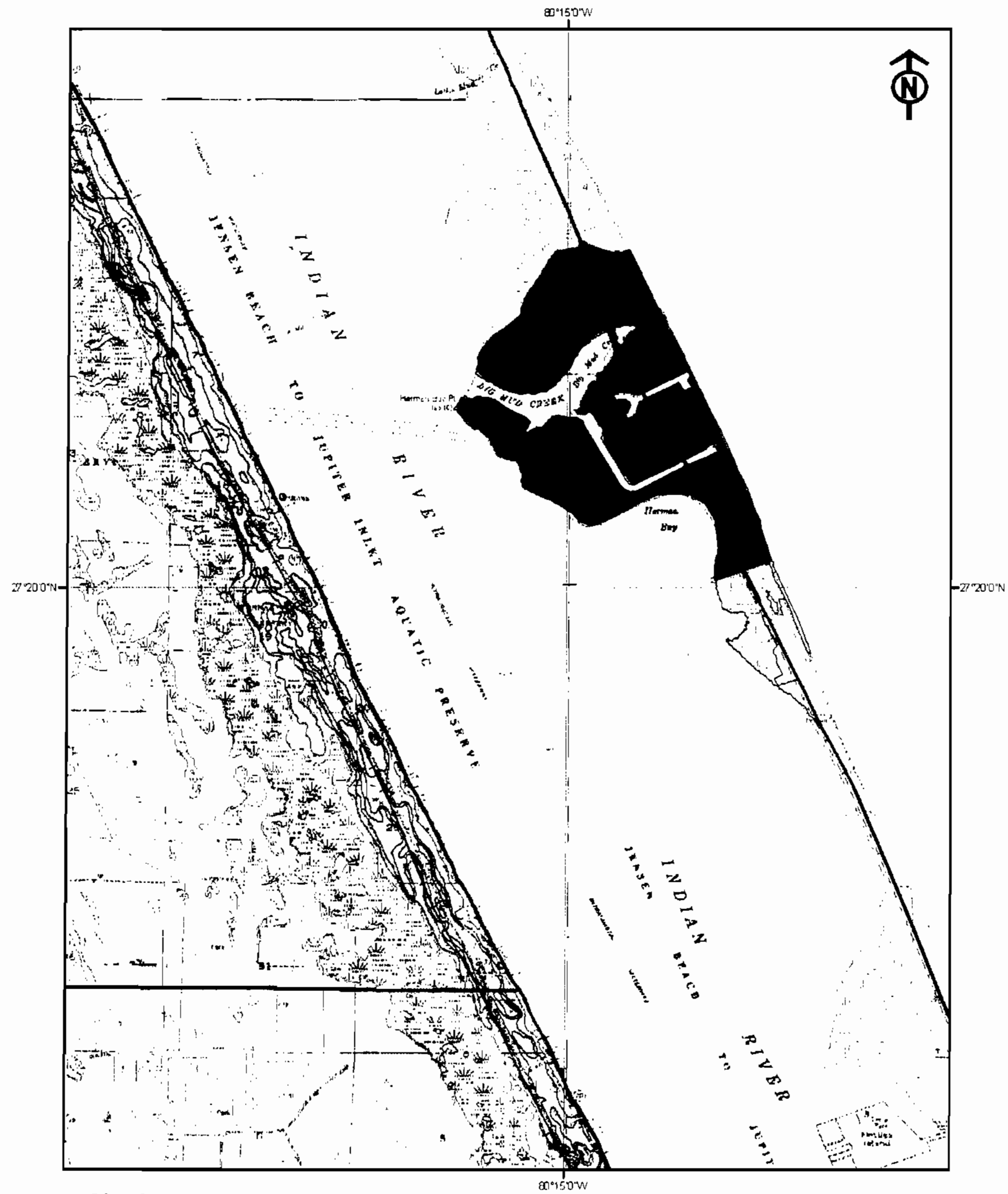


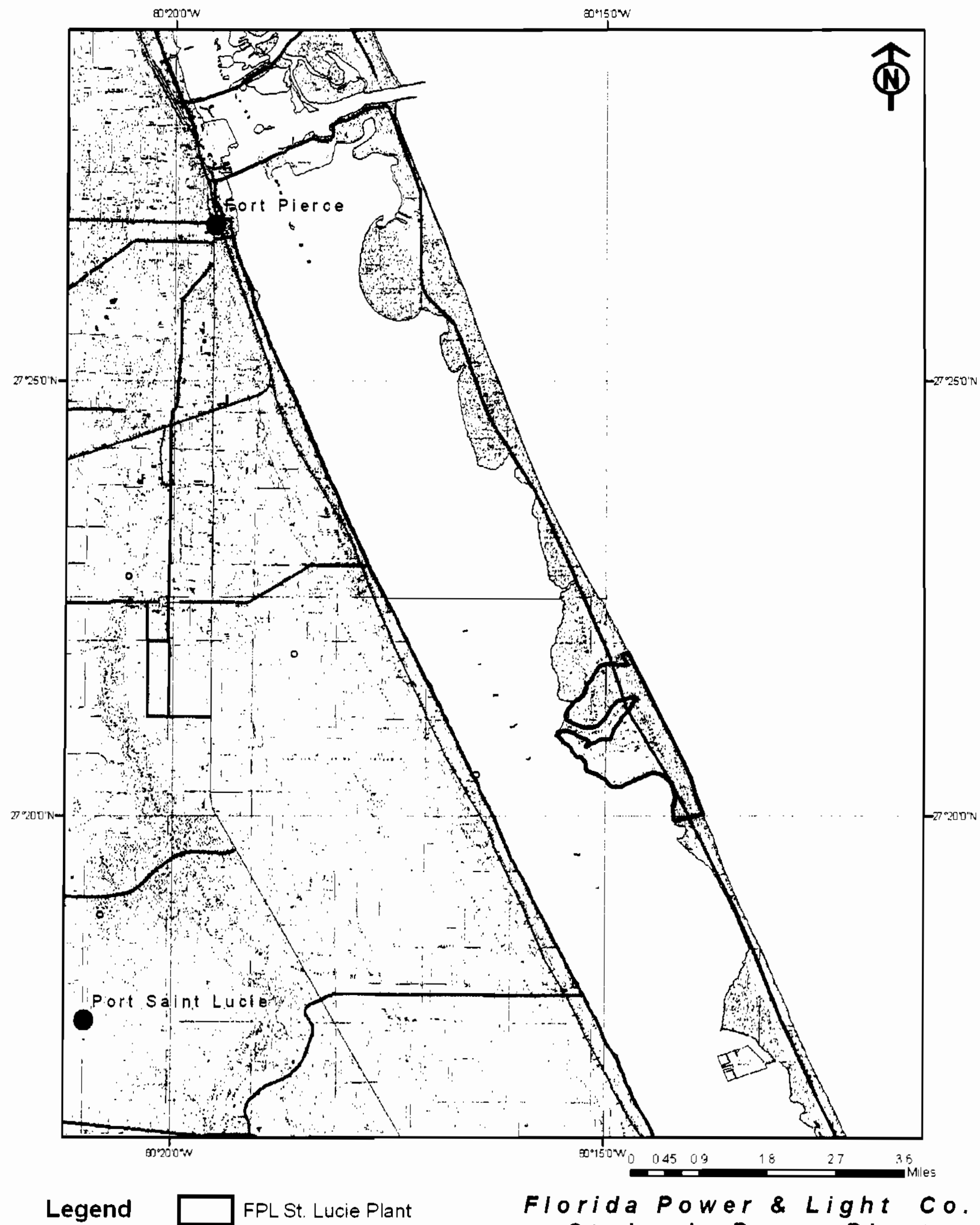
Florida Power & Light Co.
St. Lucie Power Plant



Site Layout

FPL St. Lucie Plant

Florida Power & Light Co.
St. Lucie Power Plant



Florida Power & Light Co.
St. Lucie Power Plant

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Environmental and Land Use Information: Supplemental Information

Preferred Site: Turkey Point Plant

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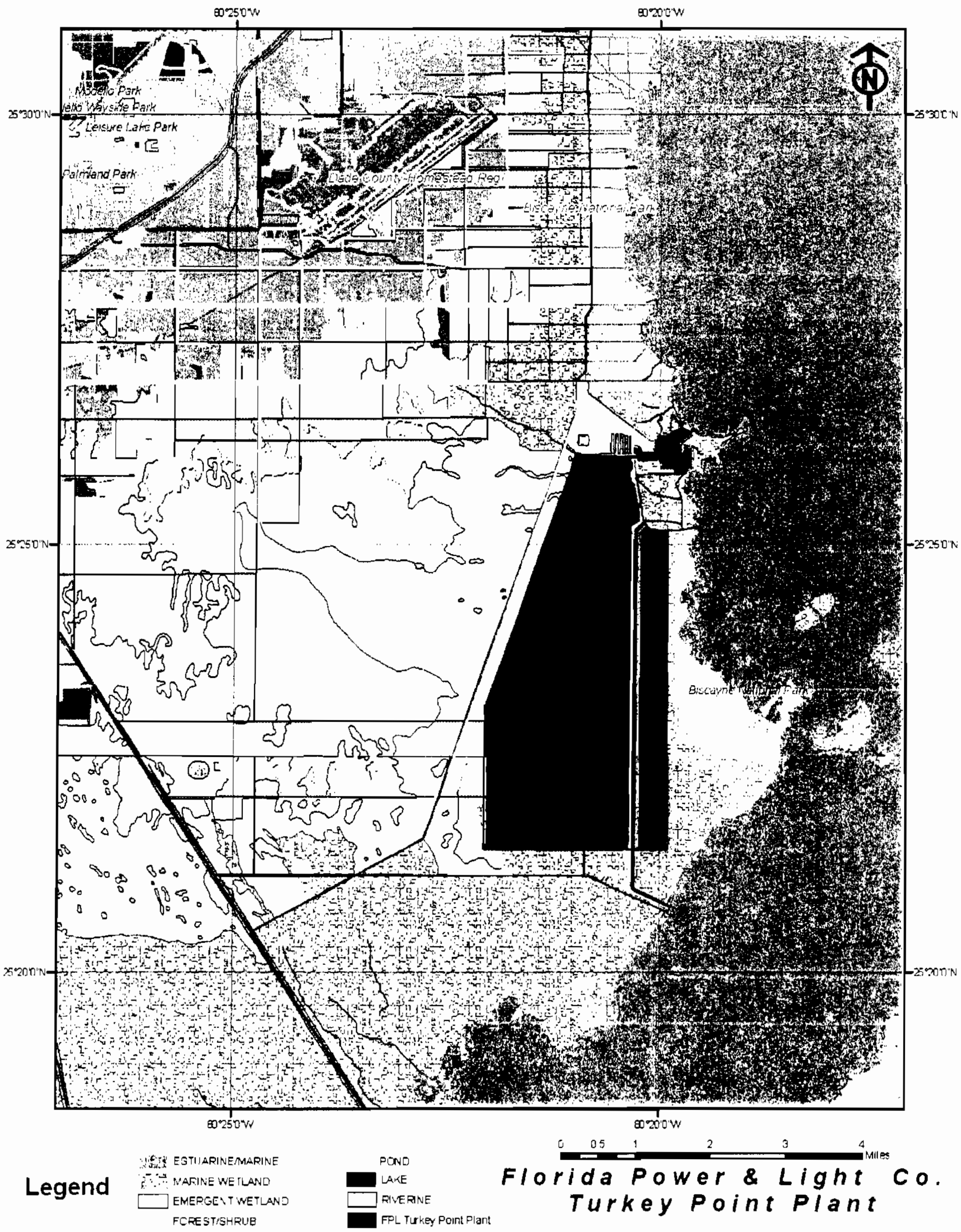
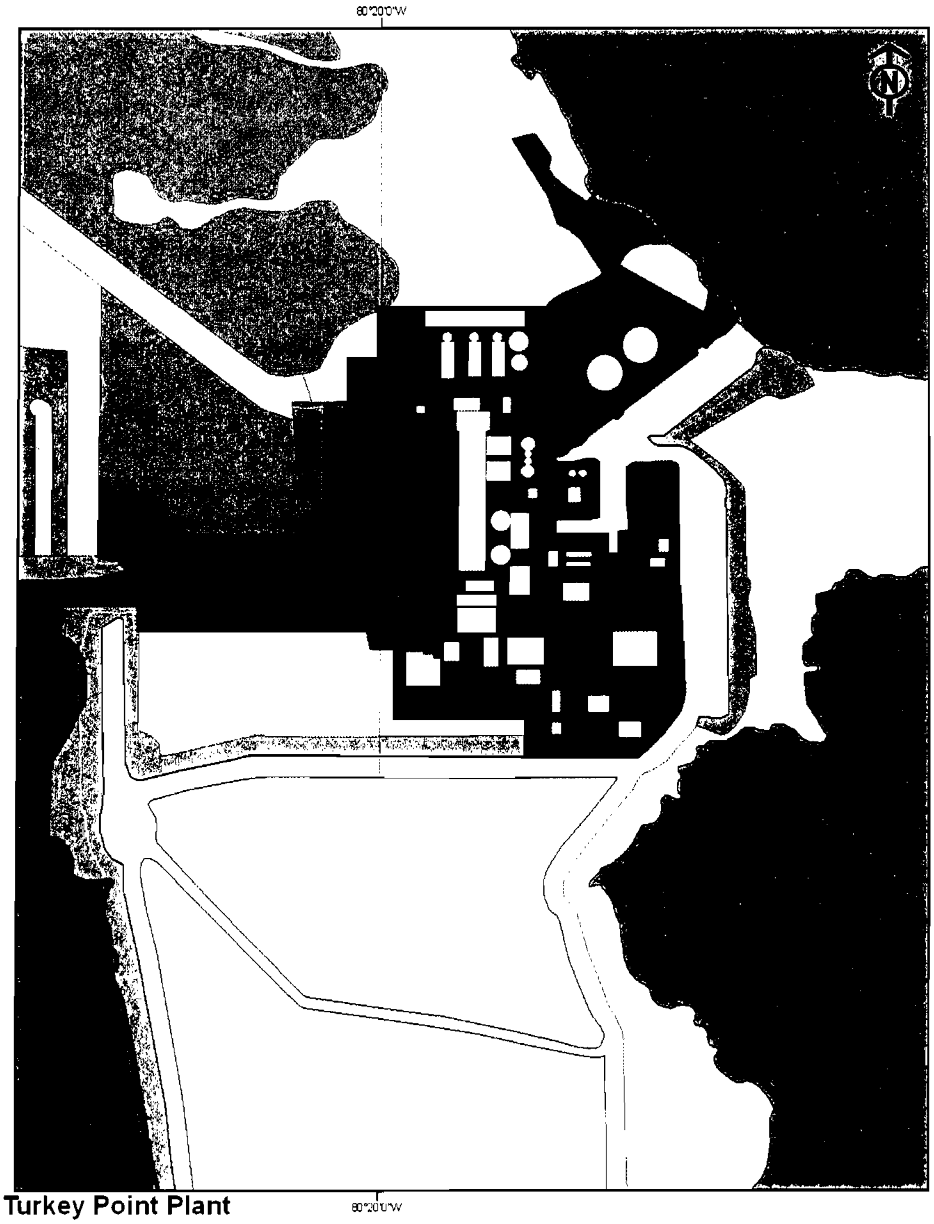

80°25'0"W
80°20'0"W
25°30'0"N
25°25'0"N
25°20'0"N
N
Leisure Lake Park
Palmland Park
0 0.5 1 2 3 4 Miles
Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL Turkey Point Plant
Florida Power & Light Co.
Turkey Point Plant



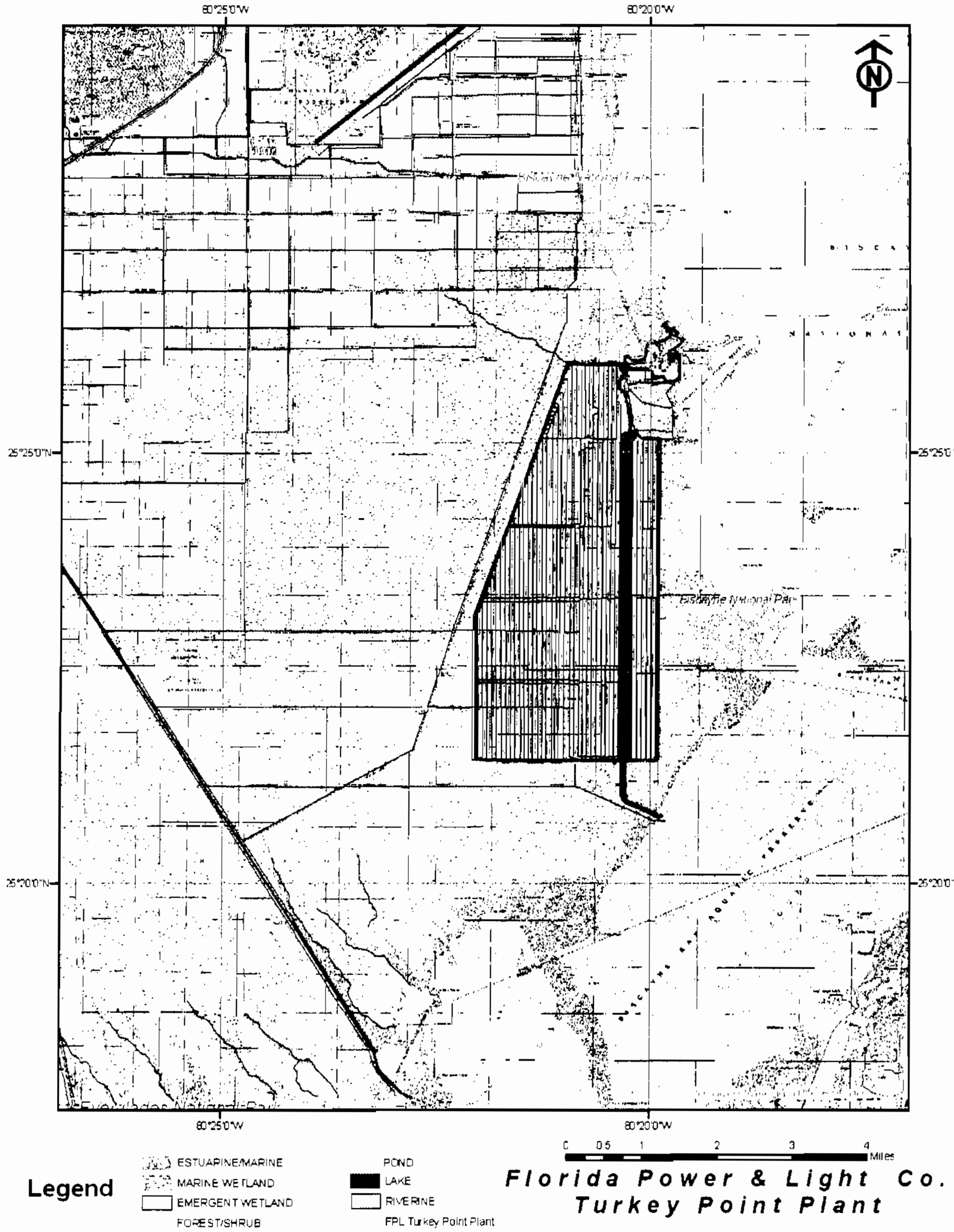
Turkey Point Plant
Facility Layout

Turkey Point Plant Site

Facility Structures

0 0.05 0.1 0.2 0.3 0.4 Miles

Florida Power & Light Co.
Turkey Point Plant


80°25'0"W
80°20'0"W
25°25'0"N
25°20'0"N
N
0 0.5 1 2 3 4
Miles
Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL Turkey Point Plant
Florida Power & Light Co.
Turkey Point Plant

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Environmental and Land Use Information: Supplemental Information

Potential Site #1: Cape Canaveral Plant

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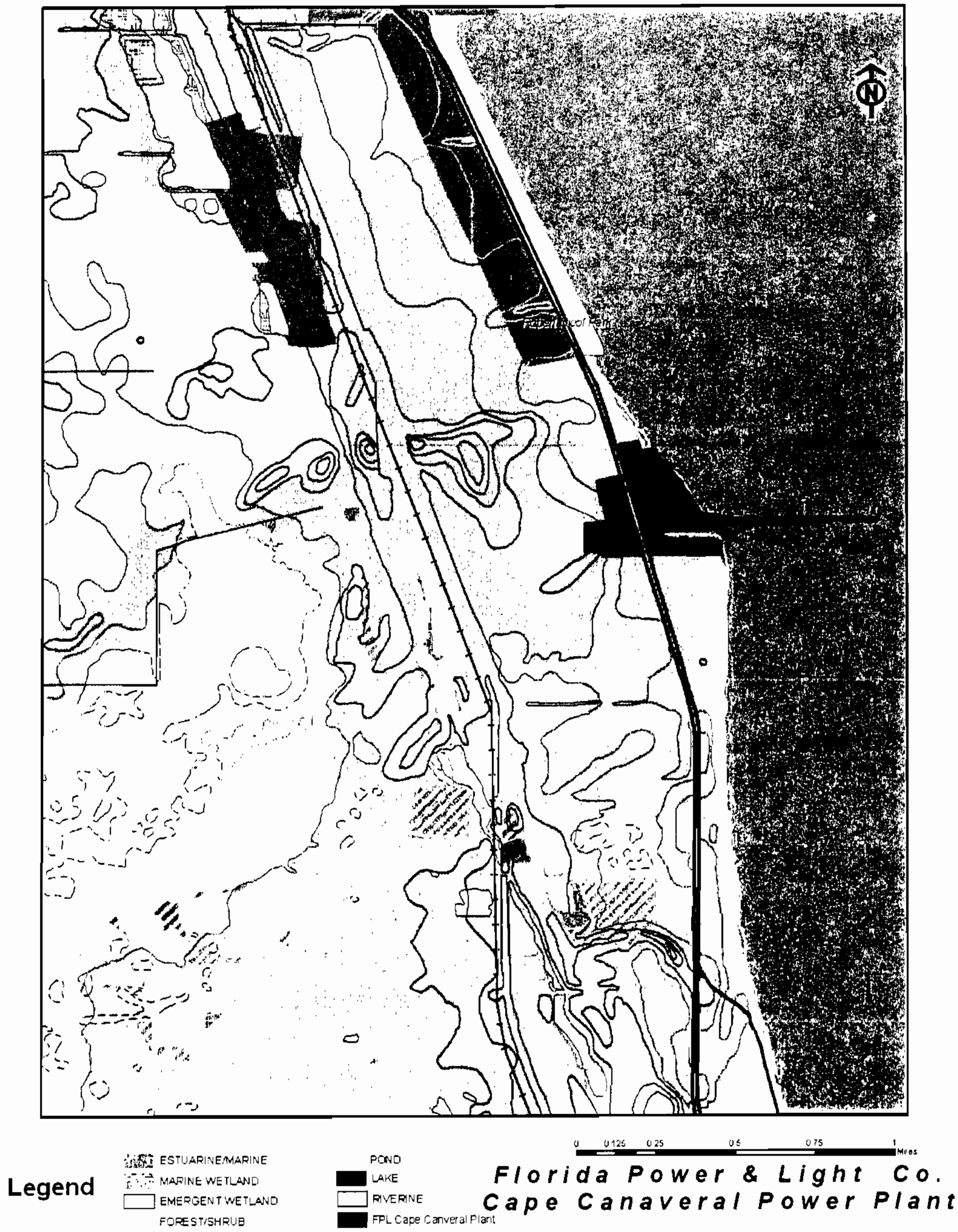
Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL Cape Canveral Plant
0
0.125
0.25
0.5
0.75
1
Miles
Florida Power & Light Co.
Cape Canaveral Power Plant

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Environmental and Land Use Information: Supplemental Information

Potential Site #2: Desoto County

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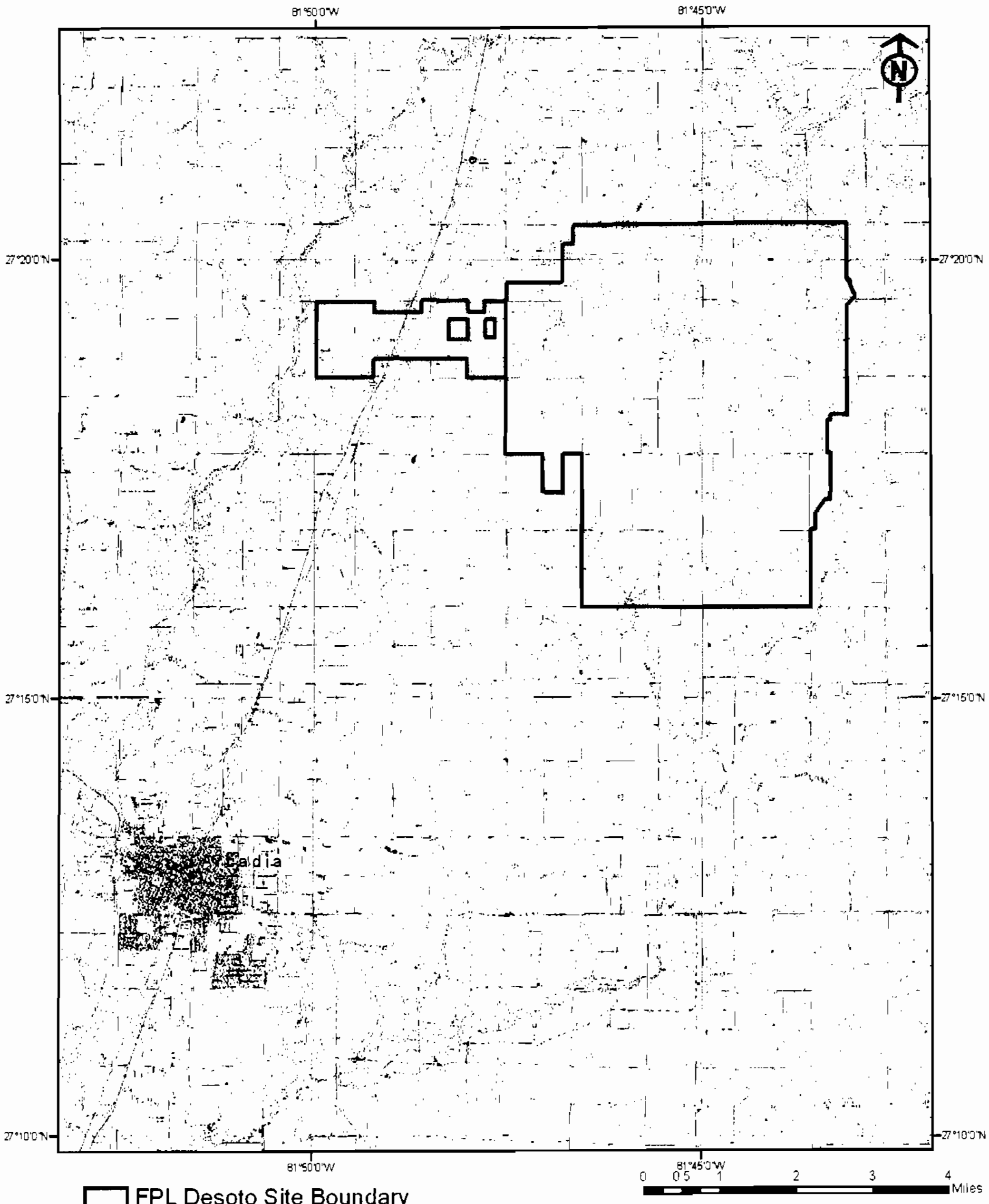

Florida Power & Light Co.
Desoto Greenfield Site

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Environmental and Land Use Information: Supplemental Information

Potential Site #3: Ft. Myers Plant

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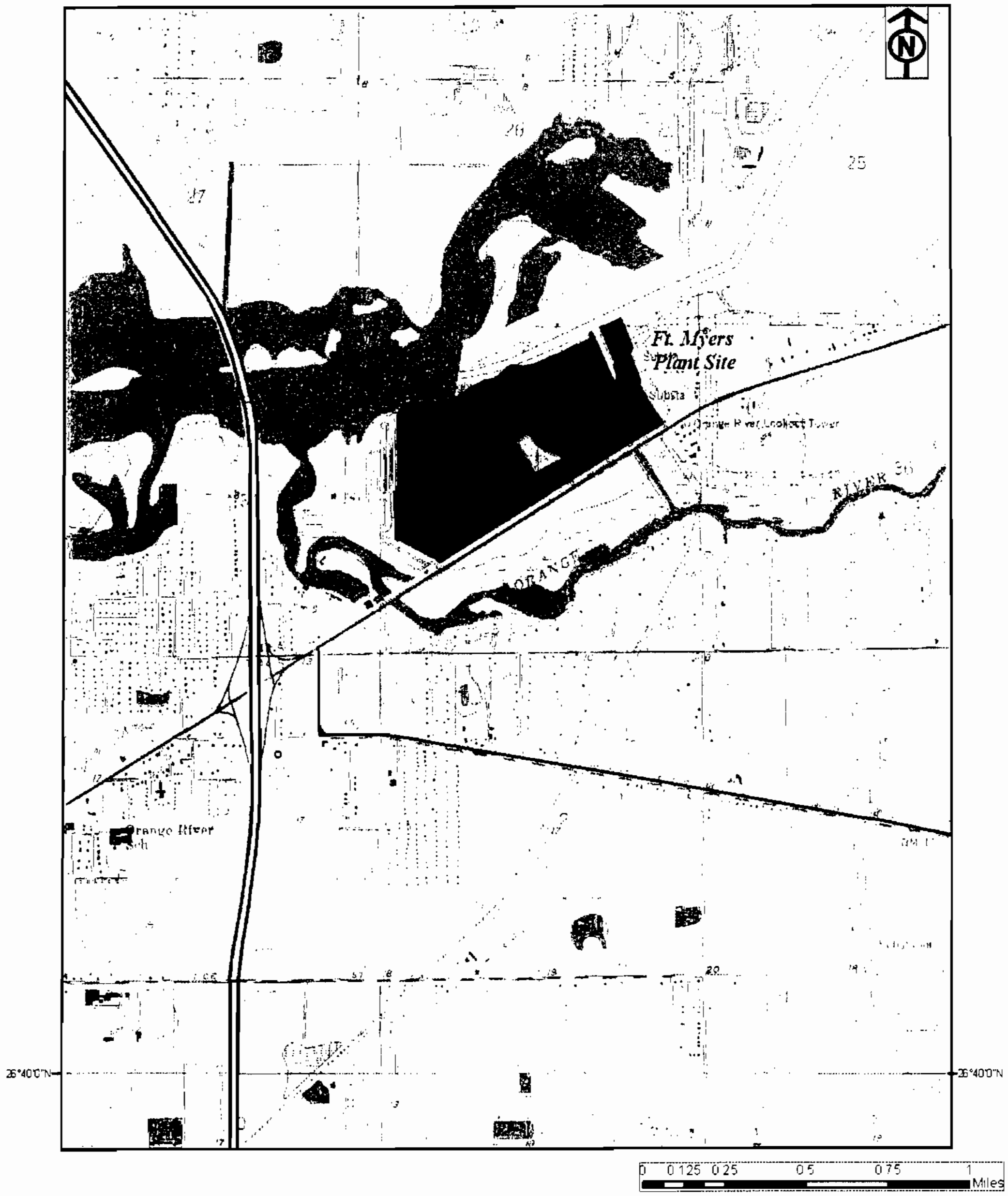

FPL Ft. Myers Plant Site Boundary

Florida Power & Light Co.
Ft. Myers Plant Site

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Environmental and Land Use Information: Supplemental Information

Potential Site # 4: Lauderdale Plant

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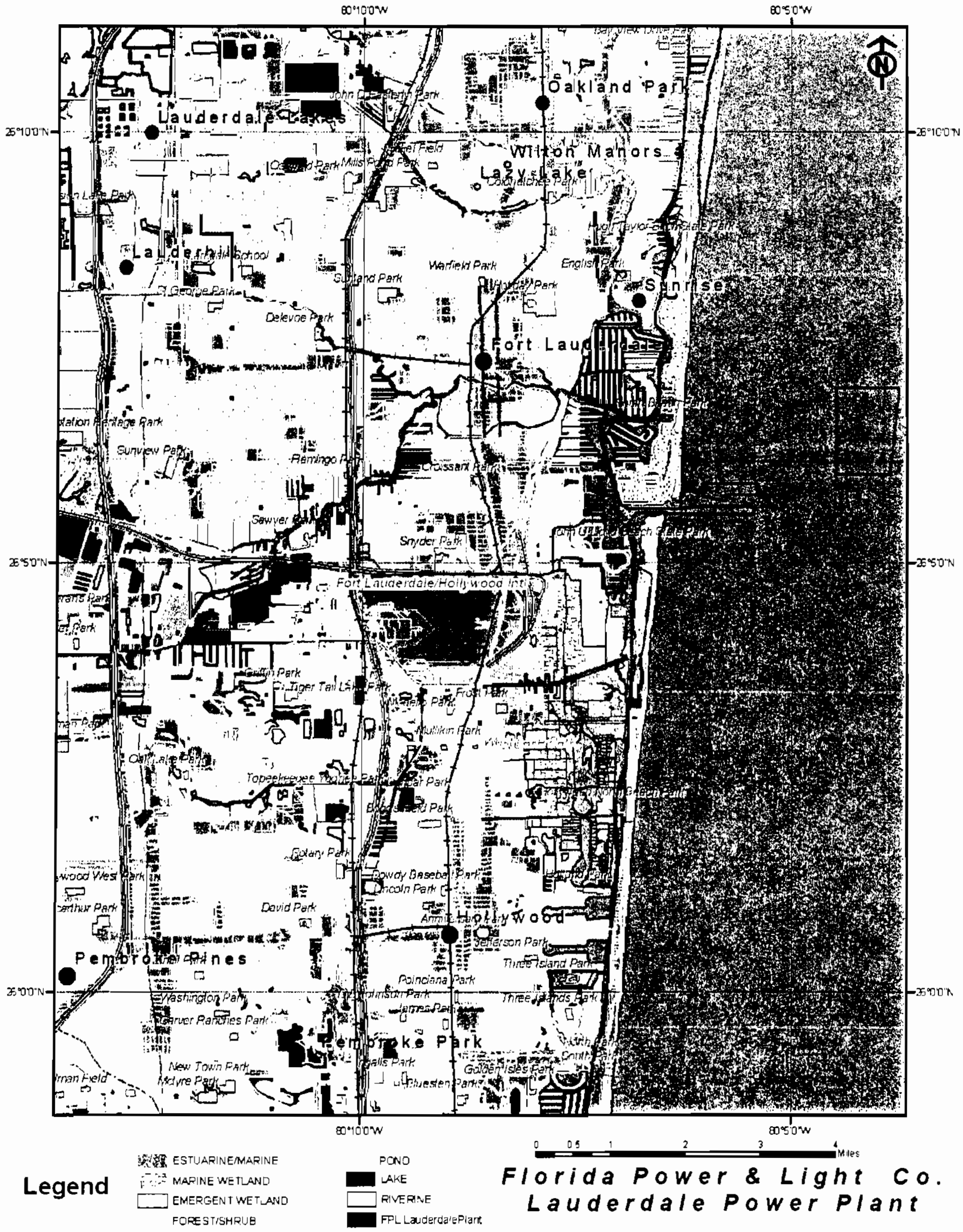
80°10'0"W
80°5'0"W
25°10'0"N
25°5'0"N
25°0'0"N
Oakland Park
Lauderdale Lakes
Wilton Manors
Lazy Lake
Lauderhill
Sunrise
Fort Lauderdale
Fort Lauderdale/Hollywood Intl
Hollywood
Pembroke Pines
Pembroke Park
Warfield Park
Delevoe Park
Sunview Park
Snyder Park
Griffin Park
Tiger Tail Lake Park
Mullikin Park
Topeekeegee Yugnee Park
Rotary Park
David Park
Jefferson Park
Poinciana Park
Three Islands Park
Carver Ranches Park
New Town Park
Golden Isles Park
Bluesten Park
0 0.5 1 2 3 4 Miles
Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL LauderdalePlant
Florida Power & Light Co.
Lauderdale Power Plant

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Environmental and Land Use Information: Supplemental Information

Potential Site #5: Martin County

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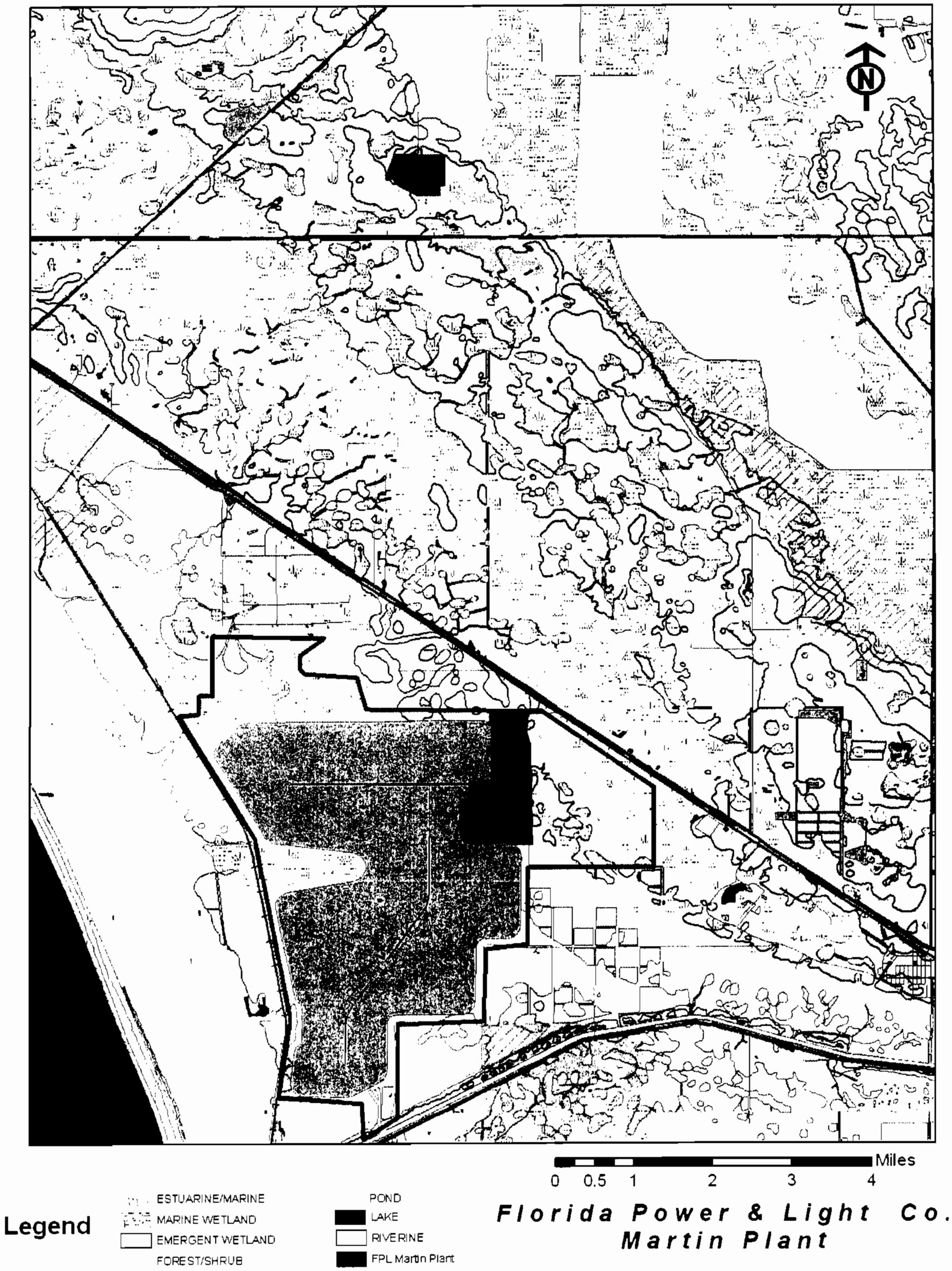
Miles
0 0.5 1 2 3 4
Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL Martin Plant
Florida Power & Light Co.
Martin Plant

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Environmental and Land Use Information: Supplemental Information

Potential Site #5: Port Everglades

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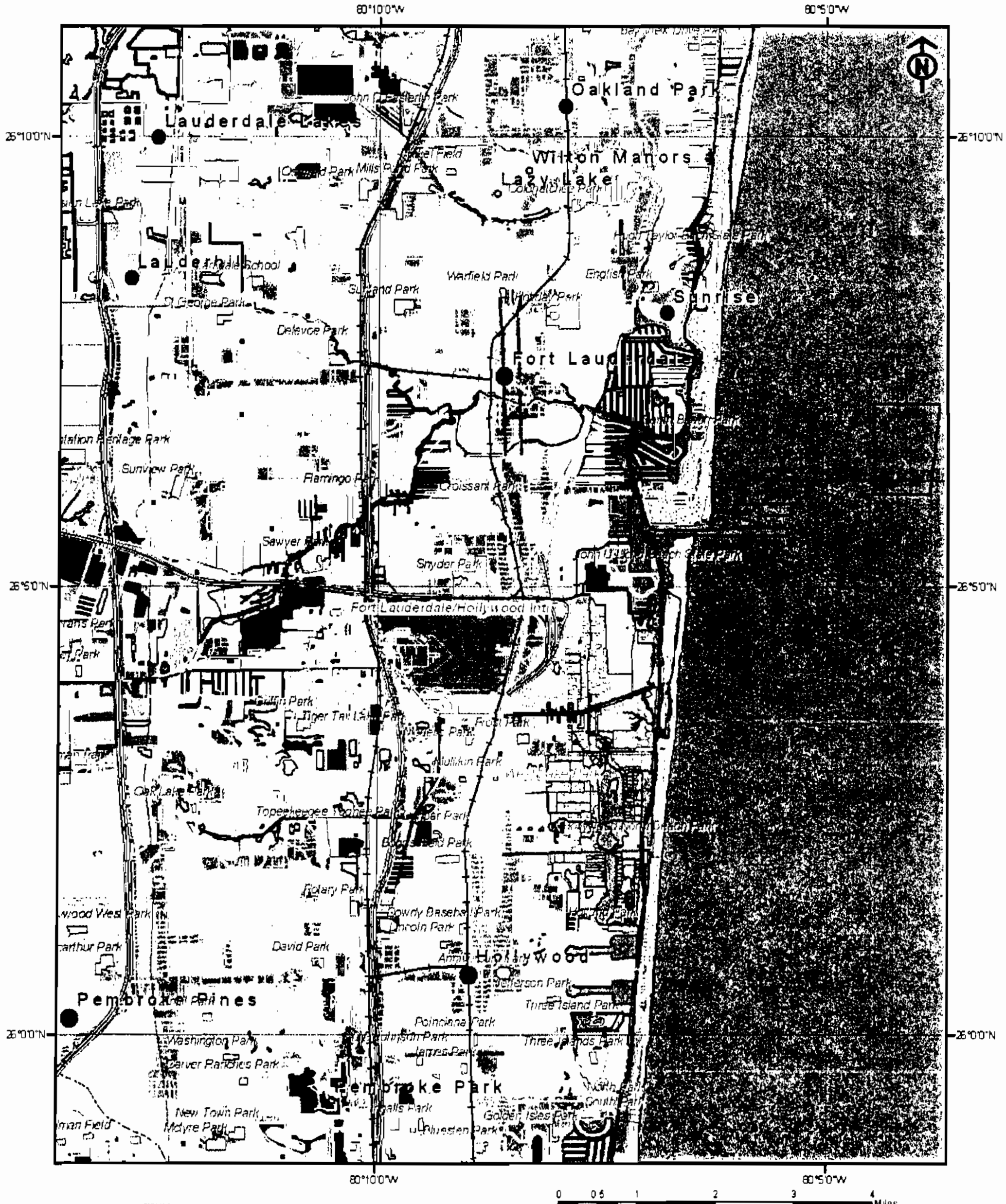

Legend

ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL Port Everglades Plant

Florida Power & Light Co.
Port Everglades Power Plant

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Environmental and Land Use Information: Supplemental Information

Potential Site #6: Riviera Plant

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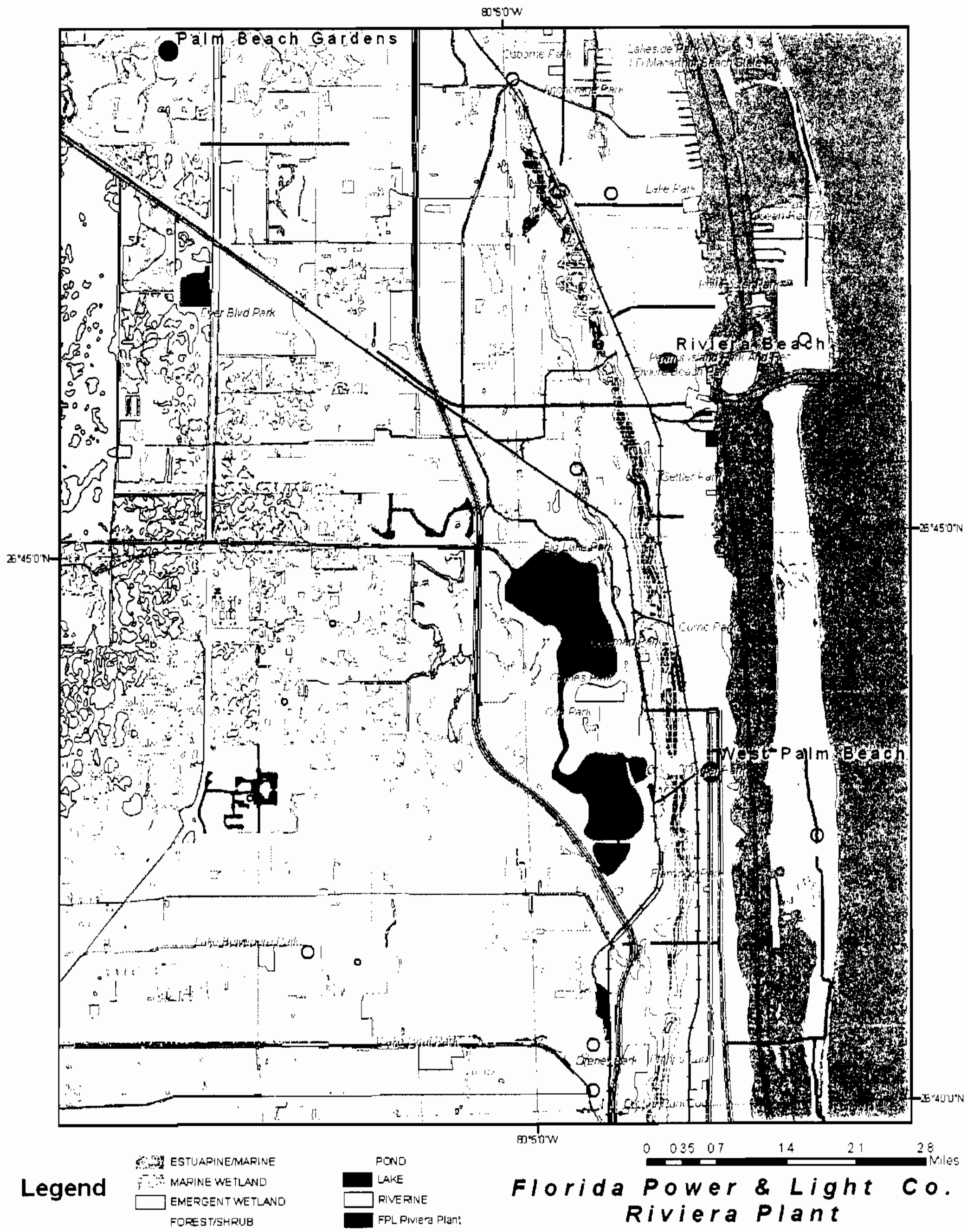
80°5'0"W
Palm Beach Gardens
Riviera Beach
West Palm Beach
26°45'0"N
26°40'0"N
0 0.35 0.7 1.4 2.1 2.8
Miles
Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL Riviera Plant
Florida Power & Light Co.
Riviera Plant

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Environmental and Land Use Information: Supplemental Information

Potential Site #7: West Broward

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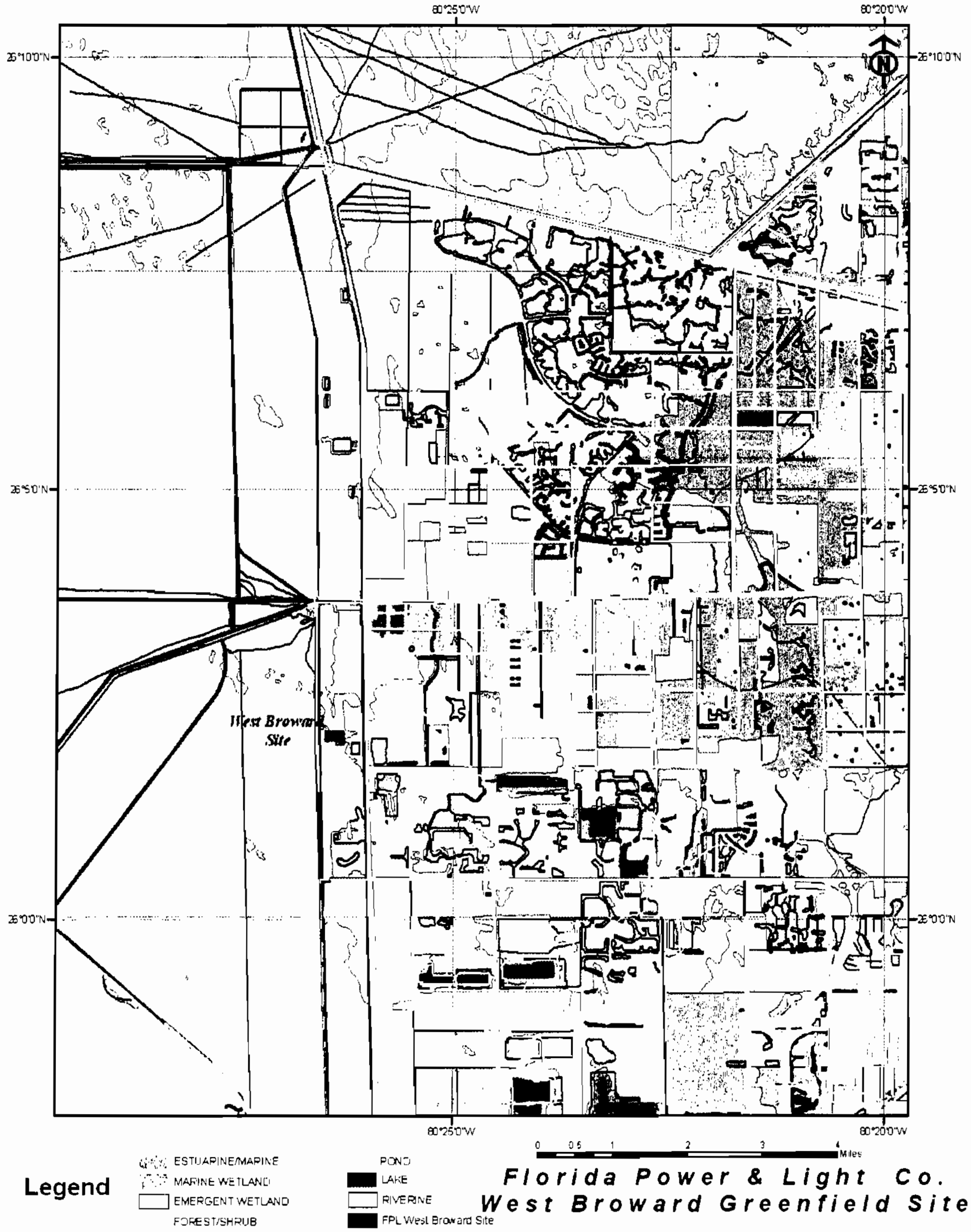
80°25'0"W
80°20'0"W
26°10'0"N
26°5'0"N
26°0'0"N
N
West Broward Site
0 0.5 1 2 3 4 Miles
Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL West Broward Site
Florida Power & Light Co.
West Broward Greenfield Site

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CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information". These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important since they affect the development of assumptions for the amount of external assistance which is available to the FPL system and the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new units that may not adversely impact such limitations. The internal transmission limitations are also addressed by developing the direct costs for siting new units at different locations and by evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system. Both site- and system-related transmission costs are developed for each different unit/unit location option or groups of options. In addition, transfer limits for capacity and energy that can be imported into the Southeastern region of FPL's system are also developed for use in FPL's production costing analyses. (A further discussion of the Southeastern Florida region and transmission imports is found in Section III.C.)

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's planned transmission facilities to interconnect and integrate FPL's resource plans and those that must be certified under the Transmission Line Siting Act are presented in Section III.E.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements for the FPL system.[3]

In its resource planning work in 2007, FPL utilized the load forecast that was presented in FPL's Determination of Need filings to the FPSC for advanced technology coal units, capacity uprates to FPL's existing nuclear units, and for two new nuclear units. In its resource planning work in early 2008, FPL utilized an updated load forecast. Both forecasts were considered the base forecast at those times and no sensitivity tests to either of those load forecasts were developed or utilized.

[3] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis, the lowest rate basis and the lowest system revenue requirements basis are identical. In such cases FPL evaluates options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its fuel price forecasts are discussed in Chapter III of this document. FPL's 2007 and early 2008 resource planning work utilized up to four different fuel cost forecasts (and four different environmental compliance cost forecasts). Detailed discussions of those fuel cost forecasts, and the results of utilizing them on the resource plans being analyzed in each filing, were presented to the FPSC in FPL's filings for Determination of Need for advanced technology coal units, capacity uprates to FPL's existing nuclear units, and for two new nuclear units.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item #3, FPL used up to four fuel forecasts in the filings for Determination of Need for advanced technology coal units, capacity uprates to FPL's existing nuclear units, and for two new nuclear units. While these forecasts did not represent a constant cost differential between oil/gas and coal, a variety of fuel cost differentials were represented in these forecasts.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 and Schedule 8 present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options which were considered in the resource planning work. A summary of this information for the new capacity options FPL projects to add, for planning purposes, over the planning horizon is presented on the Schedule 9 forms.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

In its 2007 and early 2008 resource planning work, FPL used a variety of key financial assumptions as forecasts changed. A 44.2% debt and 55.8% equity FPL capital structure was used throughout. In analysis for the advanced coal technology units, FPL used a 7.2% projected debt, an equity return of 12.3%, and after-tax discount rate of 8.93% for generation costs and 8.82% for all other costs. In analysis for the combined cycle units, FPL used a 6.43% projected debt, an equity return of 11.75%, and after-tax discount rate of 8.4% for generation costs and 8.3% for all other costs. FPL did not test the sensitivity of a specific resource plan to varying financial assumptions.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item #2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective are identical when DSM levels are unchanged between competing plans. Therefore, in planning work in which DSM levels were unchanged, the equivalent cumulative present value of revenue requirements perspective was utilized.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses two system reliability criteria in its resource planning work. One of these is a minimum 20% Summer and Winter reserve margin. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the reliability standards established by the North American Electric Reliability Corporation (NERC) in its *Reliability Standards*. FPL has applied these planning criteria in a manner consistent with prudent utility practice. The *NERC Reliability Standards* are available on the internet (http://www.nerc.com/.)

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Transmission Facility Rating Methodology* document that are also available on FPL's Open Access Same Time Information System (OASIS) at https://www.oatioasis.com/FPL/index.html.

The normal voltage criteria for FPL stations is given below:

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09

There may be isolated cases for which FPL may determine it prudent to deviate from the general criteria stated above. The overall potential impact on customers and the probability of an outage actually occurring, as well as other factors, would influence the decision in such cases.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The impact of FPL's DSM Programs on demand and energy consumption is revised periodically. Engineering models, calibrated with field-metered data, are updated when significant efficiency changes occur in the marketplace. Participation trends are tracked for all of the FPL DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants.

Survey data is collected from non-participants in order to establish the baseline efficiency. Participant data is compared against non-participant data to establish the demand and energy saving benefits of the utility program versus what would be installed in the absence of the program. For these DSM measures which involve the utilization of load management, FPL conducts periodic tests of the load control equipment to ensure that it is functioning correctly.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The Executive Summary provides a discussion of two system concerns that are typically addressed in FPL's resource planning work: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida. In addition, the Executive Summary also presented a discussion of a new factor introduced in 2007 that impacts FPL's resource planning work, the Executive

Order issued by Florida's Governor Crist in July 2007 that, in part, called for a significant reduction in greenhouse gas emissions in Florida and for an increase in the amount of energy provided by renewable, non-emitting sources.

In addition to these system concerns/issues, there are other strategic factors FPL typically considers when choosing between resource options. These include the following: (1) technology risk; (2) environmental risk, and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology which has not achieved general commercial acceptance has a higher risk than a technology in wide use and, therefore, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the FPL system, including environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for a plan are those which minimize environmental impacts for the FPL system as a whole through highly efficient fuel use and state of the art controls.

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decisions, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As has been previously discussed, elements of FPL's capacity additions include the construction of new generating capacity at the West County Energy Center (WCEC) site, WCEC Units 1 & 2. This generation construction projects was selected after evaluating competing bids received in response to Requests for Proposals (RFP) issued by FPL. The FPSC subsequently approved FPL's decision to construct these new combined cycle units in

Determination of Need dockets. FPL has followed a virtually identical RFP process in reaching its WCEC 3 decision.

The construction capacity addition decisions projected in this document for 2014 and beyond are expected to be conducted in a manner consistent with the Commission's Bid Rule.

Identification of self-build options beyond those units already approved by the FPSC and Governor and Siting Board, or units for which FPL is currently seeking approval, in FPL's Site Plan is not an indication that FPL has pre-judged any capacity solicitation it may conduct. The identification of future capacity units is required of FPL and represents those alternatives that appear to be FPL's best, most cost-effective self-build options at this time. FPL reserves the right to refine its planning analyses and to identify other self-build options. Such refined analyses have the potential to yield a variety of self-build options, some of which might not require an RFP. If an RFP is issued for supply-side resources, FPL reserves the right to choose the best alternative for its customers, even if that option is not an FPL self-build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

(1) FPL identified the need for a new 230kV transmission line (by December 2008) that required certification under the Transmission Line Siting Act which was issued on April 21, 2006. The new line, when completed, will connect FPL's St. Johns Substation to FPL's proposed Pringle Substation (also shown on Table III.E.1). The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

(2) FPL has identified the need for a new 230kV transmission line (by December 2011) that requires certification under the Transmission Line Siting Act. The new line will connect FPL's Manatee Substation to FPL's proposed BobWhite Substation (also shown on Table III.E.1). The construction of this line is necessary to serve existing and future customers in the Manatee and Sarasota areas in a reliable and effective manner.

FPL

Florida Power & Light Company, P.O. Box 029100, Miami, FL 33102-9100

April 1, 2009

VIA HAND DELIVERY

RECEIVED-FPSC
09 APR -1 PM 4:27
COMMISSION CLERK

Ms. Ann Cole
Division of the Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

RE: 2009-2018 Ten-Year Power Plan Site Plan 090000-OT

Dear Ms. Cole:

In accordance with Rule 25-22.071, F.A.C., please find enclosed for filing the original and twenty-five (25) copies of Florida Power & Light Company's 2009-2018 Ten-Year Power Plant Site Plan.

Please acknowledge your receipt of the above filing on the enclosed copy of this letter and return to the undersigned. Thank you for your assistance on this matter.

Sincerely,

Monica L. Padron

Monica Padron

COM ___
ECR ___
GCL 1
OPC ___
RCP ___
SSC ___
SGA ___
ADM ___
CLK 2

MP: ec
Enclosures

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 44
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-I

DOCUMENT NUMBER-DATE
02906 APR-1 8
FPSC-COMMISSION CLERK

Ten Year Power Plant Site Plan 2009 – 2018

FPL

FPL

Ten Year Power Plant Site Plan

2009-2018

Submitted To:

**Florida Public
Service Commission**

**Miami, Florida
April 2009**

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List of Figures and Tables

Potential Sites

List of Schedules

Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan. This plan includes an estimate of the utility's electric power generating needs, a projection of how those needs will be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. This information is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

This Ten Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) integrated resource planning (IRP) analyses that were carried out in 2008 and that were on-going in the first Quarter of 2009. The forecasted information presented in this plan addresses the 2009–2018 time frame.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information, especially for the latter years of the ten-year time horizon, and is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, based on FPL's IRP work in 2008 and

early 2009.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as Preferred and Potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional information that is to be included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	***Abbreviation***	***Definition***
Unit Type	BIT	Bituminous Coal
	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	IC	Internal Combustion
	NP	Nuclear Power
	PV	Photovoltaic
	ST	Steam Unit
Fuel Type	UR	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	P	Planned Unit
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete

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Executive Summary

Florida Power & Light Company's (FPL) 2009 Ten Year Power Plant Site Plan (Site Plan) presents FPL's current plans to augment and enhance its electric generation capability (owned or purchased) as part of its efforts to meet its projected incremental resource needs for the 2009 - 2018 time period. By design, the primary focus of this document is on supply side additions; i.e., electric generation capability. The supply side additions discussed in this document are resources projected to be needed after accounting for FPL's extensive demand side management (DSM) contributions and the significant energy efficiency contributions from the latest, enhanced federal appliance and lighting efficiency standards. The projected impacts of the federal appliance and lighting efficiency standards are included in FPL's load forecast presented in this document. The projected impacts of FPL's DSM contributions are addressed as reductions to the forecasted load.

The resource plan that is presented in FPL's 2009 Site Plan contains two key similarities to the resource plan presented in FPL's 2008 Site Plan, especially for the early years of the ten-year period. However, there are also three significant changes in the current resource plan compared to the resource plan presented in the 2008 Site Plan. These similarities to, and changes from, the 2008 Site Plan, plus the factors driving these changes are discussed below.

I. Similarities to the Resource Plan Presented in the 2008 Site Plan:

There are two key similarities in the current resource plan presented in this document compared to the resource plan presented in the 2008 Site Plan.

Similarity # 1: Three highly efficient combined cycle (CC) generating units and increases in generating capacity at FPL's existing nuclear units will be added to FPL's system in 2009 - 2012.

One similarity is the addition of new highly efficient natural gas-fired CC generating units and increased generating capacity from FPL's existing nuclear units in the 2009 through 2012 time period. FPL will be adding three 1,219 MW (Summer) CC units in western Palm Beach County during 2009 through 2011. The site for these units is named the West County Energy Center (WCEC) and these units are identified as WCEC Units 1, 2, and 3. The WCEC Unit 1 and WCEC Unit 2 were approved by the Florida Public Service Commission (FPSC) in June 2006. Site certification for these units under the Florida Electric Power Plant Siting Act was approved by the Governor and the Cabinet serving as the Siting Board in December 2006. The WCEC Unit 3 was approved by the FPSC in September 2008 and FPL's site certification for this unit was approved in November 2008.

In addition, FPL will be adding approximately 400 MW of increased generating capacity at its existing nuclear power plants at its Turkey Point and St. Lucie sites. This increased capacity is scheduled to come in-service in 2011 and 2012. The need for these capacity "uprates" was approved by the FPSC in January 2008. The Final Order for the Site Certification was issued in September 2008 for the St. Lucie uprates and October 2008 for the Turkey Point uprates.

Similarity # 2: The amount of projected DSM additions remains unchanged in this Site Plan. These projections are subject to change in late 2009 based on the outcome of the 2009 DSM Goals proceeding before the FPSC.

The other key similarity to the resource plan presented in the 2008 Site Plan is the amount of additional DSM that is projected to be implemented annually over the ten-year period. There is essentially no change in the amount of projected annual DSM additions between the 2008 Site Plan and the 2009 Site Plan.

The DSM values presented in the 2009 Site Plan are based on meeting FPL's currently approved DSM Goals through 2014, plus implementing additional cost-effective DSM through 2014 that was identified by FPL after the current DSM Goals were established, and a projection of continued DSM additions in 2015 through 2017 at an annual implementation rate commensurate with that in the years leading up to 2014. Because the 2009 Site Plan addresses one more year (2018) than did the 2008 Site Plan, FPL has extended its DSM projection out one more year to 2018 using a similar annual implementation rate.

However, FPL is scheduled to present its new projections of cost-effective DSM to the FPSC in June 2009. These new projections will be used to determine FPL's new DSM Goals for the years 2010 through 2019. The analyses to develop these new projections of cost-effective DSM for the new DSM Goals are currently a work in progress at the time the 2009 Site Plan is being filed. The final order from the FPSC establishing FPL's new DSM Goals is expected in the 4th Quarter of 2009. The subsequent development and approval of FPL's DSM Plan (with which FPL will meet the new Goals) will likely be made in early 2010. Therefore, the impact of FPL's new DSM Goals and DSM Plan will be reflected next year in FPL's 2010 Site Plan.

II. Factors That Are Driving Changes in FPL's Resource Plan:

There are two primary "change factors" that are largely driving the changes in FPL's 2009 resource plan compared to the resource plan presented in FPL's 2008 Site Plan. These two change factors, and their impacts on the resource plan, are summarized below and are addressed in more detail in Chapters II and III of this document.

Change Factor # 1: The load forecast is significantly lower than in previous years.

The first factor that is driving changes in the current resource plan is FPL's new long-term load forecast that was prepared in January 2009. With this new forecast, FPL now projects lower growth in electrical demand over the ten-year period addressed in this document. The projection of lower load growth is primarily driven by several factors including: a forecasted lower rate of population growth, an economic downturn lasting several years, and increased energy efficiency impact from the latest enhanced federal appliance and lighting efficiency standards. The combined effect of these three drivers results in projected lower growth in electrical demand for the entire ten-year period (2009 – 2018) addressed in this document, compared to the projected load growth discussed in FPL's 2008 Site Plan.

Change Factor # 2: Highly Efficient New Generation Capacity has been approved by the FPSC and is now reflected in FPL's Resource Plan in 2010-2018.

The second change factor is the inclusion of highly efficient new generating capacity that was approved by the FPSC during 2008. This new generating capacity was shown to be cost-effective, to enhance system fuel diversity, and to reduce FPL's system emission rates. This new generating capacity consists of new generating units that are nuclear, solar, or highly efficient new natural gas-fired CC units.

These new generating unit additions include the following:

- Two new nuclear units (Turkey Point Units 6 & 7) are projected to be brought into service in 2018 and 2020, respectively. Each unit is projected to add approximately 1,100 MW of firm capacity. The FPSC approved the need for these new nuclear units in April 2008. As part of this approval, FPL will be providing an annual feasibility analysis as part of the annual nuclear cost recovery process. A multi-year licensing and permitting review process for these units is currently underway. Because this Site Plan addresses the time period through 2018, the first of these two units, Turkey Point Unit 6, is now included in the 2009 Site Plan.

- Two new photovoltaic (PV) solar facilities are projected to be brought into service by 2010. One of these PV facilities will be placed in DeSoto County and will be named the DeSoto Next Generation Solar Energy Center. This facility is projected to have a nameplate rating of 25 MW. The second PV facility will be placed in Brevard County and will be named the Space Coast Next Generation Solar Energy Center. This PV facility is projected to have a nameplate rating of 10 MW. The FPSC approved the eligibility of expenditures for these PV facilities to be recovered through the environmental cost recovery clause in August 2008. The DeSoto Next Generation Solar Energy Center obtained an Environmental Resource Permit and an Army Corps of Engineers permit in October 2008. The Space Coast Next Generation Solar Energy Center received the Army Corps of Engineers permit in December 2008 and the Environmental Resource Permit is expected to be received in mid-2009.
- A new solar thermal facility at FPL's existing Martin plant site is also projected to be brought into service in 2010. This solar thermal facility, named the Martin Next Generation Solar Energy Center, is projected to be able to produce up to 75 MW of steam capability, thus allowing reduced use of fossil fuels by FPL when the solar thermal facility is producing steam. The FPSC approved the eligibility of expenditures for this solar thermal facility to be recovered through the environmental cost recovery clause in August 2008. FPL also received the site certification modification approval in August 2008.
- Two existing generating plants, each consisting of two older fossil fired steam generating units, are projected to be converted into new, highly efficient CC units. The existing two-unit plant at FPL's Cape Canaveral site will be replaced by a new CC unit with a projected output of 1,219 MW (Summer) in 2013. This new unit will be called the Cape Canaveral Next Generation Clean Energy Center. The existing two-unit plant at FPL's Riviera site will also be replaced by a new CC unit with a projected output of 1,207 MW (Summer) in 2014. This new unit will be called the Riviera Beach Next Generation Clean Energy Center. These conversions were approved by the FPSC in September 2008. The site certification application for Cape Canaveral was filed in December 2008 and the site certification application for Riviera Beach was filed in February 2009. A decision is expected to be reached regarding these applications by early 2010.

These new generating units were selected and incorporated into FPL's resource plan for a variety of reasons including cost-effectiveness, significant system fuel savings, and significant system emission reductions, including greenhouse gas emission reductions. In addition, the solar projects will increase the contribution of renewable energy sources towards meeting the electricity needs of FPL's customers.

III. Resulting Changes in FPL's Resource Plan Compared to the 2008 Site Plan:

The impact of the two change factors discussed above, plus other concerns discussed later in this chapter and in Chapter III, have resulted in three significant changes in FPL's resource plan presented in this document compared to the resource plan presented in FPL's 2008 Site Plan. These resulting changes are summarized below.

Resulting Change # 1: FPL's resource plan now reflects greater contributions from nuclear energy and renewable energy.

The first of FPL's two planned 1,100 MW nuclear units that is scheduled to come in-service in 2018 (the second unit is scheduled to come in-service in 2020 but is not addressed in this document due to the later in-service date), plus the addition of 35 MW of PV and 75 MW of solar thermal in 2010, are new to FPL's resource plan this year. These new units will increase the contribution from both nuclear and renewable energy. In turn, this reduces fossil fuel use by FPL's system from what it otherwise would have been.

This decrease in fossil fuel usage will also contribute to lowering FPL system emission rates, including greenhouse gas emission rates, thus lowering system emissions from what they would otherwise have been if these generating units were not added. In regards to carbon dioxide (CO_2), FPL already has a relatively low CO_2 emission rate (CO_2 tons per MWh generated) compared to other utilities. The planned additions of new nuclear capacity, highly efficient CC capacity including the conversions of two existing plants, and the PV and solar thermal contributions will result in a further lowering of FPL's system CO_2 emission rate, thus working to offset the upward pressure on emissions that will be caused by continuing population and electrical load growth in FPL's service territory.

Resulting Change # 2: Other than the new generating units that have recently been approved, FPL projects that it will add no additional new generating units to meet capacity needs through 2018.

FPL's lower load forecast in January 2009 results in a significantly lower resource need projection for the next ten years than was the case with the 2008 Site Plan. The lower resource need can be effectively met by the new generating units that have recently been approved. As shown by the table ES.1 below, FPL projects no additional FPL generation unit additions through 2018 beyond the above-mentioned units that were approved in 2008. (However, this resource plan is subject to change for a variety of reasons including the need to address potential new laws and/or regulations related to renewable energy.)

Resulting Change # 3: FPL will also place on Inactive Reserve some of its existing generating units starting in 2009.

The lower resource need projection discussed above has also led FPL to reflect in its resource plan the temporary removal of a number of its existing, older, less efficient generating units from active service starting in 2009. These units will continue to be maintained and will be returned to active service as needed.

FPL's existing Cape Canaveral and Riviera plants will be placed in Inactive Reserve as early as the Summer of 2009. The Cape Canaveral plant is scheduled to be permanently removed in 2010, and the Riviera plant will be permanently removed in 2011, as part of the conversion projects. In addition, the following older, less efficient units will also be placed on Inactive Reserve status in 2009 and 2010: Cutler Units 5 & 6, Port Everglades Units 1 & 2, Sanford Unit 3, Martin Unit 2, and Manatee Unit 2[1]. FPL will continue to maintain these units and will again utilize these units (other than those at Riviera and Cape Canaveral where new units will be constructed) as resource needs dictate. For purposes of this planning document, FPL projects that these units will begin to be returned to operation starting in 2016. A further discussion of these units is presented in Chapter III.

Table ES.1 presents a current projection of the changes in the generating resources portion of FPL's resource plan based on the factors and changes discussed above. As such, this table does not directly address FPL's significant DSM contributions, but FPL's significant projected DSM contributions were fully accounted for by FPL and the FPSC in the process of approving the need for the new generating units presented in the table.

FPL's ongoing resource planning efforts will continue to be influenced by the two change factors discussed above (i.e., a new lower load forecast and the addition of highly efficient nuclear, solar, and CC generation already approved by the FPSC). In addition, other items will also influence FPL's resource planning work. Among these items are two that FPL refers to as on-going system concerns that FPL has considered in its resource planning work for a number of years. These on-going system concerns include: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida.

In addition, two other relatively recent developments will also influence FPL's continuing resource planning efforts. One of these is the Executive Orders directive issued in 2007 by Governor Crist calling for reduction in greenhouse gas emissions and greater contribution from renewable

[1] The two 800 MW units, Martin Unit 2 and Manatee Unit 2, on this list may be replaced at some time in the future by two similar size units, Martin Unit 1 and Manatee Unit 1. If this were to occur, Martin Unit 1 and Manatee Unit 1 would be temporarily placed on Inactive Reserve status and Martin Unit 2 and Manatee Unit 2 would be returned to active service.

energy sources. As previously discussed, FPL's resource planning has already taken positive steps in regard to both of these issues.

The other development is the ongoing effort to establish a Florida standard for renewable energy contributions to a utility system. A Renewable Portfolio Standard (RPS) proposal prepared by the FPSC has been sent to the Florida Legislature for consideration during the legislative session that began in March 2009. Because the eventual RPS outcome is not known at the time the 2009 Site Plan is being prepared, the resource plan presented in FPL's 2009 Site Plan does not directly address any RPS decision. Assuming that an RPS decision is reached later in 2009, FPL will then determine what steps need to be taken to address the standard. These steps will be discussed next year in FPL's 2010 Site Plan.

Table ES.1: Projected Capacity Changes and Reserve Margins for FPL

Year	Projected Capacity Changes	Net Capacity Changes (MW) Winter (2)	Summer (3)	Reserve Margin (%) Winter	Summer
2009	Changes to Existing Purchases (4)	---	(479)	53.1%	28.1%
	West County Unit 1 (5)	---	1,219		
	DeSoto Next Generation Solar Energy Center (PV) (6)	---	---		
	Riviera Unit 3 - offline for conversion	---	(276)		
	Riviera Unit 4 - offline for conversion	---	(286)		
	Changes to Existing Units	(78)	10		
	Inactive Reserve of Existing Units - offline (8)	---	(766)		
2010	Changes to Existing Purchases (4)	(559)	(352)	58.2%	20.7%
	West County Unit 1 (5)	1,335	---		
	West County Unit 2 (5)	1,335	1,219		
	Martin Next Generation Solar Energy Center (Solar Thermal) (7)	---	---		
	Space Coast Next Generation Solar Energy Center (PV) (6)	---	---		
	Riviera Unit 3 - offline for conversion	(277)	---		
	Riviera Unit 4 - offline for conversion	(288)	---		
	Cape Canaveral Unit 1 - offline for conversion	---	(395)		
	Cape Canaveral Unit 2 - offline for conversion	---	(388)		
	Changes to Existing Units	53	36		
	Inactive Reserve of Existing Units - offline (8)	(777)	(1,648)		
2011	Changes to Existing Purchases (4)	(46)	(45)	41.8%	25.8%
	West County Unit 3 (5)	---	1,219		
	Cape Canaveral Unit 1 - offline for conversion	(397)	---		
	Cape Canaveral Unit 2 - offline for conversion	(397)	---		
	Inactive Reserve of Existing Units - offline (8)	(1,663)	10		
	Changes to Existing Units	130	(92)		
2012	Changes to Existing Purchases (4)	---	(156)	45.7%	23.6%
	West County Unit 3 (5)	1,335	---		
	Changes to Existing Units	(11)	(11)		
	Existing Nuclear Units Capacity Uprates - St. Lucie 1	103	103		
	Existing Nuclear Units Capacity Uprates - St. Lucie 2	---	88		
	Existing Nuclear Units Capacity Uprates - Turkey Point 3	---	104		
2013	Changes to Existing Purchases (4)	(180)	---	44.1%	29.1%
	Existing Nuclear Units Capacity Uprates - St. Lucie 2	88	---		
	Existing Nuclear Units Capacity Uprates - Turkey Point 3	104	---		
	Existing Nuclear Units Capacity Uprates - Turkey Point 4	104	104		
	Cape Canaveral Next Generation Clean Energy Center (5)	---	1,219		
2014	Changes to Existing Purchases (4)	---	50	44.0%	28.0%
	Cape Canaveral Next Generation Clean Energy Center (5)	1,343	---		
	Riviera Beach Next Generation Clean Energy Center	---	1,207		
2015	Riviera Beach Next Generation Clean Energy Center	1,310	---	46.0%	25.1%
2016	Inactive Reserve of Existing Units - online (8)	---	814	42.3%	20.0%
	Changes to Existing Purchases (4)	---	(1,311)		
2017	Inactive Reserve of Existing Units - online (8)	825	822	41.5%	21.1%
2018	Turkey Point Nuclear Unit 6 (5)	---	1,100	38.2%	22.2%
	Inactive Reserve of Existing Units - online (8)	834	---		
	TOTALS =	4,226	3,119		

Table heading: Projected Capacity Changes and Reserve Margins for FPL (1)

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are values for January of the year shown.
(3) Summer values are values for August of the year shown.
(4) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(5) All new unit additions are scheduled to be in-service in June of the year shown except for WCEC 1 and WCEC 2 that are projected to be in-service in August 2009 and December 2009, respectively. WCEC 1 is included in the Summer reserve margin calculation starting in 2009 and in the Winter reserve margin calculation starting in 2010. WCEC 2 is included in both the Summer and Winter starting in 2010. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.
(6) Because of the intermittent nature of the photovoltaics (PV) resource, FPL is currently assigning no firm capacity benefit to these generating additions. FPL will reassess this once actual operating data from the PV facilities at these locations is available. This location-specific information is needed in order to gauge consistent output during the peak hours which are accounted for in FPL's reserve margin calculations.
(7) The Martin solar thermal facility is designed to provide steam for FPL's existing Martin Unit 8 combined cycle unit, thus reducing FPL's use of natural gas. No additional capacity (MW) will result from the operation of the solar thermal facility.
(8) A number of existing FPL power plants are being temporarily removed from service and placed on Inactive Reserve status. FPL plans to return these units to active service in the future as needed. The timing of the return of these units to full-time active status is uncertain at this time primarily due to the uncertainty regarding FPL's future load. However, for planning purposes, FPL is showing in this document that these units begin to return to active service starting in 2016.

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 8.7 million people. FPL served an average of 4,509,729 customer accounts in thirty-five counties during 2008. These customers were served from a variety of resources including: FPL-owned fossil and nuclear generating units, non-utility owned generation, demand side management (DSM), and interchange/purchased power.

I.A. FPL-Owned Resources

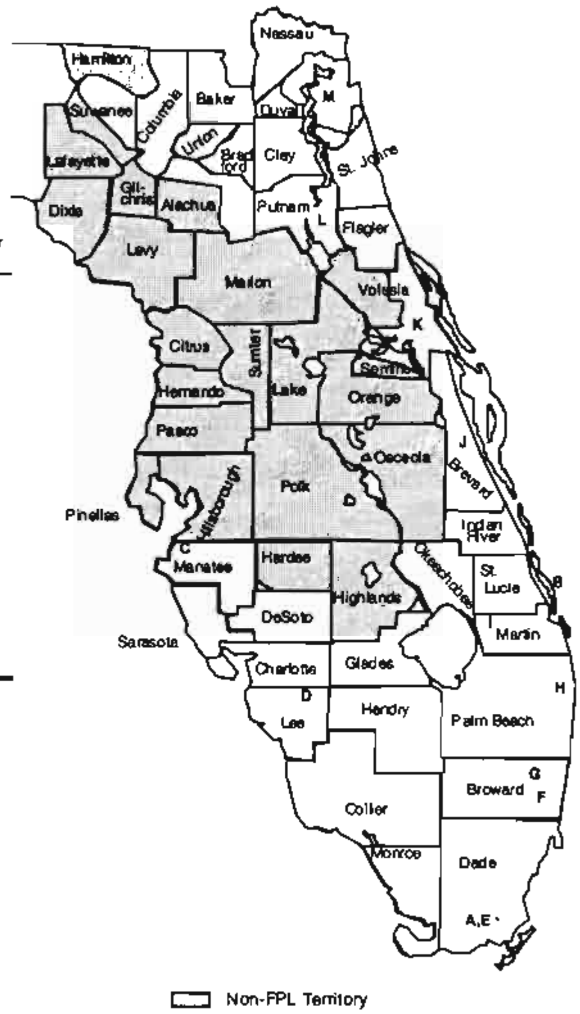
The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory and also include partial ownership of one unit located in Georgia and two units located in Jacksonville, Florida. The current generating facilities consist of four nuclear units, three coal units, twelve combined cycle (CC) units, seventeen fossil steam units, forty-eight combustion gas turbines, one simple cycle combustion turbine, and five diesel units. The location of these ninety generating units is shown on Figure I.A.1 and in Table I.A.1. The second page of Table I.A.1 provides a "break down" of the capacity provided by the combustion turbine (CT) and steam turbine (ST) components of FPL's existing CC units.

FPL's bulk transmission system is comprised of 6,727 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 580 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3 shows FPL's interconnection ties with other utilities.

FPL Generating Resources by Location

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	5	3,322
B	St. Lucie *	2	1,553
C	Manatee	3	2,735
D	Fort Myers	2	1,758
E	Cutler	2	205
F	Lauderdale	2	884
G	Port Everglades	4	1,205
H	Riviera	2	565
I	Martin	5	3,701
J	Cape Canaveral	2	792
K	Sanford	3	2,050
L	Putnam	2	498
M	SJRPP **	2	254
	Scherer ***	1	646
	Gas Turbines	48	1,908
	Internal Combustion Turbines	5	12
	FPL Generation =	90	22,087



* Represents FPL's ownership share: St Lucie nuclear: 100% unit 1, 85% unit 2; St. Johns River: 20% of two units.

** SJRPP = St. John's River Power Park

*** The Scherer unit is located in Georgia and is not shown on this map.

Figure I.A.1: Capacity Resources by Location (as of December 31, 2008)

Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2008)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Combined-Cycle *				
Lauderdale	Dania, FL	2	Gas/Oil	884
Martin	Indiantown,FL	2	Gas	944
Martin	Indiantown,FL	1	Gas/Oil	1,105
Sanford	Lake Monroe, FL	2	Gas	1,912
Putnam	Palatka, FL	2	Gas/Oil	498
Fort Myers	Fort Myers, FL	1	Gas	1,440
Manatee	Parrish,FL	1	Gas	1,111
Turkey Point	Florida City, FL	1	Gas	1,148
Total Combined Cycle		**12**		**9,041**
Combustion Turbines *				
Fort Myers **	Fort Myers, FL	1	Gas/Oil	318
Total Combustion Turbines		**1**		**318**
Nuclear				
Turkey Point	Florida City, FL	2	Nuclear	1,386
St. Lucie ***	Hutchinson Island, FL	2	Nuclear	1,553
Total Nuclear		**4**		**2,939**
Coal Steam				
SJRPP ****	Jacksonville, FL	2	Coal	254
Scherer	Monroe County, Ga	1	Coal	646
Total Coal Steam		**3**		**900**
Oil/Gas Steam				
Cape Canaveral	Cocoa, FL	2	Oil/Gas	792
Cutler	Miami, FL	2	Gas	205
Manatee	Parrish, FL	2	Oil/Gas	1,624
Martin	Indiantown,FL	2	Oil/Gas	1,652
Port Everglades	Port Everglades, FL	4	Oil/Gas	1,205
Riviera	Riviera Beach, FL	2	Oil/Gas	565
Sanford	Lake Monroe, FL	1	Oil/Gas	138
Turkey Point	Florida City, FL	2	Oil/Gas	788
Total Oil/Gas Steam		**17**		**6,969**
Gas Turbines(GT)/Diesels(IC)				
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Turkey Point (IC)	Florida City, FL	5	Oil	12
Total Gas Turbines/Diesels		**53**		**1,920**
Total Units:		**90**		
Total Net Generating Capability:				**22,087**

* The Combined Cycles and Combustion Turbines are broken down by components on Table 1.A.2.
** This unit consists of two combustion turbines.
*** Total capability of each unit is 853/839 MW. FPL's ownership share of St. Lucie 1 and 2 is 100% and 85%, respectively. Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.
**** Represents FPL's ownership share: SJRPP coal: 20% of two units

Table I.A.2: Combined Cycle and Combustion Turbine Components

Unit Type/ Plant Name		Summer MW *
Combined-Cycle		
Lauderdale 4 - Total		**442**
	CTA	160
	CTB	160
	Steam	122
Lauderdale 5 - Total		**442**
	CTA	160
	CTB	160
	Steam	122
Martin 3 - Total		**473**
	CTA	161
	CTB	161
	Steam	151
Martin 4 - Total		**473**
	CTA	161
	CTB	161
	Steam	151
Martin 8 - Total		**1,107**
	CTA	159
	CTB	159
	CTC	164
	CTD	164
	Steam	461
Putnam 1 - Total		**249**
	CTA	69
	CTB	69
	Steam	111
Putnam 2 - Total		**249**
	CTA	69
	CTB	69
	Steam	111
Ft Myers 2 - Total		**1,443**
	CTA	159
	CTB	159
	CTC	159
	CTD	159
	CTE	159
	CTF	159
	Steam 1	61
	Steam 2	428
Sanford 4 - Total		**956**
	CTA	158
	CTB	158
	CTC	158
	CTD	158
	Steam	324
Sanford 5 - Total		**955**
	CTA	158
	CTB	156
	CTC	158
	CTD	158
	Steam	323
Manatee 3 - Total		**1,111**
	CTA	164
	CTB	164
	CTC	164
	CTD	164
	Steam	455
Turkey Point 5 - Total		**1,147**
	CTA	171
	CTB	171
	CTC	171
	CTD	171
	Steam	463
Combustion Turbines		
Ft. Myers 3 - Total		**318**
	CTA	157
	CTB	161

* The total MW rating of the units might be slightly off from those shown in Table 1.A.1 due to rounding.

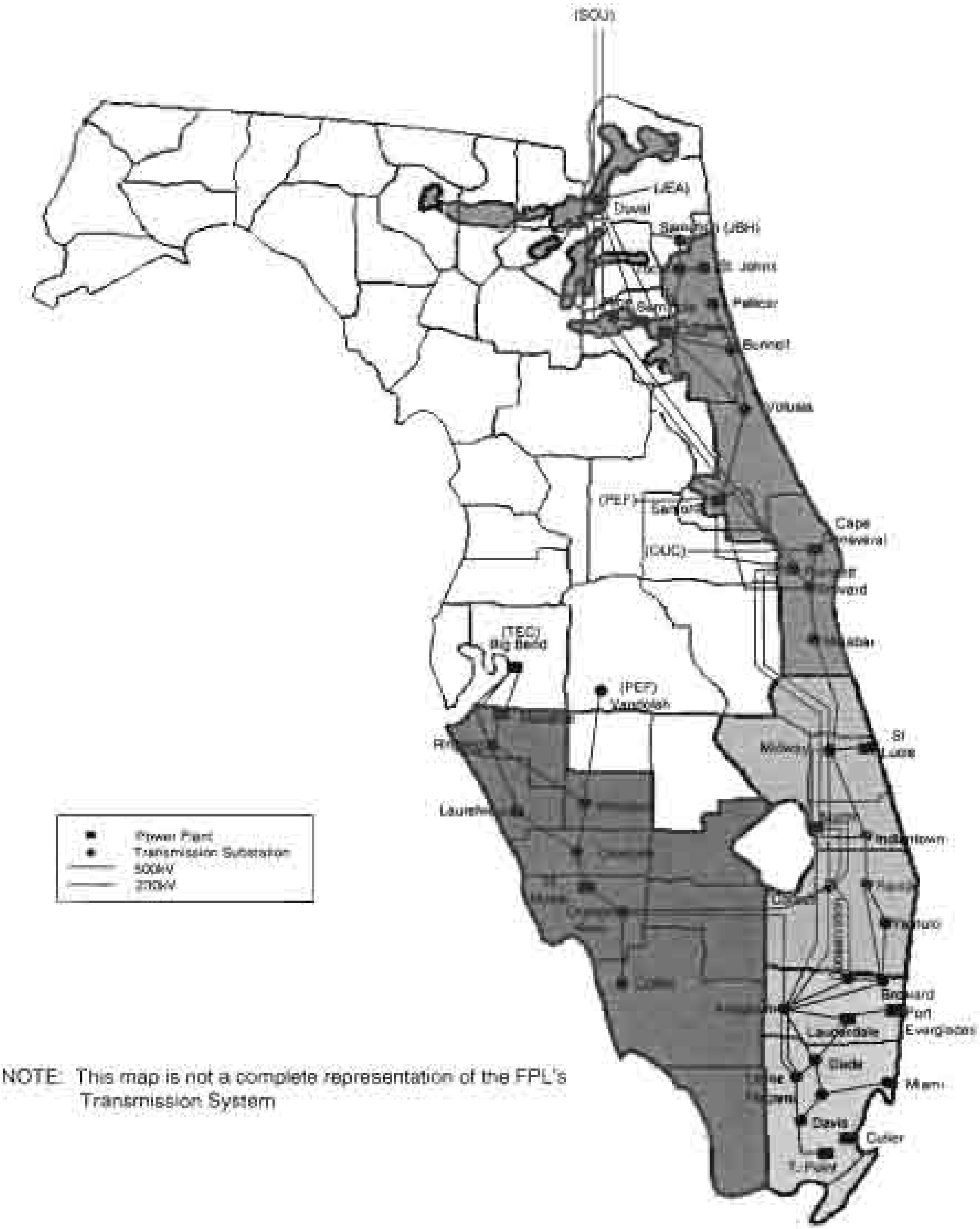
Table I.A.3: Purchase Power Resources by Contract (as of December 31, 2008)

Firm Capacity and Energy Purchases (MW)

	Location (City or County)	Fuel	Summer MW
I. Purchases from QFs: Cogeneration Small Power Production Facilities			
Cedar Bay Generating Co.	Duval County	Coal (Cogen)	250
Indiantown Cogen., LP	Martin County	Coal (Cogen)	330
Broward South	Broward County	Solid Waste	54
Broward North	Broward County	Solid Waste	56
Palm Beach SWA	Palm Beach County	Solid Waste	48
		Total:	**738**
II. Purchases from Utilities:			
UPS from Southern Co.	Various	Coal	931
SJRPP	Jacksonville,FL	Coal	381
		Total:	**1,312**
III. Other Purchases:			
Reliant/Indian River	Brevard County	Oil	576
Oleander (Extension)	Brevard County	Gas	156
Williams	Outside of Florida	Gas	106
Progress Energy Ventures	Outside of Florida	Gas	105
		Total:	**943**
	Total Net Firm Generating Capability:		**2,993**

Non-Firm Energy Purchases (MWH)

Plant Name	Location (City or County)	Fuel	Energy (MWH) Delivered to FPL in 2008
Tropicana	Manatee County	Natural Gas	24,266
Elliot	Palm Beach County	Natural Gas	101
US Sugar-Bryant	Palm Beach County	Bagassee	0
Okeelanta	Palm Beach County	Bagassee/Wood	343,209
Georgia Pacific	Putnam County	Paper by-product	1,232
Tomoka Farms	Volusia County	Landfill Gas	20,140
Rothenbach Park	Sarasota County	PV	269
Customer Owned PV	Various	PV	167
	Total Non-Firm Generating MWH:		**389,384**



NOTE: This map is not a complete representation of the FPL's Transmission System

Figure I.A.2: FPL Substation and Transmission System Configuration

FPL Interconnection Diagram

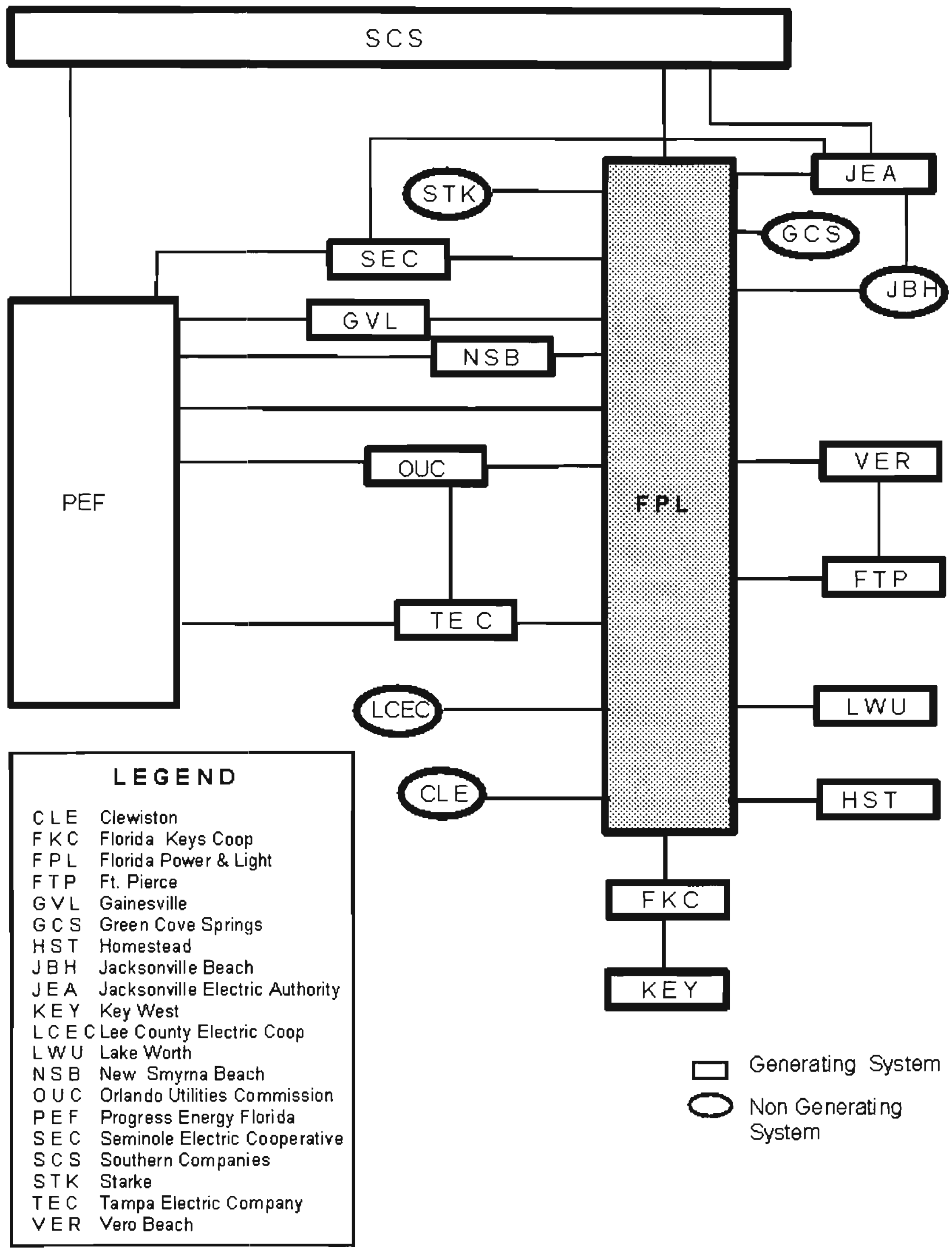


Figure I.A.3: FPL Interconnection Diagram

I.B Firm Capacity Power Purchases

Purchases from Qualifying Facilities (QF):

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has contracts with five qualifying facilities; i.e., cogeneration/small power production facilities, to purchase firm capacity and energy as shown in Table I.A.2, Table I.B.1, and I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

Purchases from Utilities:

FPL has a Unit Power Sales (UPS) contract to purchase 931 MW, with a minimum of 380 MW, of coal-fired generation from the Southern Company (Southern) through May 2010. An additional contract with Southern will result in FPL receiving 930 MW from June 2010 through the end of December 2015. This capacity will be supplied by Southern from a mix of gas-fired and coal-fired units.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 381 MW (Summer) and 390 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. However, due to Internal Revenue Service (IRS) regulations, the total amount of energy that FPL may receive from this purchase is limited. FPL currently assumes, for planning purposes, that this limit will be reached in the first half of 2016. Once this limit is reached, FPL will be unable to receive firm capacity and energy from these purchases.

These purchases are shown in Table I.A.2, Table I.B.1, and Table I.B.2. FPL also has ownership interest in the SJRPP units. The ownership amount is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.

Other Purchases:

FPL has other firm capacity purchase contracts with a variety of Non-QF suppliers. These purchases are generally near-term in nature. Table I.B.1 and I.B.2 present the Summer and Winter MW, respectively, resulting from all firm purchased power contracts discussed above through the year 2018. For planning purposes, FPL assumes an additional 105 MW of firm capacity will be supplied from renewable energy sources. This firm capacity is expected to be provided from two sources including: 55 MW through contract extension with an existing renewable facility currently under contract with FPL but whose contract is set to expire in 2010, and 50 MW through one or more proposals received in response to a Renewable RFP, such as the RFP that FPL issued in April 2008.

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration/Small Power Production Facilities	Contract Start Date	Contract End Date	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Broward South	04/01/91	08/01/09	0	0	0	0	0	0	0	0	0	0
Broward South	01/01/93	12/31/26	1	1	1	1	1	1	1	1	1	1
Broward South	01/01/95	12/31/26	2	2	2	2	2	2	2	2	2	2
Broward South	01/01/97	12/31/26	1	1	1	1	1	1	1	1	1	1
Broward North	04/01/92	12/31/10	45	45	0	0	0	0	0	0	0	0
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	2	2	2	2	2	2	2	2	2	2
Broward North	01/01/97	12/31/26	3	3	3	3	3	3	3	3	3	3
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA	04/01/92	03/31/10	50	0	0	0	0	0	0	0	0	0
Palm Beach SWA-extension	04/01/12	04/01/32	0	0	0	55	55	55	55	55	55	55
		QF Purchases Sub Total:	**690**	**640**	**595**	**650**	**650**	**650**	**650**	**650**	**650**	**650**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UPS from Southern Co.	07/20/88	05/31/10	931	0	0	0	0	0	0	0	0	0
UPS Replacement	06/01/10	12/31/15	0	930	930	930	930	930	930	0	0	0
SJRPP	04/02/82	04/01/16	381	381	381	381	381	381	381	0	0	0
		Utility Purchases Sub Total:	**1,312**	**1,311**	**1,311**	**1,311**	**1,311**	**1,311**	**1,311**	**0**	**0**	**0**

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Total of QF and Utility Purchases =	**2,002**	**1,951**	**1,906**	**1,961**	**1,961**	**1,961**	**1,961**	**650**	**650**	**650**

III. Other Purchases:

	Contract Start Date	Contract End Date	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reliant/Indian River	01/01/06	12/31/09	250	0	0	0	0	0	0	0	0	0
Oleander (Extension)	06/01/07	05/31/12	156	156	156	0	0	0	0	0	0	0
Williams	03/01/06	12/31/09	106	0	0	0	0	0	0	0	0	0
Progress Energy Ventures	04/01/06	03/31/09	0	0	0	0	0	0	0	0	0	0
New Renewable Firm Capacity	Assumed	Assumed	0	0	0	0	0	50	50	50	50	50
		Other Purchases Sub Total:	**512**	**156**	**156**	**0**	**0**	**50**	**50**	**50**	**50**	**50**

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Total "Non-QF" Purchase Sub-Total =	**1,824**	**1,467**	**1,467**	**1,311**	**1,311**	**1,361**	**1,361**	**50**	**50**	**50**

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Summer Firm Capacity Purchases Total MW:	**2,514**	**2,107**	**2,062**	**1,961**	**1,961**	**2,011**	**2,011**	**700**	**700**	**700**

Table I.B.2: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's:

Cogeneration/Small Power Production Facilities	Start Date	End Date	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Broward South	04/01/91	08/01/09	51	0	0	0	0	0	0	0	0	0
Broward South	01/01/93	12/31/26	1	1	1	1	1	1	1	1	1	1
Broward South	01/01/95	12/31/26	2	2	2	2	2	2	2	2	2	2
Broward South	01/01/97	12/31/26	1	1	1	1	1	1	1	1	1	1
Broward North	04/01/92	12/31/10	45	45	0	0	0	0	0	0	0	0
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	2	2	2	2	2	2	2	2	2	2
Broward North	01/01/97	12/31/26	3	3	3	3	3	3	3	3	3	3
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA	04/01/92	03/31/10	50	50	0	0	0	0	0	0	0	0
Palm Beach SWA-extension	04/01/12	04/01/32	0	0	0	0	55	55	55	55	55	55
		QF Purchases Sub Total:	**740**	**690**	**595**	**595**	**650**	**650**	**650**	**650**	**650**	**650**

II. Purchases from Utilities:

	Start Date	End Date	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UPS from Southern Co.	07/20/88	05/31/10	931	931	0	0	0	0	0	0	0	0
UPS Replacement	06/01/10	12/31/15	0	0	930	930	930	930	930	0	0	0
SJRPP	04/02/82	04/01/16	390	390	390	390	390	390	390	390	0	0
		Utility Purchases Sub Total:	**1,321**	**1,321**	**1,320**	**1,320**	**1,320**	**1,320**	**1,320**	**390**	**0**	**0**

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Total of QF and Utility Purchases =	**2,061**	**2,011**	**1,915**	**1,915**	**1,970**	**1,970**	**1,970**	**1,040**	**650**	**650**

III. Other Purchases:

	Contract Start Date	Contract End Date	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reliant/Indian River	01/01/06	12/31/09	250	0	0	0	0	0	0	0	0	0
Oleander (Extension)	06/01/07	05/31/12	180	180	180	180	0	0	0	0	0	0
Williams	03/01/06	12/31/09	106	0	0	0	0	0	0	0	0	0
Progress Energy Ventures	04/01/06	03/31/09	105	0	0	0	0	0	0	0	0	0
New Renewable Firm Capacity	Assumed	Assumed	0	0	0	0	0	50	50	50	50	50
		Other Purchases Sub Total:	**641**	**180**	**180**	**180**	**0**	**50**	**50**	**50**	**50**	**50**

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
"Non-QF" Purchase Sub-Total =	**1,962**	**1,501**	**1,500**	**1,500**	**1,320**	**1,370**	**1,370**	**440**	**50**	**50**

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Winter Firm Capacity Purchases Total MW:	**2,702**	**2,191**	**2,095**	**2,095**	**1,970**	**2,020**	**2,020**	**1,090**	**700**	**700**

I.C Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. Table I.C.1 shows the amount of energy purchased in 2008 from these facilities.

Table I.C.1: As-Available Energy Purchases From Non-Utility Generators in 2008

Project	*County*	*Fuel*	*In-Service Date*	*Energy (MWH) Delivered to FPL in 2008*
Tropicana	Manatee	Natural Gas	2/90	24,266
Elliot	Palm Beach	Natural Gas	7/05	101
US Sugar-Bryant	Palm Beach	Bagassee	2/80	0
Okeelanta	Palm Beach	Bagassee/Wood	11/95	343,209
Georgia Pacific	Putnam	Paper by-product	2/94	1,232
Tomoka Farms	Volusia	Landfill Gas	7/98	20,140
Rothenbach Park	Sarasota	PV	10/07	269
Customer Owned PV	Various	PV	Various	167

I.D. Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include a number of conservation/energy efficiency and load management initiatives. FPL's DSM efforts through 2008 have resulted in a cumulative Summer peak reduction of approximately 4,109 MW at the generator and an estimated cumulative energy saving of approximately 46,646 Gigawatt Hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2008 have eliminated the need to construct the equivalent of approximately 12 new 400 MW generating units.

For purposes of the projections presented in this document, FPL is utilizing essentially the same projection of DSM that was utilized in FPL's 2008 Site Plan. This amount of DSM is based on: FPL's current DSM Goals that were approved by the Florida Public Service Commission through 2014, additional cost-effective DSM identified by FPL after these DSM Goals were established, and a projection of continued DSM implementation for 2015 – 2018 at an implementation rate commensurate with the projected annual rate of implementation for the years immediately preceding 2014.

FPL will be submitting proposed new DSM Goals for 2010 – 2019 to the FPSC in a June 2009 filing and the analysis work that will lead to FPL's proposed new DSM Goals is in its early stages as this document is prepared. A final order from the FPSC regarding the proposed DSM amounts is expected in the 4th Quarter of 2009. FPL will formally incorporate the approved new DSM Goals amounts into its resource planning work at that time. The new DSM Goals amounts, the approved DSM Plan with which FPL will achieve those Goals, and the resource planning work that incorporates this DSM will be presented in FPL's 2010 Site Plan.

Schedule 1

Existing Generating Facilities
As of December 31, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt.					
						Fuel		Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport.		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Cape Canaveral		Brevard County 19/24S/36F									804,100	796	792
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	398	396
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	398	396
Cutler		Miami Dade County 27/55S/40E									236,500	207	205
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	75,000	69	68
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	161,500	138	137
Fort Myers		Lee County 35/43S/25E									2,895,890	2,709	2,406
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,775,390	1,570	1,440
	3A & B		CT	NG	FO2	PL	PL	Unknown	Jun-03	Unknown	376,380	370	318
	1-12		GT	FO2	No	PL	No	Unknown	May-74	Unknown	744,120	769	648
Lauderdale		Broward County 30/50S/42E									1,873,968	1,988	1,724
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	485	442
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	485	442
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	509	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,734	509	420
Manatee		Manatee County 18/33S/20E									2,951,110	2,831	2,735
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	822	812
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	822	812
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,187	1,111

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Plant Name	Unit No.	Location	Unit Type	Fuel Pri.	Fuel Alt.	Fuel Transport Pri.	Fuel Transport Alt.	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen.Max. Nameplate KW	Net Capability 1/ Winter MW	Net Capability 1/ Summer MW
Martin		Martin County 29/29S/38E									4,317,510	3,827	3,701
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	832	826
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	832	826
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	498	472
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	498	472
	8*		CC	NG	FO2	PL	PL	Unknown	Jun-05	Unknown	1,224,510	1,167	1,105
Port Everglades		City of Hollywood 23/50S/42E									1,710,384	1,720	1,625
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	247,775	214	213
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	247,775	214	213
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	389	387
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	394	392
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	509	420
Putnam		Putnam County 16/10S/27E									580,008	560	498
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,004	280	249
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,004	280	249
Riviera		City of Riviera Beach 33/42S/43E									620,840	571	565
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	280	277
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	291	288
Sanford		Volusia County 16/19S/30E									2,533,970	2,217	2,050
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	156,250	140	138
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,860	1,040	958
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	1,037	954

1/ These ratings are peak capability.

* Martin 8 A and B combustion turbine units went into service on 6/14/2001 and the conversion to Combined Cycle went into service 6/30/2005.

Schedule 1

Existing Generating Facilities
As of December 31, 2008

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW
Scherer 2/		Monroe, GA									680,368	652	646
	4		BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	680,368	652	646
St. Johns River Power Park 3/		Duval County 12/15/28E (RPC4)									271,836	250	254
	1		BIT	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	125	127
	2		BIT	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	125	127
St. Lucie		St. Lucie County 16/36S/41E									1,573,775	1,579	1,553
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	850,000	853	839
	2	4/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	723,775	726	714
Turkey Point		Miami Dade County 27/57S/40E									3,560,548	3,451	3,334
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	398	396
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	394	392
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	759,900	717	693
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	759,900	717	693
	5		CC	NG	FO2	PL	PL	Unknown	May-07	Unknown	1,224,510	1213	1,148
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	12,138	12	12
										Total System as of December 31, 2008 =		**23,358**	**22,087**

1/ These ratings are peak capability.
2/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.
3/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No. 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80%.
4/ Total capability of each unit is 853/839 MW. FPL's ownership share of St. Lucie 1 and 2 is 100%(853/839) and 85% (714/726) respectively as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.

CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

II. A. Overview of the Load Forecasting Process

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are typically developed on an annual basis for resource planning work at FPL. New long-term forecasts were developed by FPL in January 2009 that replaced the previous long-term load forecasts that were used by FPL during 2008 in much of its resource planning work and which were presented in FPL's 2008 Site Plan. These new load forecasts are utilized throughout FPL's 2009 Site Plan. These forecasts are a key input to the models used to develop FPL's integrated resource plan. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

Consistent with past forecasts, the primary drivers to develop these forecasts include economic conditions and weather.

The projections for the national and Florida economies are obtained from the consulting firm Global Insight. Population projections are obtained from the Bureau of Economic and Business Research (BEBR) of the University of Florida. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects FPL's energy sales and peak demand. Two sets of weather variables are developed and used in FPL's forecasting models:

1. Cooling and Heating Degree-Hours are used to forecast energy sales.
2. Temperature data is used to forecast Summer and Winter peaks.

The Cooling and Heating Degree-Hours are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. A composite temperature hourly profile is derived using hourly temperatures across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained. In developing the composite hourly profile, these regional temperatures are weighted by regional energy sales. This composite temperature is used to derive Cooling and Heating Degree-Hours which are based on starting point temperatures of 72°F and 66°F degrees, respectively. Similarly, composite temperature and hourly profile of temperatures are used for the Summer and Winter peak models.

II. B. Comparison of FPL's Current and Previous Load Forecasts

FPL's current load forecast is significantly different from the load forecast presented in its 2008 Site Plan. The current load forecast projects lower load growth. There are three factors that are the primary drivers behind the lower load forecast: projected lower population growth, higher energy efficiency impacts from new enhanced federal standards for appliance and lighting efficiency, and the effects of a lingering recession.

The customer forecast is based on a review of recent population projections from the University of Florida and Global Insight, as well as an analysis of historical population trends. Population projections through 2011 are derived from the University of Florida's October 2008 population projections which are significantly lower than prior projections. According to the University of Florida, net migration has fallen to a record low as a result of the economic slowdown and is expected to remain at historically low levels until 2010. Consequently, FPL's projects that customer growth in 2009 and 2010 will be significantly below the historical average. As population growth recovers, a modest rebound in customer growth is projected in 2011. Population growth after 2011 is based on the average levels experienced historically. As a result of lower growth in the initial years of the forecast, the total number of customers in the current load forecast remains below the levels projected in FPL's 2008 Site Plan in all years.

The impact of higher energy efficiency resulting from new federal standards for appliances and lighting is based on estimates developed by ITRON, an energy industry consulting firm. ITRON developed estimates for the impact of the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the naturally occurring energy reductions resulting from the adoption of compact florescent light bulbs. As a result of these appliance and lighting standards, FPL now projects that by 2018, FPL's Summer peak demand will be approximately 2,095 MW lower than it otherwise would have been. This projected impact from higher appliance and lighting standards is 839 MW more than the 1,256 MW reduction assumed in the 2008 Site Plan. In the 2008 Site Plan, only the impact of the 2005 National Energy Policy Act was considered.

Economic conditions in the state are also projected to have a significant impact on the forecast. Economic conditions in the state have deteriorated significantly since the 2008 Site Plan was published. After leading the nation in job creation, Florida is now leading the nation in job losses. Likewise, Florida now ranks second in the nation in terms of foreclosures and personal bankruptcies. The severity of current economic conditions suggests that Florida will likely experience a longer recession than that projected by Global Insight. Based on the examination of past recessions and review of forecasts from a number of outside experts, FPL developed an economic outlook reflecting a lingering recession through 2010 and below average growth in 2011. A resumption of cyclical growth, as forecasted by Global Insight, is forecasted by 2012.

Although the projected load growth for FPL is below that presented in FPL's 2008 Site Plan, the total growth projected by FPL for the ten-year reporting period of this document is still substantial. The Summer peak is projected to increase to 26,143 MW by 2018, an increase of 5,066 MW over the 2008 actual summer peak. Likewise, NEL is projected to reach 132,136 GWH in 2018, an increase of 21,092 GWH from the actual 2008 value. This compares to projected increases of 6,659 MW and 41,352 GWH over the ten-year reporting period presented in FPL's 2008 Site Plan compared to the 2007 actual values.

II.C. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for each revenue class for the forecasting period of 2009-2027 and are adjusted to match the NEL forecast. The results of these sales forecasts for the years 2009-2018 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and NEL forecast are outlined below.

1. <u>Residential Sales</u>

Residential electric usage per customer is estimated by using an econometric model. Residential sales are a function of: Cooling Degree-Hours and Heating Degree-Hours, real price of electricity (a 12-month moving average), Florida real household disposable income, dummy variables for the month of January and the specific month of November 2005, and an intercept term. A dummy variable for the calendar month of January was included to improve the predictability of the model by accounting for the otherwise higher than predicted usage in that model. A dummy variable for November 2005 was included because an analysis of residuals identified that data point as an outlier. The price of electricity plays a role in explaining electric usage, because electricity, like all other goods and services, will be used in greater or lesser quantities depending upon its price. To capture economic conditions, the model includes Florida's real household disposable income. The degree of economic prosperity can, and does, affect residential electricity sales. The impact of weather is captured by the Cooling Degree-Hours and Heating Degree-Hours. Residential energy sales are forecast by multiplying the residential use per customer forecast by the number of residential customers forecasted.

2. **Commercial Sales**

The commercial sales forecast is also developed using an econometric model. Commercial sales are a function of the following variables: Florida non-agricultural employment, commercial real price of electricity (a 12-month moving average), Cooling Degree-Hours, as well as an autoregressive term. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. Cooling Degree-Hours are used to capture weather-sensitive load in the commercial sector. The model also includes an intercept and two binary variables to account for statistical outliers in November 2005 and January 2007.

3. **Industrial Sales**

Industrial sales were forecasted using an econometric model. The model utilizes the following variables: Florida Housing Starts, Cooling Degree-Hours, industrial real price of electricity (a 24-month moving average), and several dummy variables for outliers. The Cooling Degree-Hour is used to capture the weather-sensitive load in the industrial class.

4. **Railroad & Railways Sales and Street and Highway Sales**

The forecast for street and highway sales is developed using historical usage patterns and multiplying these usage levels by the number of forecasted customers. The projections for railroad & railways sales are based on historical average use per customer because the number of customers is projected to remain the same. This class consists solely of the Miami-Dade County's Metrorail system.

5. **Other Public Authority Sales**

This revenue class is a closed class with no new customers being added. This class consists of sports fields and a government account. The forecast for this class is based on historical knowledge of its usage characteristics.

6. **Total Sales to Ultimate Customer**

Sales forecasts by revenue class are summed to produce a total sales forecast.

7. Sales for Resale

Sales for resale (wholesale) customers are composed of municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers. Currently there are four customers in this class: the Florida Keys Electric Cooperative; City of Key West; Metro-Dade County; and Seminole Electric Cooperative. In addition, FPL will begin serving the Lee County load in 2010.

FPL provides service to the Florida Keys under a long-term partial requirements contract. The sales for Florida Keys are forecasted using a regression model.

FPL's sales to the City of Key West are expected to terminate in 2013. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor.

Metro-Dade County sells 60 MW to Florida Progress. Line losses are billed to Metro-Dade under a wholesale contract.

Seminole Electric Cooperative has contracted for delivery of 75 MW for the period of December 2008 through December 2009. Also included in the forecast is a 200 MW sale to Seminole Electric beginning in June 2014 to December 2040.

Lee County has contracted for FPL to supply a portion of their load beginning in January 2010 and for FPL to supply their total load beginning in January 2014 through December 2033. Forecasted sales to Lee County are based on assumptions regarding their contract demand and expected load factor.

II.D. Net Energy for Load (NEL)

An econometric model is developed to produce an NEL forecast. The key inputs to the model are: the real price of electricity (a 12-month moving average), Cooling and Heating Degree-Hours, and Florida real household disposable income. In addition, the model also includes an autoregressive term as well as a dummy variable for the calendar month of February. A dummy variable for the calendar month of February was added to account for the lower than otherwise predicted usage associated with that month.

The forecast is further adjusted for the impacts of the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and compact florescent light bulbs. The forecast was also adjusted for additional load estimated from hybrid cars beginning in 2012 which resulted in an increase of approximately 244 GWH by the end of the ten-year reporting period. An adjustment was also made to the forecast to account for the increase in the number of empty homes which has resulted from the current housing slump. Because the increase in empty homes is viewed as a cyclical phenomenon, only the initial years of the forecast were impacted by this adjustment.

Once the NEL forecast is obtained using the above-mentioned model, total billed sales are computed using a historical ratio of sales to NEL. The sales by class forecasts previously discussed are then adjusted to match the NEL from the annual NEL model. The forecasted NEL values for 2009 – 2018 are presented in Schedule 3.3 that appears at the end of this chapter.

II.E. System Peak Forecasts

The rate of absolute growth in FPL system peak load has been a function of a growing customer base, varying weather conditions, projected economic growth, changing patterns of customer behavior (including an increased stock of electricity-consuming appliances), and more efficient appliances and lighting. FPL developed the peak forecast models to capture these behavioral relationships. Similar to the NEL forecast, the peak forecasts are also adjusted for the empty homes in the first three years of the forecast horizon as well as for the impacts of the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the impact of compact fluorescent light bulbs. The forecast was also adjusted for additional load estimated from hybrid cars which resulted in an increase of approximately 49 MW by the end of the ten-year reporting period.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2009–2018 are presented in Schedules 3.1 and 3.2 as well as in Schedules 7.1 and 7.2.

1. <u>System Summer Peak</u>

The Summer peak forecast is developed using an econometric model. The variables included in the model are the price of electricity, Florida real household disposable income, Cooling Degree-Hours in the day prior to the peak, and the average temperature on the day of the peak. The model below is based on the Summer peak contribution per customer and is, therefore, multiplied by total customers to derive FPL's system Summer peak.

2. System Winter Peak

Like the system Summer peak model, this model is also an econometric model. The model consists of two weather-related variables: the average temperature on the peak day and Heating Degree-Hours for the prior day as well as for the morning of the Winter peak day. In addition, Florida real household disposable income is a variable used in the model. The model below is based on the Winter peak contribution per customer and is, therefore, multiplied by total customers to derive FPL's system Winter peak.

3. Monthly Peak Forecasts

The forecasting process for monthly peaks is basically the same as for the monthly NEL forecast and consists of the following actions:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to seasonal peaks.

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.F. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2009-2027 are produced using a System Load Forecasting "shaper" program. This model uses years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

II.G. Uncertainty

In order to address uncertainty in the forecasts of aggregate peak demand and NEL, FPL first evaluates the assumptions underlying the forecasts. FPL takes a series of steps in evaluating the input variables, including comparing projections from different sources, identifying outliers in the series, and assessing the series' consistency with past forecasts. In addition, FPL reviews factors which may affect the input variables. This may require reviewing data from local economic development boards or from FPL's own Customer Service Business Unit. Other factors which may be considered include demographic trends and housing characteristics such as starts, size, and vintage of homes.

Uncertainty is also addressed in the modeling process. Generally, econometric models are used to forecast the aggregate peak demand and NEL. During the modeling process, the relevant statistics (goodness of fit, F-statistic, P-values, mean absolute deviation (MAD), mean absolute percentage error (MAPE), etc.) are scrutinized to ensure that the models adequately explain historical variation. Once a forecast is developed, it is compared with past forecasts. Deviations from past forecasts are examined in light of changes in input assumption to ensure that the drivers underlying the forecast are well understood. Finally, forecasts of aggregate peak demand and NEL are compared with their actual values as they become available. An ongoing process of variance analyses is performed. To the extent that the variance analysis identifies large unexplained deviations between the forecast and actual values, revisions to the econometric model may be considered.

The inherent uncertainty in load forecasting is addressed in different ways in regard to FPL's overall resource planning and operational planning work. In regard to FPL's resource planning work, FPL's utilization of a 20% reserve margin criterion (approved by the FPSC) is designed, in part, to maintain reliable electric service for FPL's customers in light of forecasting uncertainty. In regard to operational planning, a extreme weather load forecast for the projected Summer peak day is produced. The maximum average temperature on the day of the Summer peak over the last twenty years is used to produce this extreme weather forecast. Likewise, the minimum average temperature on the day of the Winter peak is used to estimate the extreme weather Winter peak forecast. The extreme weather scenarios are typically estimated for a two-to- five year period.

II.H. DSM

The effects of FPL's DSM implementation to-date are assumed to be imbedded in the actual usage data for forecasting purposes. Any change in usage pattern, be it the impact of FPL's DSM efforts, price impact, or weather impact, is reflected in the actual observed load data. Therefore, energy efficiency impacts, whether market-driven or as a result of FPL's DSM programs, are assumed to be included in the historical usage data for peaks and NEL.

The load forecasts provided in the schedules at the end of this chapter are not adjusted for incremental energy efficiency that FPL plans to implement in future years. The impacts of this incremental energy efficiency, plus the impacts of FPL's cumulative and incremental load management programs, are accounted for as "line item reductions" to the forecasts as part of the IRP process as shown in Schedules 7.1 and 7.2. After making these adjustments to the load forecasts, the resulting "firm" load forecast is then used in FPL's IRP work.

Schedule 2.1
History and Forecast of Energy Consumption And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population 1/	Members per Household	GWH 2/	Average 3/ No. of Customers	Average KWH Consumption Per Customer	GWH 2/	Average 3/ No. of Customers	Average KWH Consumption Per Customer
1999	7,412,744	2.22	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,603,964	2.23	46,320	3,414,002	13,568	37,001	415,295	89,096
2001	7,754,846	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,898,628	2.21	50,865	3,566,167	14,263	40,029	435,313	91,955
2003	8,079,316	2.21	53,485	3,652,663	14,643	41,425	444,650	93,163
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,620,855	2.21	54,570	3,906,201	13,970	44,487	478,930	92,889
2007	8,729,806	2.19	55,138	3,981,451	13,849	45,921	493,130	93,121
2008	8,771,694	2.20	53,229	3,992,257	13,333	45,561	500,748	90,987
2009	8,775,903	2.20	52,041	3,994,173	13,029	44,878	509,881	88,016
2010	8,812,518	2.20	51,427	4,010,837	12,822	45,417	521,804	87,039
2011	8,912,688	2.20	51,654	4,056,428	12,734	46,620	534,717	87,187
2012	9,100,508	2.20	52,438	4,141,910	12,660	48,460	548,319	88,380
2013	9,287,417	2.20	52,639	4,226,978	12,453	49,537	562,200	88,113
2014	9,472,518	2.20	52,818	4,311,223	12,251	51,273	576,590	88,924
2015	9,656,156	2.20	53,087	4,394,802	12,080	52,822	591,382	89,319
2016	9,838,819	2.20	53,614	4,477,937	11,973	54,515	606,467	89,889
2017	10,020,376	2.20	54,249	4,560,569	11,895	56,233	621,955	90,414
2018	10,200,558	2.20	55,175	4,642,575	11,885	58,198	637,980	91,222

Historical Values (1999 - 2008):

1/ Population represents only the area served by FPL.

2/ Actual energy sales include the impacts of existing conservation. These values are at the meter.

3/ Average No. of Customers is the annual average of the twelve month values.

Projected Values (2009 - 2018):

1/ Population represents only the area served by FPL.

2/ Forecasted energy sales do not include the impact of incremental conservation. These values are at the meter.

3/ Average No. of Customers is the annual average of the twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads & Railways	Street & Highway Lighting	Other Sales to Public Authorities	Total [4/] Sales to Ultimate Consumers
Year	GWH [2/]	Average [3/] No. of Customers	Average KWH Consumption Per Customer	GWH	GWH [2/]	GWH	GWH
1999	3,948	16,040	246,135	79	473	465	84,676
2000	3,768	16,410	229,616	81	408	381	87,960
2001	4,091	15,445	264,875	86	419	67	90,212
2002	4,057	15,533	261,186	89	420	63	95,523
2003	4,004	17,029	235,128	93	425	64	99,496
2004	3,964	18,512	214,139	93	413	58	99,095
2005	3,913	20,392	191,873	95	424	49	102,296
2006	4,036	21,216	190,232	94	422	49	103,659
2007	3,774	18,732	201,499	91	437	53	105,415
2008	3,587	13,377	268,168	81	423	37	102,919
2009	3,584	12,527	286,133	91	446	37	101,078
2010	3,606	12,686	284,271	91	451	36	101,029
2011	3,656	12,980	281,675	91	457	35	102,514
2012	3,690	13,257	278,319	91	464	34	105,177
2013	3,687	13,397	275,187	91	474	33	106,461
2014	3,676	13,497	272,380	91	484	33	108,375
2015	3,662	13,575	269,744	91	494	33	110,188
2016	3,645	13,604	267,928	91	504	33	112,401
2017	3,631	13,604	266,896	91	515	33	114,752
2018	3,622	13,610	266,117	91	525	33	117,644

Historical Values (1999 - 2008):

2/ Actual energy sales include the impacts of existing conservation.

3/ Average No.of Customers is the annual average of the twelve month values.

4/ GWH Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Projected Values (2009 - 2018):

2/ Forecasted energy sales do not include the impact of incremental conservation.

3/ Average No. of Customers is the annual average of the twelve month values.

4/ GWH Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(17)	(18)	(19)	(20)	(21)
Year	Sales for Resale GWH	Utility Use & Losses GWH	Net [5/] Energy For Load GWH [6/]	Average [3/] No. of Other Customers	Total Average [3/,7/] Number of Customers
1999	953	5,829	91,458	2,605	3,756,009
2000	970	7,059	95,989	2,694	3,848,401
2001	970	7,222	98,404	2,722	3,935,281
2002	1,233	7,443	104,199	2,792	4,019,805
2003	1,511	7,386	108,393	2,879	4,117,221
2004	1,531	7,464	108,091	3,029	4,224,509
2005	1,506	7,498	111,301	3,157	4,321,896
2006	1,569	7,909	113,137	3,216	4,409,563
2007	1,499	7,401	114,315	3,276	4,496,589
2008	993	7,092	111,004	3,347	4,509,729
2009	1,149	7,213	109,440	3,405	4,519,986
2010	2,137	7,042	110,207	3,435	4,548,763
2011	2,252	7,161	111,926	3,470	4,607,594
2012	2,280	7,358	114,815	3,519	4,707,005
2013	2,172	7,394	116,027	3,580	4,806,155
2014	5,122	7,631	121,128	3,649	4,904,959
2015	5,844	7,768	123,800	3,722	5,003,480
2016	5,952	7,925	126,278	3,796	5,101,804
2017	6,070	8,087	128,908	3,871	5,199,999
2018	6,202	8,289	132,136	3,946	5,298,111

Historical Values (1999 - 2008):

3/ Average No.of Customers is the annual average of the twelve month values.

5/ GWH Col. (19) = Col. (16) + Col. (17) + Col. (18). Actual NEL include the impacts of existing conservation and agrees to Col. (8) on Schedule 3.3.

6/ Actual energy sales include the impacts of existing conservation. These values are at the generator.

7/ Total Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Projected Values (2009 - 2018):

2/ Forecasted energy sales do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

3/ Average No.of Customers is the annual average of the twelve month values.

5/ GWH Col. (19) = Col. (16) + Col. (17) + Col. (18). Matches to Col (2) on Schedule 3.3 for Forecasted \

6/ Total Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1) August of Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) Small Business Load Management	(10) C/I Conservation	(11) Net Firm Demand
1999	17,615	169	17,446	0	673	592	438	15	420	16,490
2000	17,808	161	17,647	0	719	645	448	19	451	16,622
2001	18,754	169	18,585	0	737	697	449	40	481	17,529
2002	19,219	261	18,958	0	770	755	441	49	517	17,960
2003	19,668	253	19,415	0	781	799	516	61	554	18,310
2004	20,545	258	20,287	0	783	847	517	71	578	19,174
2005	22,361	264	22,097	0	790	895	516	84	611	20,971
2006	21,819	256	21,563	0	809	948	516	120	640	20,375
2007	21,962	261	21,701	0	954	982	515	200	683	20,293
2008	21,060	181	20,879	0	974	1042	538	221	705	19,327
2009	21,124	241	20,882	0	1,016	76	753	86	65	19,128
2010	21,147	381	20,765	0	1,034	122	772	93	98	19,028
2011	21,368	385	20,983	0	1,053	171	780	100	132	19,132
2012	21,933	393	21,540	0	1,073	222	788	107	167	19,576
2013	22,249	354	21,895	0	1,095	275	796	114	203	19,788
2014	23,533	1,184	22,349	0	1,120	329	804	121	240	20,919
2015	24,142	1,205	22,937	0	1,146	385	812	128	278	21,393
2018	24,772	1,229	23,543	0	1,172	440	820	136	316	21,888
2017	25,401	1,256	24,145	0	1,198	496	828	143	353	22,383
2018	26,143	1,284	24,860	0	1,207	514	831	145	366	23,080

Historical Values (1999 - 2008):

Col. (2) - Col. (4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 10), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (10) for 1999 through 2008 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC) and Commercial /Industrial Demand Reduction (CDR).

Col (9) represents FPL's Business On Call program.

Col. (11) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (11) is derived by the formula:Col. (11) = Col.(2) - Col.(6) - Col.(8)- Col. (9).

Projected Values (2009 - 2018):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2004 are incorporated into the load forecast.

Col. (5) - Col. (10) represent all incremental conservation,current load management and incremental load management. These values are projected August values and the conservation values are based on projections with a 1/2008 starting point designed for use with the 2008 load forecast.

Col (9) represents FPL's Business On Call program.

Col. (11) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (11) is derived by using the formula: Col. (11) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9)-Col (10).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1) January of Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) Small Business Load Management	(10) C/I Conservation	(11) Net Firm Demand
2000	17,057	142	18,915	0	741	434	438	0	176	15,878
2001	18,199	150	18,049	0	791	459	448	0	183	16,960
2002	17,597	145	17,452	0	811	500	457	0	196	18,329
2003	20,190	246	19,944	0	847	546	453	0	206	18,890
2004	14,752	211	14,541	0	857	570	532	0	230	13,363
2005	18,108	225	17,863	0	862	583	542	0	233	18,704
2006	19,883	225	19,458	0	870	600	550	0	240	18,263
2007	16,815	223	16,592	0	894	620	577	0	249	15,344
2008	18,055	163	17,892	0	879	644	635	0	279	16,541
2009	20,031	216	19,815	0	922	48	729	0	31	18,380
2010	18,790	329	18,461	0	938	73	767	0	41	18,971
2011	19,120	334	18,786	0	955	105	775	0	53	17,232
2012	19,710	340	19,370	0	973	138	763	0	67	17,749
2013	20,098	346	19,752	0	992	171	791	0	81	18,063
2014	21,154	878	20,278	0	1,012	205	799	0	97	19,041
2015	21,882	1,100	20,783	0	1,036	239	807	0	113	19,687
2016	22,396	1,123	21,273	0	1,060	273	815	0	130	20,118
2017	22,912	1,148	21,764	0	1,084	307	823	0	146	20,552
2018	23,466	1,173	22,293	0	1,106	338	631	0	181	21,030

Historical Values (1999 - 2008):

Col. (2) - Col. (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 10), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col.(10) for 2000 through 2008 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC) and Commercial/Industrial Demand Reduction (CDR).

Col (9) represents FPL's Business On Call program.

Col. (11) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (11) is derived by the formula: Col. (11) = Col. (2) - Col. (6) - Col. (8).

Projected Values (2009 - 2018):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2004 are incorporated into the load forecast.

Col. (5) - Col.(10) represent all incremental conservation and cumulative load control. These values are projected January values and the conservation values are based on projections with a 1/2008 starting point designed for use with the 2008 load forecast.

Col (9) represents FPL's Business On Call program.

Col. (11) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (11) is derived by using the formula: Col. (11) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9)- Col.(10).

Schedule 3.3
History of Annual Net Energy for Load - GWH: Base Case
(All values are "at the generator"value except for Col (8))

(1)	(2) = (3) + (3) + (5)	(3)	(4)	(5)	(6)	(7)	(8) = (5) - (6) - (7)	(9)
Year	Total Net Energy For Load without DSM	Residential Conservation	C/I Conservation	**Actual** Net Energy For Load	Sales for Resale GWH	Utility Use & Losses	**Actual** Total Billed Retail Energy Sales (GWH)	Load Factor(%)
1999	94,365	1,542	1,365	91,458	953	5,829	84,676	59.3%
2000	99,097	1,674	1,434	95,989	970	7,059	87,960	61.4%
2001	101,739	1,789	1,545	98,404	970	7,222	90,212	59.9%
2002	107,755	1,917	1,639	104,199	1,233	7,443	95,523	61.9%
2003	112,160	2,008	1,759	108,393	1,511	7,386	99,496	62.9%
2004	112,031	2,106	1,834	108,091	1,531	7,464	99,095	59.9%
2005	115,440	2,205	1,934	111,301	1,506	7,498	102,298	56.6%
2006	117,490	2,312	2,041	113,137	1,569	7,909	103,659	59.2%
2007	118,894	2,373	2,206	114,315	1,499	7,401	105,415	59.4%
2008	115,755	2,485	2,267	111,004	993	7,092	102,919	60.0%

Historical Values (1999 - 2008):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5).

Col.(3) & Col.(4) for 1999 through 2008 are DSM values starting in January 1988 and are annual (12-month) values.Col. (3) and Col. (4) for 2008 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWH reductions actually experienced each year .

Col. (5) is the actual Net Energy for Load (NEL) for years 1999 - 2008.

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7).

Col. (9) is calculated using Col. (5) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (5)*1000) / ((Col.(2) * 8760)
Adjustments are made for leap years.

Forecast of Annual Net Energy for Load - GWH: Base Case
(All values are "at the generator"value except for Col (8))

(1)	(2)	(3)	(4)	(5) = (2) - (3) - (4)	(6)	(7)	(8) = (2) - (6) - (7)	(9)
Year	**Forecasted** Net Energy For Load without DSM	Residential Conservation	C/I Conservation	Net Energy For Load Adjusted for DSM	Sales for Resale GWH	Utility Use & Losses	**Forecasted** Total Billed Retail Energy Sales (GWH) without DSM	Load Factor(%)
2009	109,440	142	106	109,192	1,149	7,213	101,078	59.1%
2010	110,207	236	155	109,816	2,137	7,042	101,029	59.5%
2011	111,926	334	207	111,386	2,252	7,161	102,514	59.6%
2012	114,815	434	261	114,119	2,280	7,358	105,177	59.6%
2013	116,027	539	319	115,169	2,172	7,394	106,461	59.5%
2014	121,128	647	380	120,102	5,122	7,631	108,375	58.8%
2015	123,800	754	440	122,605	5,844	7,768	110,188	58.5%
2016	126,278	862	501	124,915	5,952	7,925	112,401	58.0%
2017	128,906	970	562	127,376	6,070	8,087	114,752	57.9%
2018	132,136	1,078	564	130,494	6,202	8,289	117,644	57.7%

Forecasted Values (2009 - 2018):

Col. (2) represents Forecasted Net Energy for Load w/o DSM values. The values are extracted from Schedule 2.3, Col. (19).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation and are mid-year (6-month) values.
The effects of conservation implemented prior to 2009 are incorporated into the load forecast.

Col. (5) is the forecasted Net Energy for Load (NEL) with DSM for years 2008 - 2017. Col (5) = Col (2) -Col (3) - Col (4).

Col. (8) is the Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7).These values are at the meter.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2008 ACTUAL		2009* FORECAST		2010* FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	18,055	8,230	18,697	7,970	18,790	7,981
FEB	15,735	7,843	15,443	7,225	15,533	7,265
MAR	16,226	8,258	16,260	8,039	16,265	8,094
APR	16,995	8,815	17,389	8,451	17,462	8,506
MAY	20,289	9,814	19,369	9,338	19,429	9,382
JUN	20,565	10,836	20,122	10,369	20,192	10,401
JUL	20,951	10,374	20,809	10,780	20,873	10,834
AUG	21,060	11,090	21,124	10,985	21,147	11,041
SEP	20,456	11,102	20,650	10,635	20,696	10,702
OCT	18,752	9,254	19,253	9,446	19,287	9,547
NOV	16,538	7,886	16,788	8,265	16,835	8,384
DEC	14,849	7,502	15,786	7,936	15,791	8,070
TOTALS		111,004		109,440		110,207

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation and are consistent with values shown in Col. (19) of Schedule 2.3 and Col (2) of Schedule 3.3.

CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990s and has since utilized the process to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of new power plants, the primary subjects of this document, are determined as part of the IRP process work. This section discusses how FPL applied this process in its 2008 and early 2009 resource planning work.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental steps to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Evaluate the competing options and resource plans in regard to system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

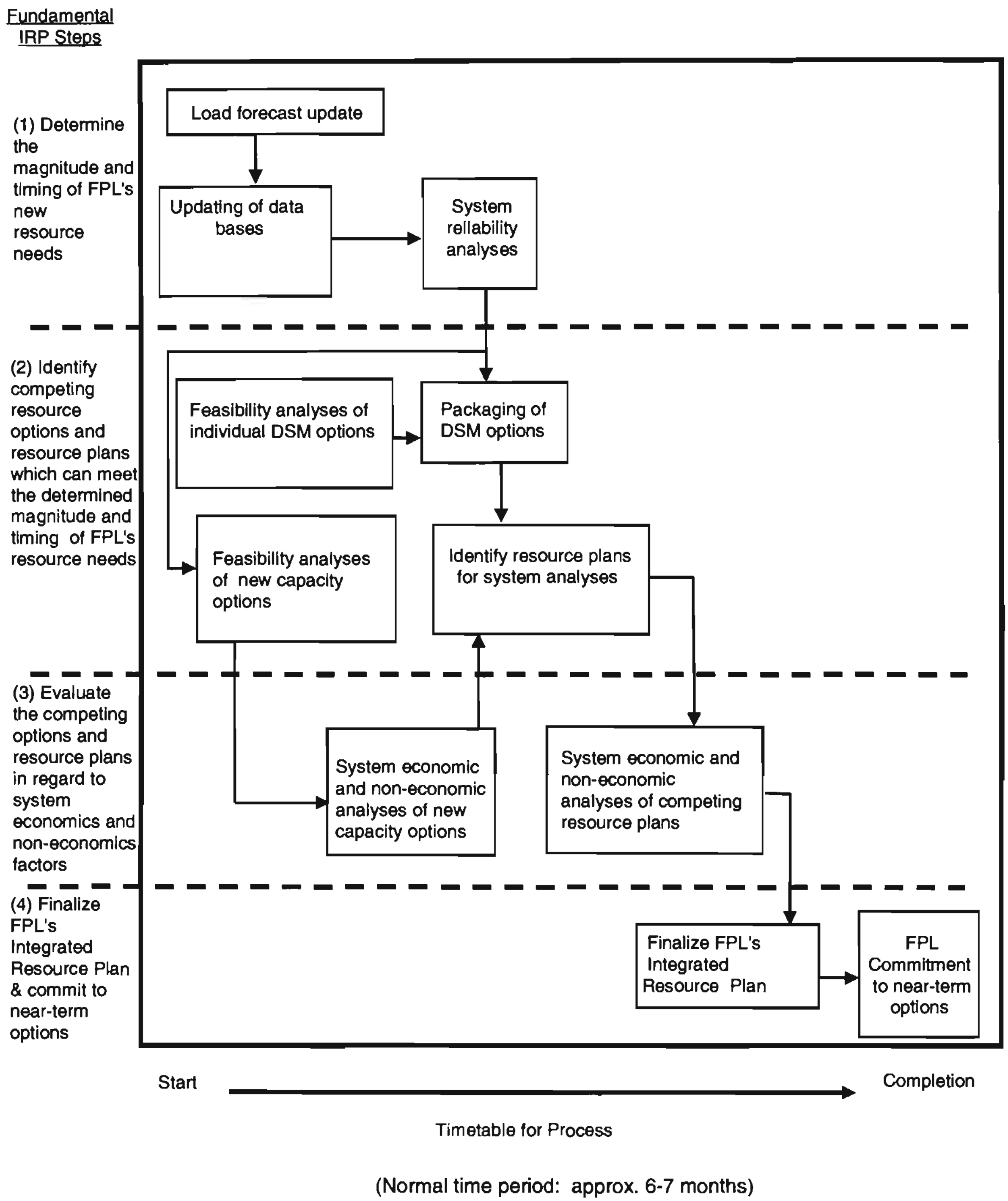

Figure III.A.1: Overview of FPL's IRP Process

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of the four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed to maintain system reliability. Also determined in this step is when the MW are needed to meet FPL's planning criteria. This step is often referred to as a reliability assessment, or resource adequacy, analysis for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include, but not limited to: delivered fuel price projections, current financial and economic assumptions, and power plant capability and reliability assumptions. FPL also includes key assumptions regarding three specific resource areas: (1) near-term construction capacity additions, (2) firm capacity power purchases, and (3) DSM implementation.

The first of these assumptions is based on new generating capacity additions that have been approved by the Florida Public Service Commission (FPSC) through Determination of Need hearings that evaluated both the need for, and the cost-effectiveness of, each of the new capacity additions. These generating capacity additions have also either received the necessary Site Certification approvals from either the Secretary of the Florida Department of Environmental Protection (FDEP) or the Governor and Cabinet (acting as the Siting Board) or, as in the case of the new nuclear units, are in the process of receiving the necessary state and federal approvals. A number of new generating unit additions will occur in the 2009 – 2018 time frame that is addressed in this document.

These generating unit additions include:

- Three new natural gas-fired CC units at FPL's West County Energy Center (WCEC) site that are scheduled to come in-service during 2009 through 2011. These new units will each add approximately 1,219 MW (Summer) of generation capacity. FPL selected these CC units, designated as WCEC Units 1, 2, & 3, after conducting two Request for Proposals (RFP) solicitations and evaluating the options received in response to the RFPs.

- Two new photovoltaic (PV) solar energy facilities are projected to be brought into service by 2010. One of these PV facilities will be placed in DeSoto County and will be named the DeSoto Next Generation Solar Energy Center. This facility is projected to have a nameplate rating of 25 MW. The second PV facility will be named the Space Coast Next Generation Solar Energy Center and is projected to have a nameplate rating of 10 MW. The FPSC approved the eligibility of expenditures for these PV facilities to be recovered through the environmental cost recovery clause in August 2008. The DeSoto Next Generation Solar Energy Center obtained an Environmental Resource Permit and an Army Corps of Engineers permit in October 2008. The Space Coast Next Generation Solar Energy Center received the Army Corps of Engineers permit in December 2008 and expects to receive the Environmental Resource Permit in mid-2009.
- A new solar thermal facility at FPL's existing Martin plant site is also projected to be brought into service in 2010. This solar thermal facility, named the Martin Next Generation Solar Energy Center, is projected to be able to produce up to 75 MW of steam capability, thus allowing reduced use of fossil fuels by FPL when the solar thermal facility is producing steam. The FPSC approved the eligibility of expenditures for this solar thermal facility to be recovered through the environmental cost recovery clause in August 2008. FPL received the site certification modification approval in August 2008.
- Two existing generating plants, each consisting of two older fossil fuel-fired generating units, are projected to be converted into new, highly efficient CC units. The existing plant at FPL's Cape Canaveral site will be replaced in 2013 by a new CC unit with a projected output of 1,219 MW. This new plant will be called the Cape Canaveral Next Generation Clean Energy Center. The existing plant at FPL's Riviera site will be replaced in 2014 by a new CC unit with a projected output of 1,207 MW. This new plant will be called the Riviera Beach Next Generation Clean Energy Center. These conversions were approved by the FPSC in September 2008. The site certification application for Cape Canaveral was filed in December 2008 and the site certification application for Riviera Beach was filed in February 2009. A decision is expected to be reached regarding these applications in early 2010.
- Two new nuclear units (Turkey Point Units 6 & 7) are projected to be brought into service in 2018 and 2020, respectively. Each unit is projected to produce approximately 1,100 MW. The FPSC approved the need for these new nuclear units in April 2008. As part of this approval, FPL will be providing a annual feasibility analysis as part of the annual nuclear cost recovery process. A multi-year permitting review process for these units is currently underway. Because this Site Plan

addresses the time period through 2018, the first of these two units, Turkey Point Unit 6, is now included in the 2009 Site Plan.

- In addition, FPL will be adding approximately 400 MW of increased generating capacity at its existing nuclear power plants at its Turkey Point and St. Lucie sites. This increased capacity is scheduled to come in-service in 2011 and 2012. These capacity "uprates" were approved by the FPSC in January 2008. The Final Order for the Site Certification was issued in September 2008 for the St. Lucie uprates and October 2008 for the Turkey Point uprates.

These new generating units were added for a variety of reasons including cost-effectiveness, significant system fuel savings, and significant system emission reductions, including greenhouse gas emission reductions. In addition, the solar projects will increase the contribution of renewable energy sources towards meeting the electricity needs of FPL's customers.

The second of these assumptions involves firm capacity power purchases. FPL's current projection of firm capacity purchases is very similar to the projection shown in FPL's 2008 Site Plan. These firm capacity purchases are from a combination of utility and independent power producers. Details, including the annual total capacity values for these purchases, are presented in Chapter I in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's resource planning work.

The third of these assumptions involves a projection of the amount of additional demand side management (DSM) that is projected to be implemented annually over the ten-year period. Since 1994, FPL's resource planning work has assumed that at least the DSM MW called for in FPL's approved DSM Goals will be achieved as planned. This is again the case with the resource plan FPL discusses in its 2009 Site Plan.

There is essentially no change in the amount of DSM shown between the 2008 Site Plan and the 2009 Site Plan. The DSM values that are presented in this 2009 Site Plan, are based on meeting FPL's currently approved DSM Goals through 2014, plus implementing additional cost-effective DSM through 2014 that was identified by FPL after the current DSM Goals were established, and a projection of continued DSM additions in 2015 through 2017 at an annual implementation rate commensurate with that in the years leading up to 2014. Because the 2009 Site Plan addresses one more year (2018) than did the 2008 Site Plan, FPL has extended its DSM projection out one more year to 2018 using a similar annual implementation rate.

However, FPL is scheduled to present its new projections of cost-effective DSM to the FPSC in June 2009. These new projections will be used to determine FPL's new DSM Goals for the years 2010 through 2019. The analyses to develop these new projections of cost-effective DSM for the new DSM Goals are currently a work in progress at the time the 2009 Site Plan is being filed. The final order from the FPSC establishing FPL's new DSM Goals is expected in the 4th Quarter of 2009. The subsequent development and approval of FPL's DSM Plan (with which FPL will meet the new Goals) will likely be made in early 2010. Therefore, the impact of FPL's new DSM Goals and DSM Plan will be reflected next year in FPL's 2010 Site Plan.

These key assumptions, plus the other updated information, are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's resource needs. This determination is accomplished by system reliability analyses which are typically based on a dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry.

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss-of-load probability or LOLP. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of

LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of the "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

The result of the first fundamental step of resource planning is a projection of how many new MW of resources are needed to meet both reserve margin and LOLP criteria, and thus maintain system reliability, and of when the MW are needed. Information regarding the timing and magnitude of these resource needs is used in the second fundamental step: identifying resource options and resource plans that can meet the determined magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, feasibility analyses of new capacity options are conducted to determine which new capacity options appear to be the most competitive on FPL's system. These analyses also establish capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. In similar analyses, feasibility analyses of new DSM options and/or continued growth in existing DSM options are conducted.

The individual new resource options emerging from these feasibility options are then typically "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet, dynamic programming, and/or linear and non-linear programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans in Regard to System Economics and Non-Economic Factors:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for evaluating these resource options and resource plans. In 2008, once the resource plans were developed, FPL utilized the P-MArea production cost model and a Fixed Cost Spreadsheet to perform the economic analyses. The P-MArea model is the model used by FPL to develop the Fuel Cost Budget and to conduct other production cost-related analyses.

FPL also utilized several other models in the economic evaluation portion of its resource planning work. For analyses of individual DSM options, FPL typically uses its DSM cost-effectiveness model which is an FPL spreadsheet model utilizing the FPSC's approved methodology for analyzing the cost-effectiveness of individual DSM measures/programs, and its non-linear programming model for analyzing the potential for lowering system peak loads through additional load management capacity.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the intent of minimizing FPL's leveled system average rate (i.e., a Rate Impact Measure or RIM methodology). However, in cases in which the DSM contribution was assumed as a given and the only competing options were new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. Consequently, the competing options and plans in such cases were evaluated on a cumulative present value revenue requirement (CPVRR) basis.

Other factors are also included in FPL's evaluation of resource options and resource plans. While these factors may have an economic component or impact, they are often discussed in quantitative, but non-economic terms, such as percentages, etc. rather than in terms of dollars. These factors are often referred to by FPL as "system concerns" that include (but are not necessarily limited to) maintaining/enhancing fuel diversity in the FPL system and maintaining a regional balance between load and generating capacity, particularly in Southeastern Florida. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL's system, both the economic and non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps were used to develop the future generation plan. This plan is presented in the following section.

III.B Incremental Resource Additions/Changes

FPL's projected incremental generation capacity additions/changes for 2009 through 2018 are depicted in Table III.B.1. These capacity additions/changes result from a variety of actions including: changes to existing units (which are frequently achieved as a result of plant component replacements during major overhauls), temporarily removing older, less efficient generating units from active service and placing them into Inactive Reserve status, changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, increases in generating capacity at FPL's four existing nuclear units, the conversion of FPL's existing steam generating units at its existing Cape Canaveral and Riviera sites into new, very fuel-efficient CC generating units, and by construction of approved new generating units.

As shown in Table III.B.1, the capacity additions are largely made up of construction of new CC and nuclear generating units, the conversion of existing steam units into new CC units, and capacity increases at FPL's existing nuclear generating units. (The DSM MW that FPL is adding each year are not presented in this table but have been accounted for by FPL and the FPSC in the process of obtaining approval for these new capacity additions.)

This table also shows the addition of the previously discussed 110 MW of new solar facilities (35 MW of PV and 75 MW of solar thermal). However, as indicated in the table and its footnotes, these new solar facilities are not projected to contribute new firm capacity. There are two reasons for this. First, one of these facilities – the 75 MW solar thermal facility at the Martin site – is designed not to add new capacity, but to serve as a "fuel substitute" facility. When sufficient sunlight is available, the solar thermal facility will produce steam that would otherwise have been produced by burning fossil fuels. Second, in regard to the two new PV facilities that together have a 35 MW nameplate rating, it is unclear at this time what the output of these PV facilities will consistently be during FPL's late afternoon Summer and early morning Winter peak hours. Consequently, FPL is not assigning a firm capacity value (i.e., those values reflected in Table III.B.1) to these PV facilities at this time. Once FPL has actual operating experience with these PV facilities in these specific locations, it will evaluate what an appropriate firm capacity value for each of the facilities should be. However, FPL's economic and non-economic analyses fully capture the system fuel and emission savings from these three new solar facilities.

FPL is also currently assuming, for planning purposes, that it is likely to obtain additional capacity and/or energy from Renewable RFP solicitations, other proposed purchases, or its own renewable energy development efforts. For purposes of this planning document, FPL is assuming that 50 MW of firm capacity purchases from new renewable facilities will be added to FPL's system in the ten-year reporting period. In addition, one of FPL's existing renewable purchase power contracts is set to expire in 2010. For purposes of this planning document, FPL is assuming that a new contract for 55 MW of firm capacity and energy will be entered into. This is discussed further in Section III.F.

The significantly lower new load forecast, coupled with the approved additions of highly efficient new nuclear, solar, and natural gas-fired generating capacity, allow the opportunity for FPL to temporarily remove some older, less efficient generating capacity from active service, resulting in savings in operational and maintenance costs. A number of such units will be placed on Inactive Reserve status starting in 2009. The existing units that will be placed on Inactive Reserve include: Cutler Units 5 & 6, Sanford Unit 3, Port Everglades Units 1 & 2, Martin Unit 2, and Manatee Unit 2. These units will continue to be maintained and will be returned to active service when needed. The timing of the return of these units is uncertain at this time primarily due to the uncertainty regarding FPL's future load. However, for planning purposes, FPL is showing in this document that these units begin to return to active service starting in 2016.

In addition, the existing units at the Cape Canaveral and Riviera sites that will be converted to CC generation as part of the Conversions, will first be placed on Inactive Reserve status, then will be completely removed from service in preparation for the construction of the new units at those sites.

In regard to FPL's projected reserve margin values, these values are higher than the values projected in the 2008 Site Plan. As a consequence, no new uncommitted generation is projected to be needed in the 2009 – 2018 time frame, subject to changes in laws and regulations regarding renewable energy.[2]

[2] For purposes of establishing a Standard Offer Contract, and using the same forecasts and other assumptions presented in this document, FPL projects that it's next fossil-fueled new generating unit would be a Greenfield 3x1 G CC with a 2021 in-service date. Details of that unit are not provided in this Site Plan because its projected in-service date is beyond the 2009-2018 time period addressed in this document.

Table III.B.1: Projected Capacity Changes for FPL

Projected Capacity Changes and Reserve Margins for FPL (1)			
		Net Capacity Changes (MW)	
Year	Projected Capacity Changes	Winter (2)	Summer (3)
2009	Changes to Existing Purchases (4)	---	(479)
	West County Unit 1 (5)	---	1,219
	DeSoto Next Generation Solar Energy Center (PV) (6)	---	---
	Riviera Unit 3 - offline for conversion	---	(276)
	Riviera Unit 4 - offline for conversion	---	(286)
	Changes to Existing Units	(78)	10
	Inactive Reserve of Existing Units - offline (8)	---	(766)
2010	Changes to Existing Purchases (4)	(559)	(352)
	West County Unit 1 (5)	1,335	---
	West County Unit 2 (5)	1,335	1,219
	Martin Next Generation Solar Energy Center (Solar Thermal) (7)	---	---
	Space Coast Next Generation Solar Energy Center (PV) (6)	---	---
	Riviera Unit 3 - offline for conversion	(277)	---
	Riviera Unit 4 - offline for conversion	(288)	---
	Cape Canaveral Unit 1 - offline for conversion	---	(395)
	Cape Canaveral Unit 2 - offline for conversion	---	(388)
	Changes to Existing Units	53	36
	Inactive Reserve of Existing Units - offline (8)	(777)	(1,648)
2011	Changes to Existing Purchases (4)	(46)	(45)
	West County Unit 3 (5)	---	1,219
	Cape Canaveral Unit 1 - offline for conversion	(397)	---
	Cape Canaveral Unit 2 - offline for conversion	(397)	---
	Inactive Reserve of Existing Units - offline (8)	(1,663)	10
	Changes to Existing Units	130	(92)
2012	Changes to Existing Purchases (4)	---	(156)
	West County Unit 3 (5)	1,335	---
	Changes to Existing Units	(11)	(11)
	Existing Nuclear Units Capacity Uprates - St. Lucie 1	103	103
	Existing Nuclear Units Capacity Uprates - St. Lucie 2	---	88
	Existing Nuclear Units Capacity Uprates - Turkey Point 3	---	104
2013	Changes to Existing Purchases (4)	(180)	---
	Existing Nuclear Units Capacity Uprates - St. Lucie 2	88	---
	Existing Nuclear Units Capacity Uprates - Turkey Point 3	104	---
	Existing Nuclear Units Capacity Uprates - Turkey Point 4	104	104
	Cape Canaveral Next Generation Clean Energy Center (5)	---	1,219
2014	Changes to Existing Purchases (4)	---	50
	Cape Canaveral Next Generation Clean Energy Center (5)	1,343	---
	Riviera Beach Next Generation Clean Energy Center	---	1,207
2015	Riviera Beach Next Generation Clean Energy Center	1,310	---
2016	Inactive Reserve of Existing Units - online (8)	---	814
	Changes to Existing Purchases (4)	---	(1,311)
2017	Inactive Reserve of Existing Units - online (8)	825	822
2018	Turkey Point Nuclear Unit 6 (5)	---	1,100
	Inactive Reserve of Existing Units - online (8)	834	---
	TOTALS =	4,226	3,119

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are values for January of the year shown.
(3) Summer values are values for August of the year shown.
(4) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(5) All new unit additions are scheduled to be in-service in June of the year shown except for WCEC 1 and WCEC 2 that are projected to be in-service in August 2009 and December 2009, respectively. WCEC 1 is included in the Summer reserve margin calculation starting in 2009 and in the Winter reserve margin calculation starting in 2010. WCEC 2 is included in both the Summer and Winter starting in 2010. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.
(6) Because of the intermittent nature of the photovoltaics (PV) resource, FPL is currently assigning no firm capacity benefit to these generating additions. FPL will reassess this once actual operating data from the PV facilities at these locations is available. This location-specific information is needed in order to gauge consistent output during the peak hours which are accounted for in FPL's reserve margin calculations.
(7) The Martin solar thermal facility is designed to provide steam for FPL's existing Martin Unit 8 combined cycle unit, thus reducing FPL's use of natural gas. No additional capacity (MW) will result from the operation of the solar thermal facility.
(8) A number of existing FPL power plants are being temporarily removed from service and placed on Inactive Reserve status. FPL plans to return these units to active service in the future as needed. The timing of the return of these units to full-time active status is uncertain at this time primarily due to the uncertainty regarding FPL's future load. However, for planning purposes, FPL is showing in this document that these units begin to return to active service starting in 2016.

III.C Issues Impacting FPL's Resource Planning Work

FPL's ongoing resource planning efforts will continue to be influenced by the two driving factors previously discussed: a new lower load forecast and the addition of a significant amount of new highly efficient nuclear, solar, and CC generating capacity that has been approved by the FPSC. In addition, there are at least four other issues that will impact FPL's resource planning work. FPL refers to two of these issues as on-going system concerns that FPL has considered in its resource planning work for a number of years. These on-going system concerns include: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida.

In addition, two other relatively recent issues have emerged that will also influence FPL's resource planning efforts. These include: (3) the Executive Orders directive issued in 2007 by Governor Crist calling for reduction in greenhouse gas emissions and greater contribution from renewable energy sources, and (4) a Florida standard for renewable energy contributions to a utility system.

These four (4) issues that impact FPL's on-going resource planning work are briefly discussed below.

1. **<u>System Fuel Diversity</u>**

FPL is currently dependent upon using natural gas to generate approximately half of the electricity it delivers to its customers. Therefore, FPL is continually seeking to maintain and enhance the fuel diversity of its system.

In 2007, FPL sought approval from the FPSC to add two new advanced technology coal units to its system. These two new units would have been placed in-service in 2013 and 2014. However, due to concerns over greenhouse gas emissions, FPL was unable to obtain approval for these units. Consequently, FPL does not believe that new advanced technology coal units are viable fuel diversity enhancement options in Florida for the foreseeable future.

Therefore, FPL has turned its attention to nuclear energy, renewable energy, and more efficient ways in which to generate electricity using natural gas in order to enhance its fuel diversity. In regard to nuclear energy, FPL obtained approval to increase capacity at each of FPL's four existing nuclear units by up to 104 MW. In total, these capacity "uprates" will add a total of approximately 400 MW to the FPL system in the 2011/2012 time period. In 2008, the FPSC approved the need for these uprates and the ability to recover expenditures related to these uprates. In 2008, FPL also obtained FPSC approval for the need to add two new nuclear units at FPL's existing Turkey Point site and the ability to recover expenditures related to these new units. These two new nuclear units are projected to add approximately 2,200 MW to FPL's system. The first of these units is projected to come in-service in 2018 and the second unit to come in-service in 2020 (i.e., outside of the ten-year reporting period of this document).

FPL also has been involved in activities to investigate adding or maintaining renewable resources as a part of its generation supply. One of these activities is a variety of discussions with existing facilities aimed at maintaining or extending current agreements that are scheduled to end during the ten-year reporting period of this document. Another activity is to attempt to solicit cost-effective new renewable projects from outside parties. With respect to the latter, FPL issued a second Request for Proposals (RFP) for new renewable energy capacity and energy in April 2008 and FPL is analyzing those responses. Also, as previously discussed, FPL sought and received approval from the FPSC to add 110 MW of new FPL-owned solar facilities, both solar thermal and PV, in 2008. These FPL facilities are all scheduled to be in-service by 2010. FPL's efforts to utilize renewable energy are discussed further in Section III.F.

In regard to using natural gas more efficiently, FPL received approvals in 2008 from the FPSC to build a third highly efficient CC unit at its West County Energy Center site (WCEC Unit 3) and to convert the older steam generating units at its existing Cape Canaveral and Riviera plant sites to new, highly efficient CC units. These new CC units will go in service in 2011, 2013, and 2014, respectively.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity. FPL also plans to maintain the ability to utilize fuel oil at those existing units that have that capability, although cost factors currently limit the expected use of these facilities. Furthermore, FPL has traditionally purchased the gas transportation capacity required for new natural gas generating units from an existing natural gas pipeline company. As an alternative, FPL is developing plans with the goal of filing for a Need Determination by the FPSC for construction of a new natural gas pipeline in Florida capable of serving future generation needs. Such a pipeline would benefit FPL and its customers by increasing the diversity of FPL's fuel supply sources, the physical reliability of the pipeline delivery system, and competition among pipelines.

2. Southeastern Florida Imbalance

In recent years an imbalance had developed between regionally installed generation and peak load in Southeastern Florida. A significant amount of energy required in the Southeastern Florida region during peak periods was being provided through the transmission system from plants located outside the region. FPL's prior planning work concluded that either additional installed generating capacity in this region, or transmission capacity capable of delivering additional electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location, four recent capacity additions: Turkey Point Unit 5, and WCEC Units 1, 2, & 3, were evaluated as the most cost-effective options to meet FPL's capacity needs in the near-term. Adding these units will significantly reduce the imbalance between generation and load in Southeastern Florida.

In addition, FPL will be adding increased capacity at FPL's existing two nuclear units at Turkey Point in 2011/2012 and will be increasing the generating capacity at its Riviera site through the conversion of the existing plants at that site in 2014. The result of these approved generating unit additions in Southeastern Florida are expected to address the imbalance for most, if not all, of the 2009-2018 reporting period addressed in this document even after accounting for temporarily placing some of the existing generating units in the region on Inactive Reserve status. However, the Southeastern Florida imbalance will remain a concern in FPL's on-going resource planning work.

3. Governor Crist's Executive Orders

The Executive Orders issued in 2007, particularly the portions of those Orders directing significant increases in renewable, non-emitting energy and decreases in greenhouse gas emissions, are being addressed by FPL in a variety of ways. With respect to renewable energy, FPL's efforts to procure capacity from renewable energy sources, and to build its own renewable energy facilities, were mentioned above in regard to fuel diversity and are also discussed in more detail in Section III.F.

These renewable energy efforts have the potential to help lower greenhouse gas emissions. In addition, significant reductions, particularly of carbon dioxide (CO_2), will be accomplished by the approved capacity uprates at FPL's existing nuclear units and the planned additions of two new nuclear units at FPL's existing Turkey Point site in 2018 and 2020. Further reductions in greenhouse gas emissions are also expected from increasing the overall fuel efficiency of FPL's system through the addition of the approved new generating units WCEC Units 1, 2, & 3 and the approved conversions of FPL's existing Cape Canaveral and Riviera plants. FPL will also continue to look for cost-effective ways to further improve the efficiency of its system that will lead to even more greenhouse gas emission reductions.

FPL's system CO_2 emission rate (amount of CO_2 emitted per MWh of electricity generated) is already relatively low due in large part to the overall efficiency of FPL's system. The efforts described above have the potential not only to continue the trend of steadily lowering FPL's already low CO_2 emission rate, but also to begin to lower total system CO_2 emissions despite continued growth in population.

4. **Renewable Portfolio Standards**

The ongoing effort to establish a Florida standard for renewable energy contributions to a utility system is still underway at the time this document is being prepared. A Renewable Portfolio Standard (RPS) proposal prepared by the FPSC has been sent to the Florida Legislature for consideration during the legislative session that began in March 2009. Because the eventual RPS outcome is not known at the time the 2009 Site Plan is being prepared, the resource plan presented in FPL's 2009 Site Plan does not directly address an RPS decision. Assuming that an RPS decision is reached later in 2009, FPL will determine what steps need to be taken to address the standard. These steps will be discussed next year in FPL's 2010 Site Plan.

III.D Demand Side Management (DSM)

FPL offers a wide variety of cost-effective DSM programs to its customers. In addition, FPL is actively engaged in DSM research and development. These DSM efforts are discussed in the remainder of this section.

Residential DSM Programs

1. **Residential Building Envelope:** Offers incentives to residential customers to install energy efficient reflective roof and ceiling insulation measures.

2. **Duct System Testing and Repair:** Provides reduced cost duct system testing to identify leaks in air conditioning duct systems, and encourages the repair of those leaks by qualified contractors. Incentives are offered for duct system repair.

3. **Residential Air Conditioning:** Offers incentives to customers to purchase higher efficiency heating, ventilating, and air conditioning equipment. The program includes additional incentives for: 1) plenum repair measure; 2) air handler units with electronically commutated motors; and, 3) units properly sized using FPL approved sizing software.

4. **Residential Load Management (On Call Program):** Offers load control of major appliances/household equipment to residential customers in exchange for monthly electric bill credits. Direct load control equipment is installed on selected customer end-use equipment, allowing FPL to control these customer loads as needed. Qualifying equipment (and applicable monthly credits) includes central electric air conditioners, central electric heaters, conventional electric water heaters, and swimming pool pumps.

5. **Residential New Construction (BuildSmart):** Encourages the design and construction of energy efficient homes by offering education to contractors on energy efficiency measures, and providing construction design reviews and home inspections.

6. **Residential Low Income Weatherization:** Combines energy audits and incentives to encourage low income housing administrators to retrofit homes with energy efficiency measures. The housing authorities include: weatherization agency providers (WAPS), non-weatherization agency providers (non-WAPS), and other providers approved by FPL. The incentives are used by these providers to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting. FPL offers incentives for HVAC maintenance, reduced air infiltration measures, and room air conditioning replacement.

7. **Residential Conservation Service:** Offers a walk-through energy audit, a computer-generated Class A audit, and a customer-assisted energy audit. For customer-assisted energy audits, a mail-in, phone, and Internet audit option may be offered. FPL does not apply demand and energy savings from this program towards its DSM Goals.

Business DSM Programs

1. **Business Heating, Ventilating, and Air Conditioning (HVAC):** Offers business customers financial incentives to upgrade to higher efficiency HVAC equipment that exceed the minimum efficiencies mandated by the Florida Energy Efficiency Code for Building Construction or ASHRAE Standard 90.1. The current FPL program includes

incentives for: 1) thermal storage; 2) chillers; 3) energy recovery ventilator units; 4) direct expansion (DX) units and efficient air conditioning room units; 5) demand control ventilation systems including kitchen hood control; and 6) electrically commutated motors for air conditioning systems.

2. **Business Efficient Lighting:** Offers business customers financial incentives to install high efficiency lighting measures at the time of replacement. The FPL current program offers incentives for linear fluorescent, plus other efficient, lighting technologies.

3. **Business Building Envelope:** Offers financial incentives to business customers to install high efficiency building envelope measures such as roof/ceiling insulation, reflective roof coatings, and window treatments.

4. **Business Custom Incentive:** Serves as a "catch-all" program for cost-effective business efficiency measures which are not included in other FPL programs. DSM measures must reduce or shift at least 25 kW during peak hours, have verifiable demand and energy savings, and pass FPL's cost-effectiveness testing.

5. **Business On Call:** Offers load control of central air conditioning units to both small non–demand-billed, and medium demand-billed, business customers in exchange for monthly electric bill credits.

6. **Commercial Industrial Demand Reduction (CDR):** Reduces peak demand by allowing the direct control of customer loads of 200 kW or greater. Participants contract for a firm demand level which may not be exceeded during load control periods. In return, participants receive a monthly credit. Participants must provide a 5-year termination notice to discontinue service under this rider.

7. **Business Energy Evaluation:** Offers free standard level energy evaluations on-site and on-line. More detailed evaluations are available through this audit program with costs shared between FPL and the participating customer. Participation in FPL's other business DSM programs is promoted through this program.

8. **Commercial/Industrial Load Control:** Reduces peak demand by controlling customer loads of 200 kW or greater in exchange for monthly electric bill credits. (This program was closed to new participants in 2000).

9. **Business Water Heating:** Provides financial incentives to encourage the installation of energy-efficient heat recovery units or heat pump water heaters.

10. **Business Refrigeration:** Provides financial incentives to encourage the installation of controls and equipment to reduce the usage of electric strip heat for defrosting purposes.

11. **Cogeneration and Small Power Production**: Facilitates FPL compliance with all regulatory requirements concerning qualifying facilities and small power producers. One role of the program is to assist customers in the evaluation of potential cogeneration projects, including self-generation. FPL does not project demand and energy savings from this program towards its DSM Goals.

Research And Development Programs

1. **Conservation Research and Development Program (CRD):** An umbrella research project under which new DSM technologies are analyzed. Several FPL DSM programs have emerged from the CRD program, including the business Building Envelope, Business On Call, and Residential New Construction programs. The program has also resulted in the addition of cost-effective measures to existing programs, such as the inclusion of Energy Recovery Ventilators in the Business HVAC Program. FPL operates the CRD program based on DSM Plan approval, or for 6 years, whichever occurs first, with a spending cap as approved in the most current DSM Plan.

2. **Residential Thermostat Load Control Pilot Project:** On June 15, 2007 FPL filed a petition with the FPSC for the Residential Thermostat Load Control Pilot Project. A typical barrier to customer acceptance of utility load control programs is reluctance to surrender control of heating and air conditioning appliances. Consequently, for an initial 24-month period, FPL proposed to evaluate whether the benefits of the existing On-Call Program can be expanded through use of a new generation of communication and control technologies that put residential customers in charge of decisions that could lower energy costs, while allowing customers to override FPL control of their heating and air conditioning appliances. The Commission approved FPL's request on August 14, 2007, and issued Consummating Order 07-0719 TRF-EG on September 28, 2007. The pilot project is underway and upon conclusion of the pilot, FPL will provide a final report on the results to the FPSC.

DSM Summary:

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include both conservation initiatives and load management. FPL's DSM efforts through 2008 have resulted in a cumulative Summer peak reduction of approximately 4,109 MW at the generator and an estimated cumulative energy saving of approximately 46,646 Gigawatt Hour (GWh) at the generator. Accounting for reserve margin requirements, FPL's DSM efforts through 2008 have eliminated the need to construct more than 12 new 400 MW generating units.

FPL has consistently been among the leading utilities nationally in DSM achievement. For example, according to the U.S. Department of Energy's 2006 data (the last year for which the DOE data was available at the time this Site Plan was being developed), FPL ranked # 1 nationally in energy efficiency demand reduction and # 3 nationally in load management demand reduction.

In June 2009, FPL will be submitting its proposed DSM Goals for the 2010 – 2019 time period to the FPSC for its approval. At the time the 2009 Site Plan is being finalized, FPL's analyses to determine what its proposed DSM Goals for 2010 – 2019 are a work in progress. Consequently, FPL's 2009 Site Plan is retaining essentially the same level of projected DSM additions as was presented in its 2008 Site Plan. However, this level of projected DSM additions is likely to change due to the DSM Goals work.

Once FPL's DSM Goals are established, FPL will then send its proposed DSM Plan, with which it plans to meet these DSM Goals, to the FPSC for approval. FPL currently anticipates that both its DSM Goals and DSM Plan for the 2010 – 2019 time period will be approved by the first Quarter of 2010. Therefore, FPL expects that both its new DSM Goals and DSM Plan will be addressed in FPL's 2010 Site Plan.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy for FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV bulk transmission lines that must be certified under the Transmission Line Siting Act.

Table III.E.1: List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	St. Johns [1/]	Pringle	25	Jun-09	230	759
FPL	Manatee [2/]	BobWhite	30	Dec-12	230	1190

1/ Final order certifying the corridor was issued on April 21, 2006. This project will be completed in two phases. Phase I consists of 4 miles of new 230kV line (Pringle to Pellicer) and is scheduled to be completed by Dec-2009. Phase II consists of 21 miles of new 230kV line (St. Johns to Pellicer) and is scheduled to be completed by Dec-2013.

2/ Final order certifying the corridor was issued on November 6, 2008. This project consists of 30 miles of new 230kV line (Manatee to Bobwhite) and is scheduled to be completed by Dec-2012

In addition, there will be transmission facilities needed to connect several of FPL's committed capacity increases and additions to the system transmission grid. These transmission facilities for the committed capacity additions at the DeSoto solar photo-voltaic (PV) site, the West County Energy Center site Units 1, 2, and 3, the capacity increases (uprates) at the existing St. Lucie and Turkey Point nuclear sites, the Cape Canaveral and Riviera Beach conversions, and the new nuclear unit addition Turkey Point Unit 6, are described on the following pages.

Certain new generation additions will not need new transmission facilities. These generation additions include the Martin Next Generation Solar Energy Center and the Space Coast Next Generation Solar Energy Center. The Martin facility does not add any new generation capacity at the site and, therefore, no new transmission facilities are required. The Space Coast facility is an addition of 10 MW of PV generation that will be connected at distribution voltage at the Grissom substation. No new transmission facilities are needed.

In regard to the existing generating units that are projected to be placed on Inactive Reserve status beginning in 2009, there are no projected impacts to FPL's transmission system from these units because these units can be returned to active service with adequate notice.

III.E.1 Transmission Facilities for West County Energy Center (WCEC) Unit 1

The work required to connect West County Energy Center (WCEC) Unit 1 in 2009 to the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with four breakers to connect the three combustion turbines (CT) and one steam turbine (ST).
2. Construct two string busses to connect the collector busses and main switchyard to Corbett 230 kV Substation.
3. Add four main step-up transformers (3-370 MVA, 1-580 MVA), one for each CT, and one for the ST.
4. Add a new Bay #4 with three breakers at the Corbett 230 kV main switchyard. Connect one string buss from the collector yard and relocate the Alva 230 kV terminal from Bay #3 to new Bay #4.
5. Connect second collector string buss to Bay #3.
6. Add relays and other protective equipment.
7. Breaker replacements:
   Corbett Substation – Replace eight 230 kV breakers
   Ranch Substation – Replace five 138 kV breakers
   Levee Substation – Replace one 230 kV breaker
   Dade Substation – Replace two 138 kV breakers

II. Transmission:

1. No upgrades expected to be necessary at this time.

III.E.2 Transmission Facilities for West County Energy Center (WCEC) Unit 2

The work required to connect West County Energy Center (WCEC) Unit 2 in 2009 to the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with four breakers to connect the three combustion turbines (CT), and one steam turbine (ST).
2. Construct two string busses to connect the collector busses and main switchyard to Corbett 500kV Substation.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. At Corbett Substation, install one breaker and relocate Martin #2 500 kV line from Bay 2S to Bay 2N. Install one West County 500 kv string bus into Bay 2S.
5. At Corbett Substation, install one breaker and second West County 500 kV string bus into Bay 1S.
6. Add relays and other protective equipment.
7. Breaker replacements:
   Dade Substation – Replace one 138 kV breaker
   Levee Substation – Replace two 230 kV breakers
   Ranch Substation – Replace one 230 kV breaker

II. Transmission:

1. No upgrades expected to be necessary at this time.

III.E.3 Transmission Facilities for DeSoto Next Generation Solar Energy Center

The work required to connect the Desoto Next Generation Solar Energy Center project in 2009 to the FPL grid is projected to be as follows:

I. Substation:

1. Build a new Sunshine 230/23 kV Substation on FPL's Keentown-Whidden 230 kV line to connect the solar PV arrays.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. Loop Keentown-Whidden 230 kV line approximately 0.5 miles to Sunshine Substation.

III.E.4 Transmission Facilities for West County Energy Center (WCEC) Unit 3

The work required to connect West County Energy Center (WCEC) Unit 3 in 2011 to the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with four breakers to connect the three combustion turbines (CT), and one steam turbine (ST).
2. Build new Sugar 230 kV Substation on WCEC site.
3. Construct two string busses to connect the collector busses and main switchyard to Sugar 230kV Substation.
4. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
5. At Corbett Substation relocate Germantown 230 kV line terminal from Corbett to Sugar Sub.
6. At Corbett Substation relocate Broward/Yamato 230 kV line terminal from Corbett to Sugar Sub.
7. At Corbett Substation install new Sugar 230 kV line terminal in Bay 2W.
8. At Corbett Substation, install one 5-ohm inductor on the 230 kV side of the 500/230 kV autotransformer.
9. Add relays and other protective equipment.

II. Transmission:

1. Relocate Germantown 230 kV line from Corbett to Sugar.
2. Relocate Broward/Yamato 230 kV line from Corbett to Sugar.
3. Construct one mile 230 kV 1190 MVA line from Sugar to Corbett.

III.E.5 Transmission Facilities for St. Lucie Units 1 & 2 Capacity Uprates

The work required to accommodate the St. Lucie Units 1 & 2 uprates in 2011 for Unit 1 and in 2012 for Unit 2 to the FPL grid is projected to be as follows:

I. Substation:

1. At Midway Substation replace two 230 kV breaker and eleven 230 kV disconnect switches, and six wave traps. Also upgrade associated jumpers, bus work and equipment connections.
2. At St. Lucie Switchyard replace twenty-six 230 kV disconnect switches and six wave traps.
3. Uprate the Unit 1A and 1B main step-up transformers to 635 MVA.
4. Uprate the spare main step-up transformer to 635 MVA to replace Unit 2A main step-up transformer.
5. Replace the Unit 2B main step-up transformer with a new one rated at 635 MVA.

II. Transmission:

1. Upgrade the existing string busses for both units 1 & 2 between the main step-up transformers and the switchyard with spacers between the conductors.
2. Upgrade the three existing St. Lucie-Midway 230 kV lines with spacers between the conductors to achieve a normal (continuous) rating of 2790 Amperes.
3. Overhead ground wire and grounding improvements.

III.E.6 Transmission Facilities for Turkey Point Units 3 & 4 Capacity Uprates

The work required to accommodate the Turkey Point Units 3 & 4 uprates in 2012 for Unit 3 and in 2012 for Unit 4 to the FPL grid is projected to be as follows:

I. Substation:

1. At Turkey Point Switchyard install two 5-Ohm series phase inductors combined with external shunt capacitors on the southeast and southwest 230 kV operating busses.
2. At Turkey Point Switchyard replace twelve 230 kV disconnect switches. Also upgrade associated jumpers, bus work and equipment connections.
3. Uprate the Unit 3 and Unit 4 main step-up transformers to 970 MVA.
4. Replace spare main step-up transformer with 970-1050 MVA transformer.
5. Add relays and other protective equipment.

II. Transmission:

1. Upgrade the existing string busses for both Units 3 & 4 between the main step-up transformers and the switchyard with spacers between the conductors.

III.E.7 Transmission Facilities for Cape Canaveral Next Generation Clean Energy Center (Conversion)

The work required to connect the Cape Canaveral Next Generation Clean Energy Center in 2013 to the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with four breakers to connect the three combustion turbines (CT), and one steam turbine (ST).
2. Construct two string busses to connect the collector busses to Cape Canaveral 230kV Substation.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. At Cape Canaveral Switchyard replace eight 230 kV disconnect switches. Also upgrade associated jumpers, bus work and equipment connections.
5. Expand switchyard relay vault and add relays and other protective equipment.
6. Breaker replacements:
   Cape Canaveral Switchyard – Replace four 230 kV breakers.

II. Transmission:

1. Relocate the Cape Canaveral-Grissom 115 kV line.

III.E.8 Transmission Facilities for Riviera Beach Next Generation Clean Energy Center (Conversion)

The work required to connect the Riviera Beach Next Generation Clean Energy Center in 2014 to the FPL grid is projected to be as follows:

I. Substation:

1. Expand the Riviera 230 kV Switchyard five breakers to accommodate terminals for one combustion turbine (CT), and one steam turbine (ST).
2. Construct a new 138 kV Riviera Switchyard - five bays, fourteen breakers with terminals to connect two CT units and seven 138 kV lines.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. Add relays and other protective equipment.
5. At Ranch Substation add a new 230 kV bay 5 and upgrade bay 4 to 3000 Amperes.
6. Breaker replacements:
   Ranch Substation – Replace one 230 kV breaker
   Broward Substation – Replace one 230 kV breaker

II. Transmission:

1. Break the Indiantown-Riviera 230kV and extend each of the line segments south (approx 4 miles) to connect to the Ranch 230 kV Substation forming Indiantown-Ranch and a Ranch-Riviera 230 kV circuits.
2. Remove Corbett-Ranch #2 230 kV line at Ranch and:
   a. extend to meet the Cedar-Lauderdale 230 kV line N/S corridor (approx 10 miles).
3. Break Cedar -Corbett 230 kV (near Ranch Sub in Corbett-Jog section) and:
   a. extend Cedar side to Riviera, (Approx 15 miles) creating new Cedar-Riviera 230 kV.
   b. extend Corbett side to meet the Cedar-Lauderdale 230 kV N/S corridor (approx 10 miles).
4. Break Cedar-Lauderdale 230 kV (near 230 corridor running N/S)
   a. connect Cedar side to meet 3.b. to create a Cedar to Corbett 230 kV.
   b. connect Lauderdale side to meet 2.a. to create a Corbett to Lauderdale 230 kV.
5. Upgrade the existing IBM-Yamato 138 kV line to 1200 Amperes.
6. New underground 138 kV tie line between new Riviera 138 kV Switchyard and 560 MVA, 230/138 kV autotransformer in the expanded Riviera 230 kV Substation.
7. Relocate six existing 138 kV lines from existing Ranch 138 kV Switchyard to new Riviera 138 kV Switchyard.

III.E.9 Transmission Facilities for Turkey Point Nuclear Unit 6

The work required to connect the Turkey Point Nuclear Unit 6 in 2018 to the FPL grid is projected to be as follows:

I. Substation:

1. Build new Clear Sky 500/230kV Switchyard with six bays on the 230 kV section for generator main step-up transformer connection, reserve auxiliary transformer connections, four 230 kV line terminals, two autotransformers and two 500 kV line terminals.
2. At Turkey Point Switchyard add a new bay to accommodate the Turkey Point-Clear Sky 230 kV line terminal.
3. At Gratigny Substation install a second 230/138 kV autotransformer with one 230 kV breaker and one 138 kV breaker.
4. At Pennsuco Substation install a fourth line terminal to accommodate the Pennsuco-Clear Sky 230 kV line by converting the ring bus to a breaker and a half scheme and adding four 230 kV breakers.
5. At Davis Substation construct two new 230kV line terminals for the Clear Sky-Davis 230 kV line and the Davis-Miami 230 kV line with a switchable inductor to be installed on the Davis-Miami 230 kV line.
6. At Levee Substation expand 500 kV section to accommodate the two Levee-Clear Sky 500 kV lines.
7. At Andytown Substation install two 5-Ohm inductors combined with external shunt capacitors on the 230kV side of the 500/230 autotransformers (one per auto).
8. At Miami Substation expand the 230kV section to a double bus configuration and add a new 230kV line terminal for Davis line and replace one autotransformer.
9. At Flagami Substation install a small inductor on one end of the Flagami-Miami 230kV #2 circuit.
10. Breaker replacements:

    Flagami Substation – Replace five 230 kV breakers and three 138 kV breakers
    Miami Substation – Replace one 230 kV breaker and four 138 kV breakers
    Davis Substation - Replace two 230 kV breakers
    Dade Substation - Replace seven 230 kV breakers
    Court Substation – Replace one 138 kV breaker.

II. Transmission:

1. FPL will design and construct two 500 kV transmission lines from the new Clear Sky Substation to the existing FPL Levee 500 kV Substation switchyard. The lines will be approximately 43 miles long.
2. Construct a new Clear Sky-Davis 230 kV line (approximately 19 miles) with a rating of 2990 Amperes.
3. Construct a new Clear Sky-Pennsuco 230 kV line (approximately 52 miles) with a rating of 2990 Amperes.
4. Construct a new Davis-Miami 230 kV line (approximately 18 miles) with a rating of 2297 Amperes.
5. Construct a new Clear Sky-Turkey Point 230 kV line (approximately 0.5 miles) with a rating of 2990 Amperes.

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to utilize renewable energy technologies to meet its customers' current and future needs. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. For purposes of discussing FPL's renewable energy efforts in this document, those efforts will be placed into five categories.

1) **Early Research & Development Efforts:**

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970s in demonstrating the first residential solar photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-kilowatt (kW) system was placed into operation in 1984. (The system was removed in 1990 to make room for substation expansion after the testing of this PV installation was completed.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. The FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's recent Green Pricing effort (which is discussed below).

2) **Demand Side & Customer Efforts:**

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was no longer cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for 6 passive homes with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the FPSC to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test were deemed to be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, and various customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

FPL then analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach did not require all of its customers to bear the high cost of PV, but facilitated the use of renewable energy by customers who were interested. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund that FPL used to make PV purchases in bulk quantities. PV modules were then installed and delivered PV-generated electricity directly into the FPL grid, thus displacing an equivalent amount of fossil fuel-generated electricity.

FPL's basic approach for this program, which was termed Green Pricing, was initially discussed with the FPSC in 1994. FPL's efforts to implement this approach were then formally presented to the FPSC as part of FPL's DSM Plan in 1995 and FPL received approval from the FPSC in 1997 to proceed. FPL began the effort in 1998 and received approximately $89,000 in contributions (that significantly exceeded the goal of $70,000). FPL purchased the PV modules and installed them at FPL's Martin Plant site.

FPL initiated two new renewable efforts in 2000. FPL's first new initiative in 2000 was FPL's Photovoltaic Research, Development, and Education Project. This demonstration project's objectives were to: increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks (as well as the total annual energy capabilities of roof tile PV systems), and assess the homeowner's financial benefits and costs of PV roof tile systems. This project was completed in 2003.

The second effort initiated in 2000 was the Green Energy Project. The objectives of this Project were to: determine customer interest in an on-going renewable energy program, determine their price responsiveness and views on the different renewable technologies, and identify potential renewable energy supply sources that would meet the forecasted customer demand for this type of product. This Project formed the basis for FPL's Green Power Pricing Research Project, and then led to FPL's Business Green Energy Research Project.

Both the Green Power Pricing Research Project and the Business Green Energy Research Project examined the feasibility of purchasing tradable renewable energy credits generated from renewable resources including solar-powered technologies, biomass energy, landfill methane, wind energy, low impact hydroelectric energy, and/or other renewable sources. Customers who participate are charged a premium for purchasing the tradable renewable energy credits associated with electric energy generated by these sources.

Development of the Green Pricing Research Project was completed and filed with the FPSC in August 2003. As part of this process, a supply contract was put into place that allowed FPL to match supply with demand for green energy. Tradable renewable energy credits were used to supply the renewable benefits required of this project. The FPSC approved the program in December 2003 and program implementation began during the first Quarter of 2004. The project was offered to customers as FPL's Sunshine Energy® program. As part of the project, FPL made a commitment that 150 kilowatts (kW) of solar capacity would be put in place for every 10,000 program participants. The Business Green Energy Research Project focused on determining the interest and needs for business customers in this area. In 2006 FPL petitioned the FPSC for approval to make the Green Pricing Research Project a permanent program and expand eligibility to business customers. This approval was granted in the fourth Quarter of 2006.

As Florida entered the next phase in promotion of renewable energy, with FPL requesting approval to build three new solar energy centers in the state (which are discussed below), in 2008 the FPSC voted to end the Sunshine Energy program. At its conclusion, the Sunshine Energy Program included approximately 38,000 participants and resulted in 494 kW of PV installed, including the largest PV array in the state at that time, a 250 kW facility at Rothenbach Park in Sarasota County. Several additional solar initiatives had also been developed through the Sunshine Energy Program including support for schools. The Sunshine Energy Program support of installing PV at schools was a continuation of previous FPL renewable activities involving schools. In 2003, as part of the State of Florida's PV for Schools program, FPL worked with three schools to install 4.8 kW of PV systems.

FPL has also been investigating fuel cell technologies through monitoring of industry trends, discussions with manufacturers, and direct field trials. From 2002 through the end of 2005, FPL conducted field trials and demonstration projects of Proton Exchange Membrane (PEM) fuel cells with the objectives of serving customer end-uses while evaluating the technical performance, reliability, economics, and relative readiness of the PEM technology. The demonstration projects were conducted in partnership with customers and included 5 locations. The research projects were useful to FPL in identifying specific issues that can occur in field applications and the current commercial viability of this technology. FPL will continue to monitor the progress of these technologies and conduct additional field evaluations as significant developments in the fuel cell technologies occur.

In addition, FPL assists customers who are interested in installing PV equipment at their facilities. In support of Florida Administrative Code Rule 25-6.065, Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned PV systems. Through December 2008, approximately 270 customer systems (predominantly residential) have been interconnected.

3) <u>Supply Side Efforts – Power Purchases:</u>

FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy and as-available energy have been purchased by FPL from these types of facilities. (Please refer to Tables I.B.1, I.B.2, and Table I.C.1 in Chapter I).

FPL is seeking cost-effective Power Purchase Agreements (PPAs) with any and all potential renewable energy providers. FPL issued a Renewable Request for Proposals (RFP) in 2007 that solicited proposals that offered capacity and/or energy from new renewable energy facilities. None of the responsive bids in this RFP were at or below FPL's projected avoided cost. FPL issued another Renewable Energy RFP in April 2008, which resulted in six bids received by July. Analysis of the bids was delayed by the extreme volatility in the commodity fuel and capital markets in late 2008. Current analysis indicates that none of the bids may have the potential to provide firm capacity and/or energy at avoided cost prices (and the FPSC has ruled that costs above FPL's projected avoided costs cannot be recovered for purchase contracts).

With regard to certain of the existing contracts that are currently scheduled to end in the near-term, and proposals resulting from the RFP process, FPL has assumed that some of this firm capacity will be available during the ten-year reporting period of this document through extended and/or new contracts. Firm renewable energy capacity from these sources, and from the FPL development activities discussed below, are assumed for planning purposes to provide 105 MW through this reporting period. 55 MW of the 105 MW total is expected to come from an extension of an existing purchased power contract that will expire soon. The remaining 50 MW are projected, for planning purposes, to come from a new purchase power contract (but could be delivered by a new FPL renewable energy facility).

4) <u>Supply Side Efforts – FPL Facilities:</u>

FPL is in the process of developing a wind generation project on South Hutchinson Island in St. Lucie County. This project is known as the St. Lucie Wind project and it consists of up to 6 wind turbine generators capable of generating up to approximately 13.8 MW. In 2007, FPL began the St. Lucie County land use approval process, and soon after applied for the necessary federal and state permitting. However, a decision by the state and federal agencies on the St. Lucie Wind project's permitting will not be finalized until the local land use approval process is completed. The in-service date will depend on the approval and permitting process.

FPL is currently constructing 110 MW of solar capacity at three sites in Florida. These projects are in response to the Florida's Legislature House Bill 7135 which was signed into law by Governor Crist in June 2008. House Bill 7135 (hereafter referred to as the 2008 Energy Bill), was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in State of Florida. Specifically, the 2008 Energy Bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land, zoning and transmission rights in place. FPL's three solar projects discussed in this section met the specified criteria, and were granted approval for cost recovery in 2008. Each of the three solar projects is discussed below.

a. **The Martin Next Generation Solar Energy Center:**
This project will provide 75 MW of solar thermal capacity in an innovative way that directly displaces fossil fuel usage in an existing FPL generating unit. This project will involve the installation of solar thermal technology that will be integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired CC plant. This project will be the first "hybrid" solar plant in the world, the second largest solar facility in the world, and the largest solar plant of any kind in the U.S. outside of California. Construction began in December 2008 and is expected to be completed by the end of 2010.

b. **The DeSoto Next Generation Solar Energy Center:**
This project will provide 25 MW of photovoltaic (PV) capacity, making it the largest PV facility in the U.S.. The facility will utilize a tracking array that is designed to follow the sun as it traverses through the sky. Construction began in November 2008 and is expected to be completed by the end of 2009 or early 2010.

c. **The Space Coast Next Generation Solar Energy Center:**
This project will provide 10 MW of PV capacity in an innovative public/private partnership with NASA at the Kennedy Space Center. Construction is expected to begin in 2009 and is expected to be completed in 2010.

Each of these facilities is a significant and innovative renewable generating plant in its own right. Collectively, these Next Generation Solar Energy Centers are expected to produce a total of 223,000 megawatt hours (MWh) of electricity each year, and at peak production provide enough power and energy to serve the requirements of more than 15,000 homes.

For resource planning purposes, FPL projects that the energy delivered from these renewable facilities will be "as available", non-firm energy. This is due to several factors. First, the Martin solar thermal facility is designed as a "fuel-substitute" facility, not as a facility that will result in additional capacity and energy being generated. The solar thermal facility will displace the use of fossil fuel on the FPL system when the solar thermal facility is operating. Second, in regard to the two PV facilities, the intermittent nature of the solar resource makes it difficult to accurately determine what contribution the PV facilities at these specific locations can consistently make at FPL late Summer afternoon and early Winter morning peak load hours. Once site-specific operating data has been gathered for an appropriate amount of time, FPL will then re-evaluate the actual output from each PV facility to determine what portion, if any, of its output can be projected as firm capacity at the projected peak hours in FPL's resource planning work.

In addition to these three approved projects; FPL is currently in the process of identifying other potential solar sites in the state in the event that a future Renewable Portfolio Standard (RPS) or other enabling legislation is enacted by the Florida legislature. FPL is evaluating existing FPL generation sites along with potential greenfield sites within FPL's service territory. Sites which are considered potential candidates will be developed so that the necessary local land use and zoning designations are consistent with the future development of solar generation. Sites that have been identified for further evaluation include the potential expansion of the DeSoto site for additional PV, and the expansion of the Manatee site for a solar thermal facility. These sites are discussed further in Chapter IV.

5) **<u>Ongoing Research & Development Efforts:</u>**

FPL has developed alliances with several Florida universities to promote development of emerging technologies. For example, an alliance as been established with the newly formed Center for Ocean Energy Technology at Florida Atlantic University (FAU), which will focus on the commercialization of ocean current, ocean thermal (i.e., energy conversion as well as cold water air conditioning) and hydrogen technologies. FPL has been taking the lead in assisting FAU with the discussions being held with the U.S. Department of the Interior's Minerals

Management Service Department (MMS). MMS is working to establish the permitting process for ocean energy development on the outer continental shelf.

FPL has also developed an alliance with the University of Florida to support its studies of biomass renewable potential and wind studies in the state. In addition, FPL has partnered with the Florida Institute of Technology on fuel cell technology and with the Florida State Universities Center for Applied Power System in regard to grid integration of ocean energy and other renewables.

FPL is also developing a "living lab" to demonstrate FPL's solar energy commitment to employees and visitors at its Juno Beach facility. FPL will evaluate multiple solar technologies and applications to develop a renewable business model resulting in the most cost-effective and reliable source(s) of solar energy to FPL customers.

FPL has also been in discussion with several private companies on multiple emerging technology initiatives including ocean current, ocean thermal, hydrogen, fuel cell technology, biomass, biofuels, and energy storage.

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fired generation. In the early 1980s, FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership and additional purchases from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit 4 which began serving FPL's customers in 1991. Starting in 1997, petroleum coke was added to the fuel mix as a blend stock with coal at SJRPP.

The trend since the early 1990s has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective CC generating units and the ready availability of natural gas. This planning document reflects an evolution in that trend in recognition that, although efficient gas-fired generation continues to provide significant benefits to FPL's customers, adding natural gas-fired additions exclusively would, in the long term, create an unbalanced generation portfolio. FPL has committed to add three new gas-fired CC units at the West County Energy Center (WCEC) site in the 2009 – 2011 time frame. In addition, FPL has also committed to convert the existing steam generating units at its existing Cape Canaveral and Riviera sites into two highly efficient new CC units, one at each site. These five new CC units will provide highly efficient generation that will dramatically improve FPL's overall system generation efficiency.

In addition, FPL is increasing its utilization of nuclear energy through capacity uprates of its four existing nuclear units. These uprates will add a total of approximately 400 MW of nuclear generation capacity by 2012. FPL has also received approval from the FPSC to pursue plans to permit and build two new nuclear units at its existing Turkey Point site that, in total, will add approximately 2,200 MW of new nuclear generating capacity. The first of these two new units, Turkey Point Unit 6, is projected to go in-service in 2018 and is presented in this document. The second new nuclear unit, Turkey Point Unit 7, is projected to have a 2020 in-service date and will be presented in future FPL Site Plans.

In regard to utilizing renewable energy, FPL has committed to add 110 MW of solar generating capacity by 2010 through a 75 MW solar thermal facility at FPL's existing Martin site, a 25 MW PV facility in DeSoto County, and a 10 MW PV facility in Brevard County.

FPL's future resource planning work will continue to focus on identifying and evaluating alternatives that would maintain and/or enhance FPL's long-term fuel diversity. These fuel diverse alternatives may include: the purchase of power from renewable energy facilities, addition of FPL-owned renewable energy facilities, obtaining access to diversified sources of natural gas such as liquefied natural gas (LNG) and natural gas from the newly developed Mid-Continent unconventional reserves, preserving FPL's ability to utilize fuel oil at its existing units, and increased utilization of nuclear energy. (New advanced technology coal generating units are not currently considered as viable options in Florida in the ten-year reporting period of this document due to concerns over greenhouse gas emissions.) The evaluation of the feasibility and cost-effectiveness of these, and other possible alternatives, will be an ongoing part of future planning cycles.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2018 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

2. Fossil Fuel Price Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future generating capacity needs. FPL's forecasts are generally consistent with other published contemporary forecasts.

Future oil and natural gas prices, and to a lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short-and long-term price of oil, natural gas, coal, and petroleum coke. These drivers include:

a. Current and projected worldwide demand for crude oil and petroleum products;

b. Current and projected worldwide refinery capacity/production;

c. Expected worldwide economic growth, in particular in China, India, and the other Pacific Rim countries;

d. Organization of Petroleum Exporting Countries (OPEC) production and the availability of spare OPEC production capacity and the assumed growth in spare OPEC production capacity;

e. Non-OPEC production and expected growth in non-OPEC production;

f. The geopolitics of the Middle East, West Africa, the Former Soviet Union, Venezuela, etc., as well as, the uncertainty and impact upon worldwide energy consumption related to U. S. and worldwide environmental legislation, politics, etc.;

g. Current and projected North American natural gas demand;

h. Current and projected U.S., Canadian, and Mexican natural gas production;

i. The worldwide supply and demand for LNG; and

j. The growth in solid fuel generation on a U. S. and worldwide basis.

The inherent uncertainty and unpredictability in these factors today and tomorrow clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal and petroleum coke) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed and utilized Low, Medium, and High price forecasts for oil, natural gas, and solid fuel in much of its 2008 resource planning work, particularly in regard to the Determination of Need filings for WCEC Unit 3 and the conversions of FPL's existing Cape Canaveral and Riviera plants, and the nuclear cost recovery filings.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

a. For 2008 through 2010, the methodology used the November 6, 2008 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil, ultra low sulfur diesel, and Henry Hub natural gas commodity prices;

b. For the next two years (2011 and 2012), FPL used a 50/50 blend of the November 6, 2008 forward curve and the most current projections at the time from The PIRA Energy Group;

c. For the 2013 through 2020 period, FPL used the annual projections from The PIRA Energy Group, and;

d. For the period beyond 2020, FPL used the real rate of escalation provided in the Energy Information Administration (EIA) *Annual Energy Outlook 2008* publication. FPL assumed a 2.5% annual rate of escalation to convert real prices to nominal prices prior to 2020, with no escalation from 2020 forward. In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach:

a. The price forecasts for Central Appalachian coal (CAPP), South American coal, and petroleum coke were provided by JD Energy;

b. The marine transportation rates from the loading port for coal and petroleum coke to an import terminal were also provided by JD Energy;

c. The Terminal Throughput Fee was based on a range of offers from comparable facilities throughout the Southeast U.S.. The coal price forecast for FPL's existing coal plants at SJRPP and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for oil, natural gas, coal, and petroleum coke prices were based upon the historical relationship of prices compared to the average prices for the 2000 through 2007 time frame. FPL developed these forecasts to account for the uncertainty which exists within each commodity as well as across commodities. These forecasts reflect a range of reasonable forecast outcomes.

3. Nuclear Fuel Cost Forecast

This section reviews the various steps needed to fabricate nuclear fuel for delivery to the nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

a) Steps Required for Nuclear Fuel to be delivered to FPL's Plants

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

(1) Mining: Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U3O8 (sometimes referred to as yellowcake).

(2) Conversion: During the second step, the U3O8 is chemically converted into UF6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

(3) **Enrichment:** The third step is called enrichment. Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 3% to as high as 5%). The output of this enrichment process is enriched uranium in the form of UF6.

(4) **Fabrication:** During the last step, fuel fabrication, the enriched UF6 is changed to a UO2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) **Mining:** There is a significant volatility in the current uranium market. Demand is rather stable but inventory sales are a significant source of supply to complement outputs from production facilities. To the extent that source of supply can be restricted and inventories held from the market, price will rise significantly. The following are the current major contributors to this uranium price volatility:

- Hedge funds have been purchasing a significant amount of uranium, reducing availability of uranium. However, the recent financial crisis has caused significant sales of inventories and has caused the market to drop earlier than predicted.

- The large inventory from the U.S. Department of Energy (DOE) is being withheld from the market due to political pressure from suppliers concerned about further price drop already affected by the current financial downturn.

- The Russians have announced that they would not supply down-blended weapons material to the U.S. government after 2013 for sale in the U.S. market.

- The U.S. Department of Commerce (DOC) has imposed restrictions on the import of nuclear fuel from France and Russia.

However, FPL expects these issues to be addressed within the next few years, returning price behavior to be more consistent with market fundamentals. 2008 saw a number of actions to resolve restrictions of imports of foreign uranium. Recent law enacted in 2008 resolved the import of Russian-enriched uranium, by allowing some imports of Russian-enriched uranium to about 20-25% of needs for currently operating units, but with no restriction on the first core for new units and no restrictions after 2020. The financial crisis has also had a major impact and eliminated speculative demands with uranium pricing returning to close to the fundamentals earlier than was expected last year. The hedge funds have significantly reduced their activities.

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies.

(2) Conversion: FPL's price forecast considers the construction of new nuclear units. Just like for raw uranium, an increase in demand for conversion services would result from this need. Insufficient planned production is currently forecast after 2013 to meet the higher demand scenario. As with additional raw uranium production, supply will expand beyond current level once more firm commitments are made including commitments to building new nuclear units.

(3) Enrichment: With no new production capacity, and if the current restrictions on imports of enrichment services from Russia continue, the current tight market supply for economically produced enrichment services will continue until 2013. A high projection of new nuclear unit construction shows a shortage of low cost enrichment services starting in 2010. The current expensive diffusion plant can make up any gaps in supply of enrichment services. In addition, there are a number of new facilities coming on-line starting in 2009 through 2013, using more efficient and proven processes such as the use of centrifuges for enrichment of uranium. In addition, as with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the Nuclear Regulatory Commission (NRC), not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand is expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast

The calculations for the nuclear fuel costs are performed consistent with the method currently used for FPL's Fuel Clause filings, including the assumption of a fuel lease and the assumption of refueling outages every 18 months. The costs for each step to fabricate the nuclear fuels are added and capitalized to come up with the total costs of the fresh fuel to be loaded at each refueling (capitalized acquisition costs). The capitalized acquisition cost for each group of fresh fuel assemblies are then amortized over the energy produced by each group of fuel assemblies, and carrying costs are also added on the total unrecovered costs to derive the total fuel costs to be charged to customers. FPL also adds 1 mill per kilowatt hour net to reflect payment to DOE for spent fuel disposal.

Schedule 5
Fuel Requirements 1/

Fuel Requirements	Units	Actual 2/ 2007	2008	Forecasted 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1) Nuclear	Trillion BTU	240	261	262	247	253	275	304	309	299	305	309	305
(2) Coal	1,000 TON	2,961	3,599	4,047	3,349	4,098	3,356	4,116	3,976	3,963	3,985	3,969	3,956
(3) Residual (FO6)- Total	1,000 BBL	15,524	9,379	13,317	1,788	980	852	325	285	408	1,096	1,470	1,356
(4) Steam	1,000 BBL	15,524	9,379	13,317	1,788	980	852	325	285	408	1,096	1,470	1,356
(5) Distillate (FO2)- Total	1,000 BBL	114	38	12	211	149	130	2	1	18	120	80	41
(6) Steam	1,000 BBL	0	11	0	0	0	0	0	0	0	0	0	0
(7) CC	1,000 BBL	64	8	0	0	0	0	0	0	0	0	0	0
(8) CT	1,000 BBL	50	20	12	211	149	130	2	1	18	120	80	41
(9) Natural Gas -Total	1,000 MCF	447,354	449,819	375,691	470,309	494,198	504,620	481,036	507,792	524,072	580,258	598,896	585,348
(10) Steam	1,000 MCF	66,914	143,581	17,180	18,364	19,092	18,193	7,691	6,450	8,901	22,942	28,899	26,913
(11) CC	1,000 MCF	370,039	303,942	357,811	449,246	473,101	485,010	473,261	501,270	514,850	556,001	568,953	557,878
(12) CT	1,000 MCF	10,401	2,296	700	2,699	2,004	1,417	84	73	322	1,316	1,044	557

1/ Reflects fuel requirements for FPL only.
2/ Source: A Schedules.

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 1/ 2007	2008	Forecasted 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	Annual Energy Interchange 2/	GWH	10,686	10,141	11,109	8,462	5,962	5,867	5,646	5,462	5,978	798	0	0
(2)	Nuclear	GWH	21,899	24,024	23,510	22,116	22,730	24,705	27,276	27,751	26,790	27,355	27,751	32,816
(3)	Coal	GWH	6,856	6,423	7,381	6,205	7,462	6,138	7,378	7,142	7,160	7,161	7,131	7,108
(4)	Residual(FO6) -Total	GWH	9,651	5,702	8,844	1,208	658	573	218	191	274	735	983	906
(5)	Steam	GWH	9,651	5,702	8,844	1,208	658	573	218	191	274	735	983	906
(6)	Distillate(FO2) -Total	GWH	27	17	3	70	52	39	0	0	4	39	26	13
(7)	Steam	GWH	0	6	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	6,7	3	0	0	0	0	0	0	0	0	0	0
(9)	CT	GWH	20	9	3	70	52	39	0	0	4	39	26	13
(10)	Natural Gas -Total	GWH	59,300	58,820	52,723	66,854	70,179	72,030	69,662	74,106	76,449	83,660	86,064	84,241
(11)	Steam	GWH	6,205	7,257	1,683	1,813	1,689	1,600	759	636	880	2,269	2,855	2,656
(12)	CC	GWH	52,717	51,368	50,990	64,860	68,156	70,140	68,898	73,465	75,548	81,311	83,142	81,549
(13)	CT	GWH	378	195	50	181	134	90	6	5	22	61	67	36
(14)	Other 3/	GWH	5,893	5,877	5,871	5,294	4,864	5,464	5,844	6,478	7,147	6,533	6,953	7,052
	Net Energy For Load 4/	GWH	114,314	111,004	109,440	110,207	111,926	114,815	116,027	121,128	123,800	126,278	128,908	132,135

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
4/ Net Energy For Load values for the years 2009 - 2018 are also shown in Schedule 2.3.

Schedule 6.2
Energy Sources % by Fuel Type

	Energy Source	Units	Actual 1/		Forecasted									
			2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	Annual Energy Interchange 2/	%	9.3	9.1	10.2	7.7	5.3	5.1	4.9	4.5	4.8	0.6	0.0	0.0
(2)	Nuclear	%	19.2	21.6	21.5	20.1	20.3	21.5	23.5	22.9	21.6	21.7	21.5	24.8
(3)	Coal	%	6.0	5.8	6.7	5.6	6.7	5.3	6.4	5.9	5.8	5.7	5.6	5.4
(4)	Residual (FO6) -Total	%	8.4	5.1	8.1	1.1	0.6	0.5	0.2	0.2	0.2	0.6	0.8	0.7
(5)	Steam	%	8.4	5.1	8.1	1.1	0.6	0.5	0.2	0.2	0.2	0.6	0.8	0.7
(6)	Distillate (FO2) -Total	%	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	CT	%	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	51.9	53.0	48.2	60.7	62.7	62.7	60.0	61.2	61.8	66.3	66.8	63.8
(11)	Steam	%	5.4	6.5	1.5	1.6	1.7	1.6	0.7	0.5	0.7	1.8	2.2	2.0
(12)	CC	%	46.1	46.3	46.6	58.9	60.9	61.1	59.4	60.7	61.0	64.4	64.5	61.7
(13)	CT	%	0.3	0.2	0.0	0.2	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.0
(14)	Other 3/	%	5.2	5.3	5.4	4.8	4.4	4.8	6.0	5.3	5.8	5.2	5.4	5.3
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules.
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled
Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(6)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Total Installed[1/] Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available[2/] MW	Total Peak[3/] Demand MW	DSM[4/] MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance[5/] MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance[6/] MW	% of Peak
2009	21,985	1,824	0	690	24,499	21,124	1,997	19,126	5,372	26.1	0	5,372	28.1
2010	20,609	1,467	0	640	22,916	21,147	2,119	19,027	3,889	20.4	0	3,889	20.4
2011	21,946	1,467	0	595	24,008	21,368	2,236	19,132	4,876	25.5	0	4,876	25.5
2012	22,230	1,311	0	650	24,191	21,933	2,357	19,578	4,614	23.6	0	4,614	23.6
2013	23,553	1,311	0	650	25,514	22,249	2,463	19,766	5,746	29.1	0	5,748	29.1
2014	24,760	1,361	0	650	26,771	23,533	2,615	20,916	5,853	28.0	0	5,853	28.0
2015	24,760	1,361	0	650	26,771	24,142	2,749	21,393	5,377	25.1	0	5,377	25.1
2016	25,574	50	0	650	26,274	24,772	2,884	21,886	4,386	20.0	0	4,366	20.0
2017	26,396	50	0	650	27,096	25,401	3,019	22,363	4,713	21.1	0	4,713	21.1
2018	27,496	50	0	650	28,196	26,143	3,064	23,079	5,116	22.2	0	5,116	22.2

1/ Capacity additions and changes projected to be in-service by June 1st are generally considered to be available to meet Summer peak loads are forecasted to occur during August of the year Indicated. All values are Summer net MW.
2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).
3/ These forecasted values reflect the 2009 load forecast without Incremental DSM or cumulative load management.
4/ The DSM MW shown represent cumulative load management capability plus Incremental conservation from 1/2006-on designed for use with the 2008 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.
5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)
6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled
Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
January of Year	Total Installed Capability [1/] MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available [2/] MW	Total Peak [3/] Demand MW	DSM [4/] MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance [5/] MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance [6/] MW	% of Peak
2009	23,280	1,962	0	740	25,982	18,697	1,730	16,968	9,014	53.1	0	9,014	53.1
2010	24,661	1,501	0	690	26,852	18,790	1,819	16,971	9,880	58.2	0	9,880	58.2
2011	22,338	1,500	0	595	24,433	19,120	1,888	17,231	7,201	41.8	0	7,201	41.8
2012	23,765	1,500	0	595	25,860	19,710	1,960	17,749	8,110	45.7	0	8,110	45.7
2013	24,061	1,320	0	650	26,031	20,098	2,035	18,063	7,967	44.1	0	7,967	44.1
2014	25,404	1,370	0	650	27,424	21,154	2,113	19,041	8,382	44.0	0	8,382	44.0
2015	26,714	1,370	0	650	28,734	21,882	2,196	19,687	9,047	46.0	0	9,047	46.0
2016	27,539	440	0	650	28,629	22,396	2,278	20,118	8,510	42.3	0	8,510	42.3
2017	28,373	50	0	650	29,073	22,912	2,361	20,551	8,521	41.5	0	8,521	41.5
2018	28,373	50	0	650	29,073	23,466	2,436	21,030	8,043	38.2	0	8,043	38.2

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the 2009 load forecast without incremental DSM or cumulative load management.

4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2008-on desinged for use with the 2008 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2009														
Cape Canaveral	1	Brevard County	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	402,050	(1)	(1)	OT
Cape Canaveral	2	Brevard County	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	402,050	(8)	(8)	OT
Cutler	5	Miami Dade County	ST	NG	No	PL	No	Jan-09	May-09	Unknown	75,000	(4)	---	OT
DeSoto Next Generating Solar Energy Center (PV)		DeSoto County	PV											P
Ft. Myers	2	Lee County	CC	NG	No	PL	No	Jan-09	Jun-09	Unknown	1,775,390	5	6	OT
Ft. Myers	3	Lee County	CT	NG	FO2	PL	PL	Jan-09	Jun-09	Unknown	376,380	6	8	OT
Lauderdale	4	Broward County	CC	NG	FO2	PL	PL	Jan-09	Jun-09	Unknown	526,250	4	2	OT
Lauderdale	5	Broward County	CC	NG	FO2	PL	PL	Jan-09	Jun-09	Unknown	526,250	1	(1)	OT
Manatee	1	Manatee County	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	863,300	(3)	(1)	OT
Manatee	2	Manatee County	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	863,300	12	10	OT
Manatee	3	Manatee County	CC	NG	No	PL	No	Jan-09	Jun-09	Unknown	1,224,510	(55)	9	OT
Martin	1	Martin County	ST	FO6	NG	PL	PL	Jan-09	Jun-09	Unknown	934,500	7	—	OT
Martin	2	Martin County	ST	FO6	NG	PL	PL	Jan-09	Jun-09	Unknown	934,500	7	--	OT
Martin	3	Martin County	CC	NG	No	PL	No	Jan-09	Jun-09	Unknown	612,000	(17)	(30)	OT
Martin	4	Martin County	CC	NG	No	PL	No	Jan-09	Jun-09	Unknown	612,000	(3)	(5)	OT
Martin	8	Martin County	CC	NG	FO2	PL	PL	Jan-09	Jun-09	Unknown	1,224,510	13	8	OT
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	402,050	6	6	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	402,050	5	5	OT
Putnam	1	Putnam County	CC	NG	FO2	PL	WA	Jan-09	Jun-09	Unknown	290,004	5	---	OT
Putnam	2	Putnam County	CC	NG	FO2	PL	WA	Jan-09	Jun-09	Unknown	290,004	6	1	OT
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	310,420	(3)	(276)	OT
Riviera	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	310,420	(3)	(286)	OT
Sanford	3	Volusia County	ST	FO6	NG	WA	PL	Jan-09	6/1/2009	--	156,250	1	--	OT
Sanford	4	Volusia County	CC	NG	No	PL	No	Jan-09	Jun-09	Unknown	1,188,860	12	9	OT
Sanford	5	Volusia County	CC	NG	No	PL	No	Jan-09	Jun-09	Unknown	1,188,860	11	9	OT
Scherer	4	Monroe, GA	BIT	BIT	No	RR	No	Jan-09	Jun-09	Unknown	680,368	(10)	(15)	OT
SJRPP	2	Duval County	BIT	BIT	Pet	RR	WA	Jan-09	Jun-09	Unknown	135,918	2	(3)	OT
SJRPP	1	Duval County	BIT	BIT	Pet	RR	WA	Jan-09	Jun-09	Unknown	135,918	2	(3)	OT
Space Coast Next Generating Solar Energy Center (PV)	1	Brevard County	PV											P
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	Jan-09	Jun-09	Unknown	402,050	(4)	(4)	OT
Turkey Point	5	Miami Dade County	CC	NG	No	PL	No	Jan-09	Jun-09	Unknown	1,224,510	(71)	11	OT
West County Combined Cycle	1	Palm Beach County	CC	NG	FO2	PL	PL	Jan-07	Aug-09	Unknown	Unknown	---	1,219	V
								2009 Changes/Additions w/o Inactive Reserve Total:				(78)	870	
Cutler	5	Miami Dade County	ST	NG	No	PL	No	---	—	—	75,000	—	(84)	OT
Cutler	6	Miami Dade County	ST	NG	No	PL	No	---	—	—	181,500	—	(137)	OT
Sanford	3	Volusia County	ST	FO6	NG	WA	PL	---	—	—	156,250	—	(139)	OT
Port Everglades	1	City of Hollywood	ST	FO6	NG	WA	PL	---	—	—	247,775	—	(213)	OT
Port Everglades	2	City of Hollywood	ST	FO6	NG	WA	PL	---	---	—	247,775	—	(213)	OT
								2009 Changes/Additions with Inactive Reserve Total:				(78)	(96)	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring later in the year will be picked up for reporting/planning purposes in the following year.

Note 2: Changes shown may include different ratings than shown in Schedule 1 due solely to ambient temperature consistent with those in FPL 's peak load forecast to maintain consistency in reserve margin calculations.

Note 3: The Photovoltaic MWs are not included in the total at this time because these facilities are assumed to provide non-firm energy only.

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2010														
Cape Canaveral	1	Brevard County	ST	FO6	NG	WA	PL		May-10	Unknown	402,050	---	(395)	
Cape Canaveral	2	Brevard County	ST	FO6	NG	WA	PL		May-10	Unknown	402,050	—	(388)	
DeSoto Next Generating Solar Energy Center (PV)	1	DeSoto County	PV											P
Lauderdale	4	Broward County	CC	NG	FO2	PL	PL	Jan-10	Jun-10	Unknown	526,250	1	1	OT
Manatee	1	Manatee County	ST	FO6	NG	WA	PL	Jan-10	Jun-10	Unknown	863,300	15	11	OT
Martin	3	Martin County	CC	NG	No	PL	No	Jan-10	Jun-10	Unknown	612,000	14	13	OT
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Jan-10	Jun-09	Unknown	310,420	(277)	---	OT
Riviera	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Jan-10	Jun-09	Unknown	310,420	(288)	--	OT
Sanford	4	Volusia County	CC	NG	No	PL	No	Jan-10	Jun-10	Unknown	1,188,860	5	5	OT
Scherer	4	Monroe, GA	BIT	BIT	No	RR	No	Jan-10	Jun-10	Unknown	680,368	4	4	OT
SJRPP	2	Duval County	BIT	BIT	Pet	RR	WA	Jan-10	Jun-10	Unknown	135,918	(2)	(2)	OT
Space Coast Next Generating Solar Energy Center (PV)	1	Brevard County	PV											P
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	Jan-10	Jun-10	Unknown	402,050	4	4	OT
West County Combined Cycle	1	Palm Beach County	CC	NG	FO2	PL	PL	Jan-07	Aug-09	Unknown	Unknown	1,335	--	V
West County Combined Cycle	2	Palm Beach County	CC	NG	FO2	PL	PL	Jan-08	Dec-09	Unknown	Unknown	1,335	1,219	V
								2010 Changes/Additions w/o Inactive Reserve Total:				2,146	472	
Martin	2	Martin County	ST	FO6	NG	PL	PL	--	—	--	934,500	—	(826)	OT
Manatee	2	Manatee County	ST	FO6	NG	WA	PL	--	—	—	863,300	—	(822)	OT
Cutler	5	Miami Dade County	ST	NG	No	PL	No	--	—	--	75,000	(69)	—	OT
Cutler	6	Miami Dade County	ST	NG	No	PL	No	—	—	—	161,500	(139)	--	OT
Sanford	3	Volusia County	ST	FO6	NG	WA	PL	—	--	—	156,250	(141)	--	OT
Port Everglades	1	City of Hollywood	ST	FO6	NG	WA	PL	---	--	--	247,775	(214)	---	OT
Port Everglades	2	City of Hollywood	ST	FO6	NG	WA	PL	—	---	—	247,775	(214)	—	OT
								2010 Changes/Additions with Inactive Reserve Total:				1,369	(1,178)	
2011														
Cape Canaveral	1	Brevard County	ST	FO6	NG	WA	PL	Jan-11	Jun-11	Unknown	402,050	(397)	---	OT
Cape Canaveral	2	Brevard County	ST	FO6	NG	WA	PL	Jan-11	Jun-11	Unknown	402,050	(397)	--	OT
Fort Myers	2	Lee County	CC	NG	No	PL	No	Jan-11	Jun-11	Unknown	1,775,390	(22)	(22)	OT
Fort Myers	3	Lee County	CT	NG	FO2	PL	PL	Jan-11	Jun-11	Unknown	378,380	(3)	(2)	OT
Lauderdale	4	Broward County	CC	NG	FO2	PL	PL	Jan-11	Jun-11	Unknown	526,250	(5)	(9)	OT
Lauderdale	5	Broward County	CC	NG	FO2	PL	PL	Jan-11	Jun-11	Unknown	526,250	(1)	(5)	OT
Manatee	1	Manatee County	ST	FO6	NG	WA	PL	Jan-11	Jun-11	Unknown	863,300	(9)	(8)	OT
Manatee	2	Manatee County	ST	FO6	NG	WA	PL	Jan-11	Jun-11	Unknown	863,300	(9)	(8)	OT
Manatee	3	Manatee County	CC	NG	No	PL	No	Jan-11	Jun-11	Unknown	1,224,510	85	(16)	OT
Martin	1	Martin County	ST	FO6	NG	PL	PL	Jan-11	Jun-11	Unknown	934,500	(5)	(4)	OT
Martin	2	Martin County	ST	FO6	NG	PL	PL	Jan-11	Jun-11	Unknown	934,500	(5)	(4)	OT
Martin	3	Martin County	CC	NG	No	PL	No	Jan-11	Jun-11	Unknown	612,000	6	23	OT
Martin	4	Martin County	CC	NG	No	PL	No	Jan-11	Jun-11	Unknown	612,000	6	11	OT
Martin	5	Martin County	CC	NG	FO2	PL	PL	Jan-11	Jun-11	Unknown	1,224,510	(10)	(9)	OT
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	Jan-11	Jun-11	Unknown	402,050	(6)	(6)	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	Jan-11	Jun-11	Unknown	402,050	(5)	(5)	OT
Putnam	1	Putnam County	CC	NG	FO2	PL	WA	Jan-11	Jun-11	Unknown	290,004	12	--	OT
Putnam	2	Putnam County	CC	NG	FO2	PL	WA	Jan-11	Jun-11	Unknown	290,004	11	(1)	OT
Sanford	4	Volusia County	CC	NG	No	PL	No	Jan-11	Jun-11	Unknown	1,188,860	14	(10)	OT
Sanford	5	Volusia County	CC	NG	No	PL	No	Jan-11	Jun-11	Unknown	1,188,860	19	(5)	OT
SJRPP	1	Duval County	BIT	BIT	Pet	RR	WA	Jan-11	Jun-11	Unknown	135,918	(2)	(2)	OT
Turkey Point	5	Miami Dade County	CC	NG	No	PL	No	Jan-11	Jun-11	Unknown	1,224,510	71	(11)	OT
West County Combined Cycle	3	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	Unknown	--	1219	T
								2011 Changes/Additions w/o Inactive Reserve Total:				(668)	1,125	
Martin	2	Martin County	ST	FO6	NG	PL	PL	--	—	---	934,500	(834)	--	OT
Manatee	2	Manatee County	ST	FO6	NG	WA	PL	--	--	---	863,300	(825)	—	OT
								2011 Changes/Additions with Inactive Reserve Total:				(2,327)	1,125	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring later in the year will be picked up for reporting/planning purposes in the following year.

Note 2: Changes shown may include different ratings than shown in Schedule 1 due solely to ambient temperature consistent with those in FPL 's peak load forecast to maintain consistency in reserve margin calculations.

Note 3: The Photovoltaic MWs are not included in the total at this time because these facilities are assumed to provide non-firm energy only.

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2012														
Scherer	4	Monroe, GA	BIT	BIT	No	RR	No	Jan-12	Jun-12	Unknown	680,368	(11)	(11)	OT
St. Lucie Uprates	1	St. Lucie County	NP	UR	No	TK	No	See Note 3	Dec-11	Unknown	850,000	103	103	T
St. Lucie Uprates	2	St. Lucie County	NP	UR	No	TK	No	See Note 3	Jun-12	Unknown	723,775	—	88	T
Turkey Point Uprates	3	Miami Dade County	NP	UR	No	TK	No	See Note 3	May-12	Unknown	759,900	—	104	T
West County Combined Cycle	3	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	Unknown	1,335	—	T
											2012 Changes/Additions w/o Inactive Reserve Total:	1,427	284	
												—	—	
											2012 Changes/Additions with Inactive Reserve Total:	1,427	284	
2013														
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	PL	Jun-11	Jun-13	Unknown	Unknown	---	1,219	T
St Lucie Uprates	2	St. Lucie County	NP	UR	No	TK	No	See Note 3	Jun-12	Unknown	723,775	88	---	T
Turkey Point Uprates	3	Miami Dade County	NP	UR	No	TK	No	See Note 3	May-12	Unknown	759,900	104	---	T
Turkey Point Uprates	4	Miami Dade County	NP	UR	No	TK	No	See Note 3	Dec-12	Unknown	759,900	104	104	T
											2013 Changes/Additions w/o Inactive Reserve Total:	296	1,323	
												—	—	
											2013 Changes/Additions with Inactive Reserve Total:	296	1,323	
2014														
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	PL	Jun-11	Jun-13	Unknown	Unknown	1,343	—	T
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	PL	PL	Jun-12	Jun-14	Unknown	Unknown	---	1,207	T
											2014 Changes/Additions w/o Inactive Reserve Total:	1,343	1,207	
												—	—	
											2014 Changes/Additions with Inactive Reserve Total:	1,343	1,207	
2015														
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	PL	PL	Jun-12	Jun-14	Unknown	Unknown	1,310	—	T
											2015 Changes/Additions w/o Inactive Reserve Total:	1,310	0	
												—	—	
											2015 Changes/Additions with Inactive Reserve Total:	1,310	0	
2016														
												---	—	
											2016 Changes/Additions w/o Inactive Reserve Total:	—	---	
Manatee	2	Manatee County	ST	FO6	NG	WA	PL		Jun-16	Unknown	863,300	---	814	OT
											2016 Changes/Additions with Inactive Reserve Total:	0	814	
2017														
												—	—	
											2017 Changes/Additions w/o Inactive Reserve Total:	—	—	
Manatee	2	Manatee County	ST	FO6	NG	WA	PL		Jun-16	Unknown	863,300	825		OT
Martin	2	Martin County	ST	FO6	NG	PL	PL		Jun-17	Unknown	934,500	—	822	OT
											2017 Changes/Additions w/o Inactive Reserve Total:	825	822	
2018														
Turkey Point Nuclear Unit	6	Miami Dade County	NP	UR	No	TK	No	Jan-11	Jun-18	Unknown	Unknown	—	1,100	T
											2018 Changes/Additions w/o Inactive Reserve Total:	0	1,100	
Martin	2	Martin County	ST	FO6	NG	PL	PL			Jun-17	934,500	834	—	OT
											2018 Changes/Additions with Inactive Reserve Total:	834	1,100	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring later in the year will be picked up for reporting/planning purposes in the following year.

Note 2: Changes shown may include different ratings than shown in Schedule 1 due solely to ambient temperature consistent with those in FPL 's peak load forecast to maintain consistency in reserve margin calculations.

Note 3: The nuclear uprates will be performed during the scheduled refueling outages for each unit.

Note 4. Certain existing FPL units that have been placed on temporarily on Inactive Reserve status are assumed, for planning purposes in this document, to being returning to active reserve starting in 2016.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit 1

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2007
b. Commercial In-service date: 2009

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** V (Under construction, more than 50% complete)

(10) **Certification Status:** V (Under construction, more than 50% complete)

(11) **Status with Federal Agencies:** V (Under construction, more than 50% complete)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2009 $/kW):	565	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	55	
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2009 $kW-Yr)	11.65	
Variable O&M ($/MWH): (2009 $/MWH)	0.138	
K Factor:	1.5834	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit 2

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2008
b. Commercial In-service date: 2009

(5) **Fuel**
a. Primary Fuel — Natural Gas
b. Alternate Fuel — Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** V (Under construction, more than 50% complete)

(10) **Certification Status:** V (Under construction, more than 50% complete)

(11) **Status with Federal Agencies:** V (Under construction, more than 50% complete)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 88%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582 Btu/kWh	(Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data **,*****

Book Life (Years):	25 years
Total Installed Cost (2010 $/kW):	519
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	57
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2010 $kW-Yr)	10.11
Variable O&M ($/MWH): (2010 $/MWH)	0.138
K Factor:	1.5873

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** DeSoto Next Generation Solar Energy Center

(2) **Capacity**
a. Summer 25 MW
b. Winter 25 MW

(3) **Technology Type:** Photovoltaic

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2009
b. Commercial In-service date: 2010

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel N/A

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** N/A

(8) **Total Site Area:** 180 Acres

(9) **Construction Status:** U (Under construction, less than 50% complete)

(10) **Certification Status:** Pemitted (Individual Permits)

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	N/A
Forced Outage Factor (FOF):	N/A
Equivalent Availability Factor (EAF):	0.98
Resulting Capacity Factor (%):	Approx. 25% (First Full Year of Operation)
Average Net Operating Heat Rate (ANOHR):	N/A Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25 years
Total Installed Cost (2010 $/kW):	6,937
Direct Construction Cost ($/kW):	-
CWIP Amount ($/kW):	369
Escalation ($/kW):	-
Fixed O&M ($/kW -Yr.): (2010 $kW-Yr)	54
Variable O&M ($/MWH): (2010 $/MWH)	0
K Factor:	1.15

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes transmission interconnection.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Space Coast Next Generation Energy Center

(2) **Capacity**
a. Summer 10 MW
b. Winter 10 MW

(3) **Technology Type:** Photovoltaic

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2009
b. Commercial In-service date: 2010

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel N/A

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** N/A

(8) **Total Site Area:** 60 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned- Individual Permits)

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	N/A
Forced Outage Factor (FOF):	N/A
Equivalent Availability Factor (EAF):	0.98
Resulting Capacity Factor (%):	Approx. 21.3% (First Full Year of Operation)
Average Net Operating Heat Rate (ANOHR):	N/A Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25 years
Total Installed Cost (2010 $/kW):	7,890
Direct Construction Cost ($/kW):	-
CWIP Amount ($/kW):	427.7
Escalation ($/kW):	-
Fixed O&M ($/kW -Yr.): (2010 $kW-Yr)	54
Variable O&M ($/MWH): (2010 $/MWH)	0
K Factor:	1.2100

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes transmission interconnection.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit 3

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2009
b. Commercial In-service date: 2011

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 93%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data **,*****

Book Life (Years):	25	years
Total Installed Cost (2011 $/kW):	709	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	71	
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2011 $kW-Yr)	11.63	
Variable O&M ($/MWH): (2011 $/MWH)	0.480	
K Factor:	1.4697	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** St. Lucie 1 Nuclear Uprate

(2) **Capacity**
a. Summer 103 MW (Incremental)
b. Winter 103 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2011

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data** *

Book Life (Years):	25	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	3,054	(See Note (1) for explanation.)
Direct Construction Cost:	3,054	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) This value does not include a plant-specific portion of the early recovery of approx. $353 million of capital carrying costs in total associated with the uprates at the four existing nuclear units, nor a plant-specific portion of a projected $45 million in total for transmission costs associated with the uprates at the four existing nuclear units.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point 3 Nuclear Uprate

(2) **Capacity**
a. Summer 104 MW (Incremental)
b. Winter 104 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data** *

Book Life (Years):	20	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	3,580	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	3,580	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) This value does not include a plant-specific portion of the early recovery of approx. $353 million of capital carrying costs in total associated with the uprates at the four existing nuclear units, nor a plant-specific portion of a projected $45 million in total for transmission costs associated with the uprates at the four existing nuclear units.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** St. Lucie 2 Nuclear Uprate

(2) **Capacity**
a. Summer 103 MW (Total Incremental), 88 MW (incremental FPL's ownership share)
b. Winter 104 MW (Total Incremental), 88 MW (incremental FPL's ownership share)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel --

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): No change from existing unit
Forced Outage Factor (FOF): No change from existing unit
Equivalent Availability Factor (EAF): No change from existing unit
Resulting Capacity Factor (%): No change from existing unit
Average Net Operating Heat Rate (ANOHR): No change from existing unit
Base Operation 75F,100% No change from existing unit

(13) **Projected Unit Financial Data *,****
Book Life (Years): 31 years (Matches the current operating license period.)
Total Installed Cost ($/kW): ** 3,271 (See Note (1) for explanation.)
Direct Construction Cost ($/kW): 3,271 (See Note (1) for explanation.)
AFUDC Amount ($/kW): (See Note (2) for explanation.)
Escalation ($/kW): (See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.): There is no additional O&M impact from this project.
Variable O&M ($/MWH): There is no additional O&M impact from this project.
K Factor: (See Note (2) for explanation.)

NOTE:
(1) This value does not include a plant-specific portion of the early recovery of approx. $353 million of capital carrying costs in total associated with the uprates at the four existing nuclear units, nor a plant-specific portion of a projected $45 million in total for transmission costs associated with the uprates at the four existing nuclear units.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point 4 Nuclear Uprate

(2) **Capacity**
a. Summer 104 MW (Incremental)
b. Winter 104 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data *,****

Book Life (Years):	22	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	3,630	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	3,630	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) This value does not include a plant-specific portion of the early recovery of approx. $353 million of capital carrying costs in total associated with the uprates at the four existing nuclear units, nor a plant-specific portion of a projected $45 million in total for transmission costs associated with the uprates at the four existing nuclear units.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Cape Canaveral Next Generation Clean Energy Center
(2)	**Capacity**		
	a. Summer	1,219 MW	
	b. Winter	1,343 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2011	
	b. Commercial In-service date:	2013	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Ultra-low sulfur distillate
(6)	**Air Pollution and Control Strategy:**		Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate
(7)	**Cooling Method:**		Once-through cooling water
(8)	**Total Site Area:**	43	Acres
(9)	**Construction Status:**	T	(Regulatory approval received, but not under construction)
(10)	**Certification Status:**	T	(Regulatory approval received, but not under construction)
(11)	**Status with Federal Agencies:**	T	(Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	
Resulting Capacity Factor (%):	Approx.90 %	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,580	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2013 $/kW):	915	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	98	
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2013 $kW-Yr)	14.81	
Variable O&M ($/MWH): (2013 $/MWH)	0.15	
K Factor:	1.494	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Riviera Beach Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,207 MW
b. Winter 1,310 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2012
b. Commercial In-service date: 2014

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 33 Acres

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,576	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (2014 $/kW):	1,057	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	122	
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2014 $kW-Yr)	15.32	
Variable O&M ($/MWH): (2014 $/MWH)	0.12	
K Factor:	1.494	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point Unit 6 Nuclear Unit

(2) **Capacity**
a. Summer 1,100 MW
b. Winter 1,100 MW

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2011
b. Commercial In-service date: 2018

(5) **Fuel**
a. Primary Fuel uranium dioxide
b. Alternate Fuel NA

(6) **Air Pollution and Control Strategy:** NA

(7) **Cooling Method:** Mechanical Draft Cooling Towers

(8) **Total Site Area:** 211 Acres

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	TBD	
Forced Outage Factor (FOF):	TBD	
Equivalent Availability Factor (EAF):	TBD	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	TBD	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	TBD	years
Total Installed Cost ($/kW):	TBD	
Direct Construction Cost ($/kW):	TBD	
AFUDC Amount ($/kW):	TBD	
Escalation ($/kW):	TBD	
Fixed O&M ($/kW -Yr.): ($kW-Yr)	TBD	
Variable O&M ($/MWH): ($/MWH)	TBD	
K Factor:		

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

West County Energy Center Unit 1

The new West County Energy Center Unit 1 does not require any "new" transmission lines.

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

West County Energy Center Unit 2

The new West County Energy Center Unit 2 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Desoto Next Generation Solar Energy Center (PV)

The new Desoto Next Generation Solar Energy Center (PV) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Space Center Next Generation Solar Energy Center (PV)

The new Space Center Next Generation Solar Energy Center (PV) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

West County Energy Center Unit 3

(1)	Point of Origin and Termination:	New Sugar Substation – Corbett Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	1 mile
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: May 2009 End date: November 2010
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$11,300,000
(8)	Substations:	New Sugar Substation and Corbett Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

St. Lucie 1 Nuclear Uprate

The St. Lucie 1 Nuclear Uprate does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point 3 Nuclear Uprate

The Turkey Point 3 Nuclear Uprate does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

St. Lucie 2 Nuclear Uprate

The St. Lucie 2 Nuclear Uprate does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point 4 Nuclear Uprate

The Turkey Point 4 Nuclear Uprate does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Cape Canaveral Next Generation Clean Energy Center (Conversion)

The Cape Canaveral Next Generation Clean Energy Center, that is the result of the conversion of the exiting Cape Canaveral power plant site, does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Riviera Beach Next Generation Clean Energy Center (Conversion)

The Riviera Beach Energy Center Conversion, that is the result of the conversion of the existing Riviera Beach power plant site, does not require any "new" transmission lines. Several lines will be extended and reconfigured to accommodate the increased capacity.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Unit 6

(1)	Point of Origin and Termination:	New Clear Sky Substation – Levee Substation
(2)	Number of Lines:	2
(3)	Right-of-way	FPL Owned
(4)	Line Length:	43 miles
(5)	Voltage:	500 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Levee Substation
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	New Clear Sky Substation – Pennsuco Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	52 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Pennsuco Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Unit 6

(1)	Point of Origin and Termination:	New Clear Sky Substation – Davis Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	19 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Davis Substation
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	Davis Substation – Miami Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	18 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$ TBD
(8)	Substations:	Davis Substation and Miami Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Unit 6

(1)	Point of Origin and Termination:	New Clear Sky Substation – Turkey Point Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	0.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Turkey Point Substation
(9)	Participation with Other Utilities:	None

Existing FIRM and NON-FIRM Capacity and Energy by Primary Fuel Type
Actuals for the Year 2008

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	**Summer (MW)**	**Summer (%)**	**Winter (MW)**	**Winter (%)**	**GWH**	**%**
(1)	Coal	900	3.6%	902	3.4%	6,423	5.8%
(2)	Nuclear	2,939	11.7%	3,013	11.4%	24,024	21.6%
(3)	Residual	6,764	27.0%	6,818	25.8%	5,702	5.1%
(4)	Distillate	660	2.6%	781	3.0%	17	0.0%
(5)	Natural Gas	10,824	43.2%	11,844	44.9%	58,820	53.0%
(6)	***FPL Existing Units Total (1):***	***22,087***	***88.1%***	***23,358***	***88.5%***	***94,986***	***85.6%***
(7)	Renewables (Purchases)- Firm	157.6	0.6%	157.6	0.6%	1,262	1.1%
(8)	Renewables (Purchases)- Non-Firm	Not Applicable		Not Applicable		365	0.3%
(9)	***Renewable Total:***	***157.6***	***0.6%***	***157.6***	***0.6%***	***1,627***	***1.47%***
(10)	***Purchases Other:***	***2,834.0***	11.3%	***2,868.0***	10.9%	***14,391***	13.0%
(11)	***Total (2):***	***25,078.6***	***100.0%***	***26,383.6***	***100.0%***	***111,004***	***100.0%***

Note:
(1) FPL Existing Units Total of 22,087 MW matches Total System found on Schedule 1.
(2) Net Energy for Load GWH of 111,004 GWH matches Schedule 6.1

Schedule 11.2

Existing NON-FIRM Self-Service Renewable Generation Facilities
Actuals for the Year 2008

(1)	(2)	(3)	(4)	(5)	(6) = (3+4)-(5)
Type of Facility	**Installed Capacity (MW)**	**Projected Annual Output (MWH)**	**Annual Energy Purchased from FPL (MWH)**	**Annual Energy Sold to FPL (MWH)**	**Projected Annual Energy Used by Customer (MWH)**
Customer-Owned PV (less than or equal to 10 kw AC)	0.839	900	33,220	153	33,967
Customer-Owned PV greater than 10 kw and less than or equal to 100 kw AC	0.233	192	558	15	735
Total:	**1.072**	**1,092**	**33,777**	**167**	**34,702**

Notes:

(1) There were approximately 262 customer-owned operating PV facilities interconnected with FPL during 2008.
(2) The Installed Capacity value is the sum of the nameplate ratings (AC kw) for all of the customer-owned PV facilities.
(3) The Projected Annual Output value is based on NREL's PV Watts program and the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.
(4) The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2008.
(5) The Annual Energy Sold to FPL is an actual value from FPL's metered data for 2008.
(6) The Projected Annual Energy Used by Customers is a projected value that is the difference between the (Projected Annual output + Annual Output value in column (2) and the actual Annual Energy Sold to FPL in column (4).

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered or threatened plant and animal species. FPL competes for air, land, and water resources that are necessary to meet the demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

FPL has been recognized for many years as one of the leaders among electric utilities for its commitment to the environment. FPL's environmental leadership has been heralded by many outside organizations as demonstrated by a few recent examples. For the second time (2007 and 2008), FPL Group is ranked first among electric and gas utilities in FORTUNE ® magazine's, "America's Most Admired Companies" edition. FPL scored number one in each of the eight attributes considered: innovation, people management, use of corporate assets, social responsibility, quality of management, financial soundness, long-term investments, and quality of products and services.

In May 2007, FPL Group was included on the KLD Global Climate 100SM Index for the third time since the Global Climate 100 was launched in 2005. The Global Climate 100 is designed to promote investment in public companies whose activities demonstrate the greatest potential for reducing the social and economic consequences of climate change. The Global Climate 100 Index includes a mix of 100 global companies that demonstrate leadership in providing near term solutions to climate change through renewable energy, alternative fuels, clean technology, and efficiency.

In January 2007, FPL Group was named one of the Global 100 Most Sustainable Corporations in the World by Corporate Knights, Inc., a Canadian media company. Some 1,800 companies from a wide range of sectors were evaluated regarding effective management of environmental, social, and governance risks and opportunities. FPL Group was one of the only two United States utility companies to make the list of 100.

FPL Group is one of America's cleanest energy providers and the emissions rates of FPL's power plants are among the lowest in the electric industry. FPL's environmental achievements were reflected by its No. 1 environmental ranking, for five consecutive years, in the Innovest Strategic Value Advisor's report that compares the environmental performance of 26 United States electric utilities. Innovest is an internationally recognized independent investment research firm specializing in environmental finance and investment opportunities.

In June 2007, FPL's Green (Vehicle) Fleet Program was named the winner of the 2007 Council for Sustainable Florida Large Business Best Practice Award for FPL's commitment to reducing fuel consumption in utilities' vehicle fleets. FPL received the award from the Council for Sustainable Florida, which honors businesses, organizations, and individuals whose work demonstrates that a healthy environment and healthy economy are mutually supportive. Since 1990, the Council has been committed to promoting and recognizing best sustainability practices in Florida.

For the third time, FPL Group was one of only four corporations in the North America Electric Power sector named in the "Climate Leadership Index," an honor roll of global corporations addressing the challenges of climate change.

In 2006, FPL and the Palm Beach County-based Arthur R. Marshall Foundation joined as "partners for the environment." FPL's support included a $25,000 donation to the non-profit organization for educational and restoration programs, including the planting of native Florida wetland trees. In 2007, FPL volunteers returned to help take care of the growing saplings.

FPL has also been the recipient of earlier environmental awards and recognition. In 2001, FPL was awarded Edison Electric Institute's National Land Management Award for its stewardship of 25,000 acres surrounding its Turkey Point Plant. In 2001, FPL was awarded the 2001 Waste Reduction and Pollution Prevention Award from the Solid Waste Association of North America. FPL received the 2001 Program Champion Award from the Environmental Protection Agency's Wastewise Program. The Florida Department of Environmental Protection named FPL a "Partner for Ecosystem Protection" in 2001 for its emission-reducing "repowering" projects at its Fort Myers and Sanford Plants. FPL won the Council for Sustainable Florida's award in 2002 for its sea turtle conservation and education programs at its St. Lucie Plant. Finally, FPL has been recognized by numerous federal and state agencies for its innovative endangered species protection programs which include such species as manatees, crocodiles, and sea turtles.

As mentioned above, FPL Group has taken a leadership role to address climate change and the call for action for a national climate change policy. The decision to step into the forefront of this issue goes hand-in-hand with FPL Group's longtime commitment to managing operations with sensitivity to the environment.

FPL is taking action now in Florida to address climate change with a number of actions. According to the U.S. Department of Energy (DOE) data, FPL is one of the nation's leaders among electric utilities for its energy efficiency/conservation and load management achievement. FPL's nationally recognized leadership in the implementation of demand side management (DSM) within its system has avoided the need to build the equivalent of more than 12 medium-sized power plants as discussed in Chapters I and III of this document. Also discussed in Chapter III are FPL's plans for adding a significant amount of renewable energy resources. FPL is the nation's leader in power plant "repowerings" and "conversions," significantly increasing the efficiency of a number of its existing power plants while reducing FPL system emissions. Currently, two of FPL's older power plants are slated for conversion to state-of-the-art CC natural gas plants. In addition, FPL's future generation plans include nuclear uprates and two new nuclear units that are projected to significantly reduce air emissions in Florida.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Commitment in 1992 to clearly define its position. This statement reflects how FPL incorporates environmental values into all aspects of its activities and serves as a framework for new environmental initiatives throughout the company. FPL's Environmental Statement is:

> It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:
>
> - Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
> - Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
> - Encourage the wise use of energy to minimize the impact on the environment.
> - Communicate effectively on environmental issues.

- Conduct periodic self-evaluations, report performance, and take appropriate actions.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an environmental management system to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program that is discussed below. Other components include: executive management support and commitment, a dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to evaluate environmental performance, verify compliance with corporate policy as well as with legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and FPL policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2008 environmental outreach activities are noted in Table IV.E.1.

Table IV.E.1: 2008 FPL Environmental Outreach Activities

Activity	# of Participants
Visitors to FPL's Energy Encounter at St. Lucie	20,000
Visitors to Manatee Park	150,000
Number of visits to FPL's Environmental Website	358,000
Number of pieces of Environmental literature distributed	>80,000

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified eight Preferred Sites and four Potential Sites for future generation additions. Preferred Sites are those locations where FPL has conducted significant reviews and has either taken action, or is planning to take action, to site new generation capacity. Potential Sites are those sites that have attributes that support the siting of generation and are under consideration as a location for future generation. Some of these sites are currently in use as existing generation sites and some are not. The identification of a Potential Site does not indicate that FPL has made a definitive decision to pursue generation (or generation expansion in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of a generator has been determined. The Preferred Sites and Potential Sites are discussed in separate sections below.

As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other Greenfield sites.

IV.F.1 Preferred Sites

FPL identifies eight Preferred Sites in this Site Plan: the West County Energy Center (WCEC) adjacent to the existing Corbett FPL substation, the existing St. Lucie plant site, the existing Turkey Point plant site, the existing Cape Canaveral plant site, the existing Riviera plant site, and three locations for new solar power generation: DeSoto County, Brevard County, and the existing Martin plant site.

The West County Energy Center site is the location for three CC capacity additions FPL will make in 2009 through 2011. The St. Lucie site is the location for nuclear capacity uprates that FPL will make in 2011 and 2012. The St. Lucie site is also the location for a proposed wind generation addition. The Turkey Point site is the location for nuclear capacity uprates that FPL will make in 2011 and 2012 and is the site for two new nuclear units, Turkey Point Units 6 & 7, that are projected to be added in 2018 and 2020, respectively. The existing Cape Canaveral and Riviera plant sites are being proposed for conversion of the two existing steam generating units at each site into one state-of-the-art CC unit at each site in 2013 and 2014, respectively. The three solar projects (DeSoto County, Brevard County, and Martin County) are being proposed for operation in 2009, 2010, and 2010, respectively.

The eight Preferred Sites are discussed below.

Preferred Site # 1: West County Energy Center , Palm Beach County

FPL has identified the property adjacent to the existing Corbett Substation property in unincorporated western Palm Beach County as a Preferred Site for the addition of new generating capacity. The site was selected for the addition of three new CC natural gas power plants with ultra-low sulfur light fuel oil (distillate) as a backup fuel. WCEC Units 1 & 2 have been approved by both the FPSC and the Governor and Cabinet acting as the Siting Board. WCEC Unit 3 has been approved by both the FPSC and the Secretary of the FDEP in lieu of the Governor and Cabinet. The units are scheduled to come in-service in 2009 through 2011, respectively. All three CC units will be identical in regard to technology and capacity.

The existing site is accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections. The facility will use natural gas as the primary fuel and state-of-the-art combustion controls.

a. U.S. Geological Survey (USGS) Map

A USGS map of the West County Energy Center (WCEC) plant site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the WCEC generating facilities at the site is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

The site was inactive until February 2007 when construction of WCEC Units 1 & 2 was initiated. The site was previously dedicated to industrial (mining) and agricultural use. The site had been excavated, back-filled, and totally re-graded to an elevation of approximately 10 feet above the surrounding land surface. Prior to initiation of power plant construction, no structures were present on the site and vegetation was virtually non-existent. Structures are now being built on the site for work associated with WCEC Units 1 & 2. Construction of WCEC Unit 3 is scheduled to begin in 2009.

e. **General Environment Features On and In the Site Vicinity**

1. **Natural Environment**

The plant site had been significantly altered by the construction and operation of a limestone mine where vegetation had been cleared and removed. The surrounding land use is predominantly sugar cane, agriculture, and limestone mining. FPL's existing Corbett substation is located north of the site. The Arthur R. Marshall Loxahatchee National Wildlife Refuge is located to the south of the site.

2. **Listed Species**

Construction and operation of new units at the site is not expected to affect any rare, endangered, or threatened species. Wildlife utilization of the property is minimal as a result of the prior mining activities. Common wading birds can be observed on areas adjacent to, and occasionally within, the property. The property is adjacent to areas that have been identified as potential habitat for wood stork.

3. **Natural Resources of Regional Significance Status**

The construction and operation of a gas-fired CC generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands including the Arthur R. Marshall Loxahatchee National Wildlife Refuge. Construction will not result in any onsite wetland impacts under federal, state, or local agency permitting criteria.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design of each of the three units is comprised of the following: new 1,219 MW (Summer capacity) unit with each unit consisting of three new combustion turbines (CT) and three new heat recovery steam generators (HRSG) and a new steam turbine. Natural gas delivered via pipeline is the primary fuel type for this facility with ultra-low sulfur light fuel oil (distillate) serving as a backup fuel.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the project site is "Rural Residential" according to the Palm Beach County Future Land Use Map. Designations for the area under the Palm Beach County Unified Land Development Code classified the project site and surrounding area as Special Agricultural District. The site has been granted conditional use for electrical power facilities under a General Industrial zoning district.

h. **Site Selection Criteria Process**

The site has been selected as a Preferred Site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues.

i. **Water Resources**

In regard to WCEC Units 1 & 2, water from the Floridan Aquifer and surface water from the L10/L12 canal (when available) will be used for cooling, service, and process water. Potable water will be purchased from the Palm Beach County water municipality.

In regard to WCEC Unit 3, the primary water source for the project will be reclaimed (reuse) water that will come from Palm Beach County Water Utilities Department. FPL will obtain the necessary approvals to also supply WCEC Units 1 & 2 using reclaimed water once WCEC Unit 3 is operational. Reclaimed water will be used for cooling, service, and process water. Backup water sources include utilizing the Floridan Aquifer allocation permitted for WCEC Units 1 & 2, potable water from Palm Beach County, and the L10/L12 canal when made available by the South Florida

Water Management District (SFWMD). Potable water will be purchased from the Palm Beach County water municipality.

j. Geological Features of Site and Adjacent Areas

The site is underlain by approximately 13,000 feet of sedimentary rock strata. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine in origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, clay, and phosphate grains. The deepest formation in Palm Beach County on which significant published data are available is the Eocene Age Avon Park. Limited information is available from wells penetrating the underlying Oldsmar formation. The published information on the sediments comprising the formations below the Avon Park Limestone is based on projections from deep wells in Okeechobee, St. Lucie, and Palm Beach counties.

Testing during construction of Exploratory Well 2 (EW-2) demonstrated the presence of a highly permeable zone (Boulder Zone) below a depth of 2,790 feet below pad level (bpl) overlain by a thick confining interval from approximately 2,000 to 2,790 feet bpl. The base of the Underground Source of Drinking Water (USDW) was identified between the depths of 1,932 and 1,959 feet bpl through interpretation of packer tests, water quality data, and geophysical logs. Injection testing has confirmed that the hydrogeology of the EW-2 site is favorable for disposal of fluids via a deep injection well system.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for industrial processing for all 3 units is approximately 675 gallons per minute (gpm) for uses such as process water and service water. Approximately 22.5 million gallons per day (mgd) of cooling water for the three generating units would be cycled through the cooling towers. Water quantities needed for other uses such as potable water are estimated to be approximately 35,000 gallons per day (gpd) for the entire WCEC site.

l. Water Supply Sources by Type

WCEC Units 1 & 2 will use available surface or ground water as the source of cooling water for the cooling towers. The cooling towers will also act as a heat sink for the facility auxiliary cooling system. Such needs for cooling and process water will comply with the existing SFWMD regulations for consumptive water use.

WCEC Unit 3 will use reclaimed water as the primary source of cooling water for the cooling tower. The cooling tower will also act as a heat sink for the facility auxiliary cooling system. Such needs for cooling and process water will comply with the existing SFWMD regulations for consumptive water use. In addition, reclaimed water used at WCEC must meet all relevant requirements of Chapter 62-610, F.A.C., Part III, for use in cooling towers.

It is anticipated that once WCEC Unit 3 is operational, reclaimed water will also become the primary cooling water source for WCEC Units 1 & 2.

m. Water Conservation Strategies Under Consideration

The use of reclaimed water is a water conservation strategy because it is a beneficial use of wastewater. Impacts on the surficial aquifer would be minimized and used only for potable water, if necessary. Water from the Floridan Aquifer or the L10/L12 canal will be used for cooling purposes as a backup water source and cooling towers will be utilized. In addition, captured stormwater may be reused in the cooling tower whenever feasible. Stormwater captured in the stormwater ponds will also recharge the surficial aquifer.

n. Water Discharges and Pollution Control

Heat will be dissipated in the cooling towers. Blowdown water from the cooling towers, along with other wastestreams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Storm water runoff will be collected and used to recharge the surficial aquifer via a storm water management system. Design elements will be included to capture suspended sediments. In addition, captured stormwater may be reused in the cooling towers, whenever feasible. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is serviced by a new natural gas transmission pipeline that is capable of providing a sufficient quantity of gas to the entire site. Ultra-low sulfur light fuel oil (distillate) would be received by truck and stored in above-ground storage tanks to serve as backup fuel for the WCEC generating units.

p. Air Emissions and Control Systems

The use of natural gas and ultra-low sulfur light fuel oil (distillate) and combustion controls will minimize air emissions from these units and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminants. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil (distillate) as backup fuel. These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of the WCEC generating units will incorporate features that will make them among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by construction at the site is expected to be below current noise levels for the residents nearest the site. Noise from the operation of the new units will be within allowable levels.

r. Status of Applications

In regard to WCEC Units 1 & 2, a Site Certification Application (SCA) for the construction and operation of the West County Energy Center project under the Florida Electrical Power Plant Siting Act was filed in April 2005 and received Site Certification by the Governor and Cabinet, acting as the Siting Board, in December 2006. The Florida Department of Environmental Protection (FDEP) issued an Underground Injection Control (UIC) Exploratory Well permit in January 2006 and another Exploratory Well Permit in December 2006. FDEP issued the Final UIC permit in May 2008. FDEP issued a Prevention of Significant Deterioration (PSD) air permit in January 2007. After acquiring these permits and authorizations, FPL initiated construction in February 2007 and anticipates an in-service date for WCEC Unit 1 of mid-2009 and Unit 2 by end of 2009.

In regard to WCEC Unit 3, an SCA was filed in December 2007 and received Site Certification by the Secretary of the FDEP, in lieu of the Governor and Cabinet, in November 2008. A Prevention of Significant Deterioration (PSD) air permit was filed in December 2007. The permit was issued by FDEP in July 2008. FPL proposes to initiate construction in 2009 and anticipates an in-service date of mid-2011. WCEC Unit 3 will utilize the UIC system permitted for the entire site.

Preferred Site # 2: St. Lucie Plant, St. Lucie County

FPL's St. Lucie Plant is located in St. Lucie County on Hutchinson Island on an FPL-owned 1,130-acre site. The plant site is bordered by the Atlantic Ocean to the east and the Indian River Lagoon to the west. Located on the site are two nuclear-powered generating units, St. Lucie Units 1 & 2, which have been in operation since 1976 and 1983, respectively. The St. Lucie site has been selected as a Preferred Site for the addition of two types of new generating capacity.

The first type of generating capacity addition is an increase in the capacity of the two existing nuclear generating units that is used to serve FPL's customers of approximately 103 MW for St. Lucie Unit 1 and 88 MW for St. Lucie Unit 2. This difference is due to FPL's 100% ownership share of St. Lucie 1 and its 85% ownership share of St. Lucie Unit 2. This work will involve changes to several existing main components within the existing facilities to increase their capability to produce steam for the generation of electricity. No new facilities are required as part of this capacity "uprate." This capacity uprate, along with a similar capacity uprate of FPL's existing Turkey Point nuclear units, was approved by the FPSC in January 2008. The capacity uprates at St. Lucie for the two nuclear units sited there are projected to be in-service in late 2011 and 2012.

The second type of generating capacity addition is the proposed installation of FPL wind generation turbines at the plant site. In 2007, FPL began the St. Lucie County land use approval process, and soon after applied for the necessary federal and state permitting. However, a decision by the state and federal agencies on the St. Lucie Wind project's permitting won't be finalized until the local land use approval process is completed. The in-service date will depend on the approval and permitting process. Six wind turbines are being proposed that, in total, would have a maximum output of approximately 13.8 MW.

a. U.S. Geological Survey (USGS) Map

A USGS map of the FPL St. Lucie Nuclear site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the proposed generating facilities at the site is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

St. Lucie Units 1 & 2 are pressurized water reactors, each having two steam generators. The prominent structures, enclosed facilities, and equipment associated with St. Lucie Units 1 & 2 include the containment building, the turbine generator building, the auxiliary building, and the fuel handling building.

Prominent features beyond the power block area include the intake and discharge canals, switchyard, spent-fuel storage facilities, technical and administrative support facilities, and public education facilities (the Energy Encounter and the College of Turtle Knowledge). Significant features surrounding the St. Lucie Units 1 & 2 are predominately undeveloped land and water bodies including; Big Mud Creek, the Atlantic Ocean, Herman's Bay, and Indian River Lagoon.

In regard to the nuclear capacity uprates, the only changes will be modifications to the existing power generation facilities within the power block area, modifications to the switchyard facilities, and modifications to the transmission lines from St. Lucie to Midway substation. None of the other existing facilities at the plant will change as a result of the uprates. No changes to the nuclear power generation facilities are projected as a result of the proposed wind turbine additions.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

FPL's St. Lucie Plant is located in St. Lucie County on Hutchinson Island on an FPL-owned 1,130-acre site. The St. Lucie Plant includes the reactor buildings, turbine buildings, access/security building, auxiliary building, maintenance facilities, and miscellaneous warehouses and other buildings associated with the operation of Units 1 & 2. The site includes adjacent undeveloped mangrove areas. As a result of the approved capacity uprates, the site characteristics will not change.

The proposed wind turbines are also located on the FPL-owned site. Impacts to the site characteristics are projected to be minimal from the proposed wind turbines.

2. Listed Species

Some listed species known to occur in the area of the plant location are atlantic sturgeon, smalltooth sawfish, loggerhead sea turtle (*Caretta caretta*), green sea turtle (*Chelonia mydas)*, leatherback sea turtle (*Dermochelys coriacea*), hawksbill sea turtle (*Eretmochelys imbriccata*), gopher tortoise (*Gopherus polyphemus*), kemp's ridley sea turtle (*Lepidochelys kempi*), wood stork (*Mycteria americana*), black skimmer (*Rynchops niger*), and least tern (*Sterna antillarum*).

In regard to the nuclear capacity uprates, neither the development work, nor the continued operation of the two nuclear units after the uprate work has been completed, are expected to adversely affect any rare, endangered, or threatened species. No changes in wildlife populations at the adjacent undeveloped areas are anticipated, including listed species. Noise and lighting impacts will not change and it is expected that wildlife will continue to use the undeveloped areas within the St. Lucie Plant boundary.

In regard to the wind turbines, some changes to the adjacent undeveloped areas are anticipated. Noise and lighting impacts will not change and the wind turbines are not anticipated to deter the continued use by wildlife of the undeveloped areas within the St. Lucie Plant boundary or any adjacent areas.

3. **Natural Resources of Regional Significance Status**

Significant features surrounding the St. Lucie Units 1 & 2 are predominately undeveloped land and water bodies including; Big Mud Creek, the Atlantic Ocean, Herman's Bay, and Indian River Lagoon.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. It is a once-through system. The effects of the discharge of cooling water via these discharge structures were evaluated and mixing zones were established to allow compliance with thermal water quality standards as a part of the Plant's NPDES (Permit No. FL0002208). These mixing zones include the volume of water beyond the discharge structures, at the edge of which the water temperature is no greater than 17°F above the ambient temperature of the intake water.

In regard to the nuclear capacity uprates, the once-through system will continue to be used for the nuclear units. In regard to the wind turbines, no water will be required.

g. **Local Government Future Land Use Designations**

St. Lucie Units 1 & 2 are located in unincorporated St. Lucie County, Florida. The County has adopted a comprehensive plan, which is updated on a periodic basis. The County Comprehensive Plan incorporates a map that depicts the future land use categories of all property falling within the unincorporated portions of the County. The St. Lucie Plant has a Future Land Use category of Transportation/Utilities (T/U) according to the St. Lucie County Future Land Use Map. The T/U category is described in the St. Lucie County Comprehensive Plan Future Land Use Element Future Land Use.

In regard to the wind turbines, FPL has submitted an application to St. Lucie County to rezone the land that would serve as the footprint of the turbines to the T/U category.

h. **Site Selection Criteria Process**

The site has been selected as a Preferred Site for the nuclear capacity uprates because it is an existing nuclear plant site and, therefore, offers the opportunity for increased nuclear capacity. The site has been selected as a Preferred Site for the wind turbines because of the available wind resource at that location.

i. Water Resources

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. The once-through system flow will not change as a result of the nuclear uprates. No water will be required to operate the wind turbines. Due to the existing nature of the St. Lucie Plant, surrounding surface waters will not be adversely affected by either of the generation capacity additions. Stormwater will be handled by the existing facilities and no new areas will be impacted. Wetlands, groundwater, and nearby surface waters will not be impacted.

j. Geological Features of Site and Adjacent Areas

Beneath the land surface, there is a peat layer 4 to 6 feet thick. Below this layer is the Anastasia Formation, a sedimentary rock formation composed of clay lenses, sandy limestone, and silty fine to medium sand with fragmented shells. This highly permeable stratum extends 35 to 90 feet below mean sea level (msl). Underlying this stratum there is a semi-permeable zone, The Hawthorn Formation, consisting of slightly clayey and very fine silt which extends 600 feet below msl.

The original surficial deposits at the St. Lucie Plant were excavated to a depth of 60 feet and backfilled with Category I or II fill. The fill is underlain by the Anastasia formation, a sequence of partially cemented sand and sandy limestone, which extend to an average depth of about 145 feet. The Anastasia is underlain to an depth of about 600 to 700 feet by the partially cemented and indurated sands, clays, and sandy limestones of The Hawthorn Formation. Underlying these surface strata are about 13,000 feet of Jurassic through Tertiary Formations, primarily carbonate rocks. These formations have a relatively gentle slope to the southeast.

k. Projected Water Quantities for Various Uses

In regard to the nuclear capacity uprates, no change is expected in the quantity or characteristics of industrial wastewaters generated by the facility. Therefore, no change in that compliance achievement status is expected. The capacity uprates will not cause any changes in hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow. The St. Lucie Plant does not directly withdraw groundwater under its current operations and it will not withdraw groundwater after the capacity uprates work is completed. The use of water supplied by the City of Fort Pierce, which does withdraw groundwater, will remain unchanged and there will be no changes to the groundwater discharges. There will be no quality, quantity, or hydrological changes, either by withdrawal or discharge to a drinking water source. Therefore, there will be no impacts on drinking water.

The wind turbines will not require water for operations and will not cause any changes in the hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow.

l. **Water Supply Sources by Type**

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. General plant service water, fire protection water, process water, and potable water are obtained from City of Fort Pierce. Process water uses include demineralizer regeneration, steam cycle makeup, and general service water use for washdowns.

The existing St. Lucie Plant water use is projected to be unchanged as a result of the nuclear capacity uprates. The wind turbines will not require water for operations.

m. **Water Conservation Strategies Under Consideration**

The existing water resources will not change as a result of the nuclear capacity uprates. The wind turbines will not require water for operations.

n. **Water Discharges and Pollution Control**

St. Lucie Units 1 & 2 use once-through cooling water from the Atlantic Ocean to remove heat from the main (turbine) condensers via the Circulating Water System (CWS), and to remove heat from other auxiliary equipment via the Auxiliary Equipment Cooling Water System (AECWS). The great majority of this cooling water is used for the CWS.

Under emergency conditions, water can be withdrawn from Big Mud Creek via the Emergency Intake Canal through two 54-inch pipe assemblies in the barrier wall that separates the Creek from the Canal. FPL does not use this intake during normal operations, but does test this system quarterly.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

The wind turbines will not require water for operations. Consequently, there will be no water discharge as a result of these turbines.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

St. Lucie Units 1 & 2 are licensed for uranium-dioxide fuel that is slightly enriched uranium-235. The uranium-dioxide fuel is in the form of pellets contained in Zircaloy tubes with welded end plugs to confine radionuclides. The tubes are fabricated into assemblies designed for loading into the reactor core. Each reactor core includes 217 fuel assemblies.

FPL currently replaces approximately one-third of the fuel assemblies in each reactor at intervals of approximately 18 months. FPL operates the reactors such that the average fuel usage by the reactors is approximately 47,000 megawatt-days per metric ton uranium. In regard to the nuclear capacity uprates, more nuclear fuel will be used due to the increased capacity of each generating unit. No changes in the fuel-handling facilities are required. The addition of the wind turbines will have no fuel-related impact; i.e., no impacts from fuel delivery, storage, waste, or pollution control. Used fuel assemblies are stored in the onsite Nuclear Regulatory Commission (NRC)-approved spent fuel storage facilities. Following completion of the uprates, approximately 11 percent more nuclear fuel will be used to increase the capacity of each unit. No changes in the fuel-handling facilities are required.

Diesel fuel is used in a number of emergency generators that include four main plant generators, two building generators, and various general purpose diesel engines. The main plant emergency generators will not be changed as a result of either of the two types of generation capacity additions. These emergency generators are for standby use only and are tested to assure reliability and for maintenance. Diesel fuel is delivered to the St. Lucie Plant by truck as needed, and stored in tanks with secondary containment.

p. Air Emissions and Control Systems

The St. Lucie Plant is classified as a minor source of air pollution, since FDEP has issued a Federally Enforceable State Operating Permit (FESOP) to keep emissions less than 100 tons per year for any air pollutant regulated under the Clean Air Act.

The applicable units at the St. Lucie Plant in regard to air emissions consist of eight large main plant diesel engines, two smaller diesel engines, and various general-purpose diesel engines. The air emissions from these engines are limited by the use of 0.05-percent sulfur diesel fuel and good combustion practices. Best Available Control Technology (BACT) is not applicable to these existing emission units.

Nitrogen oxide (NO_x) emissions from the operation of the diesel engines comprise the limiting pollutant for these diesel units at the St Lucie Plant. The FDEP FESOP limits NO_x emissions to 99.4 tons, which includes fuel use limits on the large main plant emergency diesel engines of 97,000 gallons in any 12-month consecutive period and the smaller building and general purpose diesel engines of 190,000 gallons in any 12-month consecutive period. Also, the Plant may choose to combine the diesel units' fuel-tracking, which then limits the NO_x totals for a 12-month consecutive period to a maximum of 80 tons. There will be no change in the operation or emissions of the diesel engines resulting from either the nuclear capacity uprates or the wind turbines.

In addition, neither of these types of generation capacity additions will result in an increase of carbon dioxide (CO_2) or other greenhouse gas emissions. In fact, both of these increases in generation capacity are projected to result in decreased FPL system-wide emissions of CO_2.

q. <u>Noise Emissions and Control Systems</u>

A field survey and impact assessment of noise expected to be caused by construction activities at the site was conducted in regard to both types of generation capacity additions. Predicted noise levels are not expected to result in adverse noise impacts in the vicinity of the site during construction or operation of either generating capacity additions.

r. <u>Status of Applications</u>

In regard to the nuclear capacity uprates, a Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act was filed in December 2007 and a final order issued in September 2008. The FPSC voted to approve the need for the St. Lucie (and Turkey Point) nuclear capacity uprates and the final order approving the need for these capacity additions was issued in January 2008. In regard to the wind turbines, a Site Certification Application is not required. Individual permit applications were submitted for an Environmental Resource Permit (ERP) and the Army Corps of Engineers Permits in May 2008 and the Coastal Construction Control Line in July 2008. In September of 2007, FPL submitted an application to St. Lucie County for a

Conditional Use, Rezoning, and Height Amendment. The local approvals process is ongoing.

Preferred Site # 3a: Turkey Point Plant, Miami-Dade County – Nuclear Capacity Uprates

The Turkey Point Plant site is located on the west side of Biscayne Bay, 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. Public access to the plant site is limited due to the nuclear units located there. The land surrounding the site is owned by FPL and acts as a buffer zone. The site is comprised of two nuclear units (Units 3 & 4), two natural gas/oil conventional boiler units (Units 1 & 2), one CC natural gas unit (Unit 5), 9 small diesel generators, the cooling canals, an FPL-maintained natural wildlife area, and wetlands that have been set aside as the Everglades Mitigation Bank (EMB).

Turkey Point Units 3 & 4 have been in operation since 1972 and 1973, respectively. The Turkey Point site has been selected as a Preferred Site for the increase in the capacity of its two existing nuclear generating units by approximately 103 MW each. This work will involve changes to several existing main components within the existing facilities to increase their capability to produce steam for the generation of electricity. No new or expanded facilities are required as part of this capacity "uprate." This capacity uprate, along with a similar capacity uprate of FPL's existing St. Lucie nuclear units, was approved by the FPSC in January 2008. The capacity uprates at Turkey Point are projected to be in-service in 2012.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the Turkey Point plant site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the general layout of the Turkey Point Units 3 and 4 generating facility at the site is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The five existing power generation units and support facilities occupy approximately 150 acres of the 11,000-acre Turkey Point Plant. Support facilities include service buildings, an administration building, fuel oil tanks, water treatment facilities, circulating water intake and outfall structures, wastewater treatment basins, and a system substation. The cooling canal system occupies approximately 5,900 acres. The two 400-megawatt (MW) (nominal) fossil fuel-fired steam electric generation units at the Turkey Point Plant have been in service since 1967 (Unit 1) and 1968 (Unit 2). These units currently burn residual fuel oil and/or natural gas with a maximum equivalent sulfur content of 1 percent. The two 700-MW (nominal) nuclear units have been in service since 1972 (Unit 3) and 1973 (Unit 4). Turkey Point Units 3 and 4 are pressurized water reactor (PWR) units. Turkey Point Unit 5 is a nominal 1,150-MW CC unit that began operation in 2007. Significant features in the vicinity of the site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The prominent structures and enclosed facilities and equipment associated with Units 3 & 4 include: the containment building, which contains the nuclear steam supply system, including the reactor, steam generators, reactor coolant pumps, and related equipment; the turbine generator building, where the turbine generator and associated main condensers are located; the auxiliary building, which contains waste management facilities, engineered safety components, and other facilities; and the fuel handling building, where the spent fuel storage pool and storage facilities for new fuel are located. Prominent features beyond the power block area include the intake system, cooling canal system, switchyard, spent fuel storage facilities, and technical and administrative support facilities.

2. Listed Species

The construction during the uprating of the units, and operation of the units after the capacity uprating is completed, are not expected to adversely affect any rare, endangered, or threatened species. Listed species known to occur at the site and in the nearby Biscayne National Park that could potentially utilize the site include the peregrine falcon *(Falco peregrinus)*, wood stork *(Mycteria americana)*, American crocodile *(Crocodylus acutus)*, mangrove rivulus *(Rivulus marmoratus)*, roseate spoonbill (*Ajaja ajaja*), limpkin (*Aramus guarauna*), little blue heron (*Egretta caerulea*), snowy egret (*Egretta thula*), American oystercatcher (*Haematopus palliates*), least tern (*Sterna antillarum*), the white ibis (*Eudocimus albus*), and bald eagle (*Haliaeetus leucocephalus*). No bald eagle nests are known to exist in the vicinity of the site. The federally listed, threatened American Crocodile thrives at the Turkey Point site, primarily in and around the southern end of the cooling canals which lie south of the project area. The entire site is considered crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American crocodile and is attributed with survival improvement and the downlisting of the American Crocodile from endangered to threatened.

3. <u>Natural Resources of Regional Significance Status</u>

Significant features in the vicinity on the site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park. Biscayne National Park contains 180,000 acres, approximately 95% of which is open water interspersed with more than 40 keys. The Biscayne National Park headquarters is located approximately 2 miles north of the Turkey Point plant and is adjacent to the Miami-Dade County Homestead Bayfront Park which contains a marina and day-use recreational facilities.

4. <u>Other Significant Features</u>

FPL is not aware of any other significant features of the site.

f. <u>Design Features and Mitigation Options</u>

Turkey Point Units 3 & 4 uses cooling water from a closed-cycle cooling canal system to remove heat from the main (turbine) condensers, and to remove heat from other auxiliary equipment. The existing cooling canals will accommodate the increase in heat load that is associated with the increased capacity from the uprates. The maximum predicted increase in water temperature entering the cooling canal system from the units resulting from the uprates is predicted to be about 2.5°F, from 106.1°F to 108.6°F. The associated maximum increase in water temperature returning to the units is about 0.9°F, from 91.9°F to 92.8°F.

g. **Local Government future Land Use Designations**

Local government future land use plan designates most of the site as IU-3 "Industrial, Unlimited Manufacturing District." There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. **Site Selection Criteria Process**

The site has been selected as a Preferred Site for the nuclear capacity uprates because it is an existing nuclear plant site and, therefore, offers the opportunity for increased nuclear capacity.

i. **Water Resources**

Unique to Turkey Point plant site is the self-contained cooling canal system that supplies water to condense steam used by the plant's turbine generators. The canal system consists of 36 interconnected canals. The cooling canals occupy an area approximately 2 miles wide by 5 miles long (5,900 acres), approximately four feet deep. The system performs the same function as a giant radiator. The water is circulated through the canals in a two-day journey, ending at the plant's intake pumps.

j. **Geological Features of Site and Adjacent Areas**

The Turkey Point Plant lies upon the Floridian Plateau, a partly-submerged peninsula of the continental shelf. The peninsula is underlain by approximately 4,000 to 15,000 feet of sedimentary rocks consisting of limestone and associated formations that range in age from Paleozoic to Recent. Little is known about the basement complex of Paleozoic igneous and metamorphic rocks due to their great depth.

Generally in Miami-Dade County, the surficial aquifer (Biscayne Aquifer) consists of a wedge-shaped system of porous clastic and carbonate sedimentary materials, primarily limestone and sand deposits of the Miocene to late Quaternary age. The Biscayne Aquifer is thickest along the eastern coast and varies in thickness from 80 to 200 feet thick. The surficial aquifer is typically composed of Pamlico Sand, Miami Limestone (Oolite), the Fort Thompson and Anastasia Formations (lateral equivalents), Caloosahatchee Marl, and the Tamiami formation. The lower confining layers below the surficial aquifer range in thickness from 350 to 600 feet and are composed of the Hawthorn Group. Beneath the Hawthorn Group, the Floridan Aquifer System ranges from 2,800 to 3,400 feet thick and consists of Suwannee Limestone, Avon Park Limestone, and the Oldsmar Formations.

k. Projected Water Quantities for Various Uses

The addition of nuclear generating capacity as a result of the uprates will not cause any changes in the quantity or characteristics of industrial wastewaters generated by the facility; therefore, no change in that compliance achievement status is expected. The uprates will not cause any changes in hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow. The Turkey Point Plant does not directly withdraw groundwater under its current operations and it will not do so after the capacity uprates. Locally, groundwater is present beneath the Site in the surficial or Biscayne Aquifer and in deeper aquifer zones that are part of the Floridan Aquifer System. There will be no effects on those deeper aquifer zones from the capacity uprates.

l. Water Supply Sources and Type

The source of cooling water for Turkey Point Units 3 & 4 is the cooling canal system. There will be no increase in the amount of water withdrawn as a result of the capacity uprates. General plant service water, fire protection water, process water, and potable water are obtained from Miami-Dade County. Process water uses include demineralizer regeneration, steam cycle makeup, and general service water use for washdowns. The water use for the facility will not change as a result of the capacity uprates.

m. Water Conservation Strategies

The existing water resources will not change as a result of the uprates.

n. Water Discharges and Pollution Control

Heated water discharges are dissipated using the existing closed cooling water system and the cooling canal system.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Turkey Point Units 3 & 4 utilize uranium-dioxide fuel that is slightly enriched uranium-235. The uranium-dioxide fuel is in the form of pellets contained in Zircaloy tubes with welded end plugs to confine radionuclides. The tubes are fabricated into assemblies designed for loading into the reactor core. Used fuel assemblies are stored in the onsite NRC-approved spent fuel storage facilities.

FPL currently replaces approximately one-third of the fuel assemblies in each reactor at intervals of approximately 18 months. FPL operates the reactors such that the average fuel usage by the reactors is approximately 45,000 megawatt-days per metric ton of uranium. Following completion of the uprates, more nuclear fuel will be used to increase the capacity of each unit. No changes in the fuel handling facilities are required. Following completion of the uprates, approximately 11 percent more nuclear fuel will be used to increase the capacity of each unit. No changes in the fuel-handling facilities are required.

Diesel fuel is used in a number of emergency generators that include four main emergency generators, five smaller emergency generators and various general purpose diesel engines. The emergency generators will not be changed as a result of the capacity uprates. These emergency generators are for stand-by use only and only operated for testing purposes to assure reliability and for maintenance. Diesel fuel for the emergency generators is delivered to the Turkey Point Plant by truck as needed, and stored in tanks with secondary containment.

p. <u>Air Emissions and Control Systems</u>

The normal operation of Turkey Point Units 3 & 4 does not create fossil fuel-related air emissions. However, there are 9 emergency generators associated with Units 3 & 4. Four of these 9 emergency generators are main plant emergency generators which are rated at 2.5 MW each. The remaining 5 are smaller emergency generators which are associated with the security system. In addition, various general purpose diesels are used as needed for Units 3 & 4.

Turkey Point Plant Units 3 & 4's associated emergency generators and diesel engines, together with Units 1, 2, and 5, are classified as a major source of air pollution. FDEP has issued a separate Title V Air Operating Permit for the Turkey Point Nuclear Plant (Permit Number 0250003-004-AV). There are no operating limits for the emergency generators or diesel engines. Emergency diesel generators are limited to ultra-low sulfur distillate (0.0015% sulfur). NOx emissions are regulated under Reasonably Available Control Technology (RACT) requirements in Rule 62-296.570(4)(b)7 F.A.C., which limit NO_x emissions to 4.75 lb/MMBtu. The use of 0.05

percent sulfur diesel fuel and good combustion practices serve to keep NO_x emissions under this limit.

q. Noise Emissions and Control Systems

A field survey and impact assessment of noise expected to be caused by activities associated with the uprates was conducted. Predicted noise levels are not expected to result in adverse noise impacts in the vicinity of the site.

r. Status of Applications

A Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act was filed in January 2008 and a final order was issued in October 2008. The FPSC voted to approve the need for the Turkey Point (and St. Lucie) uprates and the final order approving the need for this additional nuclear capacity was issued in January 2008.

Preferred Site # 3b: Turkey Point Plant, Miami-Dade County – Unit 6 (& 7)

The Turkey Point Plant property has been selected for two new nuclear generating units (Units 6 & 7) scheduled to come into service in 2018 and 2020, respectively. (Although the projected in-service year of Unit 7, 2020, is outside of the ten-year reporting period addressed in the 2009 Site Plan, FPL has included information regarding this unit.) The Turkey Point Plant property is located on the west side of Biscayne Bay, 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 8 miles east of Florida City on Palm Drive. Public access to the plant site is limited due to the operating nuclear units located there. The land surrounding the site is owned by FPL providing a buffer zone. The site is comprised of two existing nuclear units (Units 3 and 4), two natural gas/oil conventional boiler units (Units 1 & 2), one CC natural gas unit (Unit 5), 9 small diesel generators, the cooling canals, an FPL-maintained natural wildlife area, and wetlands that have been set aside as the FPL Everglades Mitigation Bank (EMB).

a. U.S. Geological Survey (USGS) Map

A map of the Turkey Point Units 6 & 7 site is found at the end of this chapter.

b. Proposed Facilities Layout

The Turkey Point Units 6 & 7 site layout is still under development. Information regarding the layout will be presented in future FPL Site Plans as this information becomes available.

c. Map of Site and Adjacent Areas

An overview map of the Turkey Point Units 6 & 7 site and adjacent areas is found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

Approximately 150 acres of the 11,000 acre Turkey Point Plant Property are used for the existing generation and support facilities and a closed cooling pond. The cooling canal system occupies approximately 5,900 acres. The remaining acreage primarily consists of forested uplands, disturbed uplands, and wetland habitat. Approximately 300 acres within the cooling canal system will be used for Turkey Point Units 6 & 7 site. Significant features in the vicinity include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The location for Turkey Point Units 6 & 7 operating facility is entirely within the cooling canal system that supports the operating plants. This is a previously impacted environment. Some of the associated facilities (e.g. roads, pipelines, etc.) will extend outside of the cooling canal system. These associated facilities are still under development and the potential natural environment in those areas are still under review.

2. Listed Species

Listed species known to occur at the site and in the nearby Biscayne National Park include the peregrine falcon *(Falco peregrinus)*, wood stork *(Mycteria americana)*, American crocodile *(Crocodylus acutus)*, mangrove rivulus *(Rivulus marmoratus)*, roseate spoonbill (*Ajaja ajaja)*, limpkin *(Aramus guarauna)*, little blue heron *(Egretta caerulea)*, snowy egret *(Egretta thula)*, American oystercatcher *(Haematopus palliates)*, least tern *(Sterna antillarum)*, the white ibis *(Eudocimus albus)*, and bald eagle *(Haliaeetus leucocephalus)*. No bald eagle nests are known to exist in the vicinity of the site. The federally listed, threatened American Crocodile thrives at the Turkey Point site, primarily in and around the southern end of the cooling canals that lie south of the project area. The entire site is considered crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American Crocodile and is attributed with survival improvement and the downlisting of the American Crocodile from endangered to threatened.

3. **Natural Resources of Regional Significance Status**

Significant features in the vicinity of the Turkey Point plant property include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park. Biscayne National Park contains 180,000 acres, approximately 95% of which is open water interspersed with over 40 keys. The Biscayne National Park headquarters is located approximately 2 miles north of the Turkey Point plant and is adjacent to the Miami-Dade County Homestead Bayfront Park that contains a marina and day use recreational facilities.

4. **Other Significant Features**

FPL is not aware of any other significant features of the Turkey Point Units 6 & 7 sites.

f. **Design Features and Mitigation Options**

Design features and mitigation options for Turkey Point Units 6 & 7 are still under development. Information regarding these design features and mitigation options will be presented in future FPL Site Plans as this information becomes available.

g. **Local Government future Land Use Designations**

FPL received zoning approval for Turkey Point Units 6 & 7 from Miami-Dade County in December 2007. FPL continues to work with Miami-Dade County on land use designations as project features develop.

h. **Site Selection Criteria Process**

FPL conducted an extensive site selection analysis leading to the selection of the Turkey Point site as the site that, on balance, provided the most favorable location for developing new nuclear generation to serve FPL's customers. The Site Selection

Study employed the principles of the Electric Power Research Institute (EPRI) siting guidelines and is modeled upon applicable NRC site suitability and National Environmental Policy Act (NEPA) criteria regarding the consideration of alternative sites. The study convened a group of industry and FPL subject matter experts to develop and assign weighting factors to a broad range of site selection criteria. Twenty-three candidate sites were then ranked using the siting criteria. This review allowed the list of candidates to be reduced until the best site emerged. Key factors contributing to the selection of Turkey Point include the existing transmission and transportation infrastructure to support new generation, the large size and seclusion of the site while being relatively close to the load center, and the long-standing record of safe and secure operation of nuclear generation at the site since the early 1970s.

i. Water Resources

Unique to the Turkey Point plant property is the self-contained cooling canal system that provides closed cooling to Turkey Point Units 1-4. The canal system consists of 36 interconnected canals. The cooling canals occupy an area approximately 2 miles wide by 5 miles long (5,900 acres), approximately four feet deep. The system performs the same function as a giant radiator. The water is circulated through the canals in a two-day journey, ending at the plant's intake pumps. These water resources will not be used by Turkey Point Units 6 & 7. The two new nuclear units currently propose to use reclaimed municipal wastewater as a primary cooling water source.

j. Geological Features of Site and Adjacent Areas

The Turkey Point Plant property lies upon the Floridian Plateau, a partly-submerged peninsula of the continental shelf. The peninsula is underlain by approximately 4,000 to 15,000 feet of sedimentary rocks consisting of limestone and associated formations that range in age from Paleozoic to Recent. Little is known about the basement complex of Paleozoic igneous and metamorphic rocks due to their great depth.

Generally in Miami-Dade County, the surficial aquifer (Biscayne Aquifer) consists of a wedge-shaped system of porous clastic and carbonate sedimentary materials, primarily limestone and sand deposits of the Miocene to late Quaternary age. The Biscayne Aquifer is thickest along the eastern coast and varies in thickness from 80 to 200 feet thick. The surficial aquifer is typically composed of Pamlico Sand, Miami Limestone (Oolite), the Fort Thompson and Anastasia Formations (lateral equivalents), Caloosahatchee Marl, and the Tamiami formation. The lower confining layers below the surficial aquifer range in thickness from 350 to 600 feet and are composed of the Hawthorn Group. Beneath the Hawthorn Group, the Floridan Aquifer System ranges from 2,800 to 3,400 feet thick and consists of Suwannee Limestone, Avon Park Limestone, and the Oldsmar Formations.

k. Projected Water Quantities for Various Uses

The quantities of cooling water and potable water needed for Turkey Point Units 6 & 7 are still under development. At this time it is estimated that up to 90 million gallons per day (mgd) of reclaimed wastewater will be needed for make-up cooling water. In the event that reclaimed water is not available it is estimated at this time that up to 130 mgd of saltwater will be needed for make-up cooling water.

l. Water Supply Sources and Type

Potential water supply sources for Turkey Point Units 6 & 7 are still being analyzed. FPL has conducted an extensive water alternatives analysis to identify the universe of water alternatives for the project. Based on this analysis, FPL is investigating further the use of reclaimed water as the primary source of make-up cooling water for Turkey Points Units 6 & 7. Information regarding the water supply sources and type will be presented in future FPL Site Plans as this information becomes available.

m. Water Conservation Strategies

Turkey Point Units 6 & 7 is expected to use cooling towers, which significantly reduce the cooling water requirements. Reclaimed wastewater is being developed as the primary make-up cooling source. Using reclaimed wastewater allows for a secondary beneficial use of regional municipal wastewater that would otherwise be discharged to the ocean or injected into deep wells by the Miami Dade County Water and Sewer Department. Other water conservation strategies are still in development for Turkey Point Units 6 & 7. Information regarding these water conservation strategies will be presented in future FPL Site Plans as this information becomes available.

n. Water Discharges and Pollution Control

The water discharge strategy for the Turkey Point Units 6 & 7 is still under development, but use of an Underground Injection Control (UIC) system is being considered as the primary waste discharge alternative. Information regarding water discharge will be presented in future FPL Site Plans as this information becomes available.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The delivery, storage, waste disposal and pollution control requirements for Turkey Point Units 6 & 7 are all currently under development. Information regarding these matters will be presented in future FPL Site Plans as this information becomes available.

p. Air Emissions and Control Systems

The normal operation of Turkey Point Units 6 & 7 will not create fossil fuel-related air emissions. In addition, emissions from emergency generators associated with Units 6 & 7 are expected to be insignificant. The air emissions and control system are still under development. Information regarding the air emissions and control system will be presented in future FPL Site Plans as this information becomes available.

q. Noise Emissions and Control Systems

A field survey and impact assessment of noise expected to be caused by activities associated with the Turkey Point Units 6 & 7 are under evaluation. Predicted noise levels are not expected to result in adverse noise impacts in the vicinity of the Turkey Point Units 6 & 7.

r. Status of Applications

FPL is currently collecting data and developing permit applications. FPL expects to submit applicable local, state, and federal applications for the project during mid-to-late-2009. The Turkey Point Units 6 & 7 Unusual Use approval was issued by Miami Dade County in December 2007.

Preferred Site # 4: Cape Canaveral Plant, Brevard County

This site is located on the existing FPL Cape Canaveral Plant property in unincorporated Brevard County. The site is bound to the east by the Indian River Lagoon and on the west by a four lane highway (US. 1). The city of Port St. Johns is located less than a mile away. A rail line is located near the plant.

The existing 788 MW (summer) of generating capacity at FPL's Cape Canaveral site occupies a portion of the 43 acres that are wholly owned by FPL. The generating capacity is made up of steam units (Units 1 and 2).

The Cape Canaveral Plant site has been listed as a Potential Site in previous FPL Site Plans for both CC and simple cycle generation options. FPL is proposing to convert the existing Cape Canaveral Plant, to be renamed the Cape Canaveral Next Generation Clean Energy Center (CCEC), into a modern, highly efficient, lower-emission next-generation clean energy center using the latest CC technology. The existing two (2) steam units will first be dismantled and removed from the site and will be replaced by a single new CC unit.

a. Geological Survey (USGS) Map

A USGS map of the Cape Canaveral plant site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the CCEC generating facilities at the site is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing land uses on the site are primarily dedicated to electrical generation; i.e., FPL's existing Cape Canaveral power plant Units 1 & 2. The existing land uses that are adjacent to the site consist of single- and multi-family residences to the south and southwest, commercial property to the northwest, utility systems to the west, and a private medical/office facility to the north.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The natural environment surrounding the site includes the Indian River Lagoon to the east and upland scrub, pine and hardwoods to the north and south. Vegetation with the approximately 45-acre offsite construction laydown and parking area (located west of U.S. Highway 1) consists of open land, upland scrub, pine, hardwoods along with exotic plant species.

2. **Listed Species**

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the Site, due to the existing developed nature of the Site and lack of suitable onsite habitat for listed species. Federal- or state-listed terrestrial plants and animals inhabiting the offsite construction laydown and parking area are limited to the state-listed gopher tortoise and the state- and federally-listed scrub jay. The warm water discharges from the plant attract manatees, an endangered species. FPL is working closely with state and federal wildlife agencies to ensure protection of the manatees during the conversion process and upon operation of the modernized plant.

3. **Natural Resources of Regional Significance Status**

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design option is to convert the existing steam generating units (Units 1 & 2) with one new 1,219 MW (approximate) CC unit consisting of three new combustion turbines (CT), three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit would be in-service in mid-2013. Natural gas delivered via pipeline is the primary fuel type for this unit with ultra-low sulfur light oil serving as a backup fuel.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the site is "Public Utilities" and the area has been rezoned to GML-U.. Designations for the surrounding area are primarily "Community Commercial" and "Residential". The Indian River Lagoon is to the east of the site.

h. **Site Selection Criteria Process**

The Cape Canaveral plant has been selected as a preferred site for a site conversion due to consideration of various factors including system load and economics.

Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of converting the existing steam units including a significant reduction in system air emissions and improved aesthetics at the site.

i. <u>Water Resources</u>

Condenser cooling for the steam cycle portion of the converted plant and auxiliary cooling will come from the existing cooling water intake system. Process, potable, and irrigation water for the converted plant will come from the existing City of Cocoa's potable water supply.

j. <u>Geological Features of Site and Adjacent Areas</u>

FPL's Cape Canaveral Plant is located on the Atlantic Coastal Ridge and is at an approximate elevation of 12 feet above mean sea level (msl). The land consists primarily of fine to medium sand that parallels the coast. There is a lack of shell as it was deposited during a time of transgression. The base of the sedimentary rocks is made up of a thick, primarily carbonate sequence deposited during the Jurassic age through the Pleistocene age. Starting in the Miocene age and continuing through the Holocene age, siliciclastic sedimentation became more predominant. The basement rocks in this area consist of low-grade metamorphic and igneous intrusives, which occur several thousand feet below land surface and are Precambrian, Paleozoic, and Mesozoic in age.

k. <u>Projected Water Quantities for Various Uses</u>

The estimated quantity of water required for processing is approximately 0.281 million gallons per day (mgd) for uses such as process water and service water. Approximately 619 million gallons per day (mgd) of cooling water would be cycled through the once-through cooling water system. Potable water demand is expected to average .001 mgd.

l. <u>Water Supply Sources by Type</u>

The converted plant will continue to use the Indian River Lagoon water as the source of once-through cooling water. Such needs for cooling water will comply with the existing St. John's River Water Management District (SJRWMD) Consumptive Use Permit (CUP). Process, potable, and irrigation water for the converted plant will come from the existing City of Cocoa's potable water supply.

m. **Water Conservation Strategies Under Consideration**

No additional water sources will be required as a result of the conversion project.

n. **Water Discharges and Pollution Control**

The converted site will utilize portions of the existing once-through cooling water systems for heat dissipation. The heat recovery steam generator blowdown will be mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

Natural gas for the converted unit will be transported to the site via a pipeline. New on-site gas compressors may be installed to raise the gas pressure of the existing pipeline for the converted unit. Ultra-low sulfur light fuel oil would be received by truck or barge from Port Canaveral and stored in an existing above-ground storage tank.

p. **Air Emissions and Control Systems**

The use of natural gas and ultra-low sulfur light fuel oil and combustion controls will minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of the converted CCEC plant will incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise from the operation of the new unit will be within allowable levels.

r. Status of Applications

A Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act was filed in December 2008 and is currently under review. The FPSC voted to approve the need for the conversion project and the final order was issued in September 2008.

Preferred Site # 5: Riviera Plant, Palm Beach County

This site is located on the existing FPL Riviera Plant property primarily within Riviera Beach, Palm Beach County (with a small portion of the Site in West Palm Beach). The site is bound to the east by the Lake Worth Lagoon (Intracoastal Waterway) and on the west by a four lane highway (US. 1). The site has barge access via the Port of Palm Beach. A rail line is located near the plant.

The current site generating capacity is made up of two (2) operational 300 MW (approximate) steam generating units (Units 3 & 4). Units 1 & 2 have been retired and dismantled and are no longer on the plant site.

The Riviera Plant site has been listed as a Potential Site in previous FPL Site Plans for both CC and simple cycle generation options. FPL is proposing to convert the existing Riviera Plant, to be renamed the Riviera Beach Next Generation Clean Energy Center (RBEC), into a modern, highly efficient, lower-emission next-generation clean energy center using the latest CC technology. The existing two steam units will first be removed from the site and will be replaced by a single new CC unit.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Riviera site is found at the end of this chapter.

b.

c. Proposed Facilities Layout

A general layout of the RBEC generating facilities is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing Riviera Plant currently consists of two 300 MW (approximate) units with conventional dual-fuel fired steam boilers and steam turbine units. The plant site includes minimal vegetation and a landscape buffer area south of the power plant. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of facilities related to electric power generation for the existing Riviera Plant. The site is located on the Intracoastal waterway which provides warm water refugia for manatees during cold winter days.

2. Listed Species

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the Site, due to the existing developed nature of the Site and lack of suitable onsite habitat for listed species. The warm water discharges from the plant attract manatees, an endangered species. FPL is working closely with state and federal wildlife agencies to ensure protection of the manatees during the conversion process and upon operation of the new plant.

3. Natural Resources of Regional Significance Status

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option is to convert the existing units (Units 3 & 4) to one new 1,207 MW (approximate) unit consisting of three new combustion turbines (CT), three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit would be in service in mid-2014. Natural gas delivered via pipeline is the primary fuel type for the unit with ultra-low sulfur light oil serving as a backup fuel.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is "Utility". The Port of Palm Beach is to the north of the site. Designation to the west of the site is "Commercial". To the south of the site is "Residential" and is in the City of West Palm Beach.

h. Site Selection Criteria Process

The Riviera plant has been selected as a Preferred Site to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of converting the existing steam units including a significant reduction in system air emissions and improved aesthetics at the site.

i. Water Resources

Water from the Lake Worth Lagoon (Intracoastal waterway) is currently used for once-through cooling water. The converted plant will utilize portions of the existing once through cooling water intake and discharge structures. Water for cooling pump seals and irrigation will come from three onsite surficial aquifer wells. Process and potable water for the converted plant will come from the existing City of Riviera Beach potable water supply.

j. Geological Features of Site and Adjacent Areas

FPL's Riviera Plant site is underlain by the surficial aquifer system. The Surficial aquifer system in eastern Palm Beach County is primarily composed of sand, sandstone, shell, silt, calcareous clay (marl), and limestone deposited during the Pleistocene and Pliocene Epochs. The sediments forming the aquifer system are the Pamlico Sand, Fort Thompson Formation (Pleistocene) and the Caloosahatchee Marl (Pleistocene and Pliocene). Permeable sediments in the upper part of the Tamiami Formation (Pliocene) are also part of the aquifer system. The sediments in the eastern portion of the county are appreciably more permeable than in the west due to better sorting and less silt and clay content.

The surficial aquifer is underlain by at least 600 feet the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing is approximately 0.232 mgd for uses such as process water and service water. Approximately 600 million gallons per day (mgd) of cooling water would be cycled through the once-through cooling water system. Potable water demand is expected to average .001 mgd.

l. Water Supply Sources by Type

The converted plant will continue to use the Lake Worth Lagoon water as the source of once-through cooling water. Water for cooling pump seals and irrigation will come from on-site surficial aquifer wells currently permitted by SFWMD. Process and potable water for the converted plant will come from the existing City of Riviera Beach's potable water supply.

m. Water Conservation Strategies Under Consideration

No additional water sources will be required as a result of the conversion project.

n. Water Discharges and Pollution Control

The converted plant will utilize portions of the existing once-through cooling water system for heat dissipation. The heat recovery steam generator blowdown will be mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system prior to discharge. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the converted unit will be transported to the site via a pipeline. New on-site gas compressors may be installed to raise the gas pressure of the existing pipeline to the appropriate level for the converted unit. Ultra-low sulfur light fuel oil would be received by truck, pipeline or barge from the Port of Palm Beach and stored in a new above-ground storage tank.

p. Air Emissions and Control Systems

The use of natural gas and ultra-low sulfur light fuel oil and combustion controls will minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of RBEC will incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. Status of Applications

A Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act was filed in February 2009 and is currently under review. The FPSC voted to approve the need for the conversion project and the final order was issued in September 2008.

Preferred Site # 6: DeSoto Next Generation Solar Energy Center, DeSoto County

The DeSoto site is located approximately 0.3 miles east of US 17 and immediately north of Bobay Road in Arcadia, Florida. The site is located in Section 27, Township 36 South, Range 25 East. FPL owns an approximately 13,000 acre parcel in DeSoto County. FPL has designated approximately 1,523 acres for development of a photovoltaic (PV) facility. The land surrounding the site is owned by FPL and acts as a buffer zone.

The DeSoto site has been selected as a Preferred Site for the addition of a 25 MW PV generation facility. The DeSoto Next Generation Solar Energy Center is expected to be in operation by the end of 2009.

a. U.S. Geological Survey (USGS) Map

A USGS map of the DeSoto Next Generation Solar Energy Center plant site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the DeSoto Next Generation Solar Energy Center generating facility at the site is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

This property is owned by FPL. The site was inactive until November 2008 when construction of the DeSoto Next Generation Solar Energy Center was initiated. The site was previously dedicated to agricultural use. An approximately 400 acre portion of the site has been cleared and re-graded to accommodate the PV project. Prior to initiation of construction, no structures were present on the site and the majority of the vegetation was sod. Structures are now being built on the site for work associated with DeSoto Next Generation Solar Energy Center.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The site has been altered by construction. The surrounding land use is predominantly agriculture. FPL was able to design the PV facility to avoid impacts to most of the natural wetlands.

2. Listed Species

Prior to construction and operation of the new facility one listed species was observed at the site, the gopher tortoise. Gopher tortoises are classified as threatened by the Florida Fish and Wildlife Conservation Commission, but are not listed federally by the U.S. Fish and Wildlife Service. Gopher tortoise burrows were observed in the palmetto prairie and woodland pasture. Other listed species are known to utilize gopher tortoise burrows (commensal species), including the Eastern indigo snake (*Drymarchon corais couperi*; federally and state threatened), gopher frog (*Rana capito*; state species of special concern), and Florida mouse (*Podomys floridanus*; state species of special concern). A permit was obtained to relocate the gopher tortoises and any commensal species. Construction and operation at the site is not expected to affect any rare, endangered, or threatened species.

3. **Natural Resources of Regional Significance Status**

The construction and operation of the PV generating facility at this location is not expected to have any adverse impacts on parks or recreation areas. Construction will result in minimal wetland impacts under federal, state, or local agency permitting criteria.

4. **Other Significant Features**

FPL conducted an archeological and historical survey and no artifacts were discovered. FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design consists of 25 MW of PV technology. This site is also suitable for possible expansion of PV beyond the 25 MW facility. No mitigating options are deemed necessary at the site.

g. **Local Government future Land Use Designations**

The local government future land use designation for the 25 MW project site is Agriculture on the DeSoto County Future Land Use Map.

h. **Site Selection Criteria Process**

The site has been selected as a Preferred Site for the installation of a PV technology due to consideration of various factors including prior FPL ownership of the land and its suitability for a PV facility of this magnitude.

i. **Water Resource**

No water will be required for use at the solar facility except the small amount that may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Should this minimal water be required, it will be trucked to the site as needed.

j. **Geological Features of the Site and Adjacent Areas**

The dominant soil types within the site are Myakka, Smyrna, Immokalee, EauGallie, Basinger, and Valkaria fine sands. Basinger fine sand, depressional; and Anclote muckyfine sand, depressional. All the dominant soil types are considered poorly to very poorly drained.

k. Projected Water Quantities for Various Uses

The projected water use for the solar facility is expected to be minimal with water being used occasionally only to clean the PV panels.

l. Water Supply Sources and Type

The PV facility will use a small amount of water to occasionally clean the PV panels. This water will come from groundwater. FPL will obtain a consumptive use permit once the facility goes into operation.

m. Water Conservation Strategies

This PV facility does not require water use for daily operations.

n. Water Discharges and Pollution Control

There will not be any water discharges or pollution as a result of this facility operation.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The facility will use the sun for fuel. Therefore there will not be any fuel delivery, storage, waste, or pollution at the site.

p. Air Emissions and Control Systems

No air emissions will be emitted from this facility.

q. Noise Emissions and Control Systems

Noise expected during construction is expected to be below noise level allowed by DeSoto County. No noise will be emitted from this facility during operation.

r. Status of Applications

FPL obtained an Environmental Resource Permit (ERP) from the FDEP in October 2008. FPL received an Army Corps of Engineers permit in October 2008.

Preferred Site #7: Space Coast Next Generation Solar Energy Center, Brevard County

The Space Coast site (Site) is located at Section 13, Township 23 South, and Range 36 East, North of North Courtenay Parkway. FPL is leasing approximately 60 acres from Kennedy Space Center in Brevard County. This Space Coast site has been selected as a Preferred Site for the addition of a 10 MW PV generation facility. The Space Coast Next Generation Solar Energy Center is expected to be in operation by the end of 2010.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Space Coast Next Generation Solar Energy Center plant site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the Space Coast Next Generation Solar Energy Center generating facility is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The site is inactive. The Site was previously dedicated to agricultural use as citrus groves. There are no structures on the site and the majority of the vegetation is citrus grove.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The surrounding land use is predominantly agriculture. FPL was able to design the PV facility to avoid most of the impacts to natural wetlands.

2. Listed Species

Wildlife resources at the Site were evaluated in February 2008 through pedestrian surveys. There were no listed species observed.

3. **Natural Resources of Regional Significance Status**

The construction and operation of a PV generating facility at this location is not expected to have any adverse impacts on parks or recreation areas. Construction will result in minimal wetland impacts under federal, state, or local agency permitting criteria.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design consists of 10 MW of PV technology. No mitigating options are deemed necessary at the site.

g. **Local Government future Land Use Designations**

Future land use designation for the site is Spaceport Management as designated by the Brevard County Future Land Use Map.

h. **Site Selection Criteria Process**

The site has been selected as a Preferred Site for the installation of a PV technology due to consideration of various factors including its suitability for a PV facility of this magnitude and the cooperation of the Kennedy Space Center.

i. **Water Resource**

No water will be required at the PV facility except the small amount that may be needed to occasionally clean the solar panels in the absence of sufficant rainfall. Any such water would be brought to the site by truck.

j. **Geological Features of the Site and Adjacent Areas**

The surface and near-surface deposits of east-central Florida range from surficial unconsolidated sands to well indurated limestones and dolomites at depth. In ascending order the four main geologic units present in east-central Florida are: (i) Eocene limestones; (ii) Lower and Middle Miocene compact silt and clays; (iii) Upper Miocene and Pliocene silty and clayey sands; and (iv) Pleistocene and Recent age sands with interbedded shell layers.

k. Projected Water Quantities for Various Uses

The projected water use for the PV facility is expected to be minimal with water being used occasionally only to clean the PV panels.

l. Water Supply Sources and Type

At this time, it is expected that natural rainfall will be sufficient to keep the solar panels clean. In the event that additional water is required, a small amount of water may be occasionally trucked in to clean the PV panels.

m. Water Conservation Strategies

FPL constructed this PV facility knowing it would not use water for operation and would only need a minimal amount for cleaning the PV panels.

n. Water Discharges and Pollution Control

There will not be any water discharges or pollution as a result of this facility

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The facility will use the sun for fuel. Therefore there will not be any fuel delivery, storage, waste, or pollution at this site.

p. Air Emissions and Control Systems

No air emissions will be emitted from this facility.

q. Noise Emissions and Control Systems

Noise expected during construction is expected to be below noise levels allowed by Brevard County. No noise will be emitted from this facility during operation.

r. Status of Applications

FPL applied for an Environmental Resource Permit (ERP) from the St. Johns Water Management District and a U.S. Army Corps of Engineers permit in July 2008.

Preferred Site #8: Martin Next Generation Solar Energy Center, Martin County

The Martin Next Generation Solar Energy Center (MSEC) will be located on the existing FPL Martin Plant site in unincorporated Martin County, Florida. The Martin Plant site is located in southwestern Martin County about 40 miles northwest of West Palm Beach and about 1.3 miles east of Lake Okeechobee (Figure 2.1-1). The Martin Plant site is bounded by State Road (SR) 710 and a CSX Railroad line (east and north), a Florida East Coast Railway line and SFWMD L-65 Canal (west), and the St. Lucie Waterway (south).The MSEC Project will be constructed in an approximately 600-acre area (Project Area) within FPL's existing 11,300-acre Martin Plant site. The land surrounding the site is owned by FPL and acts as a buffer zone.

The site has been selected as a Preferred Site for the addition of approximately 75 MW of solar thermal generation. The facility will produce steam that will replace steam that would otherwise have been produced by burning natural gas in one of the existing CC units at the site, Martin Unit 8. The Martin Next Generation Solar Energy Center is expected to be in operation by the end of 2010.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the Martin Next Generation Solar Energy Center plant site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the general layout of the Martin Next Generation Solar Energy Center generating facility is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

Total site acreage for the existing Martin Plant site is approximately 11,300 acres, which represents land owned by FPL. The Martin Plant site consists of a 6,800-acre cooling pond (6,500 acres of water surface and 300 acres of embankment) and approximately 400 acres for existing Units 1 through 4, Unit 8, and associated facilities. Units 1 & 2 are nominal 800-MW steam electric generating units that use natural gas and low-sulfur residual oil. Units 3 & 4 are nominal 500-MW natural gas-fired CC units. Unit 8 is a natural gas fired 4-on-1 CC unit with a nominal capacity of 1,100 MW that began operation in 2005. Light oil is used as backup in Unit 8. The other onsite facilities include water and wastewater treatment facilities, residual and light fuel oil storage, switchyards and transmission lines, offices, warehouses, maintenance buildings, and other miscellaneous uses.

Adjacent areas include agricultural uses such as croplands, pastures, and groves account for much of the land use and cover within 5 miles of the Martin Plant site. Three types of wetlands, forested freshwater, non-forested freshwater, and mixed forested and forested freshwater also account for a great deal of nearby land use.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The portions of the Martin Plant site that will be affected by the construction of the MSEC are about 550 acres that will be utilized for solar arrays and construction facilities. The solar arrays will be located east of the existing Unit 8. Activities associated with construction will occupy about 100 acres. This will include construction laydown, parking, and trailers. These areas will be cleared of any vegetation. The area for the heat exchangers will be near Unit 8 and this area has been previously impacted by the construction of Units 3, 4, and 8.

2. Listed Species

Threatened and endangered species within the Project Area are limited to avian species and gopher tortoise. No listed species of plants were identified within the MSEC Project Area. Due to the presence of large areas of similar habitat both within the Northwest Mitigation Area and areas north of the existing transmission line ROW adjacent to the Project Area, and the highly mobile nature of protected avian species, no significant adverse impacts to federally or state listed animals are expected. Creation of wood stork foraging ponds and sandhill crane habitat within the Northwest Mitigation Area provides suitable habitat to offset the loss of shallow hydroperiod wetlands within the Project Area.

Gopher tortoises are classified as threatened by the FFWCC, but are not listed federally by the USFWS. Gopher tortoise burrows were observed in the palmetto prairie and woodland pasture. Other listed species are known to utilize gopher tortoise burrows (commensal species), including the Eastern indigo snake (*Drymarchon corais couperi*; federally and state threatened), gopher frog (*Rana capito*; state species of special concern), and Florida mouse (*Podomys floridanus*; state species of special concern). A permit was obtained to relocate the gopher tortoises and any commensal species. Construction and operation at the Site is not expected to affect any rare, endangered, or threatened species

3. **Natural Resources of Regional Significance Status**

The construction and operation of a solar thermal facility at this location is not expected to have any adverse impacts on parks or recreation areas. Construction will result in minimal wetland impacts under federal, state, or local agency permitting criteria.

4. **Other Significant Features**

The Florida Department of State, Division of Historical Resources, has determined that no significant archaeological or historical sites are recorded or are likely to be present within the Project Area. As a result no construction impacts on historic properties listed or eligible for listing in the National Register of Historic Places, or otherwise of historical or archaeological value, are anticipated.

f. **Design Features and Mitigation Options**

The design consists of approximately 75 MW of solar thermal technology. FPL has already undertaken an extensive wetland mitigation program on a 1,130-acre parcel northwest of the existing Martin Plant generating units. That mitigation program was deemed successful by the SFWMD in 2001. All wetland impacts associated with the MSEC have been fully mitigated through this now-successful wetland and upland mitigation effort.

g. **Local Government future Land Use Designations**

The Martin Plant site that includes Units 1 & 2 was developed prior to the county's adoption of a future land use map. In 1982, at the time of the original land use plan map adoption, the portion of the Martin Plant site surrounding the existing units was designated Industrial. The Electric Utility Element of the Comprehensive Plan acknowledged FPL's plans to construct two coal gasification plants at the Martin Plant site and encouraged the facilities to be developed under the industrial planned unit development [PUD(i)] zoning designation. In September 1988, FPL requested a comprehensive plan land use amendment to industrial for the licensing of the Martin CG/CC Project Area and a rezoning of that area to PUD(i). In August 1989, the Martin County Board of County Commissioners (BOCC) approved the comprehensive plan amendment and the rezoning request. In June 2008, with the BOCC approval of the rezoning, a PUD Zoning Agreement was executed between Martin County and FPL in which development standards and special conditions were addressed. Most of the special conditions were addressed during earlier phases of developing the Martin Plant site. An amendment of the PUD Zoning Agreement was requested by FPL to allow renewable energy facilities to be located within the PUD area. Subsequent to the certification of the CG/CC Project, which includes the area of the MSEC, Martin County has amended its future land use element and map to designate 7,300 acres in the Martin Plant site as Public Utilities – Major Public Power Generation Facilities.

h. Site Selection Criteria Process

The site has been selected as a Preferred Site due to consideration of various factors including available land area and proximity to an existing generating unit (Martin Unit 8) to which the steam generated by the solar thermal facility could be fed.

i. Water Resource

There will be no water used at the solar thermal facility except the small amount needed to occasionally clean the solar mirrors. The additional water needed for mirror cleaning is already within the previously approved allocation of water for the Martin Plant site.

j. Geological Features of the Site and Adjacent Areas

Borings drilled in the area just east of the existing Unit 8 show that the predominant soil type is sand from the ground surface [approximately 30 feet above mean sea level (ft-msl)] to –70 ft-msl (negative number denotes feet below sea level). The sands vary in color from light to dark gray and brown. Clayey sand and sandy clay seams from a few inches to several feet in thickness are generally found at 10 ft-msl. A thin layer of greenish-gray sandy clay was found in the borings at approximately –25 ft-msl. The Pamlico and Anastasia Formations extend from the ground surface (20 to 30 ft-msl) to an average of –3 ft-msl. These strata consist of fine sands and silty sands with shell fragments. Thin beds of limestone and cemented sand occur sporadically at depths ranging from 2 to 4.5 ft-msl in localized areas; this zone may represent the boundary between the Pamlico and Anastasia Formations. In areas where the cemented sands and limestone are absent, it is not possible to differentiate the two formations.

The underlying Caloosahatchee Group extends to an average –80 ft-msl. This formation can be subdivided into two units, namely an upper limestone interbedded with sand and shell present to an average –12 ft-msl, and a lower unit of silty sand with shell fragments and shell beds to –80 ft-msl. The Tamiami Formation underlies the Caloosahatchee from –105 ft-msl to –150 ft-msl. This formation consists of silty sand varying with depth to clayey sand from –72 ft-msl. The color of the formation also varies from gray in the sands to predominantly green in the clayey zone.

The top of the Hawthorn Group occurs at approximately –105 ft-msl to –150 ft-msl. These elevations are based on the logs of test wells and exploratory borings drilled in the area. The Hawthorn, approximately 550 ft thick, consists predominantly of greenish clay with subordinate amounts of shell, limestone, silt, and sand. Major limestone zones generally occur near the base of the formation. Due to very low vertical permeability, the Hawthorn acts as a confining bed overlying the Floridan Aquifer.

k. Projected Water Quantities for Various Uses

Washing mirrors requires about 50 gallons per 120 mirrors (i.e., a 50 meter section). Based on the amount of mirrors for the MSEC, about 75,000 gallons per washing will be required. This amount of water is estimated to be no more than about 2 million gallons per year for cleaning mirrors.

l. Water Supply Sources and Type

The plant water use for MSEC can be accommodated by the current authorization for water in the Conditions of Certification (PA89-27L). The amount of water required by the MSEC is estimated to not exceed about 2 million gallons per year for cleaning mirrors, or an annual average of about 5 gallons per minute (gpm). The usage will be intermittent, with maximum usage of about 75,000 gallons every 1 or 2 weeks during periods without rain and depending upon the reflectivity of the mirrors. The source of water for the MSEC is the existing demineralized water system.

m. Water Conservation Strategies

FPL plans to construct this solar thermal facility knowing it will use very little water for operation.

n. Water Discharges and Pollution Control

There will not be any water discharges or pollution as a result of this facility.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The facility will use the sun for fuel. Therefore, there will not be any fuel delivery, storage, waste, or pollution at the site from the operation of the solar thermal facility.

p. Air Emissions and Control Systems

There will be no SO_2, NO_x, or CO_2 emissions from the solar thermal facility and its operation will result in reductions of FPL system emissions for all three types of emissions.

There will be minor amounts of volatile organic compounds (VOCs) released from the expansion tanks as a result of decomposition products of heat transfer fluids (HTF). Based on reported values from FPL Energy SEGS facilities in California, the VOC emissions from the MSEC will be about 0.8 tons per year (TPY). This amount would classify these emissions as insignificant activities and the amount is well below the threshold requiring permitting under FDEP rules in 62-210.300, F.A.C. A generic exemption is that emissions of any regulated pollutant be less than 5 TPY. The 5 TPY applies to the "potential-to-emit" for the emission unit, which would be 8,760 hours/year unless restricted as an enforceable permit condition in a permit. The exemption covers the requirement to obtain construction permits required pursuant to Rule 62-210.300(1), F.A.C.

q. Noise Emissions and Control Systems

Noise during construction is expected to be below noise level allowed by Martin County. There will not be any noise from the solar thermal facility during operation.

r. Status of Applications

FPL submitted an application for a Site Certification Modification for the Martin Next Generation Solar Energy Center to the FDEP in May 2008. FPL received the site certification modification approval in August 2008.

IV.F.2 Potential Sites for Generating Options

Four sites are currently identified as Potential Sites for near-term future generation additions to meet FPL's capacity and energy needs.[3]

[3] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other greenfield sites. Greenfield sites that FPL currently does not own, or for which FPL has not currently secured the necessary rights to, are not specifically identified as Potential Sites in order to protect the economic interests of FPL and its customers.

. These sites have been identified as Potential Sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies.

Each of these Potential Sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that will require further definition and attention. Solely for the purpose of estimating water requirements for each site, it was assumed that either one dual-fuel (natural gas and light oil) simple cycle combustion turbine (CT) or a natural gas-fired CC unit would be constructed at the Potential Sites unless otherwise noted. A simple cycle CT would require approximately 50 gallons per minute (gpm) for both process and cooling water (assuming air cooling). A CC unit would require approximately 150 gpm for service and process water and approximately 14 million gallons per day (mgd) for cooling water depending upon the water source and associated water quality. If an existing power plant site is ultimately selected for converting an existing unit(s), the water requirements discussed above for a CC unit would be approximately correct for the converted unit. If a renewable energy generating technology, such as photovoltaic or solar thermal, is ultimately selected for one of these sites, the water requirements would be less than those for CT or CC facilities.

Permits are presently considered to be obtainable for each of these sites. No significant environmental constraints are currently known for any of these sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time FPL considers each site to be equally viable.

Potential Site # 1: West Broward, Broward County

FPL has identified the Andytown Substation property in western unincorporated Broward County as a potential site for the addition of new generating capacity and FPL refers to this potential site as the West Broward site. Current facilities on-site include an electric substation. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections.

a. U.S. Geological Survey (USGS) Map

A USGS map of the site has been included at the end of this chapter.

b. **Land Uses**

The land uses for the site were designated as agricultural use.

c. **Environmental Features**

Extensive low-quality wetlands are present on the site. Construction and operation of a new facility on this site would not be expected to adversely affect any rare, endangered, or threatened species.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

Groundwater from the shallow aquifer or a local source of reclaimed (reuse) water has been identified as potential water sources. The Floridan Aquifer has also been identified as a potential cooling water source.

Potential Site # 2: Fort Myers Plant, Lee County

FPL's existing 460-acre Fort Myers property is located just east of Interstate 75 in Lee County and is adjacent to the Caloosahatchee River. The existing facilities on the site include one 1,440 MW (approximate) CC unit, 12 gas turbines, each with an approximate capacity of 54 MW, and two combustion turbines, each with an approximate capacity of 160 MW.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the Fort Myers plant site is found at the end of this chapter.

b. **Land Uses**

The land on the site is currently dedicated to industrial use with surrounding grassy and landscaped areas. Much of the site has been used in recent years for direct plant construction activities. The adjacent land uses include light commercial and retail to the east of the property, plus some residential areas located toward the west.

c. **Environmental Features**

Mixed scrub with some hardwoods can be found to the east and further south.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

The available water source is the Caloosahatchee River and the available groundwater source is the sandstone aquifer.

Potential Site # 3: Lauderdale Plant, Broward County

The Lauderdale site is located in Eastern Broward County approximately 5 miles inland from Dania Beach and less than 2 miles west of Ft. Lauderdale International Airport. The site is bounded on the south by Dania Cutoff Canal, on the east by S.W. 30th Avenue, and on the North by I-595.

The existing approximately 1,700 MW of generating capacity at FPL's Lauderdale site occupies a portion of the approximately 210 acres that are wholly owned by FPL. The generating capacity is made up of two CC units (Units 4 & 5), and 24 simple cycle gas turbine (GT) units.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site is found at the end of this chapter.

b. **Land Uses**

The existing power plant facilities are located on approximately 130 acres. The existing site has been in use since the 1920s and is adjacent to a county resource recovery project.

c. **Environmental Features**

To the north of the power plant is an area of mixed uplands with a scattering of small wetlands.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. Supply Sources

Existing groundwater or the municipal water supply are potential water sources.

Potential Site # 4: Manatee Plant, Manatee County

The site for the Project is the existing FPL Manatee Plant 9,500-acre site, located in unincorporated north-central Manatee County. The existing power generating facilities are located in all or portions of Sections 18 and 19 of Township 33S, Range 20-E. The plant site lies approximately 5 miles east of Parrish, Florida. It is approximately 5 miles east of U.S. 301 and 9.5 miles east of Interstate Highway 75 (I-75). The existing plant is approximately 2.5 miles south of the Hillsborough-Manatee County line; a portion of the north property boundary of the plant site abuts the county line. State Road 62 (SR 62) is about 0.7 mile south of the plant, with the plant entrance road going north from that highway. This site is a possibility for an FPL solar thermal facility.

a. U.S. Geological Survey (USGS) Map

A map of the site is found at the end of this chapter.

b. Land Uses

Existing Land use on the site is agricultural. FPL is attempting to rezone the property to PD-PI which will allow for electrical generation.

c. Environmental Features

There are no significant environmental features on the site.

d. Water Quantities

Minimal amounts of water would be required for a solar thermal facility.

e. Supply Sources

The existing water supply could be used for the water required to clean the mirrors for a solar thermal facility.

Environmental and Land Use Information: Supplemental Information

Preferred Site#1: West County Energy Center

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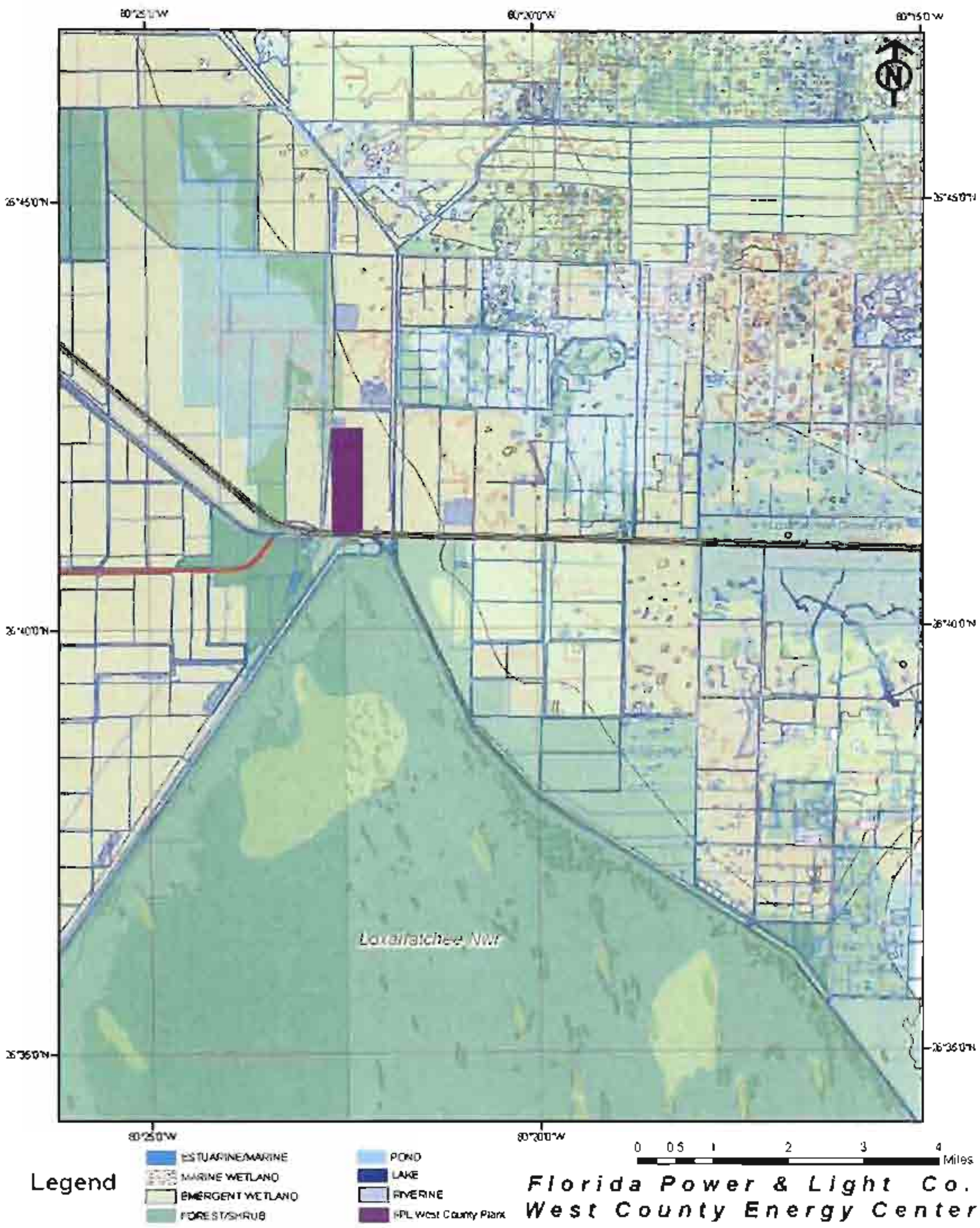
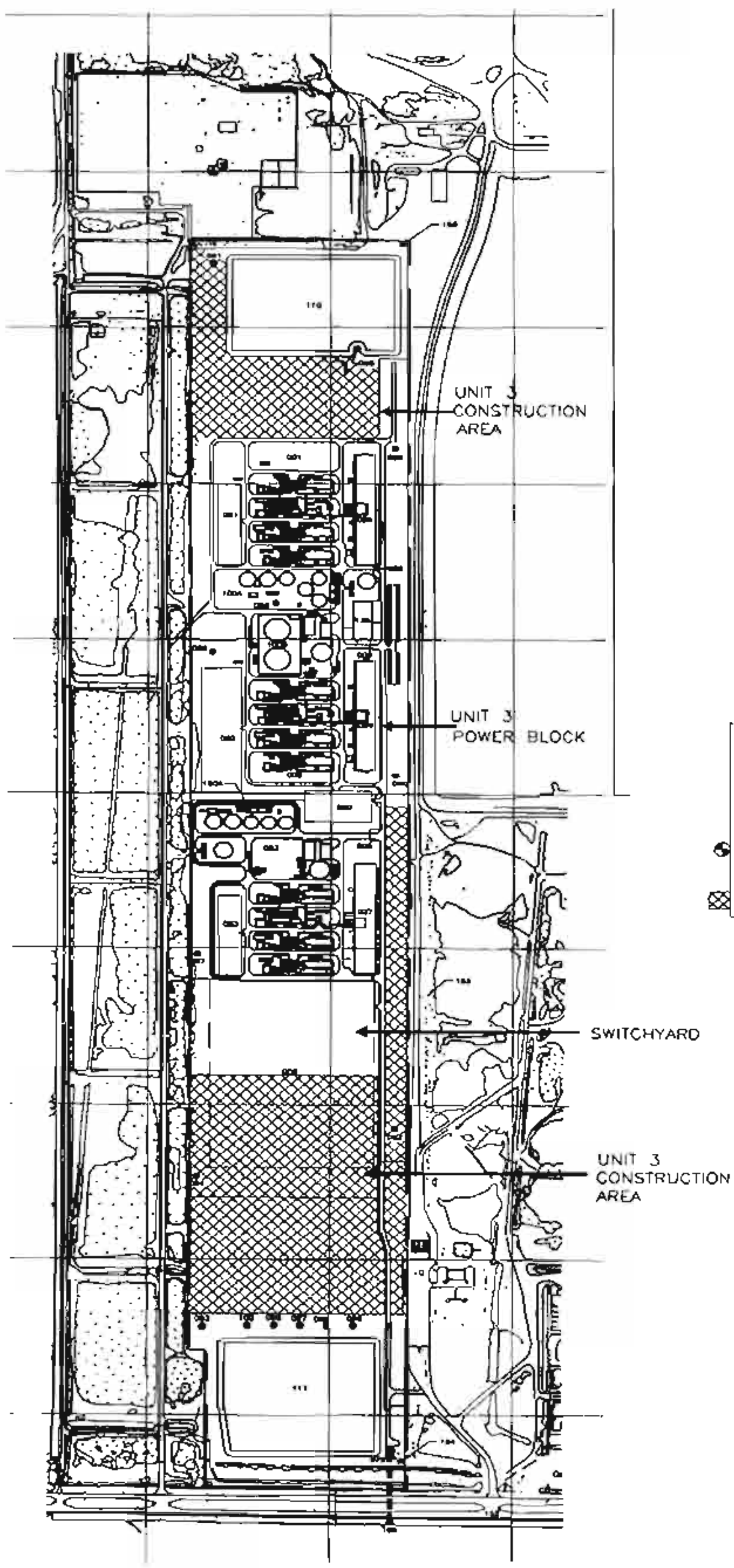
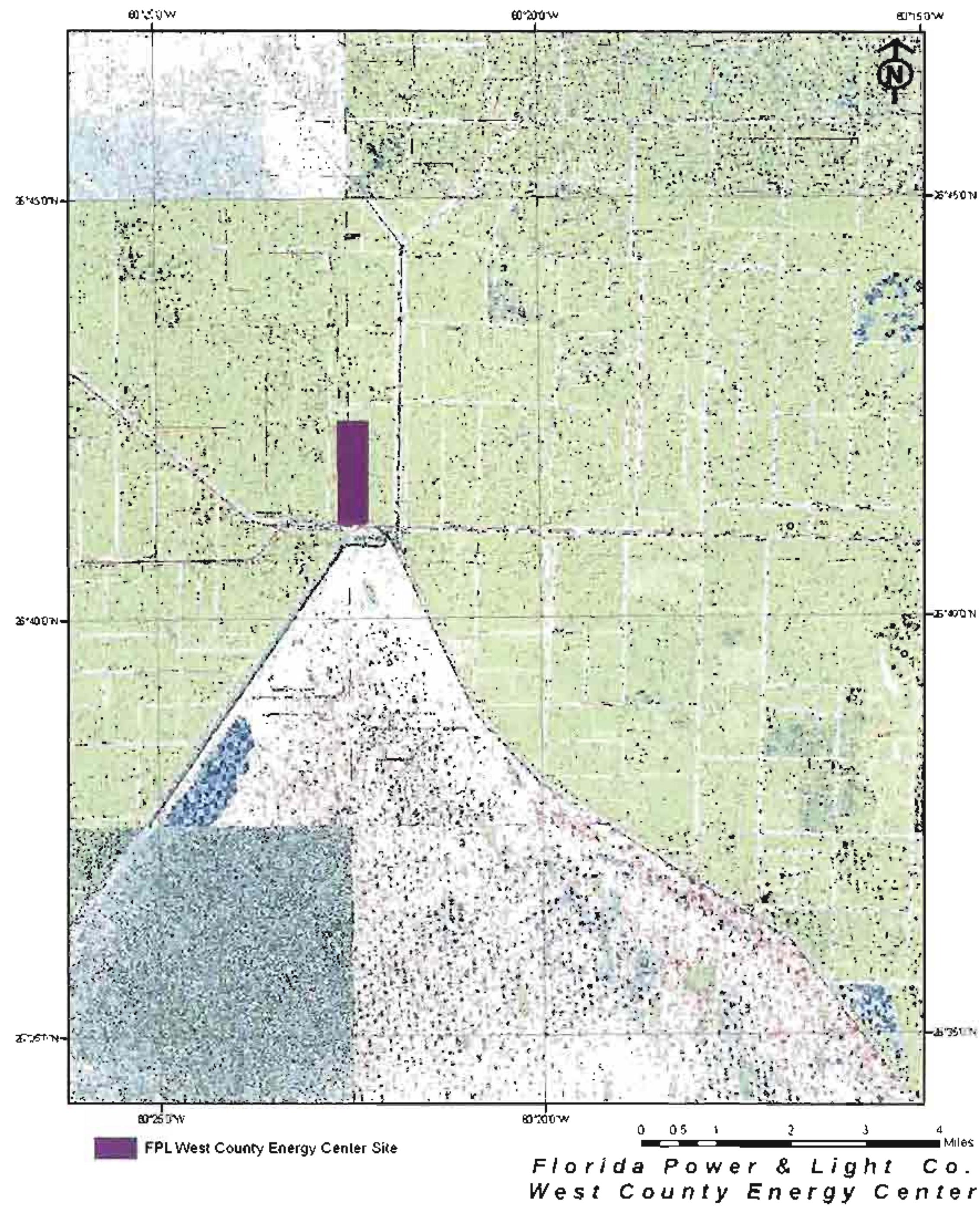

Loxahatchee Nwr
Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL West County Park
0 0.5 1 2 3 4 Miles
Florida Power & Light Co.
West County Energy Center

West County
Energy Center
Potential Site Layout



**FPL West County Energy Center
Site Layout**


FPL West County Energy Center Site
Miles
Florida Power & Light Co.
West County Energy Center

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Environmental and Land Use Information: Supplemental Information

Preferred Site #2: St. Lucie Plant

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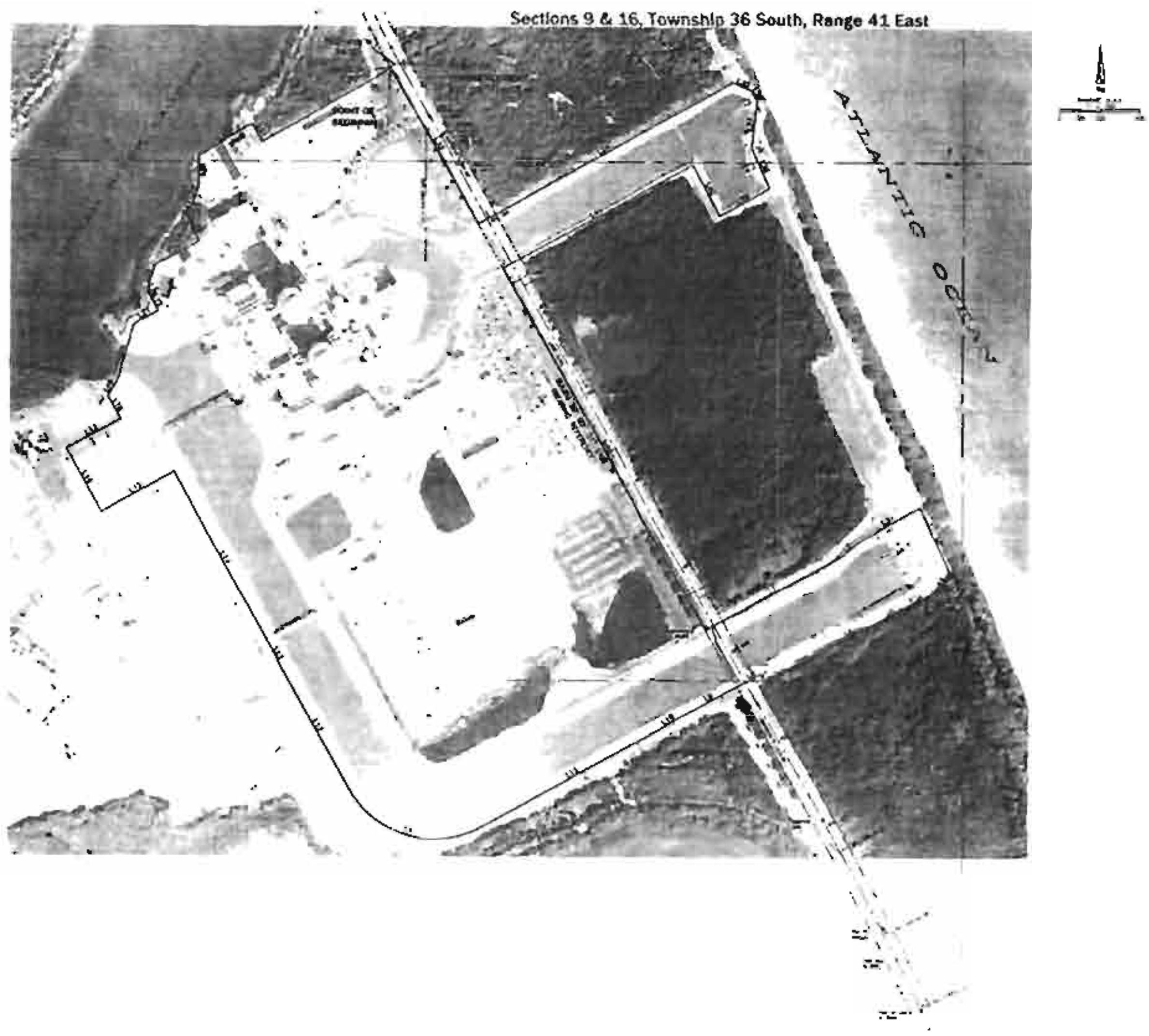

Florida Power & Light Co.
St. Lucie Power Plant


Florida Power & Light Co.
St. Lucie Power Plant
FPL St. Lucie Plant


Fort Pierce
Port Saint Lucie
N
Legend
FPL St. Lucie Plant
Florida Power & Light Co.
St. Lucie Power Plant

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Environmental and Land Use Information: Supplemental Information

Preferred Site #3: Turkey Point Plant

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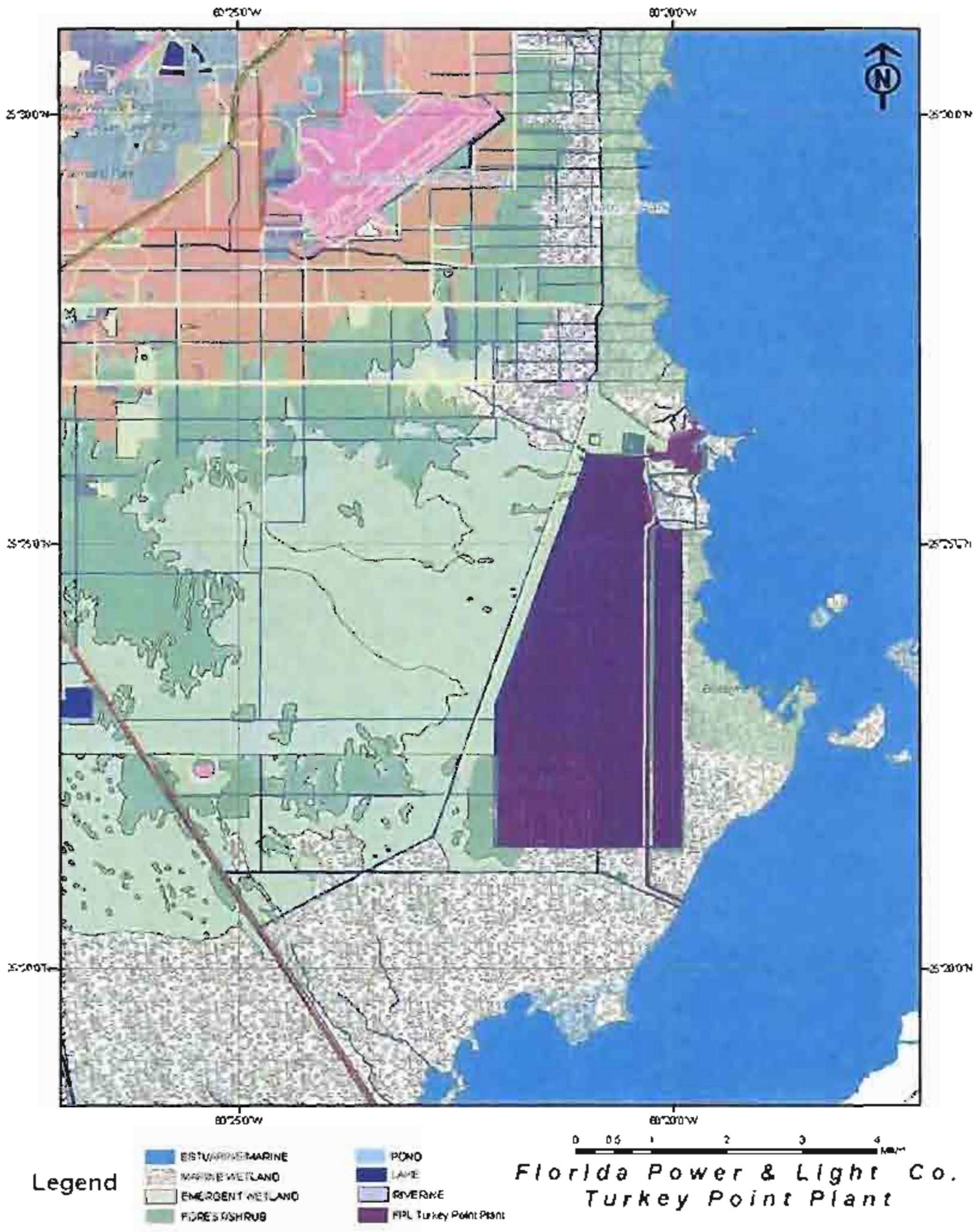
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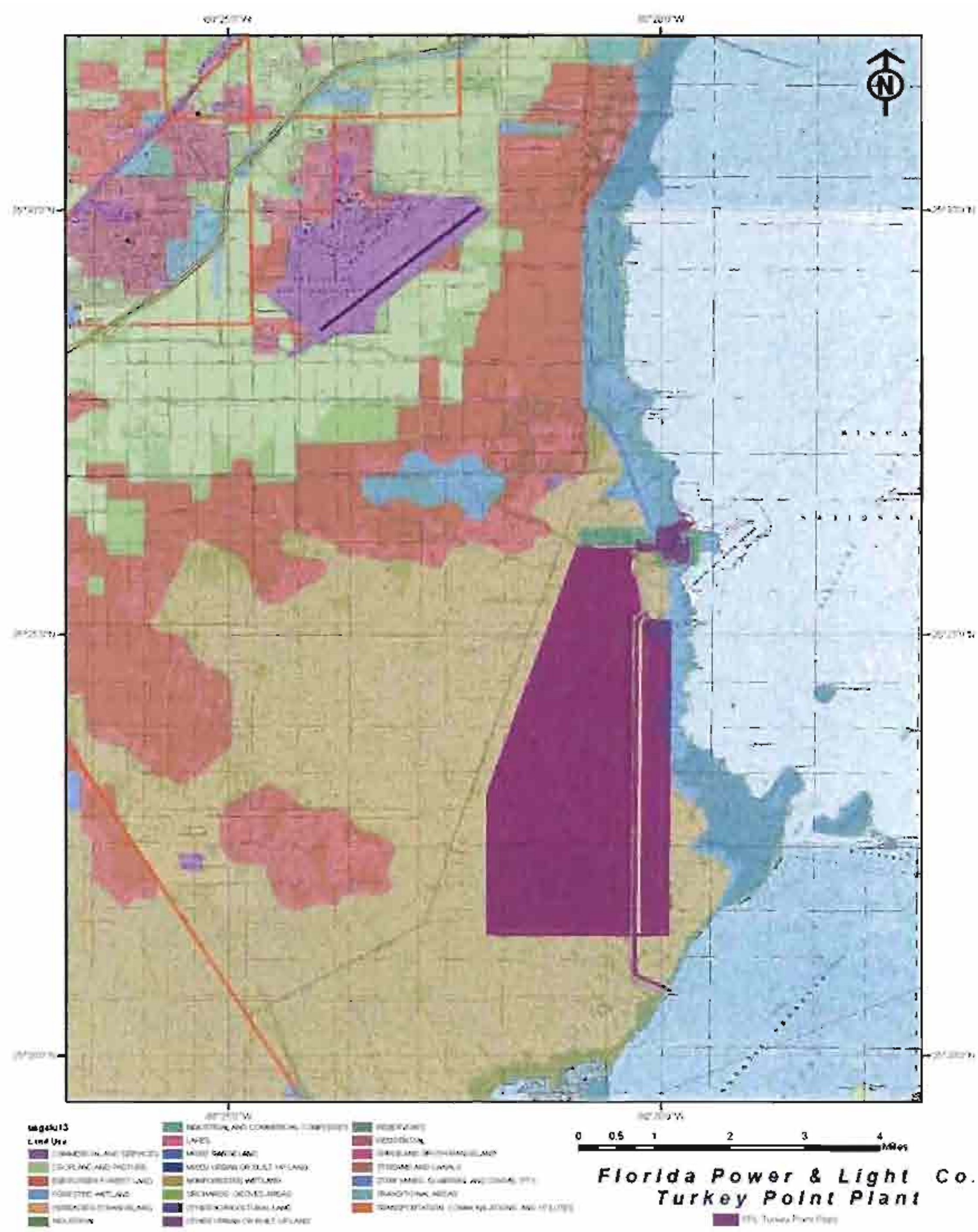
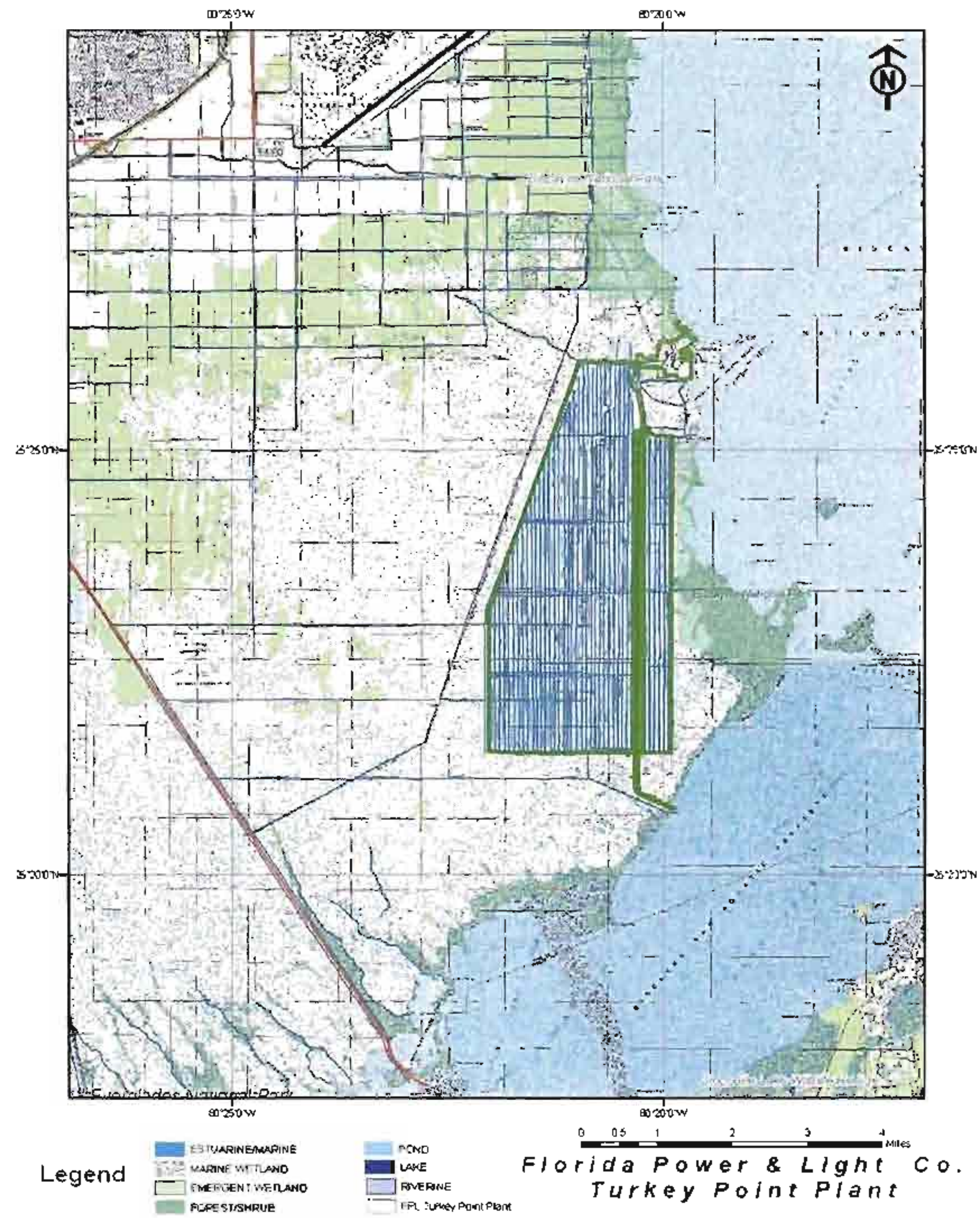
FORESTS/SHRUB
POND
RIVERINE
FPL Turkey Point Plant
Florida Power & Light Co.
Turkey Point Plant


Land Use
LAKES
0 0.5 1 2 3 4 Miles
Florida Power & Light Co.
Turkey Point Plant


80°25'0"W
80°20'0"W
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Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL Turkey Point Plant
Florida Power & Light Co.
Turkey Point Plant

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Environmental and Land Use Information: Supplemental Information

Preferred Site #4: Cape Canaveral Plant

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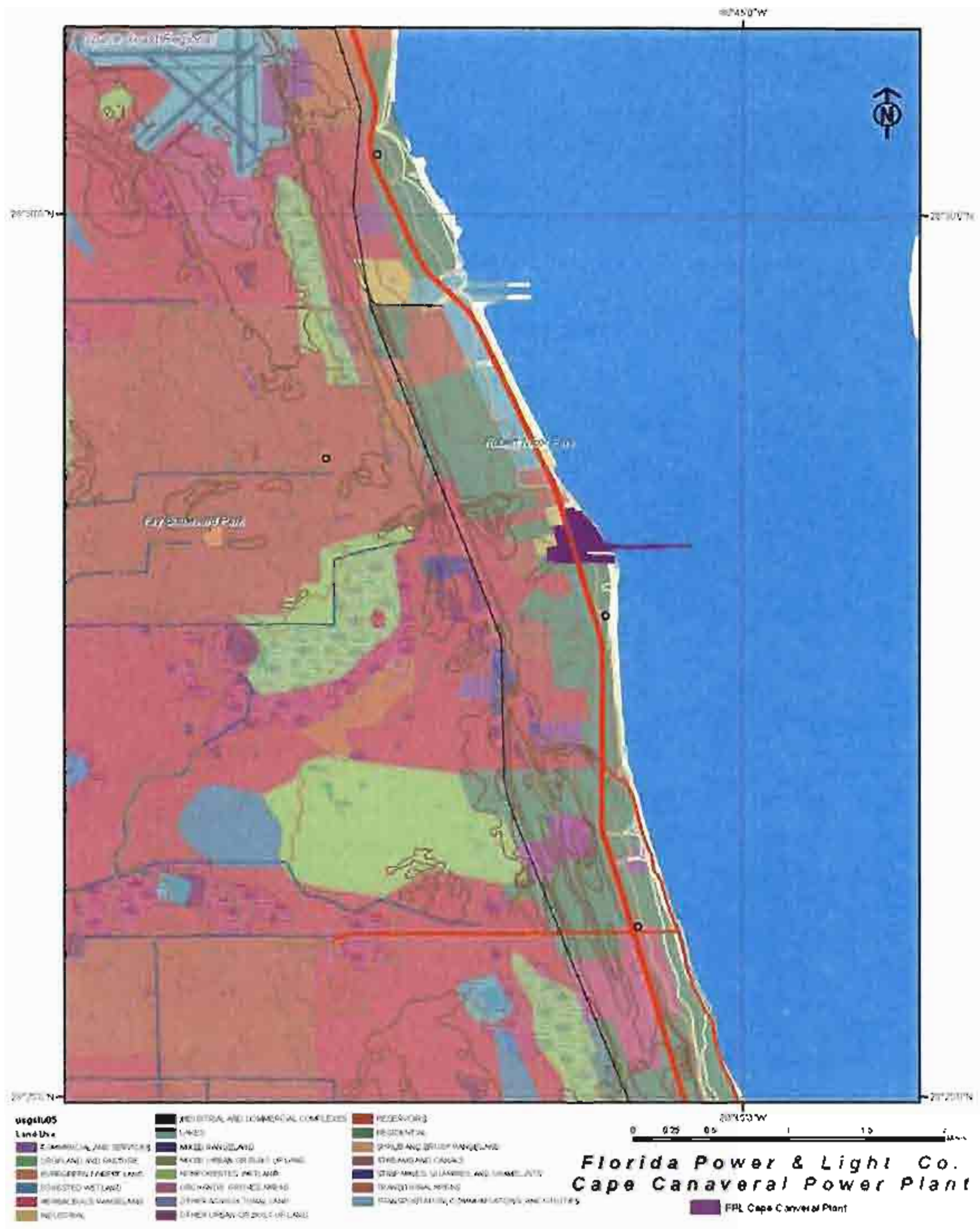
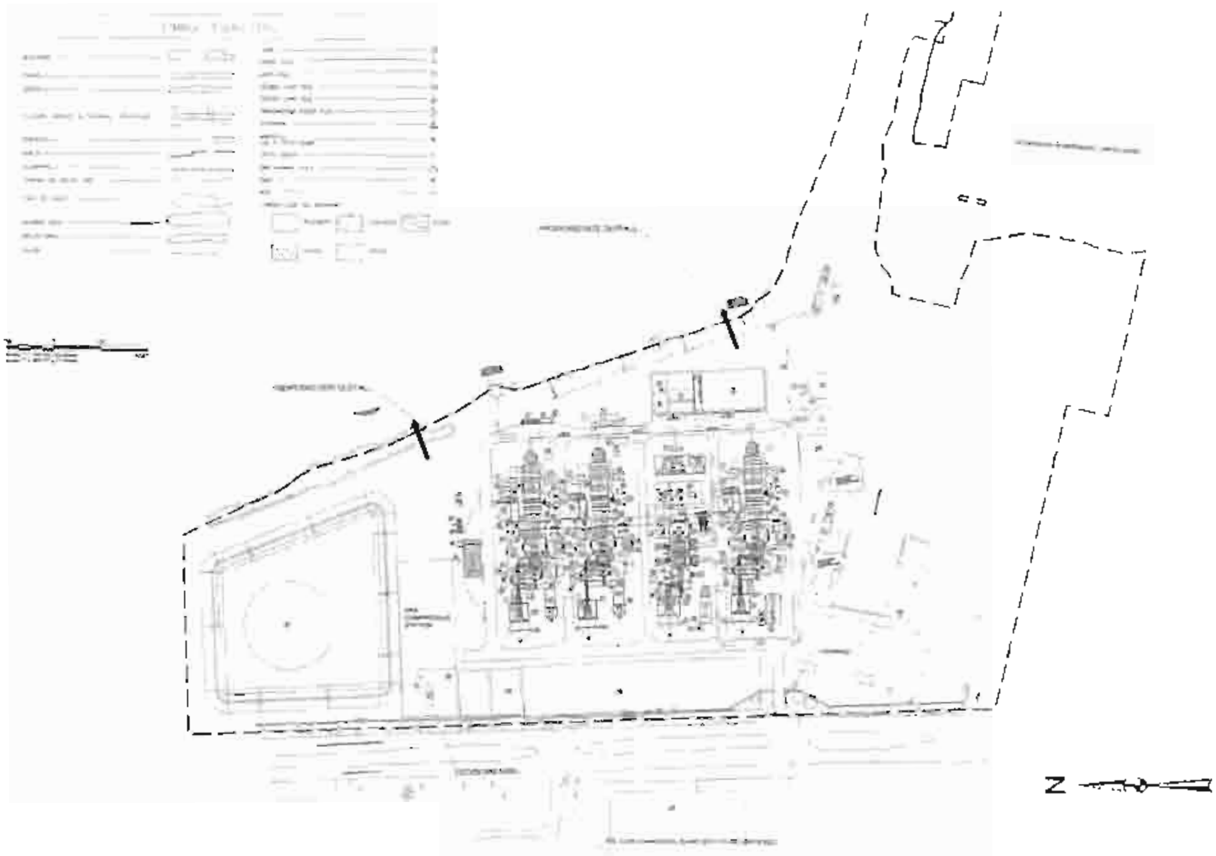
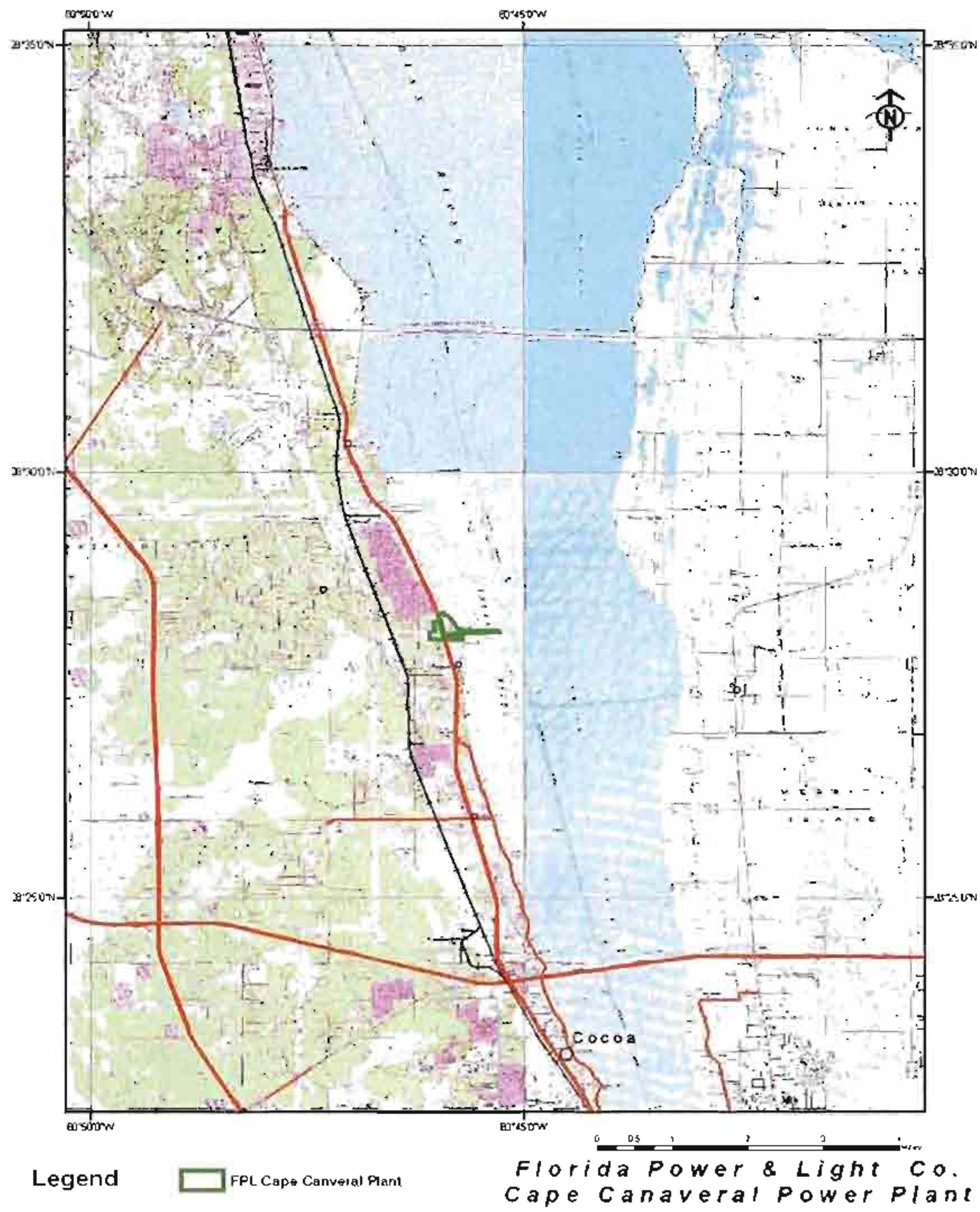

Florida Power & Light Co.
Cape Canaveral Power Plant
FPL Cape Canaveral Plant



Florida Power & Light Co.

Cape Canaveral Power Plant


Cocoa
Legend
FPL Cape Canveral Plant
Florida Power & Light Co.
Cape Canaveral Power Plant

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Environmental and Land Use Information:

Supplemental Information

Preferred Site #5: Riviera Plant

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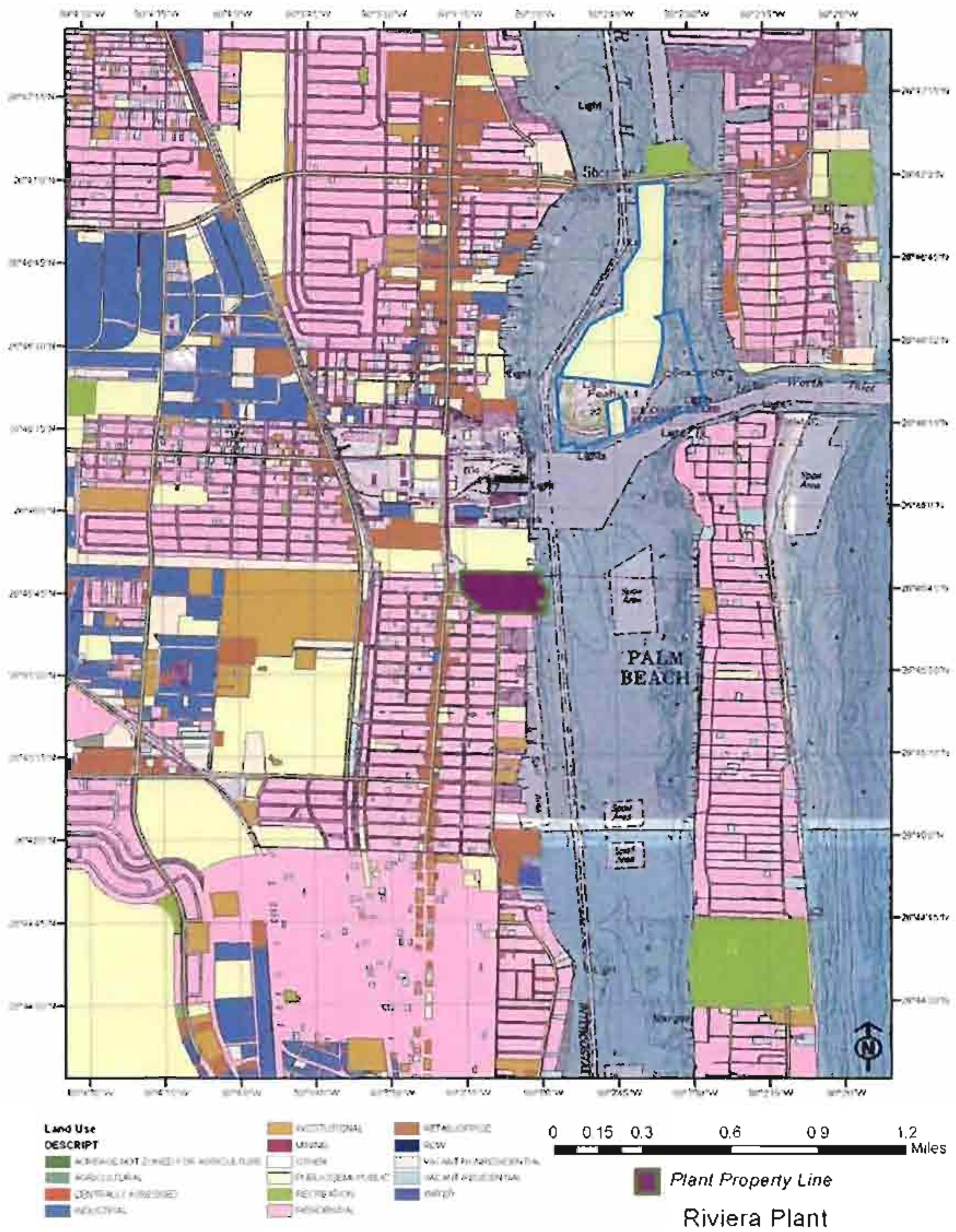
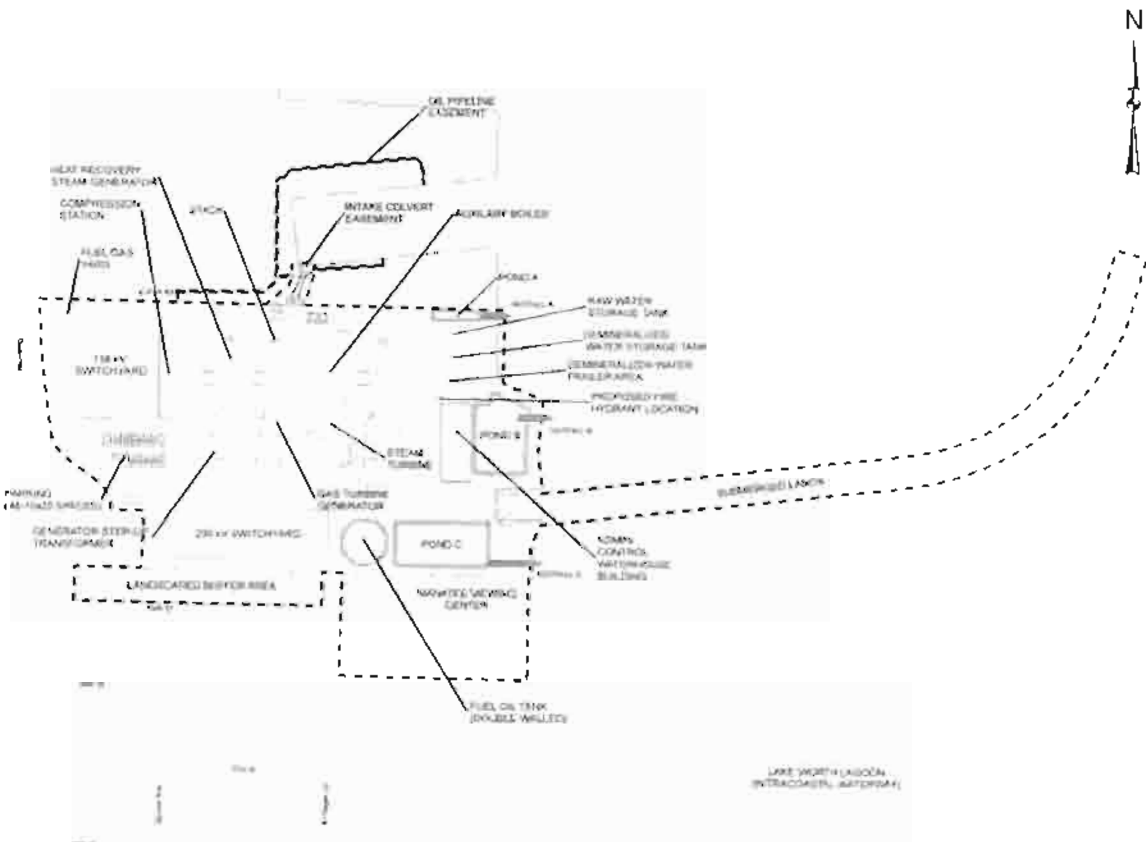
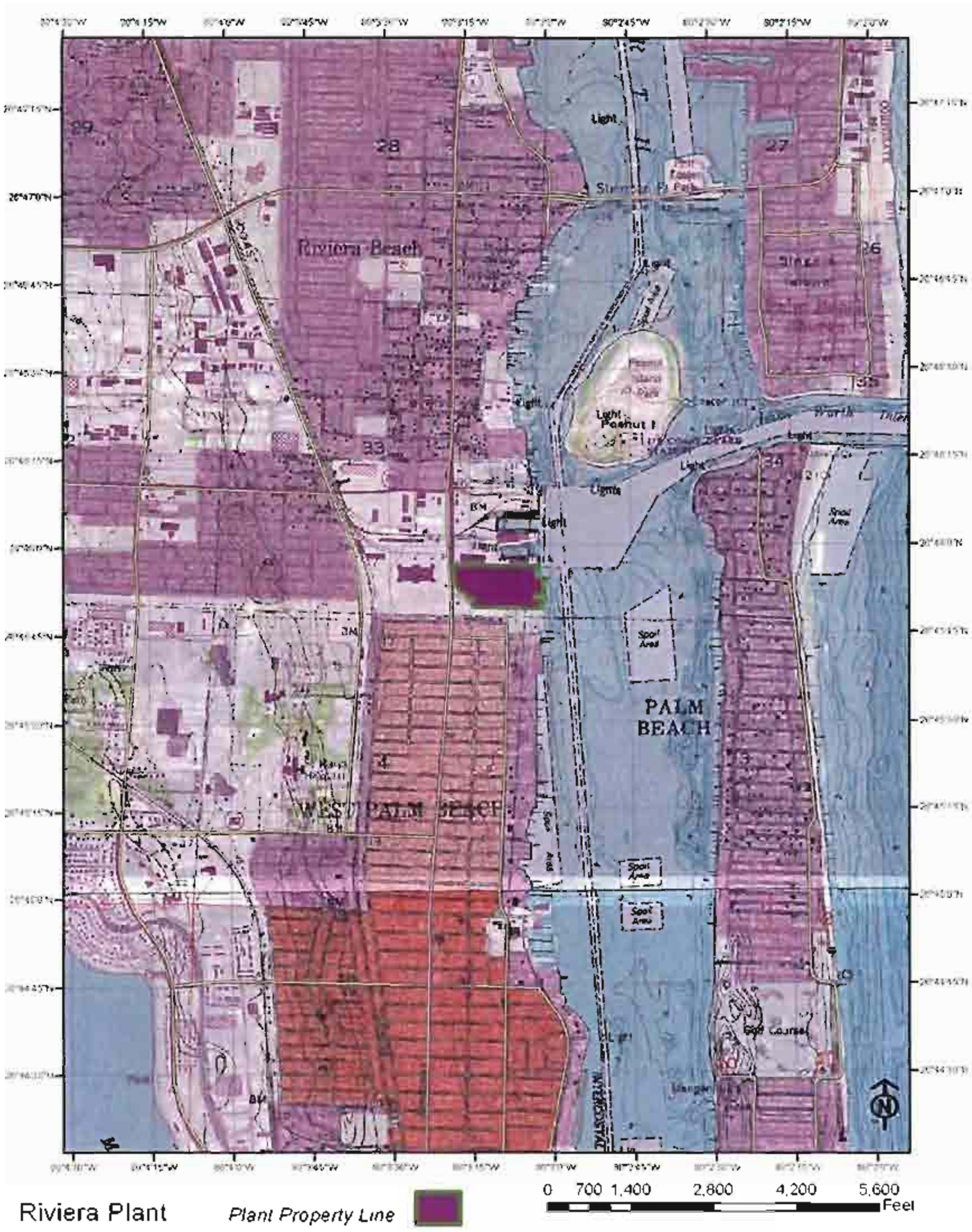

PALM BEACH
Land Use
DESCRIPT
OTHER
ROW
0 0.15 0.3 0.6 0.9 1.2 Miles
Plant Property Line
Riviera Plant



Florida Power & Light Co.
Riviera Plant



Riviera Plant
Plant Property Line

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Environmental and Land Use Information: Supplemental Information

Preferred Site #6: Desoto Next Generation Solar Energy Center

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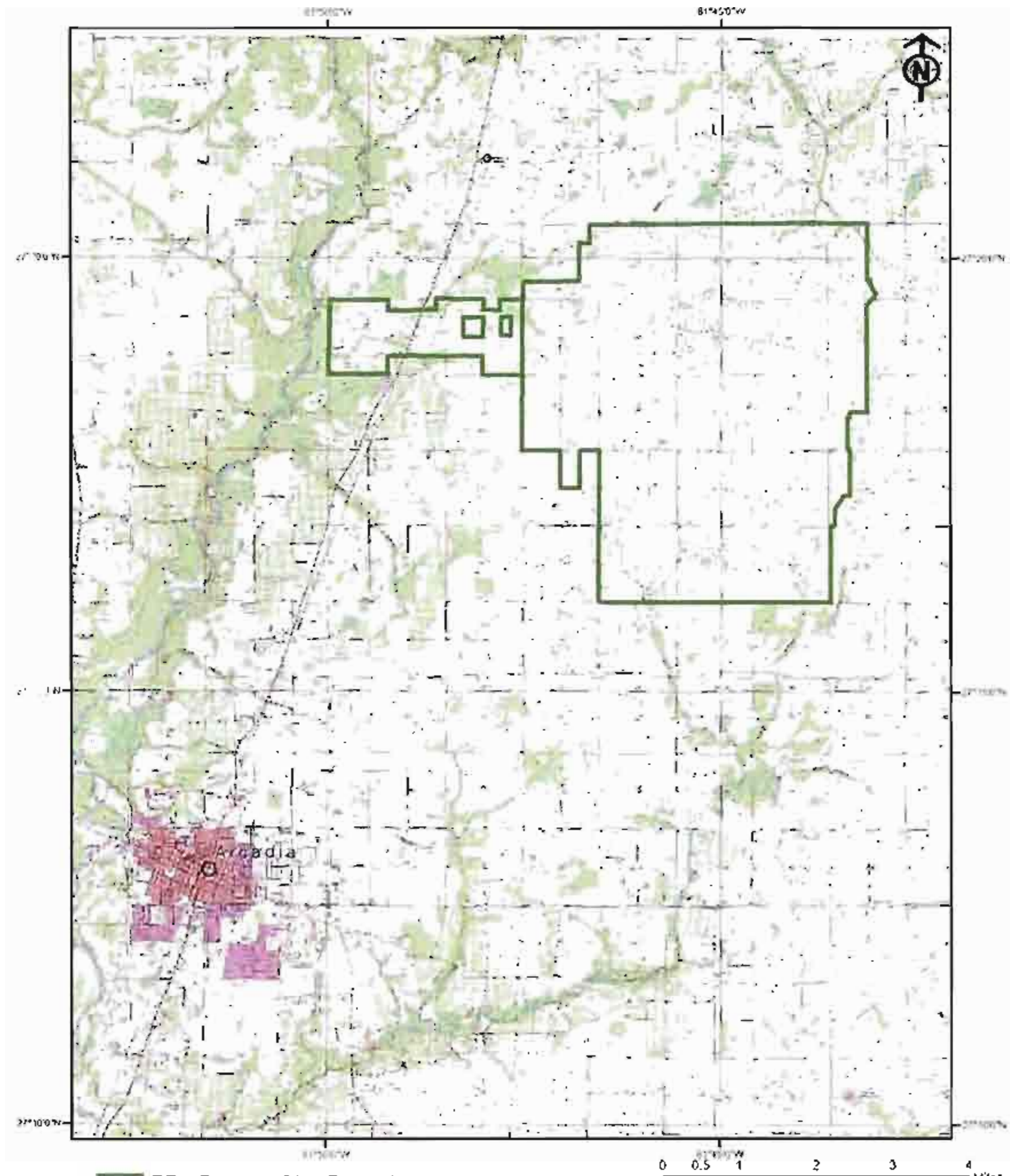
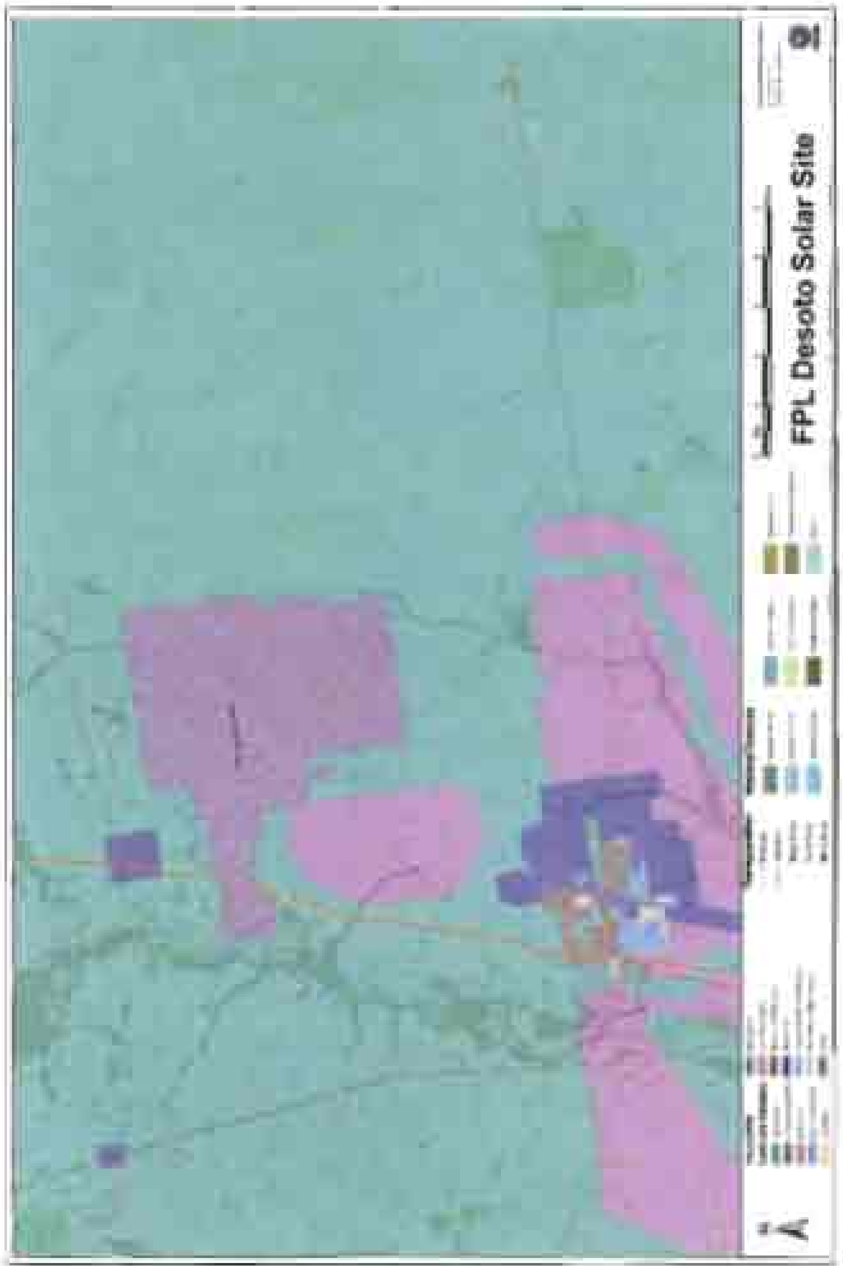


FPL Desoto Site Boundary

0 0.5 1 2 3 4 Miles

Florida Power & Light Co.
Desoto Solar Site


FPL Desoto Solar Site

Florida Power & Light Co.
Desoto Solar Site Layout

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Environmental and Land Use Information: Supplemental Information

Preferred Site #7: Space Coast Next Generation Solar Energy Center

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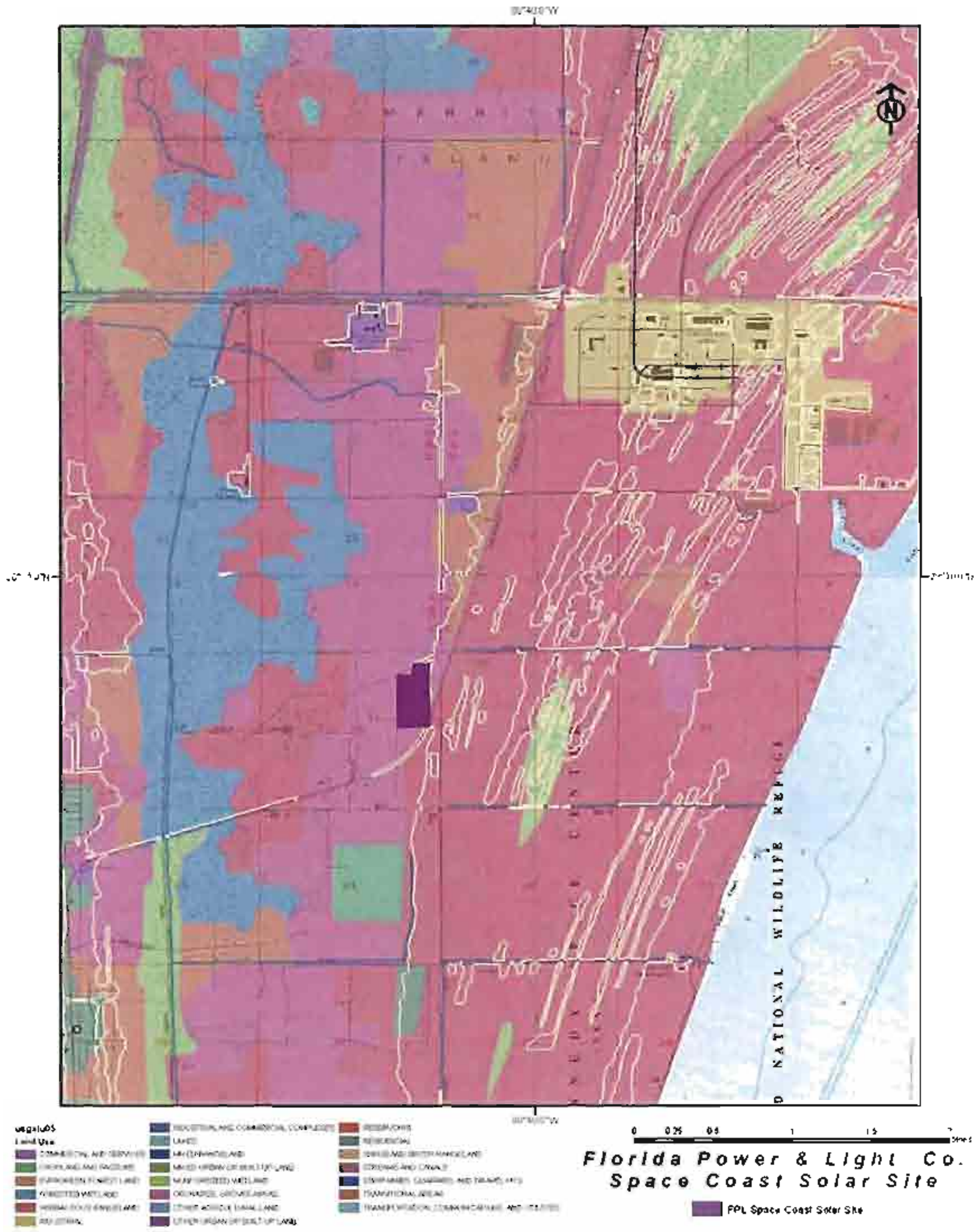
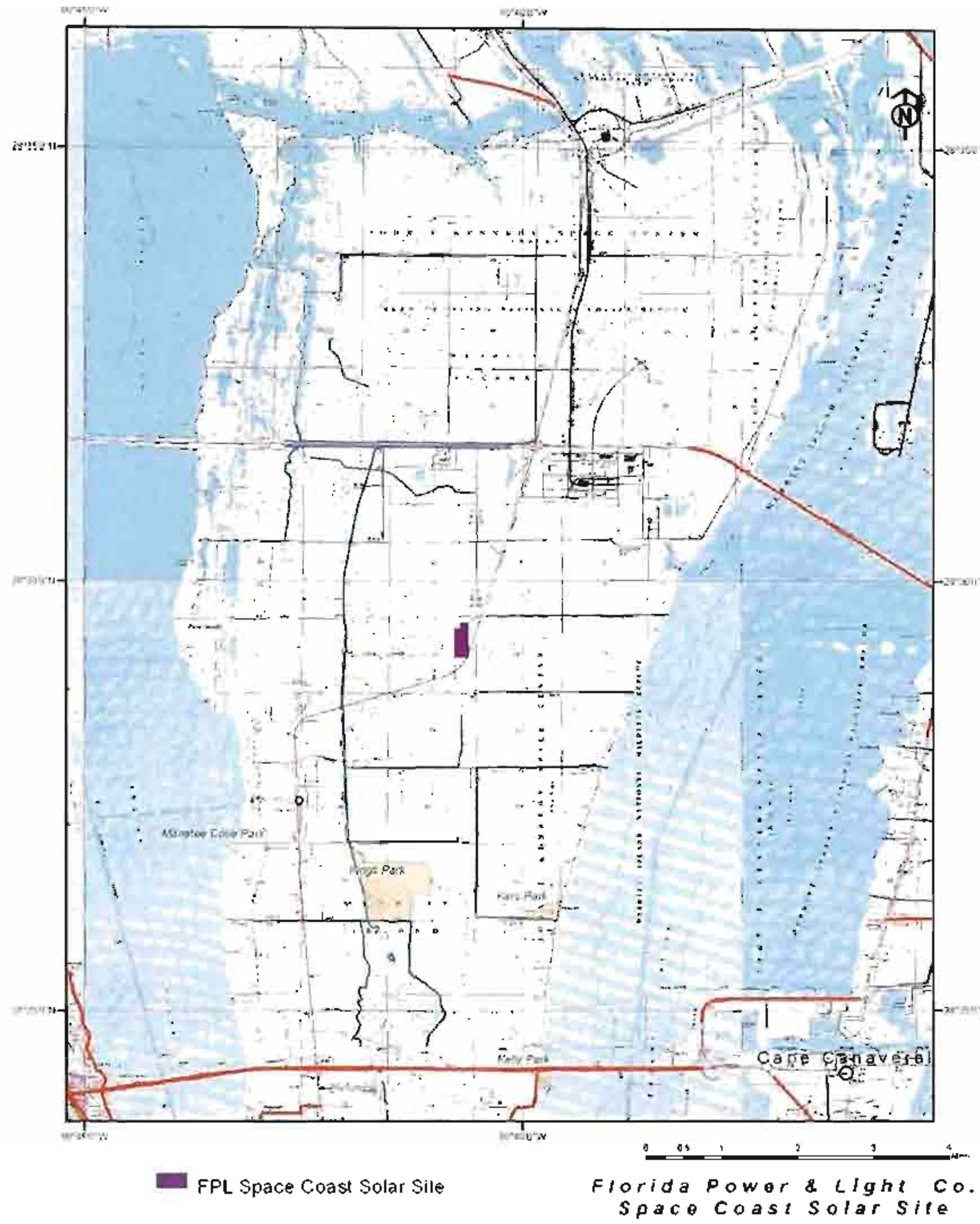
FPL Space Coast Solar Site Layout

Florida Power & Light Co.
Space Coast Solar Site


Florida Power & Light Co.
Space Coast Solar Site
FPL Space Coast Solar Site


Manatee Cove Park
Kings Park
Kars Park
Kelly Park
Cape Canaveral
FPL Space Coast Solar Site
Florida Power & Light Co.
Space Coast Solar Site

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Environmental and Land Use Information: Supplemental Information Preferred Site #8: Martin Next Generation Solar Energy Center

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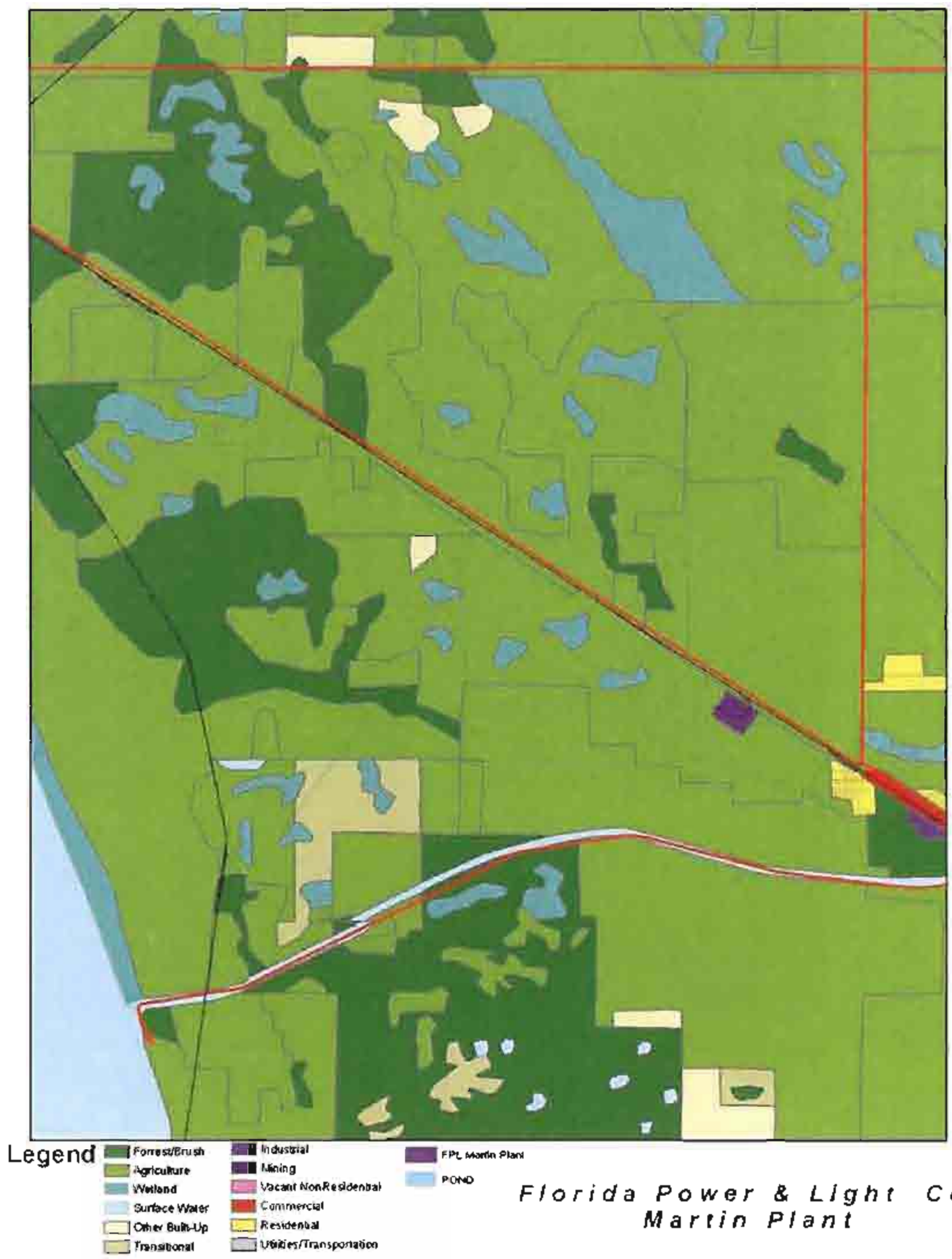
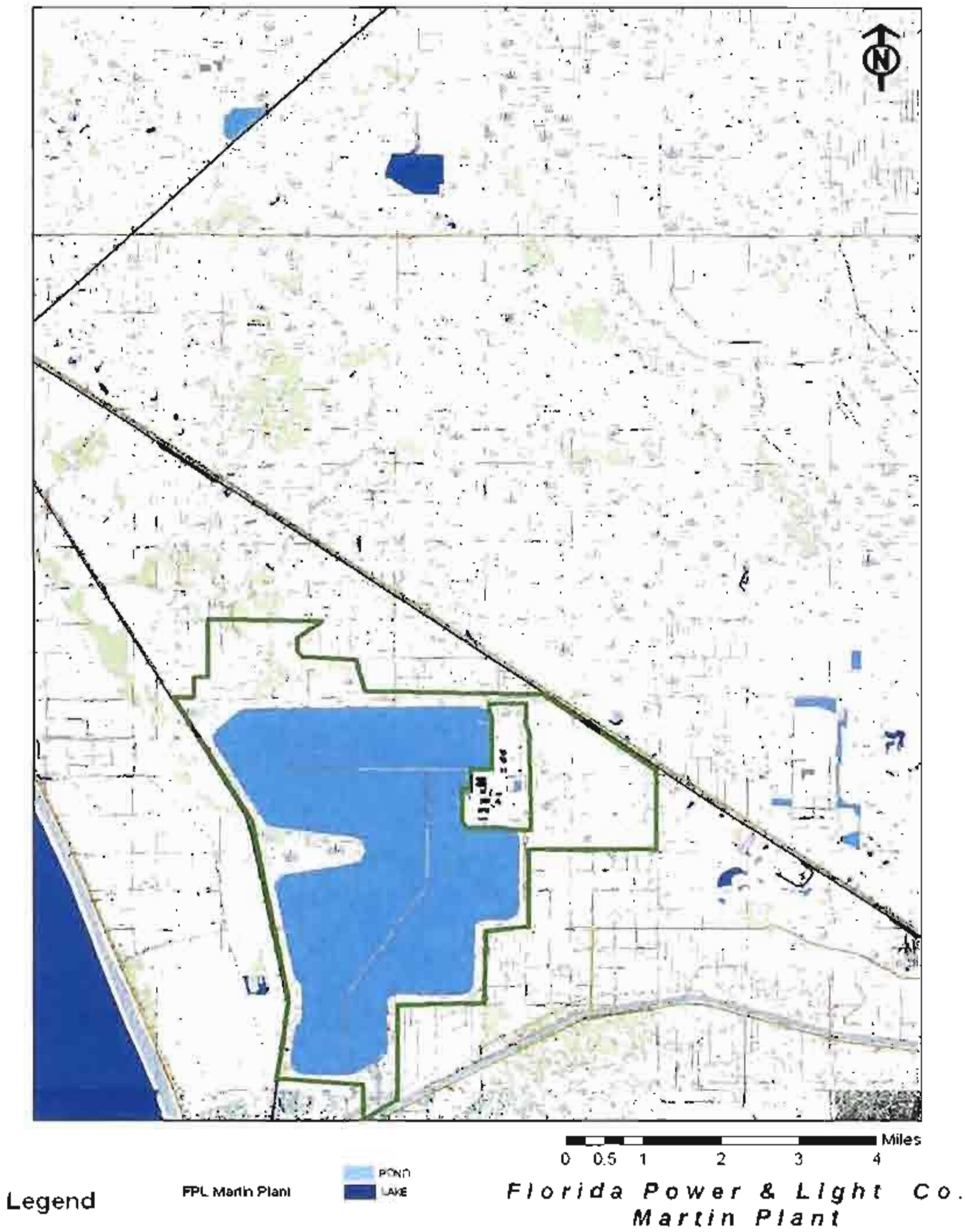
N
0 0.125 0.25 0.5 0.75 1
Miles
Martin Plant
Facility Layout
FPL Martin Plant Site
Facility Structures
Solar Thermal Plant
Florida Power & Light Co.
Martin Plant



Florida Power & Light Co.
Martin Plant


Miles
0 0.5 1 2 3 4
Legend
FPL Martin Plant
POND
LAKE
Florida Power & Light Co.
Martin Plant

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Environmental and Land Use Information: Supplemental Information

Potential Site #1: West Broward

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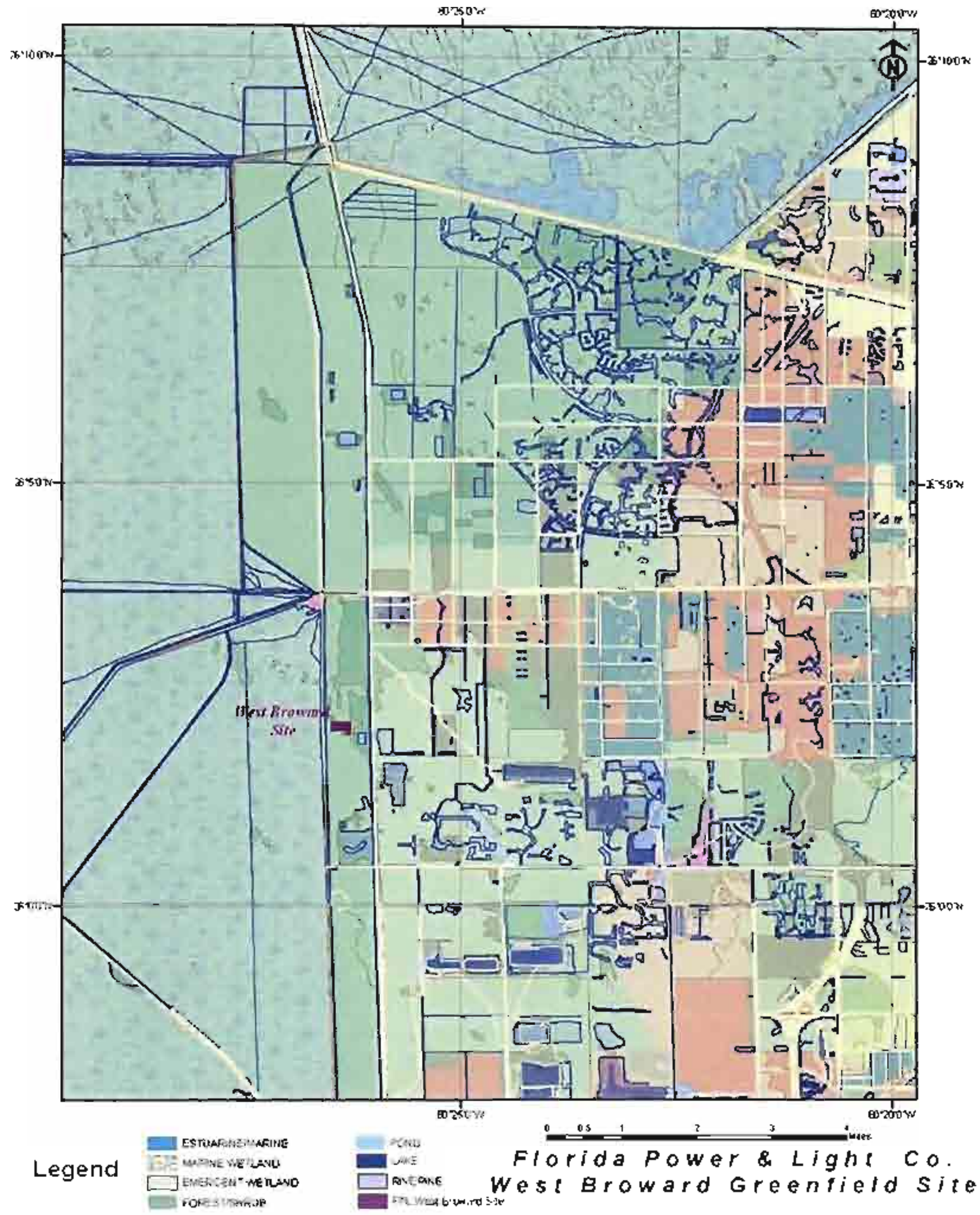
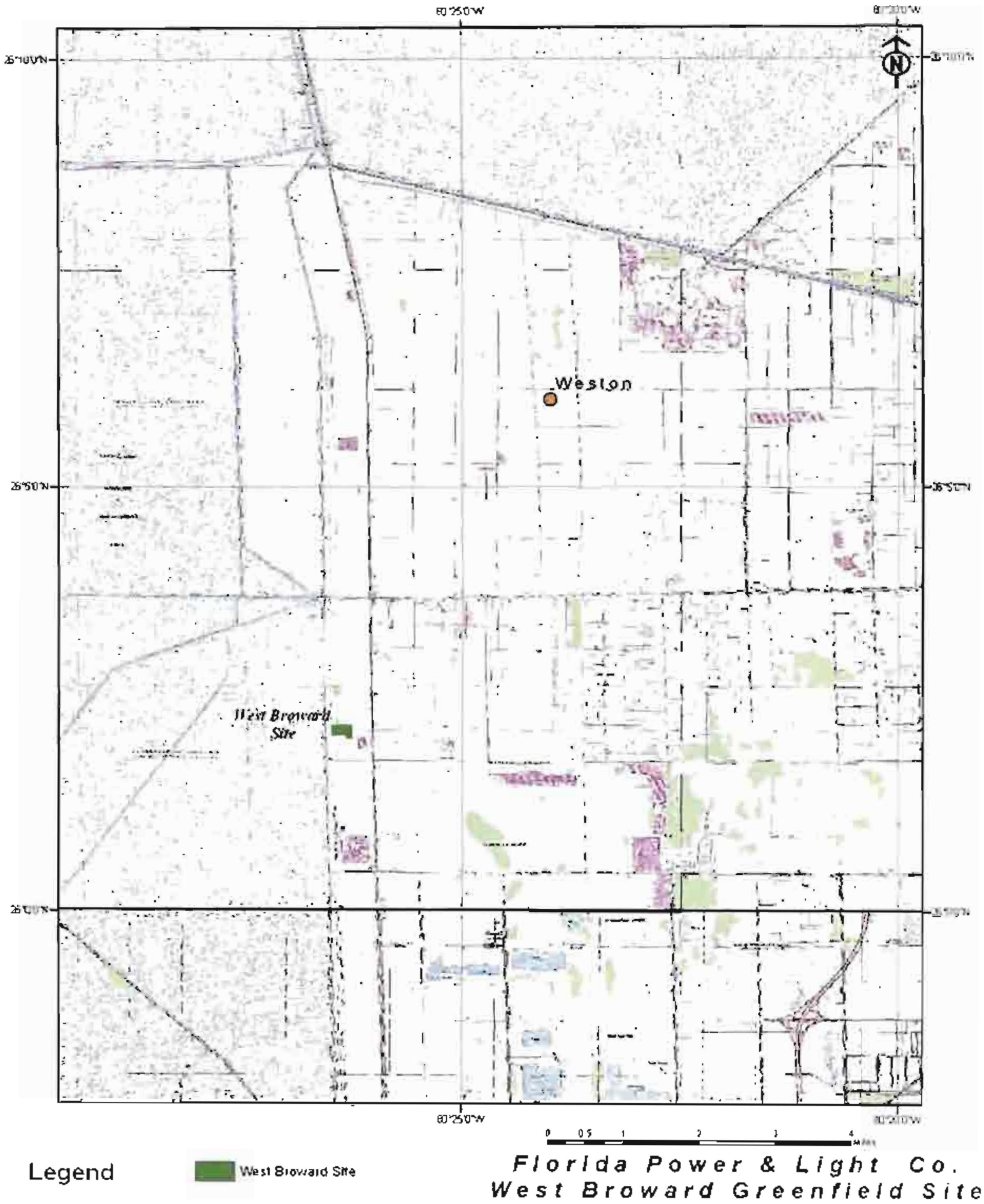

West Broward Site
Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL West Broward Site
Miles
Florida Power & Light Co.
West Broward Greenfield Site



Florida Power & Light Co.
West Broward Greenfield Site

Environmental and Land Use Information: Supplemental Information

Potential Site # 2: Ft. Myers

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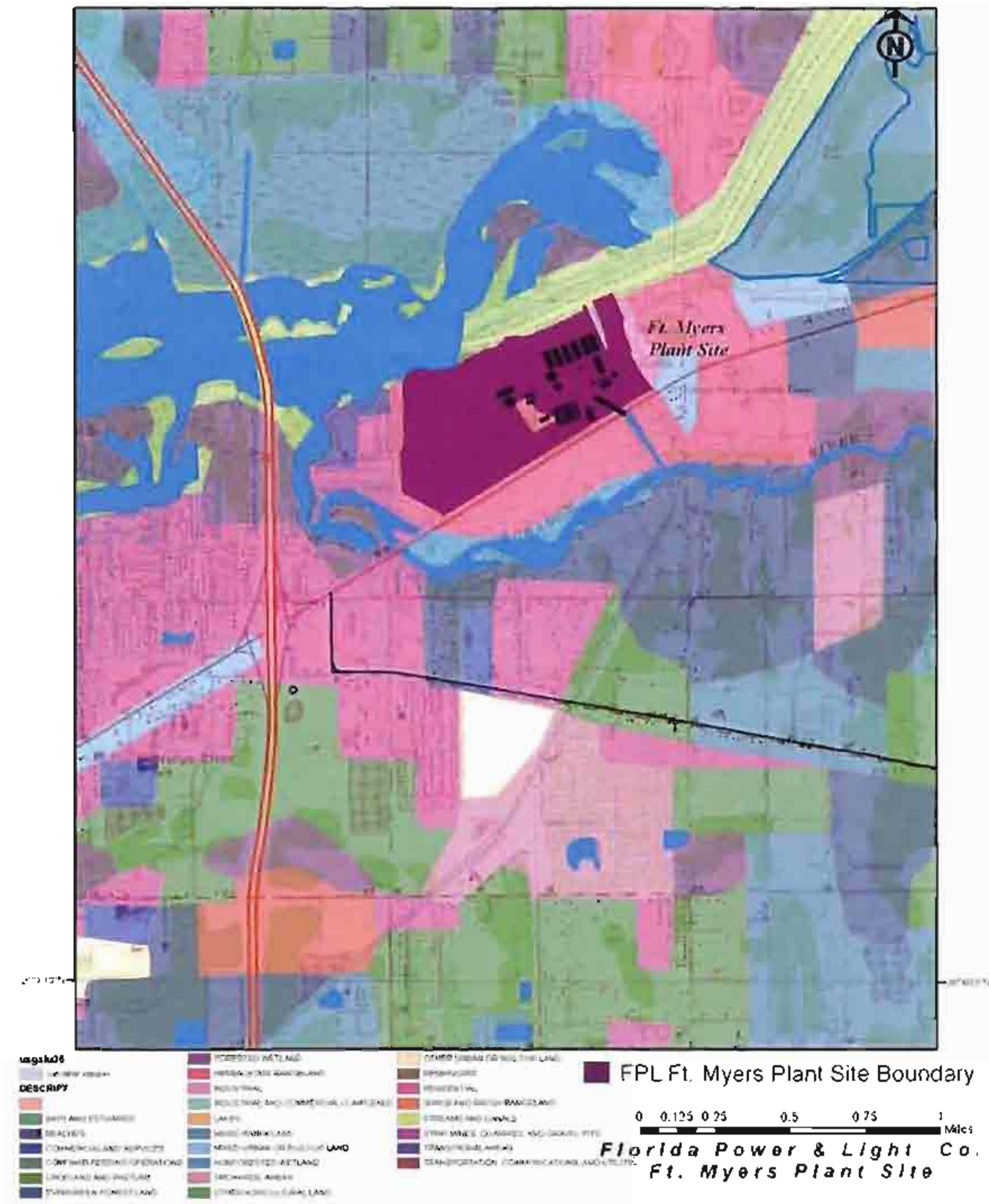
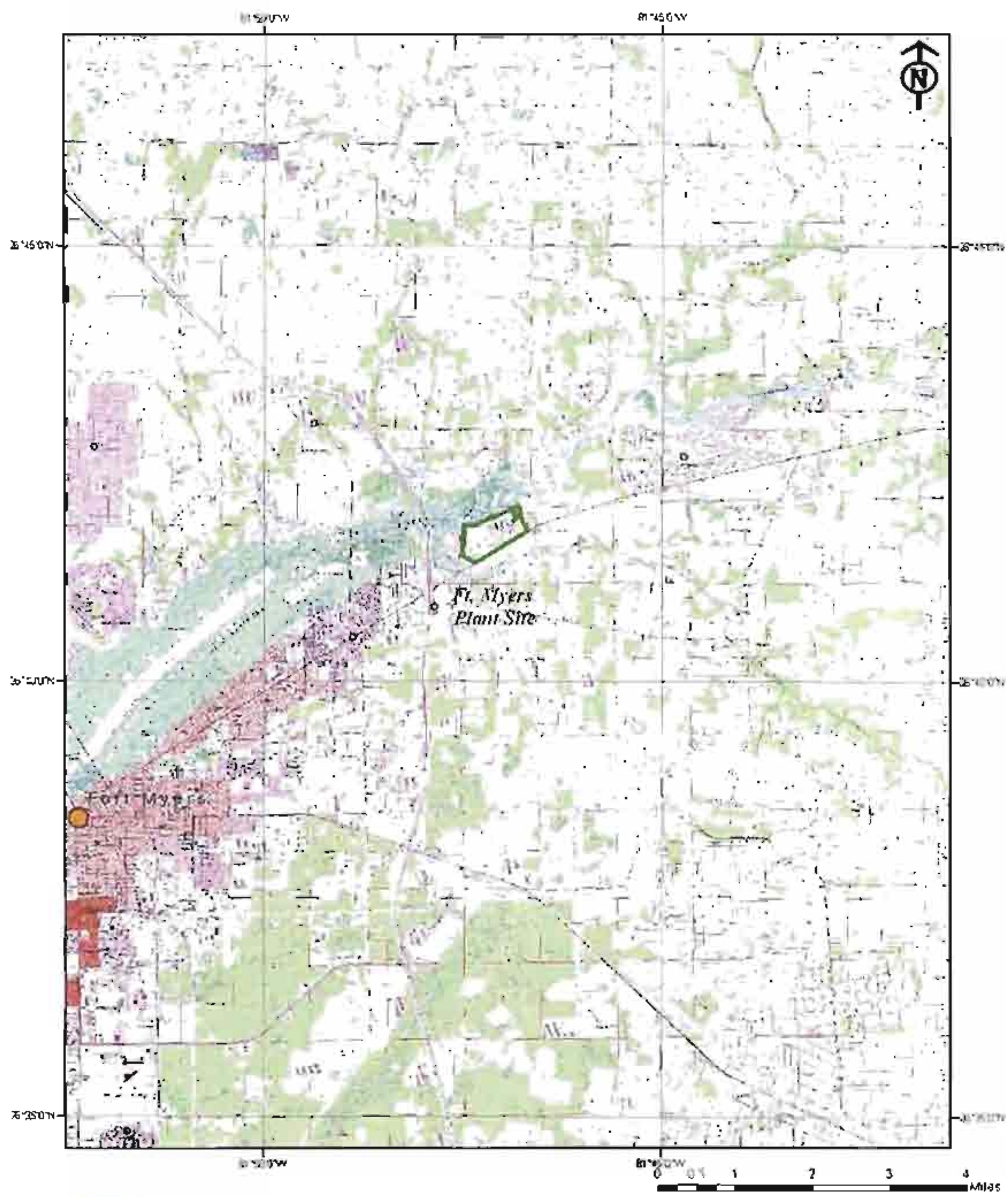

N
Ft. Myers
Plant Site
DESCRIPT
FPL Ft. Myers Plant Site Boundary
0 0.125 0.25 0.5 0.75 1
Miles
Florida Power & Light Co.
Ft. Myers Plant Site



FPL Ft. Myers Plant Site Boundary

Florida Power & Light Co.
Ft. Myers Plant Site

Environmental and Land Use Information: Supplemental Information

Potential Site #3: Lauderdale Plant

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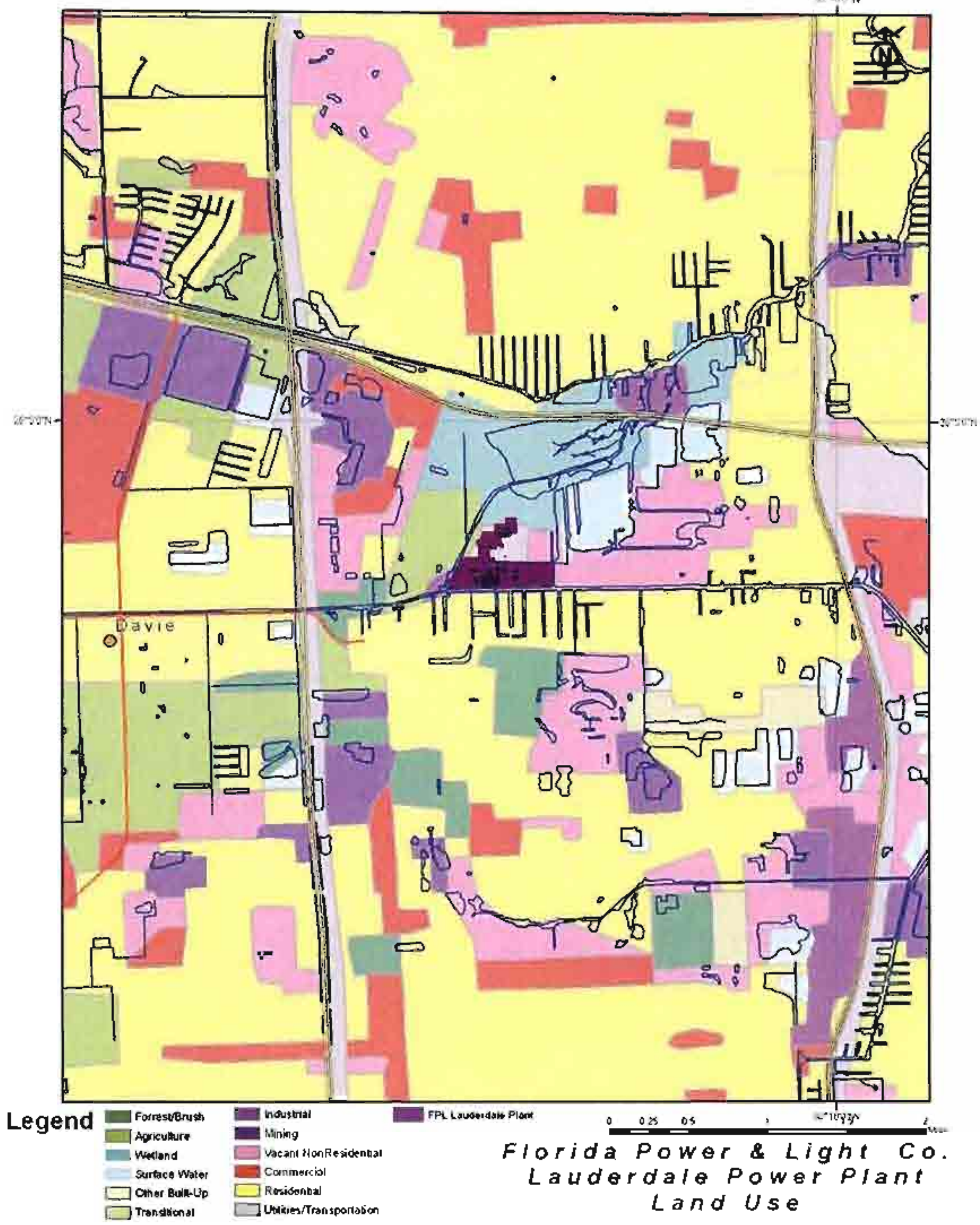
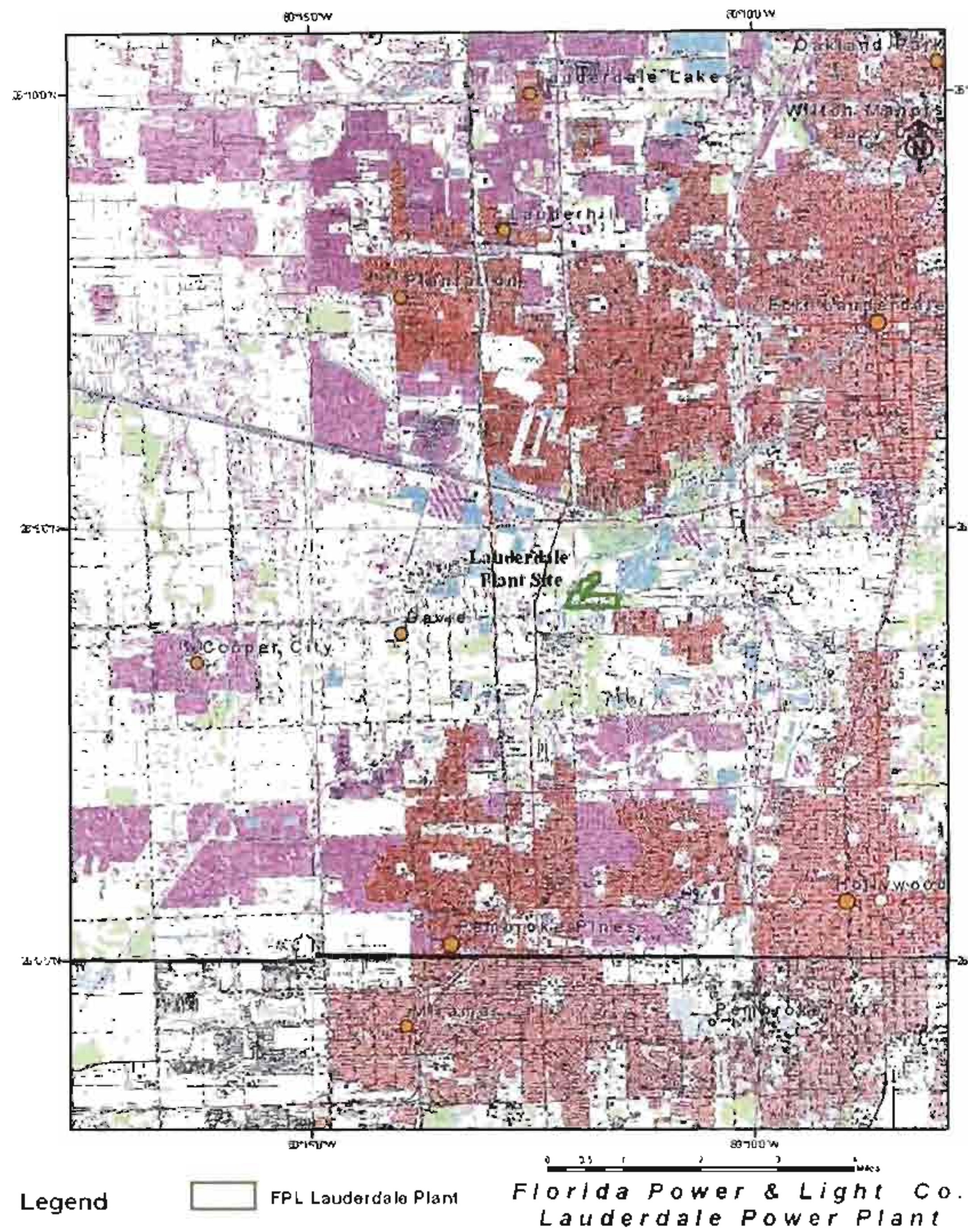


Florida Power & Light Co.
Lauderdale Power Plant
Land Use


Oakland Park
Lauderdale Lakes
Lauderhill
Plantation
Lauderdale
Plant Site
Davie
Cooper City
Hollywood
Pembroke Pines
Miramar
Pembroke Park
Legend
FPL Lauderdale Plant
Florida Power & Light Co.
Lauderdale Power Plant

Environmental and Land Use Information: Supplemental Information

Potential Site #4: Manatee Plant

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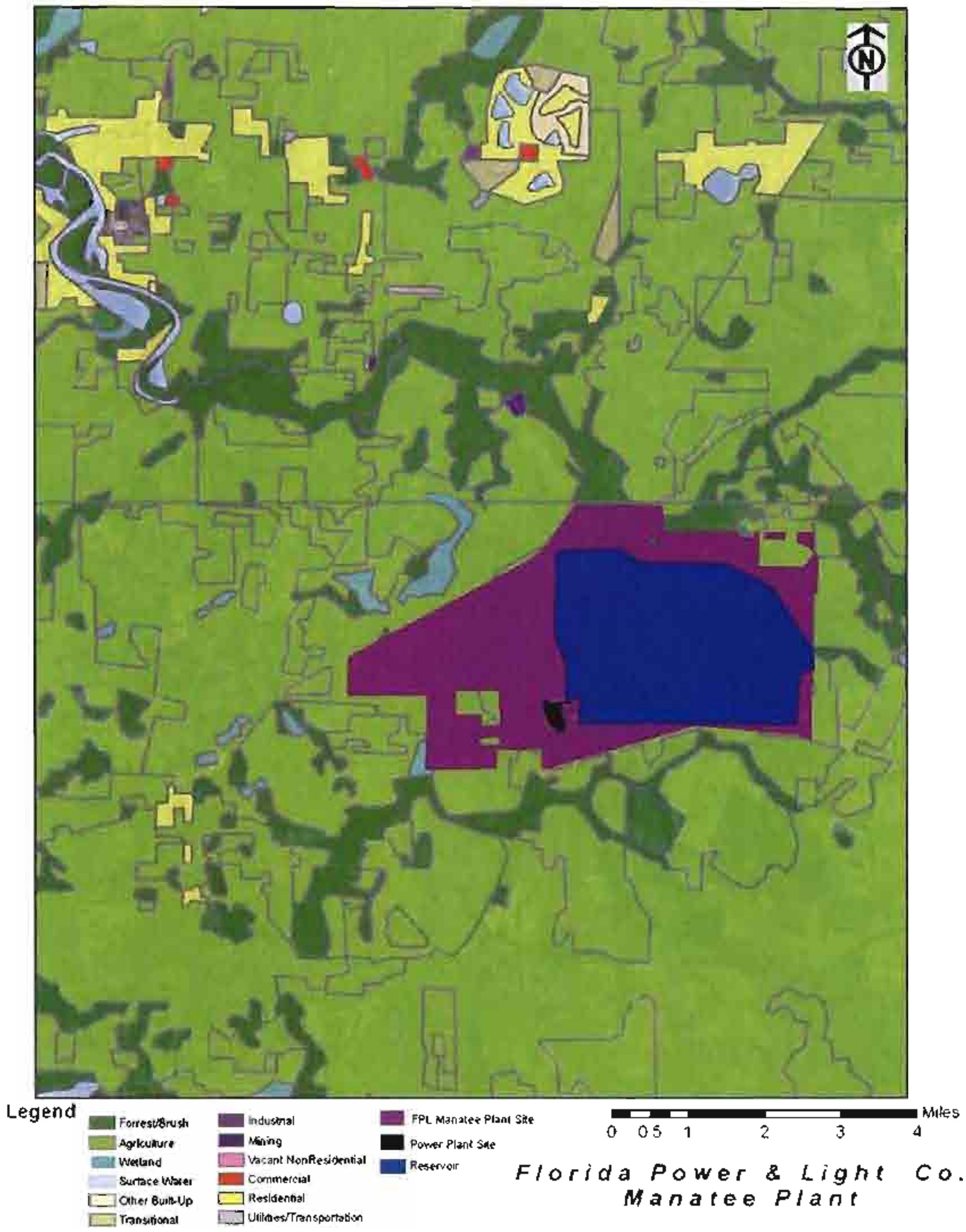
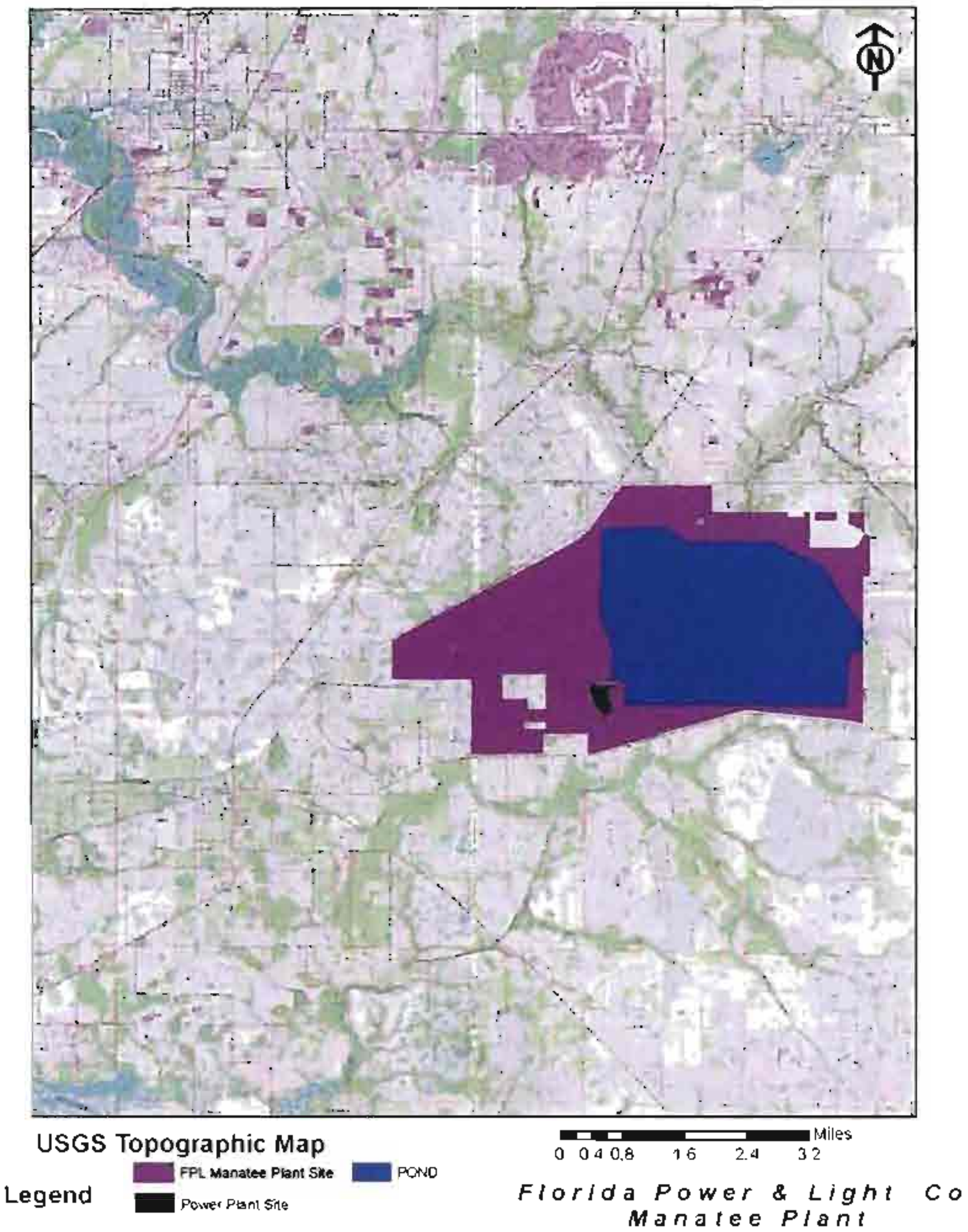

N
Legend
Forrest/Brush
Agriculture
Wetland
Surface Water
Other Built-Up
Transitional
Industrial
Mining
Vacant NonResidential
Commercial
Residential
Utilities/Transportation
FPL Manatee Plant Site
Power Plant Site
Reservoir
Miles
0 0.5 1 2 3 4
Florida Power & Light Co.
Manatee Plant


USGS Topographic Map
Legend
FPL Manatee Plant Site
POND
Power Plant Site
Miles
0 0.4 0.8 1.6 2.4 3.2
Florida Power & Light Co.
Manatee Plant

CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information". These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints: external limitations and internal limitations. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important since they affect the development of assumptions for the amount of external assistance that is available to the FPL system as well as the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new units that minimize adverse impacts to the flow of electricity within FPL's system. The internal transmission limitations are also addressed by developing the direct costs for siting new units at different locations and by evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system. Both of these site- and system-related transmission costs are developed for each different unit/unit location option or groups of options. In addition, transfer limits for capacity and energy that can be imported into the Southeastern region of FPL's system are also developed for use in FPL's production costing analyses. (A further discussion of the Southeastern Florida region and the need to maintain a regional balance between generation and transmission contributions is found in Chapter III.)

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's planned transmission facilities to interconnect and integrate FPL's resource plans and those that must be certified under the Transmission Line Siting Act are presented in Chapter III.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements for the FPL system.[4]

The load forecast that is presented in FPL's 2009 Site Plan was developed in January 2009. FPL has not performed sensitivity analyses on forecasts that differ from this recently developed load forecast.

[4] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis, the lowest rate basis and the lowest system revenue requirements basis are identical. In such cases FPL evaluates options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its fuel price forecasts are discussed in Chapter III of this document. FPL's 2008 resource planning work utilized up to four different fuel cost forecasts (and four different environmental compliance cost forecasts). Detailed discussions of those fuel cost forecasts, and the results of utilizing them on the resource plans being analyzed in each filing, were presented to the FPSC in FPL's filings for Determination of Need for WCEC Unit 3 and the conversions of FPL's existing Cape Canaveral and Riviera plants. In addition, FPL used different fuel and environmental compliance cost forecasts in the 2008 nuclear cost recovery filings for the nuclear uprates of its existing nuclear units and for the new Turkey Point Units 6 & 7.

The resource plan presented in this Site Plan is largely the result of those prior analyses. For that reason, this resource plan, with the recently developed January 2009 load forecast, has not been further tested for different fuel cost forecasts.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item # 3, FPL used up to four fuel forecasts in the filings for Determination of Need, and/or cost recovery filings, for a variety of new units as described in the previous question. While these forecasts did not represent a constant cost differential between oil/gas and coal, a variety of fuel cost differentials were represented in these forecasts.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 in Chapter I, and Schedule 8 in Chapter III, present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options in its resource planning work. A summary of this information for the new capacity options FPL projects to add over the planning horizon is presented on the Schedule 9 forms in Chapter III.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

In its 2008 resource planning work, FPL used two sets of key financial assumptions. A 44.2% debt and 55.8% equity FPL capital structure was used throughout this work. In its early 2008 analyses, FPL used a 6.43% projected debt, an equity return of 11.75%, and after-tax discount rate of 8.4% for generation costs and 8.3% for all other costs. In its analyses later in 2008, FPL used 6.6% projected debt, an equity return of 11.75%, and after-tax discount rate of 8.35%. The change in the discount rate assumption is due partly as a result of the change in the cost of debt assumption and partly because FPL no longer assumes that the federal manufacturing tax credit would likely apply to new generating units built in the time frame discussed in this analysis. This latter assumption change also resulted in the same discount rate (8.35%) being applied to both generation and non-generation costs in the analyses presented in this filing.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item # 2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective are identical when DSM levels are unchanged between competing plans. Therefore, in planning work in which DSM levels were unchanged, the equivalent cumulative present value of revenue requirements perspective was utilized.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses two system reliability criteria in its resource planning work that addresses generation, purchase, and DSM options. One of these is a minimum 20% Summer and Winter reserve margin. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability analysis work, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the Reliability Standards established by the North American Electric Reliability Council (NERC).The *NERC Reliability Standards* are available on the internet (http://www.nerc.com/.)

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Facility Rating Methodology* document that are also available on on the internet https://www.oatioasis.com/FPL /FPLdocs/Nov,2008 Revised FCR.docl.

Generally, FPL limits its transmission facilities to 100% of the applicable thermal rating. In regards to the normal and contingency voltage criteria for FPL stations, it is provided below:

	Normal/Contingency	
Voltage Level (kV)	**Vmin (p.u.)**	**Vmax (p.u.)**
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09
Turkey Point (*)	1.01/1.01	1.06/1.06
St. Lucie (*)	1.00/1.00	1.06/1.06

(*) Voltage range criteria for FPL's Nuclear Power Plants

There may be isolated cases for which FPL may have determined it is acceptable to deviate from the general criteria stated above. There are several factors could influence this criteria, such as the overall potential customers that may be impacted, the probability of an outage actually occurring, or transmission system performance, as well as others.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The impact of FPL's DSM programs on demand and energy consumption is revised periodically. Engineering models, calibrated with field-metered data, are updated when significant efficiency changes occur in the marketplace. Participation trends are tracked for all of the FPL DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants.

Survey data is collected from non-participants in order to establish the baseline efficiency. Participant data is compared against non-participant data to establish the demand and energy saving benefits of the utility program versus what would be installed in the absence of the program. For these DSM measures which involve the utilization of load management, FPL conducts periodic tests of the load control equipment to ensure that it is functioning correctly.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The Executive Summary chapter provides a discussion of two system concerns that are typically addressed in FPL's resource planning work: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida. In addition, two other relatively recent items will also influence FPL's resource planning efforts. One of these items is the Executive Orders directive issued in 2007 by Governor Crist calling for reduction in greenhouse gas emissions and greater contribution from renewable energy sources. As previously discussed in both the Executive Summary chapter and Chapter III, FPL's resource planning has already taken positive steps in regard to both of these issues. The other item is the appropriate level of renewable energy contributions to a utility system in Florida, an issue that is currently being discussed by the Florida Legislature. The outcome of these discussions regarding Renewable Portfolio Standards (RPS) is not known at the time the 2009 Site Plan is being written. However, once the RPS outcome is known, FPL will take appropriate steps in its resource planning work. Those steps will likely be discussed next year in FPL's 2010 Site Plan.

In addition to these system concerns/issues, there are other strategic factors FPL typically considers when choosing between resource options. These include the following: (1) technology risk; (2) environmental risk, and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology which has not achieved general commercial acceptance has a higher risk than a technology in wide use and, therefore, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the FPL system, including environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for a plan are those which minimize environmental impacts for the FPL system as a whole through highly efficient fuel use and state of the art controls.

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decisions, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As has been previously discussed, elements of FPL's capacity additions include the construction of new generating capacity at the West County Energy Center (WCEC) site, WCEC Units 1, 2, and 3. These generation construction projects were selected after evaluating competing bids received in response to Requests for Proposals (RFP) issued by FPL. The FPSC subsequently approved FPL's decision to construct these new combined cycle (CC) units in Determination of Need dockets.

In regard to the Conversions projects at FPL's existing Cape Canaveral and Riviera plants, the conversion projects were also evaluated using the competing bids received in response to the RFP issued for WCEC Unit 3. In addition, bids from competing vendors were also evaluated for FPL's new solar thermal and PV projects.

The nuclear capacity additions, both the nuclear uprates and the new nuclear units, do not lend themselves to an RFP approach involving bids from third parties who would build new nuclear generation capacity. For these nuclear projects, FPL's procurement activities were conducted to ensure the best combination of quality and cost for the delivered products.

Construction capacity addition decisions for non-nuclear generation for years beyond those presented in this document are expected to be conducted in a manner consistent with the Commission's Bid Rule.

Identification of self-build options, beyond those units already approved by the FPSC and Governor and Siting Board or units for which FPL may be then seeking approval, in future FPL Site Plans will not be an indication that FPL has pre-judged any capacity solicitation it may conduct. The identification of future capacity units is required of FPL in its Site Plan filings and represents those alternatives that appear to be FPL's best, most cost-effective self-build options at the time. FPL reserves the right to refine its planning analyses and to identify other self-build options. Such refined analyses have the potential to yield a variety of self-build options, some of which might not require an RFP. If an RFP is issued for Supply options, FPL reserves the right to choose the best alternative for its customers, even if that option is not an FPL self-build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

(1) FPL identified the need for a new 230kV transmission line (by June 2009) that required certification under the Transmission Line Siting Act which was issued on April 2006. The new line, when completed, will connect FPL's St. Johns Substation to FPL's proposed Pringle Substation (also shown on Table III.E.1 in Chapter III). The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

(2) FPL has identified the need for a new 230kV transmission line (by December 2012) that required certification under the Transmission Line Siting Act which was issued on November 2008. The new line will connect FPL's Manatee Substation to FPL's proposed BobWhite Substation (also shown on Table III.E.1 in Chapter III). The construction of this line is necessary to serve existing and future customers in the Manatee and Sarasota areas in a reliable and effective manner.

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April 1, 2010

RECEIVED-FPSC
10 APR -1 PM 3:49
COMMISSION CLERK

VIA HAND DELIVERY

Ms. Ann Cole
Division of the Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

100000-OT

RE: 2010-2019 Ten-Year Power Plant Site Plan

Dear Ms. Cole:

In accordance with Rule 25-22.071, F.A.C., please find enclosed for filing the original and twenty-five (25) copies of Florida Power & Light Company's 2010-2019 Ten-Year Power Plant Site Plan.

Please acknowledge your receipt of the above filing on the enclosed copy of this letter and return to the undersigned. Thank you for your assistance on this matter.

Sincerely,

Monica P. Caballero

Monica P. Caballero
Regulatory Analyst

Enclosures

COM ___
APA ___
ECR ___
GCL 2
RAD 21
SSC ___
ADM ___
OPC ___
CLK 2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 45
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-J

DOCUMENT NUMBER-DATE
02427 APR-1 2
FPSC-COMMISSION CLERK

Ten Year Power Plant Site Plan
2010 – 2019

1000000-OT

FPL

FPL

Ten Year Power Plant Site Plan

2010-2019

Submitted To:

Florida Public Service Commission

Miami, Florida April 2010

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Table of Contents

List of Figures and Tables

List of Schedules

Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan. This plan should include an estimate of the utility's future electric power generating needs, a projection of how these estimated generating needs would be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The information contained in this Site Plan is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

This Ten Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) integrated resource planning (IRP) analyses that were carried out in 2009 and that were on-going in the first Quarter of 2010. The forecasted information presented in this plan addresses the 2010–2019 time frame.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information, especially for the latter years of the ten-year time horizon, and all of this information is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, based on FPL's IRP work in 2009 and

early 2010.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as Preferred and Potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional information that is included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	*Abbreviation*	*Definition*
Unit Type	BIT	Bituminous Coal
	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	IC	Internal Combustion
	NP	Nuclear Power
	PV	Photovoltaic
	ST	Steam Unit
Fuel Type	UR	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	SUB	Sub Bituminous Coal
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	P	Planned Unit
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete

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Executive Summary

Florida Power & Light Company's (FPL) 2010 Ten Year Power Plant Site Plan (Site Plan) presents FPL's current plans to augment and enhance its electric generation capability (owned or purchased) as part of its efforts to meet its projected incremental resource needs for the 2010 - 2019 time period. By design, the primary focus of this document is on supply side additions; i.e., electric generation capability and the sites for these additions. The supply side additions discussed in this document are resources projected to be needed after accounting for FPL's demand side management (DSM) contributions and the significant energy efficiency contributions from the latest, enhanced federal appliance and lighting efficiency standards. The projected impacts of the federal appliance and lighting efficiency standards are already reflected in FPL's load forecast presented in this document. The projected impacts of FPL's DSM contributions are addressed as projected reductions to the forecasted load.

The resource plan that is presented in FPL's 2010 Site Plan contains five key similarities to the resource plan presented in FPL's 2009 Site Plan. These similarities are especially applicable to the early years of the ten-year period. Conversely, there are three specific factors that are driving changes in FPL's resource plans. In addition, there are other factors that will continue to influence FPL's on-going resource planning work. A brief discussion of these similarities, changes, and other factors is provided below.

I. Similarities to the Resource Plan Presented in the 2009 Site Plan:

There are five key similarities in the current resource plan presented in this document compared to the resource plan presented in the 2009 Site Plan.

Similarity # 1: A third highly efficient combined cycle (CC) generating unit will be added to FPL's system in 2011.

One similarity to FPL's 2009 Site Plan is the addition of a third new highly efficient natural gas-fired CC generating unit at FPL's West County Energy Center (WCEC) site in 2011. FPL placed in-service two 1,219 MW (Summer) CC units at the WCEC site in 2009. These units are identified as WCEC Units 1 and 2. The WCEC Units 1 and 2 were approved by the Florida Public Service Commission (FPSC) in June 2006. Site Certification for these units under the Florida Electric Power Plant Siting Act was approved by the Governor and the Cabinet serving as the Siting Board in December 2006.

FPL is currently constructing the third new CC unit, WCEC Unit 3, at this site. This new CC unit is projected to go into commercial operation by mid-2011. The WCEC Unit 3 was approved by the FPSC in September 2008 and Site Certification for this unit was obtained in November 2008.

Similarity # 2: Additional renewable energy generation facilities will be installed on FPL's system in 2010.

In 2009, FPL completed construction, and began operation, of a 25 MW (nameplate rating) photovoltaic (PV) generation facility in DeSoto County. This was the first of three renewable energy installations that FPL committed to place in-service in the near-term. The other two renewable energy installations are a 10 MW (nameplate rating) PV facility in Brevard County and a 75 MW (nameplate rating) solar thermal facility in Martin County. The latter two projects are currently under construction and are scheduled to begin commercial operation in 2010.

Similarity # 3: Generating capacity at FPL's four existing nuclear generation units will increase in 2011 and 2012.

FPL will be adding approximately 400 MW of increased generating capacity from its existing Turkey Point and St. Lucie nuclear power plants. This increased capacity is scheduled to come in-service in the 2011 and 2012 time period. The need for these nuclear capacity "uprates" was approved by the FPSC in January 2008. The Final Order for the Site Certification was issued in September 2008 for the St. Lucie uprates and in October 2008 for the Turkey Point uprates.

Similarity # 4: A number of existing generating units will be placed temporarily on Inactive Reserve.

In 2009, FPL began to temporarily take a number of its existing generating units out of active service and place them on Inactive Reserve status until their continued operation is again needed. This practice will continue in 2010 and is currently projected to continue beyond 2010. The specific generating units that will be placed on Inactive Reserve status are discussed in Chapter III of this document.

Similarity # 5: This Site Plan continues to reflect the modernizations of FPL's existing Cape Canaveral and Riviera plant sites in 2013 and 2014.

FPL's 2009 Site Plan projected that the modernizations of FPL existing generating units at these two sites would occur in 2013 (Cape Canaveral) and 2014 (Riviera). FPL received need determination approval from the FPSC for both of these modernizations in 2008. FPL's 2010 Site Plan continues to show this same projection for resource planning purposes. As FPL has recently stated, FPL has suspended work on the modernization projects.

II. Factors That Are Driving Changes in FPL's Resource Plan:

There are three primary factors that are driving the changes in FPL's 2010 resource plan compared to the resource plan presented in FPL's 2009 Site Plan. These three factors, and their impacts on the resource plan, are summarized below and are addressed in more detail in Chapters II and III of this document.

Factor # 1: FPL's forecast of projected load is lower in the long-term than the 2009 load forecast.

The first factor that is driving changes in FPL's resource plan is FPL's new long-term load forecast that was prepared in February 2010. This new forecast projects lower growth in electrical demand and energy starting in 2015 compared to the 2009 load forecast that was shown in FPL's 2009 Site Plan. As a result of this new lower load forecast, FPL's current projected need for new resources in the 2010 – 2019 time period is significantly lower than had been projected in 2009.

Factor # 2: The FPSC has significantly increased goals for demand side management (DSM) resources that FPL must meet in the 2010 – 2019 time period.

The second factor that is driving changes in the current resource plan is the FPSC's decision in late 2009 to impose significantly higher goals for DSM resources for FPL to add in the 2010 – 2019 period. The amount of demand (MW) reduction from the new DSM goals far exceeds the 2009 projection of FPL's remaining resource needs through 2019.[1] Now, with FPL's lower 2010 load forecast, and the commensurately lower 2010 projection of resource needs, the amount by which the MW reductions from the new DSM goals exceeds FPL's resource needs is even larger. The new level of DSM goals has other significant implications for resource planning as indicated in the following section.

[1] It is the demand (MW) reduction aspect of DSM programs, not the energy (MWh) aspect that enables DSM to meet future resource needs; i.e., avoid the need for new generating units.

Factor # 3: Due to regulatory and commercial developments in 2009, the Turkey Point 6 & 7 project schedule is under review. For planning purposes, it is now assumed that the in-service dates will not be within the ten year reporting window of this Site Plan.

In recent Site Plans, FPL discussed its plans for pursuing additional nuclear capacity (beyond the above-mentioned nuclear uprates) through the addition of new nuclear units. These previous Site Plans reflected the addition of two new nuclear units at FPL's existing Turkey Point plant site, with these new units, Turkey Point Units 6 & 7, assumed to be placed in-service in 2018 and 2020, respectively. FPL received need determination approval from the FPSC for these units in early 2008. The assumed 2018 and 2020 in-service dates represented the earliest possible dates that FPL foresaw that these new units could become operational.

Beginning in late 2009, FPL began a review of project schedule, costs, and feasibility to determine the best path forward for the Turkey Point Units 6 & 7 project in light of the most current information. A revised plan based on that review will include the steps necessary to maintain progress in creating the option for new nuclear units while maintaining an appropriate control of risk exposure. Although the revised plan is not yet completed, it has become evident that, for planning purposes, it would not be appropriate to reflect the assumed in-service dates of Turkey Point Units 6 & 7 within the period covered by this Ten Year Site Plan.

III. Resulting Changes in FPL's Resource Plan Compared to the Resource Plan Presented in the 2009 Site Plan:

The factors discussed above contribute to two significant changes in FPL's resource plan presented in this document compared to the resource plan presented in FPL's 2009 Site Plan. The changes are summarized below.

Resulting Change # 1: FPL's 2010 Site Plan now projects no additional new generating units in the 2015 through 2019 time period.

FPL's lower February 2010 load forecast significantly reduces FPL's projected resource needs. And, as previously mentioned, the FPSC-imposed new goals for DSM, especially the new MW goals, already greatly exceeded the resource needs that FPL had previously projected, even using the higher load forecast that FPL utilized in 2009. The combination of these two factors results in FPL having no need for additional resources through the 2019 reporting period addressed in this Site Plan, beyond the previously mentioned WCEC 3 unit, the modernizations of the Cape Canaveral and Riviera sites, and the nuclear uprates. All of these capacity additions are currently projected to be completed by 2014.

Therefore, as shown by Table ES-1 that is presented at the end of this Executive Summary, FPL projects no new FPL generation unit additions from 2015 through 2019.

Resulting Change # 2: For planning purposes, the assumed in-service dates for the new Turkey Point Units 6 & 7 have moved beyond the 2010 – 2019 reporting frame of this Site Plan document.

As stated above, FPL's ongoing review of the Turkey Point Units 6 & 7 project indicates that, for planning purposes, it is no longer appropriate to reflect assumed in-service dates for the Turkey Point Units 6 & 7 within the 2010 – 2019 reporting time frame of this Site Plan. This is a result of slower than anticipated progress in a number of critical project areas. As a result, FPL's 2010 Site Plan does not include either of the new nuclear units as part of its resource plan in 2010 – 2019.

FPL recognizes that the addition of new nuclear units will result in significant system fuel savings, system emission savings, (including CO_2), and gains in system fuel diversity. For these reasons, FPL is continuing to pursue the licenses that will be necessary to construct new nuclear units at Turkey Point. At the time this document is being prepared, FPL is evaluating what the revised in-service dates for Turkey Point Units 6 & 7 should be for planning purposes. FPL will address those revised in-service dates for planning purposes in its May 3, 2010 nuclear cost recovery filing to the FPSC.

IV. Additional Factors Influencing FPL's Resource Planning Work:

In addition to the factors described above, other items will also influence FPL's resource planning work. Among these other items are two that FPL typically refers to as on-going system concerns that FPL has considered in its resource planning work for a number of years. These two on-going system concerns are: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida.

A third factor that will influence FPL's on-going resource planning efforts is the Executive Order directive issued in 2007 by Governor Crist, calling for reductions in greenhouse gas emissions and for increased contribution from renewable energy sources.

A fourth factor that could affect FPL's resource planning is the possibility of the establishment of a Florida standard for renewable energy or clean energy. A Renewable Portfolio Standard (RPS) proposal was prepared by the FPSC, and then sent to the Florida Legislature for consideration, with a possible change to a Clean Portfolio Standard (CPS), during the 2009 legislative session. However, no RPS or CPS legislation was enacted during the 2009 legislative session. RPS or CPS legislation, or other legislative initiatives regarding renewable or clean energy contributions, may occur in the future. If such legislation is enacted during 2010 or in later years, FPL will then determine what steps need to be taken to address the legislation. Such steps would then be discussed in FPL's Site Plan in the year following the enactment of such legislation.

Table ES-1 presents a current projection of the changes in the generating resources portion of FPL's resource plan based on the factors and changes discussed above. As such, this table does not specifically identify the impacts of the new DSM Goals, but these impacts are reflected in the reserve margin values presented in the table. The table also presents the impacts of the temporary placement of specific existing generating units on Inactive Reserve and the beginning of the return to active service of these generating units in the latter portion of the ten-year planning period.

Table ES-1: Projected Capacity Changes and Reserve Margins for FPL

Projected Capacity Changes and Reserve Margins for FPL (1)

Year	Projected Capacity Changes	Net Capacity Changes (MW) Winter (2)	Summer (3)	Reserve Margin (%) Winter	Summer
2010	Martin Next Generation Solar Energy Center (Solar Thermal) (7)	—	—		
	Space Coast Next Generation Solar Energy Center (PV) (6)	—	—		
	Changes to Existing Purchases (4)	—	(50)		
	Riviera Unit 3 - offline for modernization	(280)	(277)		
	Riviera Unit 4 - offline for modernization	(291)	(288)		
	Cape Canaveral Unit 1 - offline for modernization	—	(396)		
	Cape Canaveral Unit 2 - offline for modernization	—	(396)		
	Changes to Existing Units	149	15		
	Inactive Reserve of Existing Units - offline (8)	(775)	(769)	43.1%	23.7%
2011	Changes to Existing Purchases (4)	(90)	(45)		
	Cape Canaveral Unit 1 - offline for modernization	(398)	—		
	Cape Canaveral Unit 2 - offline for modernization	(398)	—		
	West County Unit 3 (5)	—	1,219		
	Inactive Reserve of Existing Units - offline (8)	(394)	(1,171)		
	Changes to Existing Units	0	0	35.9%	25.4%
2012	Changes to Existing Purchases (4)	—	(100)		
	West County Unit 3 (5)	1,335	—		
	Changes to Existing Units	3	3		
	Inactive Reserve of Existing Units - offline (8)	(783)	—		
	Existing Nuclear Units Capacity Uprates - St. Lucie 1	103	103		
	Existing Nuclear Units Capacity Uprates - St. Lucie 2	—	88		
	Existing Nuclear Units Capacity Uprates - Turkey Point 3	—	104	38.2%	25.2%
2013	Changes to Existing Purchases (4)	(180)	—		
	Cape Canaveral Next Generation Clean Energy Center	—	1,210		
	Existing Nuclear Units Capacity Uprates - St. Lucie 2	88	—		
	Existing Nuclear Units Capacity Uprates - Turkey Point 3	104	—		
	Existing Nuclear Units Capacity Uprates - Turkey Point 4	104	104	37.5%	31.7%
2014	Cape Canaveral Next Generation Clean Energy Center	1,355	—		
	Riviera Beach Next Generation Clean Energy Center	—	1,212	37.8%	30.8%
2015	Riviera Beach Next Generation Clean Energy Center	1,344	—	40.9%	29.7%
2016	Changes to Existing Purchases (4)	(931)	(1,306)	34.4%	22.0%
2017	Changes to Existing Purchases (4)	(375)	—	30.7%	20.4%
2018	Inactive Reserve of Existing Units - online (8)	0	392	28.6%	19.9%
2019	Inactive Reserve of Existing Units - online (8)	394	387	28.4%	19.8%
	TOTALS =	84	39		

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are forecasted values for January of the year shown. FPL's actual 2010 Winter peak was significantly higher than forecasted.
(3) Summer values are forecasted values for August of the year shown.
(4) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(5) All new unit additions are scheduled to be in-service in June of the year shown. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.
(6) Because of the intermittent nature of the photovoltaics (PV) resource, FPL is currently assigning no firm capacity benefit to these generating additions. FPL will reassess this once actual operating data from the PV facilities at these locations is available. This location-specific information is needed in order to gauge consistent output during the peak hours which are accounted for in FPL's reserve margin calculations.
(7) The Martin solar thermal facility is designed to provide steam for FPL's existing Martin Unit 8 combined cycle unit, thus reducing FPL's use of natural gas. No additional capacity (MW) will result from the operation of the solar thermal facility.
(8) A number of existing FPL power plants are being temporarily removed from service and placed on Inactive Reserve status. FPL plans to return these units to active service in the future as needed. The timing of the return of these units to full-time active status is uncertain at this time primarily due to the uncertainty regarding FPL's future load. However, for planning purposes, FPL is showing in this document that these units begin to return to active service starting in 2018.

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CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 8.7 million people. FPL served an average of 4,499,067 customer accounts in thirty-five counties during 2009. These customers were served from a variety of resources including: FPL-owned fossil and nuclear generating units, non-utility owned generation, demand side management (DSM), and interchange/purchased power.

I.A. FPL-Owned Resources

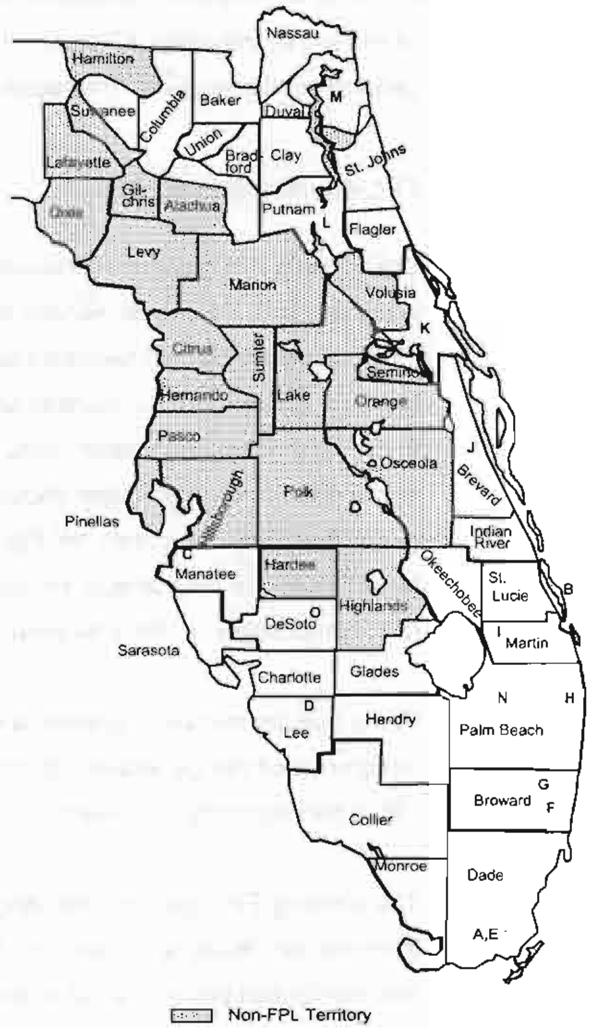
The existing FPL generating resources are located at sixteen generating sites distributed geographically around its service territory and also include partial ownership of one unit located in Georgia and two units located in Jacksonville, Florida. The current generating facilities consist of four nuclear units, three coal units, fourteen combined cycle (CC) units, seventeen fossil steam units, forty-eight combustion gas turbines, one simple cycle combustion turbine and one photovoltaic facility. The location of these eighty-eight firm generating units is shown on Figure I.A.1 and in Table I.A.1. Table I.A.2 provides a "break down" of the capacity provided by the combustion turbine (CT) and steam turbine (ST) components of FPL's existing CC units.

FPL's bulk transmission system is comprised of 6,727 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 585 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3 shows FPL's interconnection ties with other utilities.

FPL Generating Resources by Location

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	5	3,322
B	St. Lucie *	2	1,553
C	Manatee	3	2,735
D	Fort Myers	2	1,755
E	Cutler	2	205
F	Lauderdale	2	884
G	Port Everglades	4	1,205
H	Riviera	2	565
I	Martin	5	3,695
J	Cape Canaveral	2	792
K	Sanford	3	2,050
L	Putnam	2	498
M	SJRPP **	2	254
N	West County Energy Center	2	2,438
O	DeSoto ***	1	25
	Scherer ****	1	646
	Gas Turbines	48	1,908
	Total System Generating Capacity =	88	24,530
	System Firm Generating Capacity =	87	24,505



* Represents FPL's ownership share: St Lucie nuclear: 100% unit 1, 85% unit 2: St. Johns River: 20% of two units.

** SJRPP = St. John's River Power Park

*** The 25 MW of PV at DeSoto is considered as non-firm generating capacity.

**** The Scherer unit is located in Georgia and is not shown on this map.

Figure I.A.1: Capacity Resources by Location (as of December 31, 2009)

Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2009)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Nuclear				
Turkey Point	Florida City, FL	2	Nuclear	1,386
St. Lucie *	Hutchinson Island, FL	2	Nuclear	1,553
Total Nuclear		**4**		**2,939**
Coal Steam				
SJRPP **	Jacksonville, FL	2	Coal	254
Scherer	Monroe County, Ga	1	Coal	646
Total Coal Steam		**3**		**900**
Combined-Cycle ***				
Lauderdale	Dania, FL	2	Gas/Oil	884
Martin	Indiantown,FL	2	Gas	938
Martin	Indiantown,FL	1	Gas/Oil	1,105
Sanford	Lake Monroe, FL	2	Gas	1,912
Putnam	Palatka, FL	2	Gas/Oil	498
Fort Myers	Fort Myers, FL	1	Gas	1,440
Manatee	Parrish,FL	1	Gas	1,111
Turkey Point	Florida City, FL	1	Gas	1,148
West County Energy Center		2	Gas/Oil	2,438
Total Combined Cycle		**14**		**11,474**
Oil/Gas Steam				
Cape Canaveral	Cocoa, FL	2	Oil/Gas	792
Cutler	Miami, FL	2	Gas	205
Manatee	Parrish, FL	2	Oil/Gas	1,624
Martin	Indiantown,FL	2	Oil/Gas	1,652
Port Everglades	Port Everglades, FL	4	Oil/Gas	1,205
Riviera	Riviera Beach, FL	2	Oil/Gas	565
Sanford	Lake Monroe, FL	1	Oil/Gas	138
Turkey Point	Florida City, FL	2	Oil/Gas	788
Total Oil/Gas Steam		**17**		**6,969**
Gas Turbines(GT)/Diesels(IC)				
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Total Gas Turbines/Diesels		**48**		**1,908**
Combustion Turbines ***				
Fort Myers ****	Fort Myers, FL	1	Gas/Oil	315
Total Combustion Turbines		**1**		**315**
PV				
DeSoto *****	DeSoto, FL	1	Solar Energy	25
Total PV		**1**		**25**
Total System Generating Capacity as of December 31, 2009 =		**88**		**24,530**
System Firm Generating Capacity as of December 31, 2009 =		**87**		**24,505**

* Total capability of each unit is 853/839 MW. FPL's ownership share of St. Lucie 1 and 2 is 100% and 85%, respectively. Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.

** Represents FPL's ownership share: SJRPP coal: 20% of two units

*** The Combined Cycles and Combustion Turbines are broken down by components on Table 1.A.2.

**** This unit consists of two combustion turbines.

***** The 25 MW of PV at DeSoto is considered non-firm generating capacity.

Table I.A.2: Combined Cycle and Combustion Turbine Components

Combined-Cycle

Plant Name/ Unit No.	CT A	CT B	CT C	CT D	CT E	CT F	Steam 1	Steam 2	Total Unit MW
	Summer MW *								
Ft Myers 2	158	158	158	158	158	158	59	432	1,440
Lauderdale 4	158	158	---	---	---	---	127	---	442
Lauderdale 5	158	158	---	---	---	---	127	---	442
Manatee 3	164	164	164	164	---	---	457	---	1,111
Martin 3	163	163	---	---	---	---	144	---	469
Martin 4	163	163	---	---	---	---	144	---	469
Martin 8	160	160	160	160	---	---	464	---	1,105
Putnam 1	70	70	---	---	---	---	110	---	249
Putnam 2	70	70	---	---	---	---	110	---	249
Sanford 4	161	161	161	161	---	---	316	---	958
Sanford 5	160	160	160	160	---	---	315	---	954
Turkey Point 5	174	174	174	174	---	---	451	---	1,147
West County Energy Center 1	243	243	243	---	---	---	492	---	1,219
West County Energy Center 2	243	243	243	---	---	---	492	---	1,219

Combustion Turbines

Plant Name/ Unit No.	CT A	CT B	CT C	CT D	CT E	CT F	Steam 1	Steam 2	Total Unit MW
Ft. Myers 3	158	158	---	---	---	---	---	---	315

This table shows the breakdown of total MW for each unit by CT and steam component.

* The total MW values shown in this table may differ slightly from values shown in other tables due to rounding of per-component values.

Table 1.A.3: Purchase Power Resources by Contract (as of December 31, 2009)

	Location (City or County)	Fuel	Summer MW
I. Purchases from QF's: Cogeneration/Small Power Production Facilities			
Cedar Bay Generating Co.	Duval County	Coal (Cogen)	250
Indiantown Cogen., LP	Martin County	Coal (Cogen)	330
Broward South	Broward County	Solid Waste	4
Broward North	Broward County	Solid Waste	57
Palm Beach SWA	Palm Beach County	Solid Waste	50
		Total:	**691**
II. Purchases from Utilities:			
UPS from Southern Company	Various	Coal	931
SJRPP	Jacksonville, FL	Coal	381
		Total:	**1,312**
III. Other Purchases:			
Reliant/Indian River	Brevard County	Oil	250
Oleander (Extension)	Brevard County	Gas	156
Williams	Outside of Florida	Gas	106
			512
		Total Net Firm Generating Capability:	**2,515**

Non-Firm Energy Purchases (MWH)

Plant Name	Location (City or County)	Fuel	Energy (MWH) Delivered to FPL in 2009
Okeelanta	Palm Beach	Bagasse/Wood	265,929
Broward South	Broward	Garbage	130,430
Tomoka Farms	Volusia	Landfill Gas	16,436
Tropicana	Manatee	Natural Gas	53,517
Calnetix	Palm Beach	Natural Gas	44
Georgia Pacific	Putnam	Paper by-product	2,855
Rothenbach Park	Sarasota	PV	317
Customer Owned PV	Various	PV	84

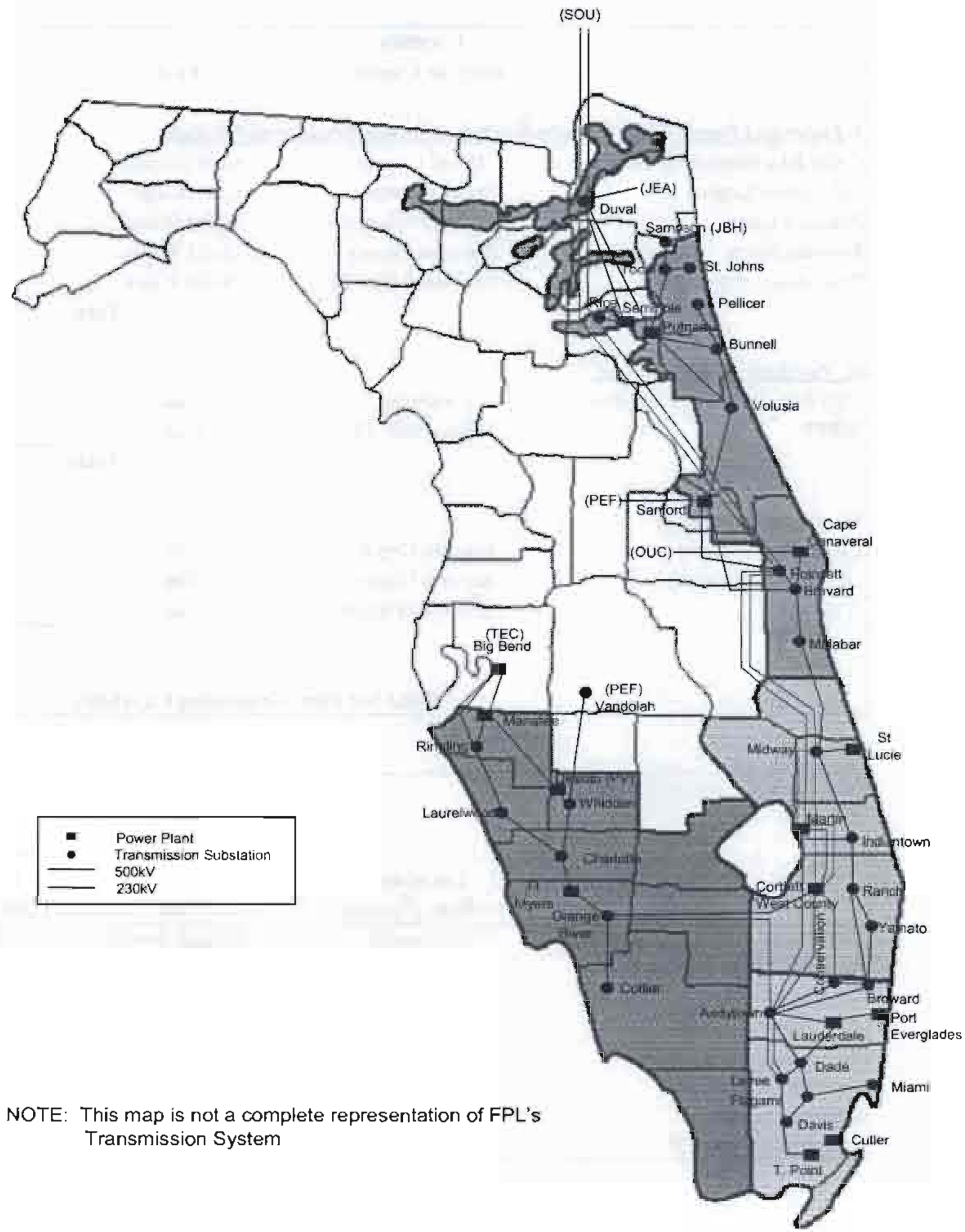
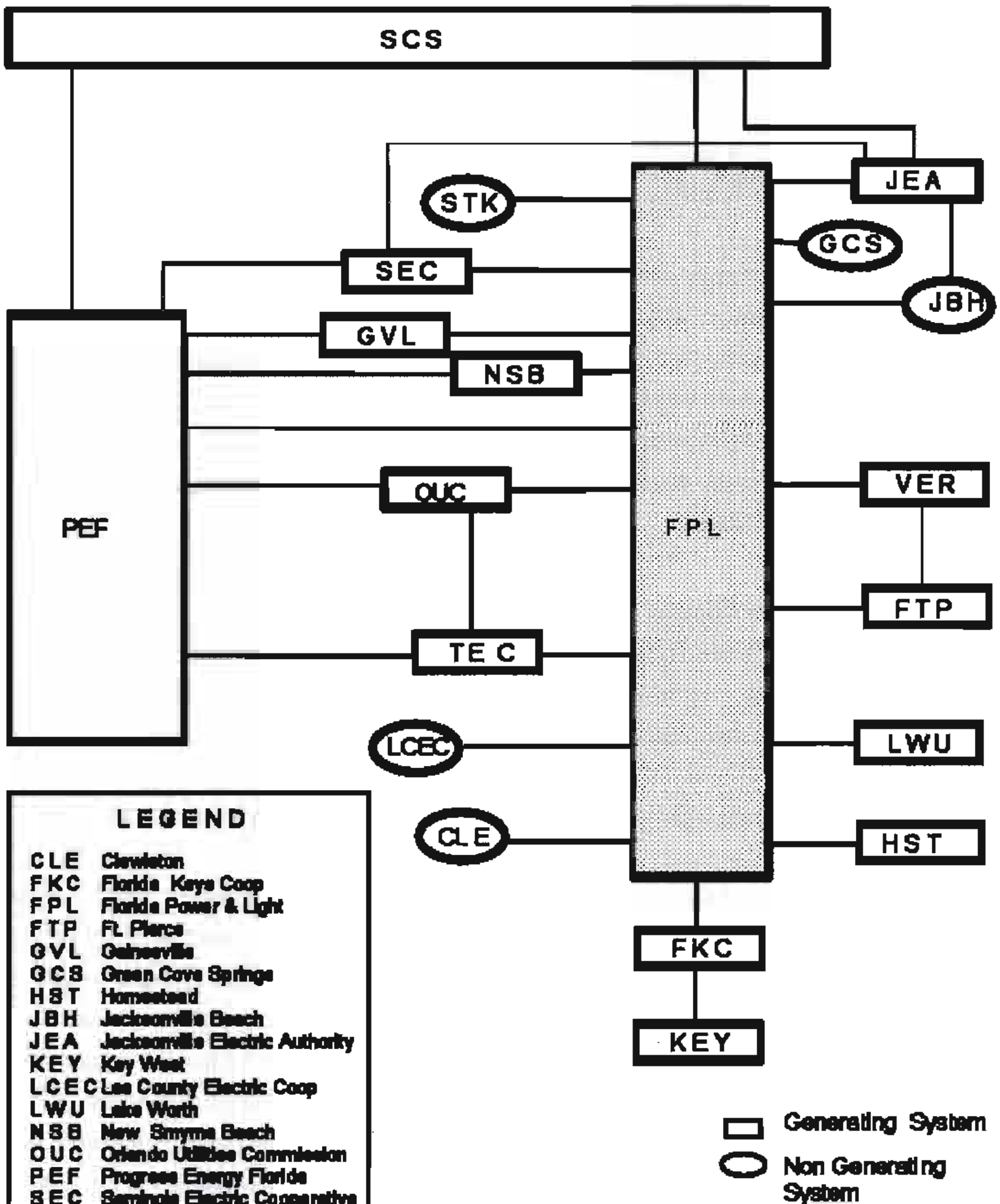


Figure I.A.2: FPL Substation and Transmission System Configuration

FPL Interconnection Diagram



LEGEND

CLE	Clewiston
FKC	Florida Keys Coop
FPL	Florida Power & Light
FTP	Ft. Pierce
GVL	Gainesville
GCS	Green Cove Springs
HST	Homestead
JBH	Jacksonville Beach
JEA	Jacksonville Electric Authority
KEY	Key West
LCEC	Lee County Electric Coop
LWU	Lake Worth
NSB	New Smyrna Beach
OUC	Orlando Utilities Commission
PEF	Progress Energy Florida
SEC	Seminole Electric Cooperative
SCS	Southern Companies
STK	Starke
TEC	Tampa Electric Company
VER	Vero Beach

Figure I.A.3: FPL Interconnection Diagram

I.B Firm Capacity Power Purchases

Purchases from Qualifying Facilities (QF):

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has contracts with five qualifying facilities; i.e., cogeneration/small power production facilities, to purchase firm capacity and energy as shown in Table I.A.2, Table I.B.1, and I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

Purchases from Utilities:

FPL has a Unit Power Sales (UPS) contract to purchase 931 MW, with a minimum of 380 MW, of coal-fired generation from the Southern Company (Southern) through May 2010. At the expiration of this contract, another contract with Southern will result in FPL receiving 930 MW from June 2010 through the end of December 2015. This capacity will be supplied by Southern from a mix of gas-fired and coal-fired units.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 381 MW (Summer) and 375 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. However, due to Internal Revenue Service (IRS) regulations, the total amount of energy that FPL may receive from this purchase is limited. FPL currently assumes, for planning purposes, that this limit will be reached in the first half of 2016. Once this limit is reached, FPL will be unable to receive firm capacity and energy from these purchases. (However, FPL will continue to receive firm capacity and energy from its ownership portion of the SJRPP units.)

These purchases are shown in Table I.A.2, Table I.B.1, and Table I.B.2. FPL also has ownership interest in the SJRPP units. The ownership amount is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.

Other Purchases:

FPL has other firm capacity purchase contracts with a variety of Non-QF suppliers. These purchases are generally near-term in nature. Table I.B.1 and I.B.2 present the Summer and Winter MW, respectively, resulting from all firm purchased power contracts discussed above through the year 2019.

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration/Small Power Production Facilities	Contract Start Date	Contract End Date	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Broward South	01/01/93	12/31/26	1	1	1	1	1	1	1	1	1	1
Broward South	01/01/95	12/31/26	2	2	2	2	2	2	2	2	2	2
Broward South	01/01/97	12/31/26	1	1	1	1	1	1	1	1	1	1
Broward North	04/01/92	12/31/10	45	0	0	0	0	0	0	0	0	0
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	2	2	2	2	2	2	2	2	2	2
Broward North	01/01/97	12/31/26	3	3	3	3	3	3	3	3	3	3
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA	04/01/92	03/31/10	0	0	0	0	0	0	0	0	0	0
Palm Beach SWA-extension	04/01/12	04/01/32	0	0	55	55	55	55	55	55	55	55
		QF Purchases Sub Total:	**640**	**595**	**650**	**650**	**650**	**650**	**650**	**650**	**650**	**650**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
UPS Replacement	06/01/10	12/31/15	930	930	930	930	930	930	0	0	0	0
SJRPP	04/02/82	4/1/2016 *	375	375	375	375	375	375	0	0	0	0
		Utility Purchases Sub Total:	**1,305**	**1,305**	**1,305**	**1,305**	**1,305**	**1,305**	**0**	**0**	**0**	**0**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total of QF and Utility Purchases =	**1,945**	**1,900**	**1,955**	**1,955**	**1,955**	**1,955**	**650**	**650**	**650**	**650**

III. Other Purchases:

	Contract Start Date	Contract End Date	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Oleander (Extension)	06/01/07	05/31/12	155	155	0	0	0	0	0	0	0	0
		Other Purchases Sub Total:	**155**	**155**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total "Non-QF" Purchase Sub-Total =	**1,460**	**1,460**	**1,305**	**1,305**	**1,305**	**1,305**	**0**	**0**	**0**	**0**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Summer Firm Capacity Purchases Total MW:	**2,100**	**2,055**	**1,955**	**1,955**	**1,955**	**1,955**	**650**	**650**	**650**	**650**

* Contract End Date shown does not represent the actual contract date. Instead, this date represents a projection of the date at which FPL's ability to receive further capacity and energy from this purchase will be suspendad due to IRS regulations.

Table I.B.2: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's:

Cogeneration/Small Power Production Facilities	Start Date	End Date	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Broward South	01/01/93	12/31/26	1	1	1	1	1	1	1	1	1	1
Broward South	01/01/95	12/31/26	2	2	2	2	2	2	2	2	2	2
Broward South	01/01/97	12/31/26	1	1	1	1	1	1	1	1	1	1
Broward North	04/01/92	12/31/10	45	0	0	0	0	0	0	0	0	0
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	2	2	2	2	2	2	2	2	2	2
Broward North	01/01/97	12/31/26	3	3	3	3	3	3	3	3	3	3
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA	04/01/92	03/31/10	50	0	0	0	0	0	0	0	0	0
Palm Beach SWA-extension	04/01/12	04/01/32	0	0	0	55	55	55	55	55	55	55
		QF Purchases Sub Total:	**690**	**595**	**595**	**650**	**650**	**650**	**650**	**650**	**650**	**650**

II. Purchases from Utilities:

	Start Date	End Date	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
UPS from Southern Co.	07/20/88	05/31/10	926	0	0	0	0	0	0	0	0	0
UPS Replacement	06/01/10	12/31/15	0	930	930	930	930	930	0	0	0	0
SJRPP	04/02/82	4/1/2016 *	375	375	375	375	375	375	375	0	0	0
		Utility Purchases Sub Total:	**1,301**	**1,305**	**1,305**	**1,305**	**1,305**	**1,305**	**375**	**0**	**0**	**0**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total of QF and Utility Purchases =	**1,991**	**1,900**	**1,900**	**1,955**	**1,955**	**1,955**	**1,025**	**650**	**650**	**650**

III. Other Purchases:

	Contract Start Date	Contract End Date	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Oleander (Extension)	06/01/07	05/31/12	180	180	180	0	0	0	0	0	0	0
		Other Purchases Sub Total:	**180**	**180**	**180**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
"Non-QF" Purchase Sub-Total =	**1,481**	**1,485**	**1,485**	**1,305**	**1,305**	**1,305**	**375**	**0**	**0**	**0**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Winter Firm Capacity Purchases Total MW:	**2,171**	**2,080**	**2,080**	**1,955**	**1,955**	**1,955**	**1,025**	**650**	**650**	**650**

* Contract End Date shown does not represent the actual contract date. Instead, this date represents a projection of the date at which FPL's ability to receive further capacity and energy from this purchase will be suspended due to IRS regulations.

I.C Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. Table I.C.1 shows the amount of energy purchased in 2009 from these facilities.

Table I.C.1: As-Available Energy Purchases From Non-Utility Generators in 2009

Project	*County*	*Fuel*	*In-Service Date*	*Energy (MWH) Delivered to FPL in 2009*
Okeelanta	Palm Beach	Bagasse/Wood	11/95	265,929
Broward South	Broward	Garbage	9/09	130,430
Tomoka Farms	Volusia	Landfill Gas	7/98	16,436
Tropicana	Manatee	Natural Gas	2/90	53,517
Calnetix	Palm Beach	Natural Gas	7/05	44
Georgia Pacific	Putnam	Paper by-product	2/94	2,855
Rothenbach Park	Sarasota	PV	10/07	317
Customer Owned PV	Various	PV	Various	84

I.D. Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include a number of conservation/energy efficiency and load management initiatives. FPL's DSM efforts through 2009 have resulted in a cumulative Summer peak reduction of approximately 4,257 MW at the generator and an estimated cumulative energy saving of approximately 51,056 Gigawatt-hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2009 have eliminated the need to construct the equivalent of approximately 13 new 400 MW generating units.

In late 2009, the Florida Public Service Commission (FPSC) imposed new goals for DSM implementation for the period 2010 through 2019. The FPSC-imposed DSM goals for FPL were significantly higher (approximately 225%) than the amount of DSM that was projected in 2009 to meet 100% of FPL's remaining resource needs through 2019. This 2009 projection of FPL's resource needs was based on FPL's 2009 load forecast.

FPL's 2010 load forecast for the 2010 – 2019 time period is substantially lower than FPL's 2009 load forecast. As a result of this lower load forecast, FPL's projected resource needs for 2010 – 2019 have also been lowered substantially below the 2009 projection. Consequently, the amount by which the FPSC-imposed DSM goals exceed FPL's projected resource needs has increased even further.

The impact of this fact on FPL's resource plan is discussed (along with other factors that impact the resource plan) in Chapter III of this document. Also, a discussion of FPL's DSM programs is presented in Chapter III.

Schedule 1

Existing Generating Facilities
As of December 31, 2009

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW
Cape Canaveral		Brevard County 19/24S/36F									804,100	796	792
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	398	396
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	398	396
Cutler		Miami Dade County 27/55S/40E									236,500	207	205
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	75,000	69	68
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	161,500	138	137
DeSoto 2/	1	DeSoto County 27/36S/25E	Photovoltaic								25,000	25	25
			PV	N/A	N/A	N/A	N/A	Unknown	10/27/2009	Unknown	25,000	25	25
Fort Myers		Lee County 35/43S/25E									2,895,890	2,660	2,403
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,775,390	1,570	1,440
	3A & B		CT	NG	FO2	PL	PL	Unknown	Jun-03	Unknown	376,380	370	315
	1-12		GT	FO2	No	PL	No	Unknown	May-74	Unknown	744,120	720	648
Lauderdale		Broward County 30/50S/42E									1,873,968	1,930	1,724
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	485	442
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	485	442
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	480	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,734	480	420
Manatee		Manatee County 18/33S/20E									2,951,110	2,831	2,735
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	822	812
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	822	812
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,187	1,111

1/ These ratings are peak capability.
2/ The capacity shown for the PV facility at DeSoto is considered as non-firm generating capacity due to the intermittent nature of the solar resource.

Schedule 1

Existing Generating Facilities
As of December 31, 2009

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability [1/] Winter MW	(14) Net Capability [1/] Summer MW
Martin		Martin County 29/29S/38E									4,317,510	3,840	3,695
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	832	826
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	832	826
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	498	469
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	498	469
	8*		CC	NG	FO2	PL	PL	Unknown	Jun-05	Unknown	1,224,510	1,180	1,105
Port Everglades		City of Hollywood 23/50S/42E									1,665,334	1,691	1,625
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	225,250	214	213
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	225,250	214	213
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	389	387
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	394	392
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	480	420
Putnam		Putnam County 16/10S/27E									580,008	536	498
	1		CC	NG	FO2	PL	WA	Unknown	4/1/1978	Unknown	290,004	268	249
	2		CC	NG	FO2	PL	WA	Unknown	8/1/1977	Unknown	290,004	268	249
Riviera		City of Riviera Beach 33/42S/43E									620,840	571	565
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	280	277
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	291	288
Sanford		Volusia County 16/19S/30E									2,533,970	2,217	2,050
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	156,250	140	138
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,860	1,040	958
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	1,037	954

1/ These ratings are peak capability.
* Martin 8 A and B combustion turbine units went into service on 6/14/2001 and the conversion to Combined Cycle went into service 6/30/2005

Schedule 1

Existing Generating Facilities
As of December 31, 2009

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen. Max. Nameplate KW	(13) Net Capability [1] Winter MW	(14) Net Capability [1] Summer MW
Scherer 2/		Monroe, GA									680,368	652	646
	4		BIT	SUB	No	RR	No	Unknown	Jul-89	Unknown	680,368	652	646
St. Johns River Power Park [3]		Duval County 12/15/28E (RPC4)									271,836	250	254
	1		BIT	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	125	127
	2		BIT	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	125	127
St. Lucie		St. Lucie County 16/36S/41E									1,573,775	1,579	1,553
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	850,000	853	839
	2	4/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	723,775	726	714
Turkey Point		Miami Dade County 27/57S/40E									3,548,550	3,405	3,322
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	398	396
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	394	392
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	759,970	717	693
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	759,970	717	693
	5		CC	NG	FO2	PL	PL	Unknown	May-07	Unknown	1,224,510	1,179	1,148
West County Energy Center		Palm Beach County 29&32/43S/40E									2,733,600	2,670	2,438
	1		CC	NG	FO2	PL	PL	Unknown	Aug-09	Unknown	1,366,800	1,335	1,219
	2		CC	NG	FO2	PL	PL	Unknown	Nov-09	Unknown	1,366,800	1,335	1,219
Total System Generating Capacity as of December 31, 2009 [5] =												25,860	24,530
System Firm Generating Capacity as of December 31, 2009 [6] =												25,835	24,505

1/ These ratings are peak capability.
2/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.
3/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No. 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80%.
4/ Total capability of each unit is 853/839 MW. FPL's ownership share of St. Lucie 1 and 2 is 100%(853/839) and 85% (714/726) respectively as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.
5/ The Total System Generating Cpacity value shown includes FPL-owned firm and non-firm generating capacity.
6/ The System Firm Generating Capacity value shown includes only firm generating capacity.

CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

II. A. Overview of the Load Forecasting Process

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are typically developed on an annual basis for resource planning work at FPL. New long-term forecasts were developed by FPL in early 2010 that replaced the previous long-term load forecasts that were used by FPL during 2009 in much of its resource planning work and which were presented in FPL's 2009 Site Plan. These new load forecasts are utilized throughout FPL's 2010 Site Plan. These forecasts are a key input to the models used to develop FPL's integrated resource plan. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

Consistent with past forecasts, the primary drivers to develop these forecasts include economic conditions and weather.

The projections for the national and Florida economies are obtained from the consulting firm IHS Global Insight. Population projections are obtained from the Bureau of Economic and Business Research (BEBR) of the University of Florida. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects FPL's energy sales and peak demand. Two sets of weather variables are developed and used in FPL's forecasting models:

1. Cooling and Heating Degree-Hours are used to forecast energy sales.
2. Temperature data, along with Cooling and Heating Degree-Hours, are used to forecast Summer and Winter peaks.

The Cooling and Heating Degree-Hours are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. A composite temperature hourly profile is derived using hourly temperatures across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained. In developing the composite hourly profile, these regional temperatures are weighted by regional energy sales. This composite temperature is used to derive Cooling and Heating Degree-Hours, which are based on starting point temperatures of 72° F and 66° F degrees, respectively. Similarly, composite temperature and hourly profile of temperatures are used for the Summer and Winter peak models.

II. B. Comparison of FPL's Current and Previous Load Forecasts

While reflecting somewhat lower growth in the later years of the forecast, FPL's current load forecast is generally in line with the load forecast presented in its 2009 Site Plan. There are two primary factors that are driving the current load forecast: projected population growth, and the lingering effects of the economic recession in Florida.

The customer forecast is based on recent population projections. Population projections are derived from the University of Florida's January 2010 population projections which are lower than prior projections. In fact, in 2009, Florida's population declined for the first time since World War II. According to the University of Florida, net migration has fallen to a record low as a result of the economic slowdown and is expected to remain at historically low levels through 2010, then gradually increase. Consequently, FPL is projecting that customer growth in 2010 will be significantly below its historical average. As population growth recovers, a modest rebound in customer growth is projected in 2011 and 2012. However, population growth is not expected to reach the level historically experienced in Florida until 2014. As a result of lower growth, the total number of customers projected in the current load forecast is below the levels projected in FPL's 2009 Site Plan.

Consistent with the economic assumptions incorporated into the 2009 Site Plan, the state's economy continues to suffer the lingering effects of an economic recession. Over the last year, Florida has lost nearly a quarter-of-a-million jobs and is second only to California in the number of mortgage foreclosures. The severity of current economic conditions suggests that Florida's economic recovery will be gradual. By 2012, the state's economy is projected to resume a more historically typical rate of growth.

Although the projected load growth in the later years of the forecast is generally below that presented in FPL's 2009 Site Plan, the total growth projected for the ten-year reporting period of this document is still significant. The Summer peak is projected to increase to 25,785 MW by 2019, an increase of 3,434 MW over the 2009 actual Summer peak. Likewise, NEL is projected to reach 131,712 GWH in 2019, an increase of 20,408 GWH from the actual 2009 value.

II.C. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for each revenue class and are adjusted to match the NEL forecast. The results of these sales forecasts for the years 2010 - 2019 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and NEL forecast are outlined below.

1. **Residential Sales**

Residential electric usage per customer is estimated by using an econometric model. Residential sales are a function of: Cooling Degree-Hours, Heating Degree-Hours, lagged Cooling Degree-Hours, lagged Heating Degree-Hours, real price of electricity (a 12-month moving average), Florida real household disposable income, a variable designed to reflect the impact of empty homes, and a dummy variable for the specific month of November 2005. The impact of weather is captured by the Cooling Degree-Hours, Heating Degree-Hours, and the one month lag of these variables. The price of electricity plays a role in explaining electric usage, because electricity, like all other goods and services, will be used in greater or lesser quantities depending upon its price. To capture economic conditions, the model includes Florida's real household disposable income. The housing crisis has also had an impact on use per customer. Consequently, the model includes a variable designed to capture the impact of empty homes. A dummy variable for November 2005 was included because an analysis of residuals identified that data point as an outlier. Residential energy sales are forecasted by multiplying the residential use per customer forecast by the number of residential customers forecasted.

2. **Commercial Sales**

The commercial sales forecast is also developed using an econometric model. Commercial sales are a function of the following variables: Florida real household disposable income, commercial real price of electricity (a 12-month moving average), Cooling Degree-Hours, Heating Degree-Hours, lagged Cooling Degree-Hours, a variable designed to reflect the impact of empty homes, seasonal dummy variables for the months of February and December, a dummy variable for the specific month of January 2007, and an autoregressive term. Cooling Degree-Hours, Heating Degree-Hours, and the one month lag of Cooling Degree-Hours are used to capture weather-sensitive load in the commercial sector.

3. **Industrial Sales**

The industrial class is comprised of two distinct groups; very small accounts (those with less than 20 kW of demand) and large, traditionally industrial customers. As such, the forecast is developed using a separate econometric model for each group of industrial customer. The small industrial sales model utilizes the following variables: Florida Housing Starts, Cooling Degree-Hours, lagged Cooling Degree-Hours, industrial real price of electricity (a 12-month moving average), and an autoregressive and seasonal autoregressive terms. The Cooling Degree-Hour is used to capture the weather-sensitive load in this group of industrial customers. Florida Housing Starts are reflective of construction activity which comprises a significant portion of this group. The large industrial sales model utilizes the following variables: Florida Housing Starts, industrial real price of electricity (a 12-month moving average), dummy variables for October and November 2004, and an autoregressive term.

4. **Railroad and Railways Sales and Street and Highway Sales**

The projections for railroad and railways sales are based on historical average use per customer because the number of customers is projected to remain the same. This class consists solely of Miami-Dade County's Metrorail system.

The forecast for street and highway sales is developed using historical usage patterns and multiplying these usage levels by the number of forecasted customers.

5. **Other Public Authority Sales**

This revenue class is a closed class with no new customers being added. This class consists of sports fields and a government account. The forecast for this class is based on historical knowledge of its usage characteristics.

6. **Total Sales to Ultimate Customer**

Sales forecasts by revenue class are summed to produce a total sales forecast.

7. **Sales for Resale**

Sales for resale (wholesale) customers are composed of municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers. Currently there are four customers in this class: the Florida Keys Electric Cooperative; City of Key West; Metro-Dade County; and Lee County

Electric Cooperative. In addition, FPL will begin making sales to Seminole Electric Cooperative under a long term agreement in June 2014.

FPL provides service to the Florida Keys Electric Cooperative under a long-term partial requirements contract. The sales to Florida Keys Electric Cooperative are forecasted using a regression model.

FPL's sales to the City of Key West are expected to terminate in 2013. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor.

Metro-Dade County sells 60 MW to Florida Progress. Line losses are billed to Metro-Dade under a wholesale contract.

Lee County has contracted with FPL for FPL to supply a portion of their load beginning in January 2010 and for FPL to supply their total load beginning in January 2014 through December 2033. Forecasted sales to Lee County are based on assumptions regarding their contract demand and expected load factor.

Seminole Electric Cooperative's contract for delivery of 75 MW expired in December 2009. A new contract included in the forecast is for delivery of 200 MW to Seminole Electric beginning in June 2014.

II.D. Net Energy for Load (NEL)

An econometric model is developed to produce a NEL per customer forecast. The key inputs to the model are: the real price of electricity (a 12-month moving average), Cooling and Heating Degree-Hours, and Florida real household disposable income. In addition, the model also includes variables for mandated energy efficiency and a variable designed to capture the impact of empty homes. Seasonal dummies are included for the months of February, July, and December.

The mandated energy efficiency variables are included to capture the impacts of the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and compact florescent light bulbs. The estimated impact of these programs for the 2010 to 2019 time period is a reduction, on average, of 7,592 GWh per year. The increase in the number of empty homes resulting from the current housing slump has affected use per customer and is captured in a separate variable. The forecast was also adjusted for additional load estimated from hybrid cars, beginning in 2010, which resulted in an increase of approximately 322 GWh by the end of the ten-year reporting period.

The NEL forecast is developed by multiplying the NEL per customer forecast by the total number of customers forecasted. Once the NEL forecast is obtained, total billed sales are computed using a historical ratio of sales to NEL. The sales by class forecasts previously discussed are then adjusted to match the total billed sales. The forecasted NEL values for 2010 – 2019 are presented in Schedule 3.3 that appears at the end of this chapter.

II.E. System Peak Forecasts

The rate of absolute growth in FPL system peak load has been a function of the size of the customer base, varying weather conditions, projected economic conditions, changing patterns of customer behavior (including an increased stock of electricity-consuming appliances), and more efficient appliances and lighting. FPL developed the peak forecast models to capture these behavioral relationships. Impacts of the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the impact of compact fluorescent light bulbs are taken into account in developing the peak forecast. The estimated impact of these federal mandates for the 2010 to 2019 time frame is a reduction of approximately 883 MW (Summer) and 334 MW (Winter) in 2010, and approximately 1,746 MW (Summer) and 941 MW (Winter) by 2019. The forecast was also adjusted for additional load estimated from hybrid cars which resulted in an increase of approximately 65 MW in the Summer and 8 MW in the Winter by the end of the ten-year reporting period.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2010 – 2019 are presented in Schedules 3.1 and 3.2 as well as in Schedules 7.1 and 7.2.

1. **System Summer Peak**

The Summer peak forecast is developed using an econometric model. The variables included in the model are the real price of electricity, Florida real household disposable income, Cooling Degree-Hours in the two days prior to the peak, the average temperature on the day of the peak, and a variable for mandated energy efficiency. The model is based on the Summer peak contribution per customer and is, therefore, multiplied by total customers to derive FPL's system Summer peak.

2. **System Winter Peak**

Like the system Summer peak model, this model is also an econometric model. The model consists of two weather-related variables: the average temperature on the peak day and Heating Degree-Hours for the prior day as well as for the morning of the Winter peak day. In addition, Florida real household disposable income is a variable used in the model. A dummy variable for the year 1996 is also utilized. The forecasted results are adjusted for the impact of mandated energy efficiency. The model is based on the Winter peak contribution per customer and is, therefore, multiplied by total customers to derive FPL's system Winter peak.

3. **Monthly Peak Forecasts**

The forecasting process for monthly peaks consists of the following actions:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to the appropriate seasonal peak.

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.F. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2010-2019 are produced using a System Load Forecasting "shaper" program. This model uses years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

II.G. Uncertainty

In order to address uncertainty in the forecasts of aggregate peak demand and NEL, FPL first evaluates the assumptions underlying the forecasts. FPL takes a series of steps in evaluating the input variables, including comparing projections from different sources, identifying outliers in the series, and assessing the series' consistency with past forecasts. In addition, FPL reviews factors which may affect the input variables. This may require reviewing data from local economic development boards or from FPL's own Customer Service Business Unit. Other factors which may be considered include demographic trends and housing characteristics such as starts, size, and vintage of homes.

Uncertainty is also addressed in the modeling process. Generally, econometric models are used to forecast the aggregate peak demand and NEL. During the modeling process, the relevant statistics (goodness of fit, F-statistic, P-values, mean absolute deviation (MAD), mean absolute percentage error (MAPE), etc.) are scrutinized to ensure that the models adequately explain historical variation. Once a forecast is developed, it is compared with past forecasts. Deviations from past forecasts are examined in light of changes in input assumption to ensure that the drivers underlying the forecast are well understood. Finally, forecasts of aggregate peak demand and NEL are compared with their actual values as they become available. An ongoing process of variance analyses is performed. To the extent that the variance analysis identifies large unexplained deviations between the forecast and actual values, revisions to the econometric model may be considered.

The inherent uncertainty in load forecasting is addressed in different ways in regard to FPL's overall resource planning and operational planning work. In regard to FPL's resource planning work, FPL's utilization of a 20% reserve margin criterion (approved by the FPSC) is designed, in part, to maintain reliable electric service to FPL's customers in light of forecasting uncertainty. In regard to operational planning, an extreme weather load forecast for the projected Summer peak day is produced based on maximum historical temperatures on the day of the Summer peak. Likewise, an extreme weather Winter peak forecast is developed by considering minimum historical temperatures at the time of the Winter peak. Statistical analysis on the distribution of historical weather data is performed to evaluate and understand the impact of extreme weather on the peaks and on NEL, and the likelihood of experiencing extreme weather.

It should be noted that despite the downturn in the economy, and negative growth in Florida's population during 2009, FPL experienced a near record Summer peak of 22,351 MW, and an all-time peak of 24,339 MW during the 2009-2010 Winter peak period. These peaks were driven by extreme weather.

II.H. DSM

The effects of FPL's DSM implementation to-date are assumed to be imbedded in the actual usage data for forecasting purposes. Any change in usage pattern, be it the impact of FPL's DSM efforts, price impact, or weather impact, is reflected in the actual observed load data. Therefore, energy efficiency impacts, whether market-driven or as a result of FPL's DSM programs, are assumed to be included in the historical usage data for peaks and NEL.

The impacts of incremental energy efficiency that FPL plans to implement in the future, plus the impacts of FPL's cumulative and incremental load management programs, are accounted for as "line item reductions" to the forecasts as part of the IRP process as shown in Schedules 7.1 and 7.2. After making these adjustments to the load forecasts, the resulting "firm" load forecast is then used in FPL's IRP work.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			**Commercial**		
Year	Population [1/]	Members per Household	GWh 2/	Average [3/] No. of Customers	Average kWh Consumption Per Customer	GWh 2/	Average [3/] No. of Customers	Average kWh Consumption Per Customer
2000	7,603,964	2.23	46,320	3,413,953	13,568	37,001	415,293	89,097
2001	7,754,846	2.22	47,588	3,490,541	13,633	37.960	426,573	88,989
2002	7,898,628	2.21	50,865	3,566,167	14,263	40,029	435,313	91,955
2003	8,079,316	2.21	53,485	3,652,663	14,643	41,425	444,650	93,163
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,620,855	2.21	54,570	3,906,267	13,970	44,487	478,867	92,901
2007	8,729.806	2.19	55,138	3,981,451	13,849	45,921	493,130	93,121
2008	8,771,694	2.20	53,229	3,992,257	13,333	45,561	500.748	90,987
2009	8,731,397	2.20	53,950	3,984,490	13,540	45,025	501,055	89,860
2010	8,773,235	2.20	52,160	3,987,834	13,080	44,652	500,788	89,164
2011	8,833,618	2.20	53,365	4,015,281	13,290	45,009	502,102	89,642
2012	8,916,643	2.20	54,310	4,053,020	13,400	45,632	505,780	90,221
2013	9,043,647	2.20	55,783	4,110,748	13,570	46,484	512,042	90,781
2014	9,186,256	2.20	57,670	4,175,571	13,811	47,787	520.279	91,849
2015	9,322,630	2.20	58,471	4,237,559	13,798	48,713	528,609	92,153
2016	9.455,432	2.20	58,782	4,297,924	13,677	49,228	536,766	91,712
2017	9,584,118	2.20	59,418	4,356,417	13,639	50,012	544,669	91,821
2018	9,709,760	2.20	60,450	4,413.527	13,696	51,158	552,418	92,607
2019	9,833,269	2.20	61,316	4,469,668	13,718	52,185	560,044	93,180

Historical Values (2000 - 2009):
1/ Population represents only the area served by FPL.
2/ Actual energy sales include the impacts of existing conservation. These values are at the meter.
3/ Average No. of Customers is the annual average of the twelve month values.

Projected Values (2010 - 2019):
1/ Population represents only the area served by FPL.
2/ Forecasted energy sales do not include the impact of incremental conservation. These values are at the meter.
3/ Average No. of Customers is the annual average of the projected twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial						
Year	GWh 2/	Average 3/ No. of Customers	Average kWh Consumption Per Customer	Railroads & Railways GWh	Street & Highway Lighting GWh 2/	Other Sales to Public Authorities GWh	Total 4/ Sales to Ultimate Consumers GWh
2000	3,768	16,411	229,578	81	408	381	87,959
2001	4,091	15,445	264,872	86	419	67	90,212
2002	4,057	15,533	261,199	89	420	63	95,523
2003	4,004	17,029	235,135	93	425	64	99,496
2004	3,964	18,512	214,139	93	413	58	99,095
2005	3,913	20,392	191,873	95	424	49	102,296
2006	4,036	21,211	190,277	94	422	49	103,659
2007	3,774	18,732	201,499	91	437	53	105,415
2008	3,587	13,377	268,168	81	423	37	102,919
2009	3,245	10,064	321,796	80	422	34	102,755
2010	3,348	9,276	360,993	89	382	36	100,668
2011	3,464	9,587	361,297	89	378	35	102,340
2012	3,530	10,232	345,009	89	383	34	103,979
2013	3,567	10,727	332,540	89	391	33	106,347
2014	3,578	10,964	326,355	89	401	33	109,558
2015	3,560	11,079	321,320	89	412	33	111,278
2016	3,534	11,156	316,775	89	425	33	112,089
2017	3,519	11,237	313,110	89	437	33	113,508
2018	3,513	11,534	304,559	89	451	33	115,693
2019	3,509	11,957	293,465	89	464	33	117,596

Historical Values (2000 - 2009):
2/ Actual energy sales include the impacts of existing conservation. These values are at the meter.
3/ Average No.of Customers is the annual average of the twelve month values.
4/ GWh Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Projected Values (2010 - 2019):
2/ Forecasted energy sales do not include the impact of incremental conservation.
3/ Average No. of Customers is the annual average of the projected twelve month values.
4/ GWh Col. (16) = Col. (4) + Col. (7) + Col (10) + Col (13) + Col (14) + Col. (15).

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh 2/ [5/]	(20) Average No. of Other Customers [3/]	(21) Total Average Number of Customers [3/,6/]
2000	970	7,059	95,989	2,693	3,848,350
2001	970	7,222	98,404	2,722	3,935,281
2002	1,233	7,443	104,199	2,792	4,019,805
2003	1,511	7,386	108,393	2,879	4,117,221
2004	1,531	7,467	108,093	3,029	4,224,509
2005	1,506	7,498	111,301	3,156	4,321,895
2006	1,569	7,909	113,137	3,218	4,409,563
2007	1,499	7,401	114,315	3,276	4,496,589
2008	993	7,092	111,004	3,348	4,509,730
2009	1,155	7,394	111,304	3,439	4,499,067
2010	2,046	7,172	109,886	3,435	4,501,332
2011	2,145	7,150	111,634	3,398	4,530,367
2012	2,166	7,372	113,516	3,438	4,572,470
2013	2,059	7,493	115,899	3,499	4,637,017
2014	4,846	8,068	122,471	3,580	4,710,393
2015	5,484	7,980	124,742	3,675	4,780,922
2016	5,513	8,070	125,672	3,779	4,849,624
2017	5,555	8,173	127,236	3,888	4,916,211
2018	5,602	8,370	129,665	3,999	4,981,479
2019	5,648	8,468	131,712	4,111	5,045,779

Historical Values (2000 - 2009):

2/ Actual energy sales include the impacts of existing conservation. These values are at the meter.
3/ Average No.of Customers is the annual average of the twelve month values.
5/ GWh Col. (19) = Col. (16) + Col. (17) + Col. (18). Actual NEL include the impacts of existing conservation and agrees to Col. (8) on schedule 3.3.
6/ Total Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Projected Values (2010 - 2019):

2/ Forecasted energy sales do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.
3/ Average No.of Customers is the annual average of the projected twelve month values.
5/ GWh Col. (19) = Col. (16) + Col. (17) + Col. (18).
6/ Total Col. (21) = Col (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1) August of Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2000	17,808	161	17,647	0	719	645	487	451	16,622
2001	18,754	169	18,585	0	737	697	488	481	17,529
2002	19,219	261	18,958	0	770	755	489	517	17,960
2003	19,668	253	19,415	0	781	799	577	554	18,310
2004	20,545	258	20,287	0	783	847	588	578	19,174
2005	22,361	264	22,097	0	790	895	600	611	20,971
2006	21,819	256	21,563	0	809	948	635	640	20,375
2007	21,982	261	21,701	0	954	982	715	683	20,293
2008	21,080	181	20,879	0	974	1035	735	708	19,351
2009	22,351	212	22,139	0	985	1084	793	734	20,573
2010	21,922	381	21,541	0	1,026	115	884	92	19,805
2011	21,788	386	21,402	0	1,039	135	954	121	19,540
2012	22,139	391	21,748	0	1,055	160	1,038	154	19,732
2013	22,332	352	21,980	0	1,073	187	1,131	192	19,751
2014	23,575	1,178	22,397	0	1,091	215	1,227	231	20,812
2015	23,924	1,200	22,724	0	1,109	242	1,321	268	20,985
2016	24,344	1,225	23,119	0	1,125	267	1,406	302	21,244
2017	24,774	1,253	23,521	0	1,140	289	1,483	333	21,528
2018	25,328	1,283	24,045	0	1,153	309	1,554	362	21,949
2019	25,785	1,314	24,470	0	1,165	328	1,619	388	22,284

Historical Values (2000 - 2009):

Col. (2) - Col. (4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) for 2000 through 2009 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC), CILC and Commercial /Industrial Demand Reduction (CDR).

Col. (11) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (11) is derived by the formula:Col. (10) = Col.(2) - Col.(6) - Col.(8).

Projected Values (2010 - 2019):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2010 are incorporated into the load forecast.

Col. (5) - Col. (9) represent all incremental conservation,current load management and incremental load management. These values are projected August values and the conservation values are based on projections with a 1/2010 starting point for use with the 2010 load forecast.

Col (8) represents FPL's Business On Call, CDR,CILC, and Curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
January of Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2000	17,057	142	16,915	0	741	434	438	176	15,878
2001	18,199	150	18,049	0	791	459	448	183	16,960
2002	17,597	145	17,452	0	811	500	457	196	16,329
2003	20,190	246	19,944	0	847	548	453	206	18,690
2004	14,752	211	14,541	0	857	570	532	230	13,363
2005	18,108	225	17,883	0	862	583	542	233	16,704
2006	19,683	225	19,458	0	870	600	550	240	18,263
2007	16,815	223	16,592	0	894	620	577	249	15,344
2008	18,055	163	17,892	0	879	644	635	279	16,541
2009	20,081	162	19,919	0	951	678	764	295	18,366
2010	20,550	376	20,174	0	937	71	768	41	18,734
2011	20,647	381	20,266	0	943	78	784	55	18,788
2012	20,861	386	20,475	0	949	87	804	72	18,949
2013	21,138	392	20,746	0	957	97	827	93	19,163
2014	22,152	1,060	21,092	0	966	108	854	116	20,108
2015	22,745	1,284	21,461	0	975	121	882	141	20,627
2016	23,118	1,311	21,807	0	984	132	908	164	20,929
2017	23,488	1,341	22,147	0	993	143	933	186	21,232
2018	23,889	1,374	22,514	0	1,001	154	957	208	21,569
2019	24,293	1,409	22,884	0	1,007	163	977	225	21,921

Historical Values (2000 - 2009):

Col. (2) - Col. (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) for 2000 through 2009 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC), CILC and Commercial /Industrial Demand Reduction (CDR).

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (11) is derived by the formula:Col. (10) = Col.(2) - Col.(6) - Col.(8) - Col.(9).

Projected Values (2010 - 2019):

Col. (2) - Col. (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2010 are incorporated into the load forecast.

Col. (5) - Col. (9) represent all incremental conservation,current load management and incremental load management. These values are projected August values and the conservation values are based on projections with a 1/2010 starting point for use with the 2010 load forecast.

Col (8) represents FPL's Business On Call, CDR,CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.3
History of Annual Net Energy for Load - GWh: Base Case

(All values are "at the generator" values except for Col (8))

(1) Year	(2) = (5) + (3) + (4) Total Net Energy For Load without DSM	(3) Residential Conservation	(4) C/I Conservation	(5) Actual Net Energy For Load	(6) Sales for Resale GWh	(7) Utility Use & Losses	(8) = (5) - (6) - (7) Actual Total Billed Retail Energy Sales (GWh)	(9) Load Factor(%)
2000	99,097	1,674	1,434	95,989	970	7,059	87,959	61.4%
2001	101,739	1,789	1,545	98,404	970	7,222	90,212	59.9%
2002	107,755	1,917	1,639	104,199	1,233	7,443	95,523	61.9%
2003	112,160	2,008	1,759	108,393	1,511	7,386	99,496	62.9%
2004	112,034	2,106	1,834	108,093	1,531	7,467	99,095	59.9%
2005	115,440	2,205	1,934	111,301	1,506	7,498	102,296	56.8%
2006	117,490	2,312	2,041	113,137	1,569	7,909	103,659	59.2%
2007	118,894	2,373	2,206	114,315	1,499	7,401	105,415	59.4%
2008	115,755	2,485	2,267	111,004	993	7,092	102,919	60.0%
2009	116,221	2,581	2,336	111,304	1,155	7,394	107,671	59.4%

Historical Values (2000 - 2009):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5).

Col.(3) & Col.(4) for 2000 through 2009 are DSM values starting in January 1988 and are annual (12-month) values. Col. (3) and Col (4) for 2009 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWh reductions actually experienced each year .

Col. (5) is the actual Net Energy for Load (NEL) for years 2000 - 2009.

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (5)*1000) / ((Col.(2) * 8760)
Adjustments are made for leap years.

Forecast of Annual Net Energy for Load - GWh: Base Case

(All values are "at the generator" values except for Col (8))

(1) Year	(2) Forecasted Net Energy For Load without DSM	(3) Residential Conservation	(4) C/I Conservation	(5) = (2) - (3) - (4) Net Energy For Load Adjusted for DSM	(6) Sales for Resale GWh	(7) Utility Use & Losses	(8) = (2) - (6) - (7) Forecasted Total Billed Retail Energy Sales (GWh) without DSM	(9) Load Factor(%)
2010	109,886	193	141	109,552	2,046	7,172	100,668	57.2%
2011	111,634	360	252	111,021	2,145	7,150	102,340	58.5%
2012	113,516	578	398	112,540	2,166	7,372	103,979	58.4%
2013	115,899	827	563	114,509	2,059	7,493	106,347	59.2%
2014	122,471	1,091	739	120,641	4,846	8,068	109,558	59.3%
2015	124,742	1,340	906	122,496	5,484	7,980	111,278	59.5%
2016	125,672	1,564	1,055	123,053	5,513	8,070	112,089	58.8%
2017	127,236	1,767	1,190	124,279	5,555	8,173	113,508	58.6%
2018	129,665	1,959	1,318	126,387	5,802	8,370	115,693	58.4%
2019	131,712	2,142	1,440	128,130	5,648	8,468	117,596	58.3%

Projected Values (2010 - 2019):

Col. (2) represents Forecasted Net Energy for Load w/o DSM values. The values are extracted from Schedule 2.3, Col. (19).

Col (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation and are mid-year (6-month) values.
The effects of conservation implemented prior to 2010 are incorporated into the load forecast

Col. (5) is the forecasted Net Energy for Load (NEL) after adjusting for DSM impacts DSM for years 2010 - 2019. Col.(5) = Col.(2) - Col.(3) - Col.(4)

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2009 ACTUAL		2010 FORECAST		2011 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	19,378	7,982	20,550	7,883	20,647	8,144
FEB	20,081	7,299	17,985	7,142	18,070	7,400
MAR	15,347	7,899	17,108	8,010	17,189	8,245
APR	17,145	8,751	17,437	8,453	17,331	8,656
MAY	19,210	9,334	19,494	9,408	19,375	9,582
JUN	22,351	10,632	20,983	10,458	20,855	10,605
JUL	21,138	10,636	21,481	10,633	21,350	10,755
AUG	21,015	11,434	21,922	11,166	21,788	11,274
SEP	20,334	10,772	21,264	10,780	21,135	10,856
OCT	21,014	9,981	19,809	9,631	19,688	9,684
NOV	19,226	8,676	17,447	8,406	17,530	8,472
DEC	16,122	7,908	17,158	7,915	17,239	7,960
TOTALS		111,304		109,886		111,634

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation and are consistent with values shown in Col. (19) of Schedule 2.3 and Col. (2) of Schedule 3.3.

CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990s and has since utilized this approach, in whole or in part as analysis needs warranted, to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of new power plants, the primary subjects of this document, are determined as part of the IRP process work.

This section describes FPL's basic IRP process. Some of the key assumptions, in addition to a new load forecast, that were used in FPL's 2009 and early 2010 resource planning work are also discussed.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental steps to FPL's resource planning. These steps can be described as follows:

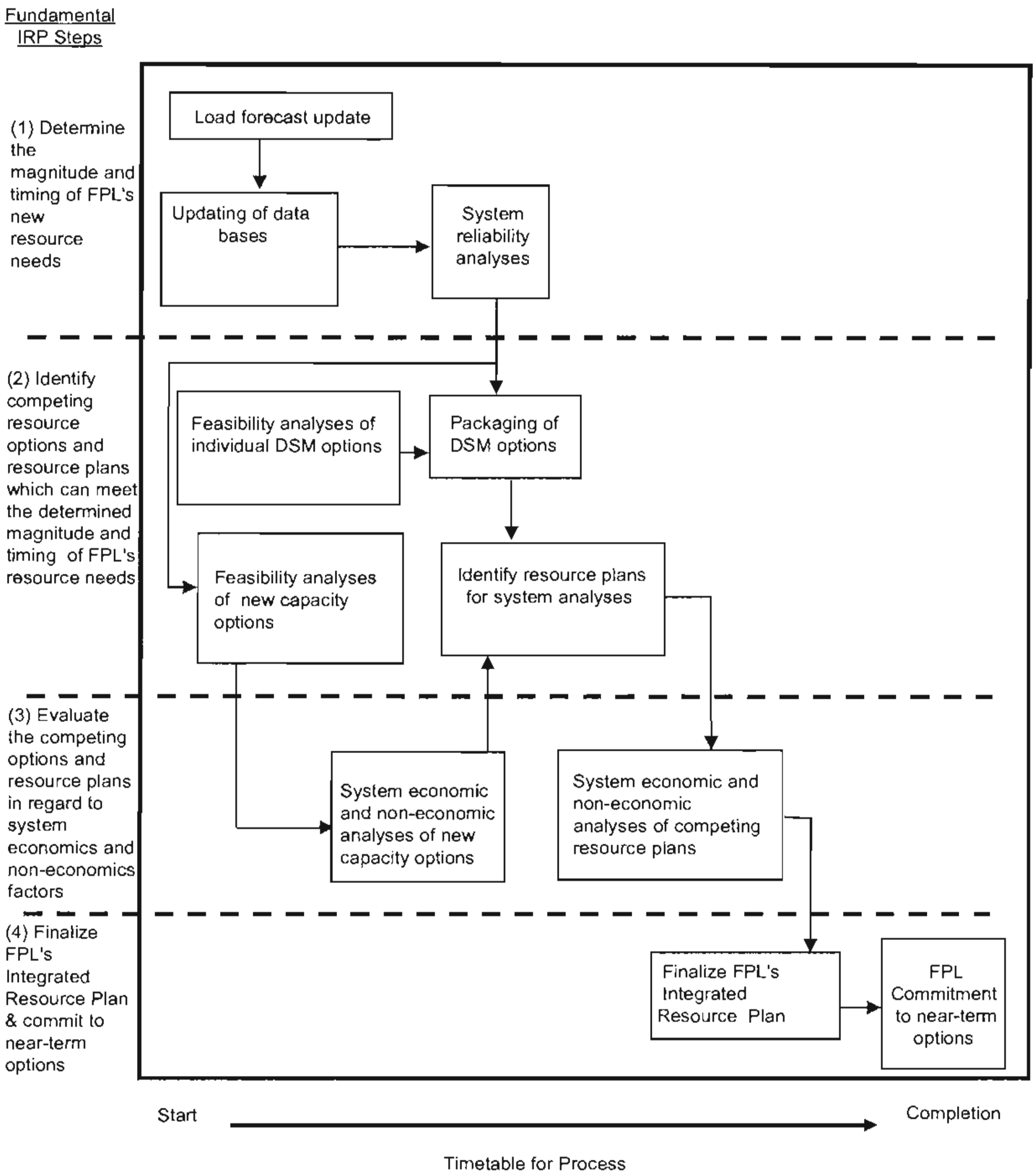
Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Evaluate the competing options and resource plans in regard to system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.



(Normal time period: approx. 6-7 months)

Figure III.A.1: Overview of FPL's IRP Process

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of the four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed to maintain system reliability. Also determined in this step is when the MW are needed to meet FPL's reliability criteria. This step is often referred to as a reliability assessment, or resource adequacy, analysis for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include, but are not limited to: delivered fuel price projections, current financial and economic assumptions, and power plant capability and reliability assumptions. FPL also includes key assumptions regarding three specific resource areas: (1) near-term construction capacity additions, (2) firm capacity power purchases, and (3) DSM implementation.

The first of these assumptions is based on new generating capacity additions that have been approved by the Florida Public Service Commission (FPSC) through Determination of Need proceedings that evaluated both the need for, and the cost-effectiveness of, each of the new capacity additions. These generating capacity additions have also either received the necessary Site Certification approvals from either the Secretary of the Florida Department of Environmental Protection (FDEP) or the Governor and Cabinet (acting as the Siting Board) or, as in the case of the new nuclear units, are in the process of receiving the necessary state and federal approvals. Several new generating unit additions will occur in the 2010 – 2019 reporting time frame of this document.

These generating unit additions include:

- The completion of a third gas-fired CC unit at FPL's West County Energy Center (WCEC) site which is scheduled to come in-service in mid-2011. This new unit, WCEC Unit 3, will add approximately 1,219 MW (Summer) of generation capacity. FPSC approval for this unit was obtained in September 2008 (PSC Order 08-0237-FOF-EI) and site certification was granted in November 2008.

- A new photovoltaic (PV) facility that is currently under construction in Brevard County and which is projected to be completed and in-service in 2010. This PV facility, named the Space Coast Next Generation Solar Energy Center, is projected to have a nameplate rating of 10 MW. The FPSC approved the eligibility of expenditures for this PV facility to be recovered through the Environmental Cost Recovery Clause (ECRC) in August 2008 (PSC Order 08-0941-PAA-EI). The Space Coast Next Generation Solar Energy Center received the Army Corps of Engineers permit in December 2008 and received the Environmental Resource Permit in April 2009.
- A new solar thermal facility at FPL's existing Martin plant site is also under construction and projected to be brought into service in 2010. This solar thermal facility, named the Martin Next Generation Solar Energy Center, which does not add to the capacity (MW) of the Martin plant, is projected to be able to produce up to 75 MW of steam capability, thus reducing use of fossil fuels by FPL when the solar thermal facility is producing steam. The FPSC approved the eligibility of expenditures for this solar thermal facility to be recovered through the ECRC in August 2008 (PSC Order 08-0941-PAA-EI). FPL received the site certification modification approval in August 2008.
- Two existing generating plants, each consisting of two older fossil fuel-fired steam generating units, are currently projected to be modernized by removing the existing generating units and replacing them with new, highly efficient CC units. The new plant at FPL's Cape Canaveral site is projected to be placed in-service in 2013. This new CC unit is projected to have a peak output of 1,210 MW. This new plant will be called the Cape Canaveral Next Generation Clean Energy Center. The new plant at FPL's Riviera site is projected to be placed in-service in 2014. This new CC unit is projected to have a peak output of 1,212 MW. This new plant will be called the Riviera Beach Next Generation Clean Energy Center. These conversions were approved by the FPSC in September 2008 (PSC Order 08-0591-FOF-EI). The site certification application for Cape Canaveral was filed in December 2008 and granted in October 2009. The site certification application for Riviera Beach was filed in February 2009 and granted in November 2009.

  As FPL has recently stated, work on these modernization projects has been suspended.

- In addition, FPL will be adding approximately 400 MW of generating capacity at its existing nuclear power plants at the Turkey Point and St. Lucie sites. This added capacity is scheduled to come in-service in 2011 and 2012, respectively. These capacity "uprates" were approved by the FPSC in January 2008 (PSC Order 08-0021-FOF-EI). The Final Order for the Site Certification was issued in September 2008 for the St. Lucie uprates and October 2008 for the Turkey Point uprates.

These new generating units and generating capacity additions were selected for a variety of reasons including cost-effectiveness, significant system fuel savings, fuel diversity, and significant system emission reductions, including greenhouse gas emission reductions. In addition, the solar projects will increase the contribution of renewable energy sources towards meeting the electricity needs of FPL's customers.

The second of these assumptions involves firm capacity power purchases. FPL's current projection of firm capacity purchases is very similar to the projection shown in FPL's 2009 Site Plan, after accounting for the fact that the contracts for several purchases presented in the 2009 Site Plan have now ended. These firm capacity purchases are from a combination of utility and independent power producers. Details, including the annual total capacity values for these purchases, are presented in Chapter I in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's resource planning work.

The third of these assumptions involves a projection of the amount of additional demand side management (DSM) that is anticipated to be implemented annually over the ten-year period. Since 1994, FPL's resource planning work has assumed that, at a minimum, the DSM MW called for in FPL's approved DSM Goals will be achieved as planned. The resource plan presented in FPL's 2010 Site Plan accounts for the new DSM goals.

The amount of DSM included in the 2010 Site Plan is different than the amount included in the 2009 Site Plan. In late 2009, the FPSC imposed significantly higher goals for DSM resources for FPL to add in the 2010 – 2019 period. The amount of demand (MW) reduction from the new DSM goals far exceeds (i.e., is more than double) the 2009 projection of FPL's remaining resource needs through 2019. Now, with FPL's lower long-term 2010 load forecast, and the commensurately lower 2010 projection of resource needs, the amount by which the MW reductions from the new DSM goals exceeds FPL's resource needs is even larger.

These key assumptions, plus the other updated information described above, are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's future resource needs. This determination is accomplished by system reliability analyses which for FPL are currently based on dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry.

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss-of-load probability or LOLP. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of the "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

The result of the first fundamental step of resource planning is a projection of how many new MW of resources are needed to meet both reserve margin and LOLP criteria, and thus maintain system reliability, and of when the MW are needed. Information regarding the timing and magnitude of these resource needs is used in the second fundamental step: identifying resource options and resource plans that can meet the determined magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, feasibility analyses of new capacity options are conducted to determine which new capacity options appear to be the most competitive on FPL's system. These analyses also establish capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. In similar analyses, feasibility analyses of new DSM options and/or continued growth in existing DSM options are typically conducted.

The individual new resource options emerging from these feasibility options are then typically "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet, dynamic programming, and/or linear and non-linear programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans in Regard to System Economics and Non-Economic Factors:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for evaluating these resource options and resource plans. In 2009, once the resource plans were developed, FPL utilized the P-MArea production cost model and a Fixed Cost Spreadsheet to perform the economic analyses. The P-MArea model is the model used by FPL to develop the Fuel Cost Budget and to conduct other production cost-related analyses.

FPL also utilized several other models in the economic evaluation portion of its resource planning work. For analyses of individual DSM options, FPL typically uses its DSM cost-effectiveness model which is an FPL spreadsheet model utilizing the FPSC's approved methodology for analyzing the cost-effectiveness of individual DSM measures/programs, and its non-linear programming model for analyzing the potential for lowering system peak loads through additional load management capacity. FPL then utilizes its linear programming model to develop DSM portfolios.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the intent of minimizing FPL's leveled system average rate (i.e., a Rate Impact Measure or RIM methodology). However, in cases in which the DSM contribution was assumed as a given and the only competing options were new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. Consequently, the competing options and plans in such cases were evaluated on a cumulative present value revenue requirement (CPVRR) basis.

Other factors are also included in FPL's evaluation of resource options and resource plans. While these factors may have an economic component or impact, they are often discussed in quantitative, but non-economic terms, such as percentages, tons, etc. rather than in terms of dollars. These factors are often referred to by FPL as "system concerns" that include (but are not necessarily limited to) maintaining/enhancing fuel diversity in the FPL system, system emission levels, and maintaining a regional balance between load and generating capacity, particularly in Southeastern Florida. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL's system, both the economic and non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps were used to develop the future generation plan. This plan is presented in the following section.

III.B Incremental Resource Additions/Changes

FPL's projected incremental generation capacity additions/changes for 2010 through 2019 are depicted in Table III.B.1. These capacity additions/changes result from a variety of actions including: changes to existing units (which are frequently achieved as a result of plant component replacements during major overhauls), temporarily removing older, less efficient generating units from active service and placing them into Inactive Reserve status until their continued operation is again needed, changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, increases in generating capacity at FPL's four existing nuclear units, the projected modernizations of FPL's steam generating units at its existing Cape Canaveral and Riviera sites into new, very fuel-efficient CC generating units, and by construction of approved new generating units such as West County Energy Center (WCEC) Unit 3.

As shown in Table III.B.1, the capacity additions consist primarily of construction of one new CC unit, the projected modernization of existing steam units into new CC units, and capacity increases at FPL's existing nuclear generating units. (The DSM additions that are consistent with the DSM goals imposed by the FPSC through 2019 are not explicitly presented in this table, but have been accounted for in FPL's resource planning work. In addition, the projected MW reductions from these DSM additions are reflected in the projected reserve margin values shown in the table.)

This table also shows the addition of the previously discussed 85 MW of new solar facilities (10 MW of PV and 75 MW of solar thermal). However, as indicated in the table and its footnotes, these new solar facilities are not projected to contribute new firm capacity. There are two reasons for this. First, one of these facilities – the 75 MW solar thermal facility at the Martin site – is designed not to add new capacity, but to serve solely as a "fuel substitute" facility. (When sufficient sunlight is available, the solar thermal facility will produce steam that would otherwise have been produced by burning fossil fuels.) Second, in regard to the new PV facility that has a 10 MW nameplate rating, it is unclear at this time what the output of this facility will consistently be during FPL's late afternoon Summer and early morning Winter peak hours. Consequently, FPL is not assigning a firm capacity value (i.e., those values reflected in Table III.B.1) to this PV facility at this time. Once FPL has actual operating experience with this PV facility, it will evaluate what an appropriate firm capacity value for this facility should be. However, FPL's economic and non-economic analyses fully capture the system fuel and emission savings from both of these two new solar facilities.

The significantly lower long-term load forecast, coupled with the approved additions of highly efficient new natural gas-fired and nuclear generating capacity, and the new DSM goals imposed by the FPSC, allow the opportunity for FPL to temporarily remove some older, less efficient generating capacity from active service, resulting in savings in operational and maintenance costs. A number of such units are/will be on Inactive Reserve status in 2010. These units are: Cutler Units 5 & 6, Sanford Unit 3, Port Everglades Units 1 & 2, and Turkey Point Unit 2. In 2011, Port Everglades Units 3 & 4 are also projected to be placed on Inactive Reserve. These generating units will continue to be maintained and will be returned to active service when needed. The timing of the return of these units is uncertain at this time primarily due to the uncertainty regarding FPL's future load. However, for planning purposes, FPL is showing in this document that these units begin to return to active service starting in the latter years of the ten-year reporting period, 2018 and 2019.

In addition, the existing Cape Canaveral and Riviera units that would be removed as part of the projected modernization work, will initially be placed on Inactive Reserve status, then would be completely removed from service in preparation for the construction of the new CC units at those sites if the modernization projects proceed.

Finally, as shown in the table below, FPL is currently projecting no additional new generating units beyond those discussed above for the years 2015 through 2019. This result is primarily driven by the combination of the lower long-term 2010 load forecast and the higher DSM goals.[2]

[2] For purposes of establishing a Standard Offer Contract, and using the same forecasts and other assumptions presented in this document, FPL projects that it's next fossil-fueled new generating unit would be a Greenfield 3x1 H CC with a 2025 in-service date. Details of that unit are not provided in this Site Plan because its projected in-service date is beyond the 2010-2019 time period addressed in this document.

Table III.B.1: Projected Capacity Changes for FPL

Projected Capacity Changes and Reserve Margins for FPL [1]			
Year	*Projected Capacity Changes*	*Net Capacity Changes (MW)* Winter [2]	Summer [3]
2010	Martin Next Generation Solar Energy Center (Solar Thermal) [7]	—	—
	Space Coast Next Generation Solar Energy Center (PV) [6]	—	—
	Changes to Existing Purchases [4]	—	(50)
	Riviera Unit 3 - offline for modernization	(280)	(277)
	Riviera Unit 4 - offline for modernization	(291)	(288)
	Cape Canaveral Unit 1 - offline for modernization	—	(396)
	Cape Canaveral Unit 2 - offline for modernization	—	(396)
	Changes to Existing Units	149	15
	Inactive Reserve of Existing Units - offline [8]	(775)	(769)
2011	Changes to Existing Purchases [4]	(90)	(45)
	Cape Canaveral Unit 1 - offline for modernization	(398)	—
	Cape Canaveral Unit 2 - offline for modernization	(398)	—
	West County Unit 3 [5]	—	1,219
	Inactive Reserve of Existing Units - offline [8]	(394)	(1,171)
	Changes to Existing Units	0	0
2012	Changes to Existing Purchases [4]	—	(100)
	West County Unit 3 [5]	1,335	—
	Changes to Existing Units	3	3
	Inactive Reserve of Existing Units - offline [8]	(783)	—
	Existing Nuclear Units Capacity Uprates - St. Lucie 1	103	103
	Existing Nuclear Units Capacity Uprates - St. Lucie 2	—	88
	Existing Nuclear Units Capacity Uprates - Turkey Point 3	—	104
2013	Changes to Existing Purchases [4]	(180)	—
	Cape Canaveral Next Generation Clean Energy Center	—	1,210
	Existing Nuclear Units Capacity Uprates - St. Lucie 2	88	—
	Existing Nuclear Units Capacity Uprates - Turkey Point 3	104	—
	Existing Nuclear Units Capacity Uprates - Turkey Point 4	104	104
2014	Cape Canaveral Next Generation Clean Energy Center	1,355	—
	Riviera Beach Next Generation Clean Energy Center	—	1,212
2015	Riviera Beach Next Generation Clean Energy Center	1,344	—
2016	Changes to Existing Purchases [4]	(931)	(1,306)
2017	Changes to Existing Purchases [4]	(375)	—
2018	Inactive Reserve of Existing Units - online [8]	0	392
2019	Inactive Reserve of Existing Units - online [8]	394	387
	TOTALS =	**84**	**39**

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.

(2) Winter values are forecasted values for January of the year shown. FPL's actual 2010 Winter peak was significantly higher than forecasted.

(3) Summer values are forecasted values for August of the year shown.

(4) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.

(5) All new unit additions are scheduled to be in-service in June of the year shown. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.

(6) Because of the intermittent nature of the photovoltaics (PV) resource, FPL is currently assigning no firm capacity benefit to these generating additions. FPL will reassess this once actual operating data from the PV facilities at these locations is available. This location-specific information is needed in order to gauge consistent output during the peak hours which are accounted for in FPL's reserve margin calculations.

(7) The Martin solar thermal facility is designed to provide steam for FPL's existing Martin Unit 8 combined cycle unit, thus reducing FPL's use of natural gas. No additional capacity (MW) will result from the operation of the solar thermal facility.

(8) A number of existing FPL power plants are being temporarily removed from service and placed on Inactive Reserve status. FPL plans to return these units to active service in the future as needed. The timing of the return of these units to full-time active status is uncertain at this time primarily due to the uncertainty regarding FPL's future load. However, for planning purposes, FPL is showing in this document that these units begin to return to active service starting in 2018.

III.C Issues Impacting FPL's Resource Planning Work

As indicated in the Executive Summary, FPL's resource planning efforts in 2010 will continue to be influenced by three factors: (i) a new lower long-term load forecast, (ii) significantly increased DSM goals for the 2010-2019 time frame, and (iii) regulatory and commercial developments regarding FPL's new nuclear units, Turkey Point 6 & 7.

In addition, there are other items that will also influence FPL's resource planning work. Among these other items are two that FPL typically refers to as on-going system concerns that FPL has considered in its resource planning work for a number of years. These two on-going system concerns are: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida.

A third factor that will influence FPL's on-going resource planning efforts is the Executive Order directive issued in 2007 by Governor Crist, calling for reductions in greenhouse gas emissions and for increased contribution from renewable energy sources.

A fourth factor that could affect FPL's resource planning is the future establishment of Florida standards for renewable or clean energy contributions to a utility system. A Renewable Portfolio Standard (RPS) proposal was prepared by the FPSC, and sent to the Florida Legislature for consideration, with a possible change to a Clean Portfolio Standard (CPS), during the 2009 legislative session. However, no RPS or CPS legislation was enacted during the 2009 legislative session. RPS or CPS legislation, or other legislative initiatives regarding renewable or clean energy contributions, may occur in the future. If such legislation is enacted in 2010 or later years, FPL will then determine what steps need to be taken to address the legislation. Such steps would then be discussed in FPL's Site Plan in the year following the enactment of such legislation.

These four (4) factors that impact FPL's on-going resource planning work are briefly discussed below.

1. System Fuel Diversity

FPL is currently dependent upon using natural gas to generate slightly more than half of the electricity it delivers to its customers. In the future, the percentage of FPL's electricity that is generated by natural gas is projected to increase. Therefore, FPL is continually seeking opportunities to maintain and enhance the fuel diversity of its system.

In 2007, FPL sought approval from the FPSC to add two new advanced technology coal units to its system. These two new units would have been placed in-service in 2013 and 2014. However, due to concerns over greenhouse gas emissions, FPL was unable to obtain approval for these units. Consequently, FPL does not believe that new advanced technology coal units are viable fuel diversity enhancement options in Florida for the foreseeable future.

Therefore, FPL has turned its attention to nuclear energy, renewable energy, and more efficient ways in which to generate electricity using natural gas in order to enhance its fuel diversity. In regard to nuclear energy, FPL obtained approval to increase capacity at each of its four existing nuclear units. In total, these capacity "uprates" will add approximately 400 MW of capacity and energy for FPL's customers beginning in the 2011/2012 time period. In 2008, the FPSC approved both the need for these uprates and the ability to recover uprates-related expenditures.

FPL also has been involved in activities to investigate adding or maintaining renewable resources as a part of its generation supply. One of these activities is a variety of discussions with the owners of existing facilities aimed at maintaining or extending current agreements that are scheduled to end during the ten-year reporting period of this document. Another activity is to periodically issue a request for proposals to solicit cost-effective new renewable projects from outside parties. Also, as previously discussed, FPL sought and received approval from the FPSC in 2008 to add 110 MW through three new FPL-owned solar facilities, one solar thermal facility and two PV facilities. One 25 MW PV facility began commercial operation in 2009. The remaining two solar facilities are scheduled to be in-service by the end of 2010. FPL's efforts to utilize renewable energy are discussed further in Section III.F.

In regard to using natural gas more efficiently, FPL received approvals in 2008 from the FPSC to build a third highly efficient CC unit at its West County Energy Center site (WCEC Unit 3) and to convert the older steam generating units at its existing Cape Canaveral and Riviera plant sites to new, highly efficient CC units. WCEC Unit 3 is currently projected to go in-service in 2011.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity. FPL also plans to maintain the ability to utilize fuel oil at those existing units that have that capability, although cost factors currently limit the expected use of these facilities. Furthermore, FPL has traditionally purchased the gas transportation capacity required for new natural gas generating units from an existing natural gas pipeline company. As an alternative, FPL sought approval in 2009 from the FPSC for the construction of a new natural gas pipeline in Florida capable of serving future generation needs. Such a third pipeline was projected to have potential benefits for FPL and its customers by increasing the diversity of FPL's fuel supply sources, increasing the physical reliability of the pipeline delivery system, and enhancing competition among pipelines. However, the application for an FPL-owned pipeline was denied by the FPSC in 2009. FPL is currently re-evaluating how natural gas can be delivered to its system in the future.

2. **<u>Southeastern Florida Imbalance</u>**

In recent years, an imbalance had developed between regionally installed generation and peak load in Southeastern Florida. A significant amount of energy required in the Southeastern Florida region during peak periods was being provided through the transmission system from plants located outside the region. FPL's prior planning work concluded that either additional installed generating capacity in this region, or transmission capacity capable of delivering additional electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location, four recent capacity addition decisions (Turkey Point Unit 5 and WCEC Units 1, 2, & 3) were evaluated as the most cost-effective options to meet FPL's capacity needs in the near-term. Adding these units will significantly reduce the imbalance between generation and load in Southeastern Florida.

In addition, FPL will be adding increased capacity at FPL's existing two nuclear units at Turkey Point in 2011 and 2012 and is currently projected to increase the generating capacity at its Riviera site through a modernization of that site in 2014. These generating unit additions in Southeastern Florida are expected to address the imbalance for most, if not all, of the 2010-2019 reporting period addressed in this document even after accounting for temporarily placing some of the existing generating units in the region on Inactive Reserve status. However, the Southeastern Florida imbalance will remain a consideration in FPL's on-going resource planning work.

3. **<u>Governor Crist's Executive Order</u>**

The Executive Order directive issued in 2007, particularly the portions of the directive that call for significant increases in renewable, non-emitting energy, and decreases in greenhouse gas emissions, are being addressed by FPL in a variety of ways. With respect to renewable energy, FPL's efforts to build its own renewable energy facilities were mentioned above in regard to fuel diversity and are also discussed in more detail in Section III.F.

These renewable energy efforts have the potential to help lower greenhouse gas emissions. In addition, significant reductions, particularly of carbon dioxide (CO_2), will be accomplished in the ten-year reporting time frame of this document by the approved capacity uprates at FPL's four existing nuclear power plants. Further reductions in greenhouse gas emissions are also expected from increasing the overall fuel efficiency of FPL's system through the addition of WCEC Unit 3 and the currently projected modernizations of FPL's existing Cape Canaveral and Riviera plant sites. FPL will also continue to look for cost-effective ways to further improve the efficiency of its system that will lead to even more greenhouse gas emission reductions.

FPL's system CO_2 emission rate (amount of CO_2 emitted per MWh of electricity generated) is already relatively low due in large part to the overall efficiency of FPL's system. The efforts described above have the potential not only to continue the trend of steadily lowering FPL's already low CO_2 emission rate, but also to begin to lower total system CO_2 emissions despite continued growth in population.

4. <u>Renewable Portfolio or Clean Energy Standards (RPS or CPS)</u>

At the time this document is being prepared, Florida does not have a Renewable or Clean Energy Portfolio Standard (RPS or CPS). An RPS proposal was prepared by the FPSC and sent to the Florida Legislature for their consideration, with a possible change to a Clean Portfolio Standard (CPS), during the 2009 legislative session. However, no RPS or CPS legislation was enacted during that session. RPS or CPS legislation, or other legislative initiatives regarding renewable or clean energy contributions, may occur in the future. If such legislation is enacted in 2010 or in a later year, FPL will then determine what steps need to be taken to address the legislation. Such steps would then be discussed in FPL's Site Plan in the year following the enactment of such legislation.

III.D Demand Side Management (DSM)

As previously discussed in Chapter I, and earlier in this chapter, the FPSC in late 2009 imposed significantly higher DSM goals for FPL for 2010 – 2019 than are needed to meet 100% of FPL's remaining resource needs through 2019. In addition, the FPSC ordered

FPL to spend up to $15.5 million per year to promote DSM-based applications of solar water heating and photovoltaics (PV).

The DSM goals recently imposed by the FPSC have three components: Summer MW reductions, Winter MW reductions, and GWh reductions. Table III.D.1 presents the Summer MW reduction component of these goals. (The Summer MW component, and to a much lesser degree the Winter MW reduction component, impacts FPL's need for future resources such as those discussed in this document. The GWh reduction component has no impact on FPL's need for future resources.)

Table III.D.1: FPL's Summer MW Reduction Goals for DSM
(at the Generator)

Year	Cumulative Summer MW DSM Goals for FPL (at Generator)
2010	110
2011	253
2012	419
2013	599
2014	783
2015	955
2016	1,111
2017	1,251
2018	1,379
2019	1,498

By March 30, 2010, FPL is required to petition the FPSC for approval of the DSM Plan it proposes to implement to meet the DSM goals and renewable energy expenditure mandates. At the time this Site Plan is being prepared, FPL was still developing its DSM Plan that it will petition the FPSC for approval to implement. FPL expects that the FPSC approval process for its DSM Plan will likely take several months. Therefore, FPL does not expect to know with certainty what its portfolio of approved DSM programs will be until mid-2010 at the earliest. FPL expects to provide a description of its approved DSM programs in its 2011 Site Plan.

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include both conservation initiatives and load management. FPL's DSM efforts through 2009 have resulted in a cumulative Summer peak reduction of approximately 4,257 MW at the generator and an estimated cumulative energy saving of approximately

51,055 Gigawatt Hour (GWh) at the generator. Accounting for reserve margin requirements, FPL's DSM efforts through 2009 have eliminated the need to construct approximately 13 new 400 MW generating units.

FPL has consistently been among the leading utilities nationally in DSM achievement. For example, according to the U.S. Department of Energy's 2007 data (the last year for which the DOE data was available at the time this Site Plan is being developed), FPL ranked # 1 nationally in energy efficiency demand reduction and # 2 nationally in load management demand reduction. And, importantly, FPL has achieved these significant DSM accomplishments while minimizing the impact on electric rates for all of its customers.

FPL's intent is to address the FPSC's DSM goals and funding mandate for DSM-based solar applications, to continue its national leadership role in DSM, and to continue to minimize the electric rate impact resulting from its DSM efforts.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy to FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV bulk transmission lines that must be certified under the Transmission Line Siting Act.

Table III.E.1: List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	St. Johns 1/	Pringle	25	Dec - 13	230	759
FPL	Manatee 2/	BobWhite	30	Dec - 12	230	1190

1/ Final order certifying the corridor was issued on April 21, 2006. This project is to be completed in two phases. Phase I consisted of 4 miles of new 230kV line (Pringle to Pellicer) and was completed in May-2009. Phase II consists of 21 miles of new 230kV line (St. Johns to Pellicer) and is scheduled to be completed by Dec-2013.

2/ Final order certifying the corridor was issued on November 6, 2008. This project consists of 30 miles of new 230kV line (Manatee to Bobwhite) and is scheduled to be completed by Dec-2012

In addition, there will be transmission facilities needed to connect several of FPL's projected generating capacity additions to the system transmission grid. These transmission facilities for the projected generating capacity additions at the West County Energy Center site Unit 3, the capacity increases (uprates) at the existing St. Lucie and Turkey Point nuclear sites, and the Cape Canaveral and Riviera Beach modernizations are described on the following pages.

Certain new generation additions will not need new transmission facilities. These generation additions include the Martin Next Generation Solar Energy Center and the Space Coast Next Generation Solar Energy Center. The Martin solar thermal facility does not add any new generation capacity at the site and, therefore, no new transmission facilities are required. The Space Coast facility is an addition of 10 MW of PV generation that will be connected at distribution voltage at the Grissom substation. No new transmission facilities are needed.

In regard to the existing generating units that are projected to be temporarily placed on Inactive Reserve status in 2010 and 2011, there are no projected impacts to FPL's transmission system from these units because these units can be returned to active service with adequate notice.

III.E.1 Transmission Facilities for West County Energy Center (WCEC) Unit 3

The work required to connect West County Energy Center (WCEC) Unit 3 in 2011 to the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with four breakers to connect the three combustion turbines (CT), and one steam turbine (ST).
2. Build new Sugar 230 kV Substation on WCEC site.
3. Construct two string busses to connect the collector busses to Sugar 230kV Substation.
4. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
5. At Corbett Substation, relocate Germantown 230 kV line terminal from Corbett to Sugar Sub.
6. At Corbett Substation, relocate Broward/Yamato 230 kV line terminal from Corbett to Sugar Sub.
7. At Corbett Substation, install new Sugar 230 kV line terminal in Bay 2W.
8. At Corbett Substation, install one 5-ohm inductor on the 230 kV side of the 500/230 kV autotransformer.
9. Add relays and other protective equipment.

II. Transmission:

1. Relocate Germantown 230 kV line from Corbett to Sugar.
2. Relocate Broward/Yamato 230 kV line from Corbett to Sugar.
3. Construct one mile 230 kV 1190 MVA line from Sugar to Corbett.

III.E.2 Transmission Facilities for St. Lucie Units 1 & 2 Capacity Uprates

The work required to address the St. Lucie Units 1 & 2 uprates in 2011 for Unit 1, and in 2012 for Unit 2, in regard to the FPL grid is projected to be as follows:

I. Substation:

1. At Midway Substation, replace eleven 230 kV disconnect switches, and six wave traps. Also upgrade associated jumpers, bus work and equipment connections.
2. At St. Lucie Switchyard, replace eighteen 230 kV disconnect switches and six wave traps.
3. Uprate the Unit 1A and 1B main step-up transformers to 635 MVA.
4. Uprate the spare main step-up transformer to 635 MVA to replace Unit 2A main step-up transformer.
5. Replace the Unit 2B main step-up transformer with a new one rated at 635 MVA.
6. Add relays and other protective equipment.

II. Transmission:

1. Upgrade the three existing St. Lucie-Midway 230 kV lines with spacers between the conductors to achieve a normal (continuous) rating of 2790 Amperes.
2. Replace one existing overhead ground wire on each of the three existing St. Lucie Midway 230kV line with fiber optic overhead ground wire for protective relay communication.

III.E.3 Transmission Facilities for Turkey Point Units 3 & 4 Capacity Uprates

The work required to address the Turkey Point Units 3 & 4 uprates in 2012 in regard to the FPL grid is projected to be as follows:

I. Substation:

1. At Turkey Point Switchyard, install two 5-Ohm series phase inductors combined with external shunt capacitors on the southeast and southwest 230 kV operating busses.
2. At Turkey Point Switchyard, replace twelve 230 kV disconnect switches. Also upgrade associated jumpers, bus work and equipment connections.
3. Uprate the Unit 3 and Unit 4 main step-up transformers to 970 MVA.
4. Replace spare main step-up transformer with 1028 MVA transformer.
5. Add relays and other protective equipment.
6. Replace breaker failure panels at Davis Substation.
7. Replace breaker failure panels at Flagami Substation.

II. Transmission:

1. Upgrade the existing string busses for both Units 3 & 4 between the main step-up transformers and the switchyard with spacers between the conductors.

III.E.4 Transmission Facilities for Cape Canaveral Next Generation Clean Energy Center (Projected Modernization)

The work required to connect the projected Cape Canaveral Next Generation Clean Energy Center in 2013 to the FPL grid is forecasted to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with four breakers to connect the three combustion turbines (CT), and one steam turbine (ST).
2. Construct two string busses to connect the collector busses to Cape Canaveral 230kV Substation.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. At Cape Canaveral Switchyard replace eight 230 kV disconnect switches. Also upgrade associated jumpers, bus work and equipment connections.
5. Expand switchyard relay vault and add relays and other protective equipment.

II. Transmission:

1. Relocate the Cape Canaveral-Grissom 115 kV line.

III.E.5 Transmission Facilities for Riviera Beach Next Generation Clean Energy Center (Projected Modernization)

The work required to connect the projected Riviera Beach Next Generation Clean Energy Center in 2014 to the FPL grid is forecasted to be as follows:

I. Substation:

1. Expand the Riviera 230 kV Switchyard five breakers to accommodate terminals for one combustion turbine (CT), and one steam turbine (ST).
2. Construct a new 138 kV Riviera Switchyard - five bays, 14 breakers with terminals to connect two CT units and seven 138 kV lines.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. Add relays and other protective equipment.
5. At Ranch Substation, add a new 230 kV bay 5 and upgrade bay 4 to 3000 Amperes.
6. Breaker replacements:
   Ranch Substation – Replace one 230 kV breaker
   Broward Substation – Replace one 230 kV breaker

II. Transmission:

1. Break the Indiantown-Riviera 230kV and extend each of the line segments south (approx. 4 miles) to connect to the Ranch 230 kV Substation forming Indiantown-Ranch and a Ranch-Riviera 230 kV circuits.
2. Remove Corbett-Ranch #2 230 kV line at Ranch and:
   a. extend to meet the Cedar-Lauderdale 230 kV line N/S corridor (approx. 10 miles).
3. Break Cedar -Corbett 230 kV (near Ranch Sub in Corbett-Jog section) and:
   a. Extend Cedar side to Riviera, (approx. 15 miles) creating new Cedar-Riviera 230 kV.
   b. Extend Corbett side to meet the Cedar-Lauderdale 230 kV N/S corridor (approx. 10 miles).
4. Break Cedar-Lauderdale 230 kV (near 230 corridor running N/S)
   a. Connect Cedar side to meet 3.b. to create a Cedar to Corbett 230 kV.
   b. Connect Lauderdale side to meet 2.a. to create a Corbett to Lauderdale 230 kV.
5. Upgrade the existing IBM-Yamato 138 kV line to 1200 Amperes.
6. New underground 138 kV tie line between new Riviera 138 kV Switchyard and 560 MVA, 230/138 kV autotransformer in the expanded Riviera 230 kV Substation.
7. Relocate six existing 138 kV lines from existing Ranch 138 kV Switchyard to new Riviera 138 kV Switchyard.

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to utilize renewable energy technologies to meet its customers' current and future needs. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. For purposes of discussing FPL's renewable energy efforts in this document, those efforts will be placed into five categories.

1) **Early Research & Development Efforts:**

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970s in demonstrating the first residential solar photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-kilowatt (kW) system was placed into operation in 1984. (The system was removed in 1990 to make room for substation expansion once testing of this PV installation had been completed.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. This FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's recent Green Pricing effort (which is discussed below).

2) **Demand Side & Customer Efforts:**

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program ended (due to the fact that it was no longer cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for six passive home designs with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the FPSC to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test were deemed to be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, and various customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

FPL has since continued to analyze and promote the utilization of PV. These efforts have included a PV research, development, and education project, "green energy" research projects and pricing programs, and participation in the State of Florida's PV for Schools program. With resources from the FPL Group Foundation, FPL will contribute 30 kw of PV to schools and educational non-profits in its service area during 2010. This initiative also delivers teacher training and curriculum that is tied to the Sunshine Teacher Standards in Florida. Additionally, it provides teacher grants to promote and fund projects in the classrooms.

FPL has also been investigating fuel cell technologies through monitoring of industry trends, discussions with manufacturers, and direct field trials. From 2002 through the end of 2005, FPL conducted field trials and demonstration projects of Proton Exchange Membrane (PEM) fuel cells with the objectives of serving customer end-uses while evaluating the technical performance, reliability, economics, and relative readiness of the PEM technology. The demonstration projects were conducted in partnership with customers and included 5 locations. The research projects were useful to FPL in identifying specific issues that can occur in field applications and the current commercial viability of this technology. FPL will continue to monitor the progress of these technologies and conduct additional field evaluations as significant developments in fuel cell technologies occur.

In addition, FPL assists customers who are interested in installing PV equipment at their facilities. Consistent with Florida Administrative Code Rule 25-6.065, Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned PV systems. Through December 2009, approximately 645 customer systems (predominantly residential) have been interconnected.

Finally, as part of its DSM goals decision, the FPSC imposed a requirement for Florida's investor-owned utilities to spend up to a set, not-to-exceed amount of money annually to facilitate demand side solar water heater and photovoltaic applications. FPL's not-to-exceed annual amount of money for these applications is approximately $15.5 million. At the time this Site Plan is being prepared, FPL is developing its plan for how these expenditures will be made and is scheduled to file its plan for FPSC approval on March 30, 2010. The FPSC is expected to approve FPL's plan in mid-2010. FPL expects to provide a description of its approved plan for these DSM-based solar expenditures in its 2011 Site Plan.

3) <u>Supply Side Efforts – Power Purchases:</u>

FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy, and as-available energy, have been purchased by FPL from these types of facilities. (Please refer to Tables I.B.1, I.B.2, and Table I.C.1 in Chapter I).

Periodically, FPL invites renewables suppliers to provide proposals for renewable power and energy at or below avoided costs in response to FPL's Requests for Proposals (RFPs). FPL issued Renewable RFP's in 2007 and 2008 soliciting proposals to provide firm capacity and energy, and energy only, at or below avoided costs from renewable generators. FPL also promptly responds to inquiries for information from prospective renewable energy suppliers either by e-mail or phone.

With regard to existing contracts that have recently ended, FPL and the Solid Waste Authority of Palm Beach (SWA) agreed to extend their contract that expired March 31, 2010 for a 20 year term from April 1, 2012 through April 1, 2032. Also, the firm capacity and energy contract with Broward South that expired August 2009 was not renewed, but Broward South continues as an as-available supplier of energy to FPL

4) <u>Supply Side Efforts – FPL Facilities:</u>

FPL is in the process of developing a wind generation project on South Hutchinson Island in St. Lucie County. This project is known as the St. Lucie Wind project and it consists of up to six wind turbine generators capable of generating up to approximately 13.8 MW. In 2007, FPL began the St. Lucie County land use approval process, and soon after applied for the necessary federal and state permitting. However, a decision by the state and federal agencies on the St. Lucie Wind project's permitting will not be finalized until the local land use approval process is completed. The in-service date will depend on the approval and permitting process.

With regard to solar projects, FPL has completed construction of the nation's largest photovoltaic (PV) power generation facility in the country, the 25 MW DeSoto Next Generation Solar Energy Center. In addition, two solar projects that will add 85 MW of solar capacity are projected to be completed in 2010. These three projects are in response to the Florida Legislature's House Bill 7135 which was signed into law by Governor Crist in June 2008. House Bill 7135 (hereafter referred to as the 2008 Energy Bill), was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in the State of Florida. Specifically, the 2008 Energy Bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land, zoning and transmission rights in place. FPL's three solar projects met the specified criteria, and were granted approval for cost recovery in 2008. Each of the three solar projects is discussed below.

a. <u>The Martin Next Generation Solar Energy Center:</u>

This project will provide 75 MW of solar thermal capacity in an innovative way that directly displaces fossil fuel usage on the FPL system. This project will involve the installation of solar thermal technology that will be integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired CC plant. This project will be the first "hybrid" solar plant in the world, the second largest solar facility in the world, and the largest solar plant of any kind in the U.S. outside of California. Construction began in December 2008 and is expected to be completed by the end of 2010.

b. **<u>The DeSoto Next Generation Solar Energy Center:</u>**

This facility has been constructed and began commercial operation in October 2009. It currently is providing up to 25 MW of PV non-firm capacity and energy, making it the largest PV facility in the U.S. The facility utilizes a tracking array that is designed to follow the sun as it traverses through the sky.

c. **<u>The Space Coast Next Generation Solar Energy Center:</u>**

Located at the Kennedy Space Center, this project is part of an innovative public/private partnership with NASA. When completed, it will provide up to 10 MW of PV non-firm capacity and energy. Construction began in June 2009 and is expected to be completed in 2010.

Each of these facilities is a significant and innovative renewable generating plant in its own right. Collectively, these Next Generation Solar Energy Centers are expected to produce a total of approximately 213,000 megawatt-hours (MWh) of electricity each year, and at peak production provide enough energy to serve the requirements of more than 15,000 homes.

For resource planning purposes, FPL projects that the energy delivered from these renewable facilities will be "as available", non-firm energy. This is due to several factors. First, the Martin solar thermal facility is designed as a "fuel-substitute" facility, not as a facility that will result in additional capacity and energy being generated. The solar thermal facility will displace the use of fossil fuel on the FPL system when the solar thermal facility is operating. Second, in regard to the two PV facilities, the intermittent nature of the solar resource makes it difficult to accurately determine what contribution the PV facilities at these specific locations can consistently make at FPL's late Summer afternoon and early Winter morning peak load hours. Once site-specific operating data has been gathered for an appropriate amount of time, FPL will then re-evaluate the actual output from each PV facility to determine what portion, if any, of its output can be projected as firm capacity at the projected peak hours in FPL's resource planning work.

In addition to these three approved projects, FPL is currently in the process of identifying other potential solar sites in the state in the event that a future Renewable Portfolio Standard (RPS), Clean Energy Portfolio Standard (CPS), or other enabling legislation is enacted by the Florida legislature. FPL is evaluating existing FPL generation sites along with potential greenfield sites within FPL's service territory. These potential FPL and greenfield sites are discussed further in Chapter IV.

5) **Ongoing Research & Development Efforts:**

FPL has developed alliances with several Florida universities to promote development of emerging technologies. For example, an alliance has been established with the newly formed Center for Ocean Energy Technology at Florida Atlantic University (FAU), which will focus on the commercialization of ocean current, ocean thermal (i.e., energy conversion as well as cold water air conditioning) and hydrogen technologies. FPL has been taking the lead in assisting FAU with the discussions being held with the U.S. Department of the Interior's Minerals Management Service Department (MMS). MMS is working to establish the permitting process for ocean energy development on the outer continental shelf.

FPL has also developed an alliance with the University of Florida to support its studies of biomass renewable potential and wind studies in the state. In addition, FPL has partnered with the Florida Institute of Technology on fuel cell technology and with the Florida State Universities Center for Applied Power System in regard to grid integration of ocean energy and other renewables.

FPL is also developing a "living lab" to demonstrate FPL's solar energy commitment to employees and visitors at its Juno Beach facility. FPL will evaluate multiple solar technologies and applications to develop a renewable business model resulting in the most cost-effective and reliable source(s) of solar energy to FPL customers.

FPL has also been in discussions with several private companies on multiple emerging technology initiatives including ocean current, ocean thermal, hydrogen, fuel cell technology, biomass, biofuels, and energy storage.

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. **FPL's Fuel Mix**

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fired generation. In the early 1980s, FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership and additional purchases from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit 4 which began serving FPL's customers in 1991. Starting in 1997, petroleum coke was added to the fuel mix as a blend stock with coal at SJRPP.

The trend since the early 1990s has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective CC generating units and the ready availability of natural gas. This planning document reflects an evolution in that trend in recognition that, although efficient gas-fired generation continues to provide significant benefits to FPL's customers, adding natural gas-fired additions exclusively would, in the long term, create an unbalanced generation portfolio. In 2009, FPL placed into commercial operation two new gas-fired CC units at the West County Energy Center (WCEC) site. A third new CC unit is projected to be added to the WCEC site in 2011. In addition, FPL is currently projecting to modernize its existing Cape Canaveral and Riviera plant sites by removing the existing steam generating units and replacing them with two highly efficient new CC units, one at each site. These new CC units will provide highly efficient generation that will dramatically improve FPL's overall system generation efficiency.

In addition, FPL is increasing its utilization of nuclear energy through capacity uprates of its four existing nuclear units. These uprates will add a total of approximately 400 MW of nuclear generation capacity by 2012. (FPL is also pursuing plans to obtain permits to build two new nuclear units at its existing Turkey Point site that, in total, would add approximately 2,200 MW of new nuclear generating capacity. FPL currently assumes, for resource planning purposes, that the in-service dates for the new nuclear units are outside of the 2010-2019 reporting time frame of this document. At the time this document is being prepared, FPL is evaluating what the revised in-service dates for Turkey Point Units 6 & 7 should be for planning purposes. FPL will address those revised in-service dates for planning purposes in its May 3, 2010 nuclear cost recovery filing to the FPSC.)

In regard to utilizing renewable energy, FPL has committed to add 110 MW of solar generating capacity by 2010 through a 75 MW solar thermal facility at FPL's existing Martin site, a 25 MW PV facility in DeSoto County, and a 10 MW PV facility in

Brevard County. The 25 MW PV facility was placed into commercial operation in 2009. The other two solar facilities are projected to be completed in 2010.

FPL's future resource planning work will continue to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance FPL's long-term fuel diversity. These fuel diverse alternatives may include: the purchase of power from renewable energy facilities, addition of FPL-owned renewable energy facilities, obtaining access to diversified sources of natural gas such as liquefied natural gas (LNG) and natural gas from the Mid-Continent unconventional reserves, preserving FPL's ability to utilize fuel oil at its existing units, and increased utilization of nuclear energy. (New advanced technology coal generating units are not currently considered as viable options in Florida in the ten-year reporting period of this document due to concerns over greenhouse gas emissions.) The evaluation of the feasibility and cost-effectiveness of these, and other possible alternatives, will be an ongoing part of future planning cycles.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2019 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

2. **FPL's Fuel Mix**

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future generating capacity needs. FPL's forecasts are generally consistent with other published contemporary forecasts.

Future oil and natural gas prices, and to a lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short-and long-term price of oil, natural gas, coal, and petroleum coke. These drivers include:

a. Current and projected worldwide demand for crude oil and petroleum products;

b. Current and projected worldwide refinery capacity/production;

c. Expected worldwide economic growth, in particular in China, and other Pacific Rim countries;

d. Organization of Petroleum Exporting Countries (OPEC) production, the availability of spare OPEC production capacity and the assumed growth in spare OPEC production capacity;

e. Non-OPEC production and expected growth in non-OPEC production;

f. The geopolitics of the Middle East, West Africa, the Former Soviet Union, Nigeria, Venezuela, etc., as well as, the uncertainty and impact upon worldwide energy consumption related to U. S. and worldwide environmental legislation, politics, etc.;

g. Current and projected North American natural gas demand;

h. Current and projected U.S., Canadian, and Mexican natural gas production;

i. The worldwide supply and demand for LNG; and

j. The growth in solid fuel generation on a U. S. and worldwide basis.

The inherent uncertainty and unpredictability in these factors today and tomorrow clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal and petroleum coke) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed and utilized Low, Medium, and High price forecasts for fossil fuels in some of its 2009 resource planning work, particularly in regard to the nuclear cost recovery filings.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

a. For 2010 through 2012, the methodology used the January 26, 2010 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil, ultra low sulfur diesel, and Henry Hub natural gas commodity prices;

b. For the next two years (2013 and 2014), FPL used a 50/50 blend of the January 26, 2010 forward curve and the most current projections at the time from The PIRA Energy Group;

c. For the 2015 through 2025 period, FPL used the annual projections from The PIRA Energy Group, and;

d. For the period beyond 2025, FPL used the real rate of escalation provided in the Energy Information Administration (EIA) *Annual Energy Outlook 2009* publication. FPL assumed a 2.5% annual rate of escalation to convert real prices to nominal prices prior to 2025, with no escalation from 2025 forward. In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach:

a. The price forecasts for Central Appalachian coal (CAPP), Powder River Basin (PRB), South American coal, and petroleum coke were provided by JD Energy;

b. The marine transportation rates from the loading port for coal and petroleum coke to an import terminal were also provided by JD Energy;

c. The coal price forecast for SJRPP and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for oil, natural gas, coal, and petroleum coke prices were based on the historical volatility of the 12-month forward price, one year ahead. FPL developed these forecasts to account for the uncertainty which exists within each commodity as well as across commodities. These forecasts reflect a range of reasonable forecast outcomes.

3. <u>Nuclear Fuel Cost Forecast</u>

This section reviews the various steps needed to fabricate nuclear fuel for delivery to the nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

a) <u>Steps Required for Nuclear Fuel to be delivered to FPL's Plants</u>

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

(1) Mining: Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U3O8 (sometimes referred to as yellowcake).

(2) Conversion: During the second step, the U3O8 is chemically converted into UF6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

(3) Enrichment: The third step is called enrichment. Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 3% to as high as 5%). The output of this enrichment process is enriched uranium in the form of UF6.

(4) Fabrication: During the last step, fuel fabrication, the enriched UF6 is changed to a UO2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) Mining: There is some volatility in the current uranium market. Demand is rather stable and outputs from production facilities have been increasing steadily. The following are the current major contributors that led to less volatility in the prices for uranium:

- The recent financial crisis had caused significant sales of inventories and caused the market price to drop earlier than predicted. However, Hedge funds continue to purchase uranium, reducing its availability to end users.

- The large inventory from the U.S. Department of Energy (DOE) is being withheld from the market due to political pressure from suppliers concerned about further price drop already affected by the current financial downturn. However, some of it is made available as barter in exchange for clean-up costs for the Department of Energy enrichment facilities.

- The Russians have announced that they would not supply down-blended weapons material to the U.S. government after 2013 for sale in the U.S. market. However, there is not an agreement between the U.S. and Russian government for the sales of enriched uranium.

- The U.S. Department of Commerce (DOC) has imposed restrictions on the import of nuclear fuel from France and Russia.

FPL expects the market to be more consistent with market fundamentals. In 2008 and 2009, a number of actions resolved restrictions of imports of foreign uranium. Recent law enacted in 2008 resolved the import of Russian-enriched uranium, by allowing some imports of Russian-enriched uranium to about 20-25% of needs for currently operating units, but with no restriction on the first core for new units and no restrictions after 2020. As mentioned earlier, the economic recession has also had a major impact and eliminated a significant portion of speculative demands with uranium pricing returning to close to the fundamentals. FPL cannot discount the possibility of future periodic sharp increase in prices, but believes such occurrences will likely be temporary in nature.

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies.

(2) <u>Conversion:</u> FPL's price forecast considers the construction of new nuclear units. Just like for raw uranium, an increase in demand for conversion services would result from this need. Insufficient planned production is currently forecasted after 2013 to meet the higher demand scenario. As with additional raw uranium production, supply will expand beyond current level once more firm commitments are made including commitments to building new nuclear units.

(3) Enrichment: With no new production capacity, the current tight market supply for economically produced enrichment services will continue until 2013. The current expensive diffusion plant can make up any gaps in supply of enrichment services. In addition, there are a number of new facilities coming on-line through 2013, using more efficient and proven processes such as the use of centrifuges for enrichment of uranium. As with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand. Meanwhile, world supply and demand will continue to be balanced such that FPL expects adequate supply of enrichment services. The tight supply/demand will most likely cause the price of enrichment services to continue to rise in the future.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the Nuclear Regulatory Commission (NRC), not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand is expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast

The calculations for the nuclear fuel cost forecasts used in FPL's 2009 resource planning work were performed consistent with the method then used for FPL's Fuel Clause filings, including the assumption of a fuel lease and the assumption of refueling outages every 18 months. The costs for each step to fabricate the nuclear fuels were added to come up with the total costs of the fresh fuel to be loaded at each refueling (acquisition costs). The acquisition cost for each group of fresh fuel assemblies were then amortized over the energy produced by each group of fuel assemblies FPL also added 1 mill per kilowatt hour net to reflect payment to DOE for spent fuel disposal.[3]

[3] Consistent with the FPSC's decision in FPL's recent base rate case, FPL will no longer be leasing its nuclear fuel. This fact, and its implications on the projected costs of nuclear fuel, will be reflected in FPL's 2010 and later resource planning work.

Schedule 5
Fuel Requirements 1/

	Fuel Requirements	Units	Actual 2/		Forecasted									
			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	Nuclear	Trillion BTU	261	250	267	249	260	304	309	305	305	309	305	304
(2)	Coal	1,000 TON	3,599	3,577	3,289	3,956	3,249	3,959	3,639	3,956	3,775	3,760	3,764	3,765
(3)	Residual (FO6)- Total	1,000 BBL	9,379	7,489	2,825	1,965	1,432	730	667	759	1,459	1,750	1,876	2,067
(4)	Steam	1,000 BBL	9,379	7,489	2,825	1,965	1,432	730	687	759	1,459	1,750	1,876	2,067
(5)	Distillate (FO2)- Total	1,000 BBL	38	47	62	101	32	0	0	26	74	70	84	99
(6)	Steam	1,000 BBL	11	0	0	0	0	0	0	0	0	0	0	0
(7)	CC	1,000 BBL	8	6	5	35	0	0	0	0	0	0	0	0
(8)	CT	1,000 BBL	20	40	57	66	32	0	0	26	74	70	84	99
(9)	Natural Gas -Total	1,000 MCF	449,619	481,426	452,751	490,961	499,105	477,157	515,407	520,939	568,505	576,404	595,266	609,770
(10)	Steam	1,000 MCF	143,581	81,260	21,279	28,814	20,868	10,791	10,341	10,823	21,205	22,879	27,979	34,253
(11)	CC	1,000 MCF	303,942	395,703	430,900	461,073	477,928	486,368	505,066	509,798	546,450	552,683	568,289	574,427
(12)	CT	1,000 MCF	2,296	4,462	573	1,075	492	0	0	318	850	842	999	1,089

1/ Reflects fuel requirements for FPL only.
2/ Source: A Schedules.

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 1/		Forecasted									
			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	Annual Energy Interchange 2/	GWH	10,141	9,508	8,429	6,092	5,757	5,587	5,696	5,689	608	0	0	0
(2)	Nuclear	GWH	24,024	22,893	23,912	22,346	23,358	27,275	27,751	27,353	27,355	27,751	27,353	27,276
(3)	Coal	GWH	6,423	6,362	6,274	7,418	6,223	7,448	6,894	7,438	7,118	7,088	7,099	7,100
(4)	Residual(FO6) -Total	GWH	5,702	4,560	1,871	1,304	952	487	458	505	971	1,164	1,248	1,373
(5)	Steam	GWH	5,702	4,560	1,871	1,304	952	487	458	505	971	1,164	1,248	1,373
(8)	Distillate(FO2) -Total	GWH	17	21	23	52	9	0	0	8	23	22	27	33
(7)	Steam	GWH	6	3	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	3	3	4	30	0	0	0	0	0	0	0	0
(9)	CT	GWH	9	15	19	22	9	0	0	8	23	22	27	33
(10)	Natural Gas -Total	GWH	58,820	62,728	64,256	69,523	71,420	69,174	75,234	76,103	82,375	83,391	85,796	87,531
(11)	Steam	GWH	7,257	8,705	2,105	2,844	2,043	1,070	1,025	1,071	2,093	2,260	2,762	3,376
(12)	CC	GWH	51,368	53,636	62,109	66,602	69,343	68,104	74,209	75,011	80,224	81,074	82,967	64,086
(13)	CT	GWH	195	387	42	76	34	0	0	22	58	57	67	70
(14)	Other 3/	GWH	5,877	5,231	5,122	4,901	5,799	5,931	6,438	7,645	7,224	7,821	8,142	8,400
	Net Energy For Load 4/	GWH	111,004	111,304	109,886	111,634	113,516	115,899	122,471	124,742	125,672	127,236	129,665	131,712

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
4/ Net Energy For Load values for the years 2010 - 2019 are also shown in Schedule 2.3.

Schedule 6.2
Energy Sources % by Fuel Type

	Energy Source	Units	Actual 1/ 2008	2009	Forecasted 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	Annual Energy Interchange 2/	%	9.1	8.5	7.7	5.5	5.1	4.8	4.7	4.6	0.5	0.0	0.0	0.0
(2)	Nuclear	%	21.6	20.6	21.6	20.0	20.6	23.5	22.7	21.9	21.8	21.6	21.1	20.7
(3)	Coal	%	5.8	5.7	5.7	6.6	5.5	6.4	5.6	6.0	5.7	5.6	5.5	5.4
(4)	Residual (FO6) -Total	%	5.1	4.1	1.7	1.2	0.8	0.4	0.4	0.4	0.8	0.9	1.0	1.0
(5)	Steam	%	5.1	4.1	1.7	1.2	0.8	0.4	0.4	0.4	0.8	0.9	1.0	1.0
(6)	Distillate (FO2) -Total	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	53.0	56.4	58.5	62.3	62.9	59.7	61.4	61.0	65.5	65.5	66.2	66.5
(11)	Steam	%	6.5	7.8	1.9	2.5	1.6	0.9	0.6	0.9	1.7	1.8	2.1	2.6
(12)	CC	%	46.3	46.2	56.5	59.7	61.1	58.6	60.6	60.1	63.6	63.7	64.0	63.8
(13)	CT	%	0.2	0.3	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
(14)	Other 3/	%	5.3	4.7	4.7	4.4	5.1	5.1	5.3	6.1	5.7	6.1	6.3	6.4
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules.
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.
3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled
Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Firm Installed 1/ Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	% of Peak
2010	22,394	1,460	0	640	24,494	21,922	2,118	19,804	4,689	23.7	0	4,689	23.7
2011	22,442	1,460	0	595	24,497	21,788	2,249	19,539	4,958	25.4	0	4,958	25.4
2012	22,740	1,305	0	650	24,695	22,139	2,408	19,731	4,963	25.2	0	4,963	25.2
2013	24,054	1,305	0	650	26,009	22,332	2,583	19,749	6,259	31.7	0	6,259	31.7
2014	25,266	1,305	0	650	27,221	23,575	2,765	20,810	6,410	30.8	0	6,410	30.8
2015	25,266	1,305	0	650	27,221	23,924	2,941	20,983	6,238	29.7	0	6,238	29.7
2016	25,266	0	0	650	25,916	24,344	3,103	21,242	4,674	22.0	0	4,674	22.0
2017	25,266	0	0	650	25,916	24,774	3,248	21,526	4,390	20.4	0	4,390	20.4
2018	25,658	0	0	650	26,308	25,328	3,381	21,947	4,360	19.9	0	4,360	19.9
2019	26,045	0	0	650	26,695	25,785	3,502	22,282	4,412	19.8	0	4,412	19.8

1/ Capacity additions and changes projected to be in-service by June 1st are generally considered to be available to meet Summer peak loads w are forecasted to occur during August of the year indicated. All values are Summer net MW.
2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).
3/ These forecasted values reflect the 2010 load forecast without incremental DSM or cumulative load management.
4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2010-on intended for use with the 2010 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.
5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)
6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
January of Year	Firm Installed Capability 1/ MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	% of Peak
2010	24,638	1,481	0	690	26,809	20,550	1,816	18,734	8,074	43.1	0	8,074	43.1
2011	23,448	1,485	0	595	25,528	20,647	1,859	18,788	6,740	35.9	0	6,740	35.9
2012	24,106	1,485	0	595	26,186	20,861	1,912	18,949	7,237	38.2	0	7,237	38.2
2013	24,402	1,305	0	650	26,357	21,138	1,974	19,164	7,193	37.5	0	7,193	37.5
2014	25,757	1,305	0	650	27,712	22,152	2,044	20,108	7,604	37.8	0	7,604	37.8
2015	27,101	1,305	0	650	29,058	22,745	2,118	20,627	8,428	40.9	0	8,428	40.9
2016	27,101	375	0	650	28,126	23,118	2,189	20,929	7,196	34.4	0	7,196	34.4
2017	27,101	0	0	650	27,751	23,488	2,255	21,233	6,518	30.7	0	6,518	30.7
2018	27,101	0	0	650	27,751	23,889	2,316	21,573	6,178	28.6	0	6,178	28.6
2019	27,495	0	0	650	28,145	24,293	2,372	21,921	6,224	28.4	0	6,224	28.4

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the 2010 load forecast without incremental DSM or cumulative load management.

4/ The DSM MW shown represent cumulative load management capability plus incremental conservation from 1/2010-on intended for use with the 2010 load forecast. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm	Expected	Gen. Max.	Firm Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr	In-Service Mo./Yr	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2010														
Cape Canaveral	1	Brevard County	ST	FO6	NG	WA	PL	Unknown	Unknown	Unknown	402,050	(398)	(396)	
Cape Canaveral	2	Brevard County	ST	FO6	NG	WA	PL	Unknown	Unknown	Unknown	402,050	(398)	(396)	
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Unknown	310,420	(280)	(277)	
Riviera	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Unknown	310,420	(291)	(288)	
Lauderdale	4	Broward County	CC	NG	FO2	PL	PL	Jan-10	Jun-10	Unknown	526,250	2	—	OT
Lauderdale	5	Broward County	CC	NG	FO2	PL	PL	Jan-10	Jun-10	Unknown	526,250	2	—	OT
Lauderdale	1-12	Broward County	GT	NG	FO2	PL	PL	Jan-10	Jun-10	Unknown	410,734	29	—	OT
Lauderdale	12-24	Broward County	GT	NG	FO2	PL	PL	Jan-10	Jun-10	Unknown	410,734	29	—	OT
Manatee	3	Manatee County	CC	NG	No	PL	No	Jan-10	Jun-10	Unknown	1,224,510	(2)	6	OT
Ft. Myers	2	Lee County	CC	NG	No	PL	No	Jan-10	Jun-10	Unknown	1,775,390	(3)	—	OT
Ft. Myers	3A & B	Lee County	CT	NG	FO2	PL	PL	Jan-10	Jun-10	Unknown	376,380	(2)	3	OT
Ft. Myers	1-12	Lee County	GT	FO2	No	PL	No	Jan-10	Jun-10	Unknown	744,120	49	—	OT
Martin	3	Martin County	CC	NG	No	PL	No	Jan-10	Jun-10	Unknown	612,000	—	3	OT
Martin	4	Martin County	CC	NG	No	PL	No	Jan-10	Jun-10	Unknown	612,000	—	3	OT
Martin	8	Martin County	CC	NG	No	PL	No	Jan-10	Jun-10	Unknown	1,224,510	—	10	OT
Martin Next Generation Solar Energy Center		Martin County	PV						Dec-10			See Note 3		
Port Everglades	1-12	City of Hollywood	GT	NG	FO2	PL	PL	Jan-10	Jun-10	Unknown	410,734	29		OT
Putnam	1	Putnam County	CC	NG	FO2	PL	WA	Jan-10	Jun-10	Unknown	290,004	12	—	OT
Putnam	2	Putnam County	CC	NG	FO2	PL	WA	Jan-10	Jun-10	Unknown	290,004	12	—	OT
Scherer	4	Monroe, GA	BIT	SUB	No	RR	No	Jan-10	Jun-10	Unknown	680,368	(8)	(8)	OT
SJRPP	1	Duval County	BIT	BIT	Pet	RR	WA	Jan-10	Jun-10	Unknown	135,918	(1)	(1)	OT
SJRPP	2	Duval County	BIT	BIT	Pet	RR	WA	Jan-10	Jun-10	Unknown	135,918	(1)	(1)	OT
Space Coast Next Generating Solar Energy Center (PV)	1	Brevard County	PV						Jun-10		10,000	See Note 4		P
Turkey Point	5	Miami-Dade County	CC	NG	FO2	PL	PL	Jan-10	Jun-10	Unknown	1,224,510	2	—	OT
								2010 Changes/Additions w/o Inactive Reserve Total:				(1,218)	(1,342)	
Cutler	5	Miami Dade County	ST	NG	No	PL	No	—	—	—	75,000	(69)	(68)	OT
Cutler	6	Miami Dade County	ST	NG	No	PL	No	—	—	—	161,500	(138)	(137)	OT
Port Everglades	1	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	225,250	(214)	(213)	OT
Port Everglades	2	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	225,250	(214)	(213)	OT
Sanford	3	Volusia County	ST	FO6	NG	WA	PL	—	—	—	156,250	(140)	(138)	OT
								2010 Changes/Additions with Inactive Reserve Total:				(1,993)	(2,111)	
2011														
West County Energy Center	3	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	1,366,800	—	1219	T
								2011 Changes/Additions w/o Inactive Reserve Total:				0	1,219	
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	—	(387)	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	—	(392)	OT
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	402,050	(394)	(392)	
								2011 Changes/Additions with Inactive Reserve Total:				(394)	48	
2012														
Scherer	4	Monroe, GA	BIT	SUB	No	RR	No	Jan-12	Jun-12	Unknown	680,368	3	3	OT
St. Lucie (Uprates)	1	St. Lucie County	NP	UR	No	TK	No	See Note 5	Dec-11	Unknown	850,000	103	103	T
St. Lucie (Uprates)	2	St. Lucie County	NP	UR	No	TK	No	See Note 5	Jun-12	Unknown	723,775	—	88	T
Turkey Point (Uprates)	3	Miami Dade County	NP	UR	No	TK	No	See Note 5	May-12	Unknown	759,960	—	104	T
West County Energy Center	3	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	1,366,800	1,335	—	T
								2012 Changes/Additions w/o Inactive Reserve Total:				1,441	298	
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(389)	—	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(394)	—	OT
								2012 Changes/Additions with Inactive Reserve Total:				658	298	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring later in the year will be picked up for reporting/planning purposes in the following year.

Note 2. Changes shown may include different ratings than shown in Schedule 1 due solely to ambient temperature consistent with those in FPL 's peak load forecast to maintain consistency in reserve margin calculations.

Note 3. The Martin solar thermal facility is designed to provide steam for FPL's existing Martin Unit 8 combined cycle unit, thus reducing FPL's use of natural gas. No additional capacity (MW) will result from the operation of the solar thermal facility.

Note 4: The Photovoltaic MWs are not included in the total at this time because these facilities are assumed to provide non-firm energy only.

Note 5: The nuclear uprates will be performed during the scheduled refueling outages for each unit.

Note 6: Certain existing FPL units that have been placed temporarily on inactive Reserve status are assumed, for planning purposes, to return to active reserve starting in 2016.

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

Plant Name (1)	Unit No. (2)	Location (3)	Unit Type (4)	Fuel Pri. (5)	Fuel Alt. (6)	Fuel Transport Pri. (7)	Fuel Transport Alt. (8)	Const. Start Mo./Yr. (9)	Comm In-Service Mo./Yr. (10)	Expected Retirement Mo./Yr. (11)	Gen. Max. Nameplate KW (12)	Firm Net Capability Winter MW (13)	Firm Net Capability Summer MW (14)	Status (15)
ADDITIONS/ CHANGES														
2013														
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	PL	Jun-11	Jun-13	Unknown	1,296,750	—	1,210	T
St. Lucie (Uprates)	2	St. Lucie County	NP	UR	No	TK	No	See Note 3	Jun-12	Unknown	723,775	88	—	T
Turkey Point (Uprates)	3	Miami Dade County	NP	UR	No	TK	No	See Note 3	May-12	Unknown	759,900	104	—	T
Turkey Point (Uprates)	4	Miami Dade County	NP	UR	No	TK	No	See Note 3	Dec-12	Unknown	759,900	104	104	T
2013 Changes/Additions w/o Inactive Reserve Total:												296	1,314	
												—	—	
2013 Changes/Additions with Inactive Reserve Total:												296	1,314	
2014														
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	PL	Jun-11	Jun-13	Unknown	1,296,750	1,355	—	T
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	PL	PL	Jun-12	Jun-14	Unknown	1,296,750	—	1,212	T
2014 Changes/Additions w/o Inactive Reserve Total:												1,355	1,212	
												—	—	
2014 Changes/Additions with Inactive Reserve Total:												1,355	1,212	
2015														
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	PL	PL	Jun-12	Jun-14	Unknown	1,296,750	1,344	—	T
2015 Changes/Additions w/o Inactive Reserve Total:												1,344	0	
												—	—	
2015 Changes/Additions with Inactive Reserve Total:												1,344	0	
2016														
												—	—	
2016 Changes/Additions w/o Inactive Reserve Total:												0	0	
												—	—	
2016 Changes/Additions with Inactive Reserve Total:												0	0	
2017														
												—	—	
2017 Changes/Additions w/o Inactive Reserve Total:												0	0	
												—	—	
2017 Changes/Additions w/o Inactive Reserve Total:												0	0	
2018														
												—	—	
2018 Changes/Additions w/o Inactive Reserve Total:												0	0	
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	402,050	—	392	OT
2018 Changes/Additions with Inactive Reserve Total:												0	392	
2019														
												—	—	
2019 Changes/Additions w/o Inactive Reserve Total:												0	0	
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	402,050	394	--	OT
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	—	387	OT
2019 Changes/Additions with Inactive Reserve Total:												394	387	

Note 1: The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring later in the year will be picked up for reporting/planning purposes in the following year.

Note 2: Changes shown may include different ratings than shown in Schedule 1 due solely to ambient temperature consistent with those in FPL 's peak load forecast to maintain consistency in reserve margin calculations.

Note 3: The nuclear uprates will be performed during the scheduled refueling outages for each unit.

Note 4: Certain existing FPL units that have been placed temporarily on Inactive Reserve status are assumed, for planning purposes,to return to active reserve starting in 2018

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Space Coast Next Generation Energy Center

(2) **Capacity**
a. Summer 10 MW
b. Winter 10 MW

(3) **Technology Type:** Photovoltaic

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2009
b. Commercial In-service date: 2010

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel N/A

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** N/A

(8) **Total Site Area:** 60 Acres

(9) **Construction Status:** U (Under Construction)

(10) **Certification Status:** Permitted (Individual Permits)

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	N/A
Forced Outage Factor (FOF):	N/A
Equivalent Availability Factor (EAF):	0.98
Resulting Capacity Factor (%):	Approx. 21.3% (First Full Year of Operation)
Average Net Operating Heat Rate (ANOHR):	N/A Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25 years
Total Installed Cost (2010 $/kW):	7,890
Direct Construction Cost ($/kW):	-
CWIP Amount ($/kW):	427.7
Escalation ($/kW):	-
Fixed O&M ($/kW -Yr.): (2010 $kW-Yr)	54
Variable O&M ($/MWH): (2010 $/MWH)	0
K Factor:	1.2100

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes transmission interconnection.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	West County Energy Center Combined Cycle Unit 3	
(2)	**Capacity**		
	a. Summer	1,219 MW	
	b. Winter	1,335 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2009	
	b. Commercial In-service date:	2011	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low No_x Combustors, SCR 0.0015% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Tower
(8)	**Total Site Area:**	220	Acres
(9)	**Construction Status:**	U	(Under construction, less than or equal to 50% Complete)
(10)	**Certification Status:**	Permitted	
(11)	**Status with Federal Agencies:**	Permitted	

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 93%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582	Btu/kWh (Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data **,*****

Book Life (Years):	25	years
Total Installed Cost (2011 $/kW):	709	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	71	
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2011 $kW-Yr)	11.63	
Variable O&M ($/MWH): (2011 $/MWH)	0.480	
K Factor:	1.4697	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** St. Lucie 1 Nuclear (Uprate)

(2) **Capacity**
a. Summer 103 MW (Incremental)
b. Winter 103 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2011

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel —

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data** *

Book Life (Years):	25	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost:	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2010 Nuclear Cost recovery filing.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:**		Turkey Point 3 Nuclear (Uprate)	
(2) **Capacity**			
a. Summer	104	MW (Incremental)	
b. Winter	104	MW (Incremental)	
(3) **Technology Type:**	Nuclear		
(4) **Anticipated Construction Timing**			
a. Field construction start-date:		During scheduled refueling outage	
b. Commercial In-service date:		2012	
(5) **Fuel**			
a. Primary Fuel		Uranium	
b. Alternate Fuel		---	
(6) **Air Pollution and Control Strategy:**		No change from existing unit	
(7) **Cooling Method:**		No change from existing unit	
(8) **Total Site Area:**		No change from existing unit	
(9) **Construction Status:**	T	(Regulatory approval received, but not under construction)	
(10) **Certification Status:**	T	(Regulatory approval received, but not under construction)	
(11) **Status with Federal Agencies:**	T	(Regulatory approval received, but not under construction)	
(12) **Projected Unit Performance Data:**			
Planned Outage Factor (POF):		No change from existing unit	
Forced Outage Factor (FOF):		No change from existing unit	
Equivalent Availability Factor (EAF):		No change from existing unit	
Resulting Capacity Factor (%):		No change from existing unit	
Average Net Operating Heat Rate (ANOHR):		No change from existing unit	
Base Operation 75F,100%		No change from existing unit	
(13) **Projected Unit Financial Data** *			
Book Life (Years):		20	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **		TBD	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):		TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):			(See Note (2) for explanation.)
Escalation ($/kW):			(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):		There is no additional O&M impact from this project.	
Variable O&M ($/MWH):		There is no additional O&M impact from this project.	
K Factor:			(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2010 Nuclear Cost recovery filing.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** St. Lucie 2 Nuclear (Uprate)

(2) **Capacity**
a. Summer 103 MW (Total Incremental), 88 MW (incremental FPL's ownership share)
b. Winter 104 MW (Total Incremental), 88 MW (incremental FPL's ownership share)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel: Uranium
b. Alternate Fuel: —

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data *,****

Book Life (Years):	31	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2010 Nuclear Cost recovery filing. nuclear units.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point 4 Nuclear (Uprate)

(2) **Capacity**
a. Summer 104 MW (Incremental)
b. Winter 104 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2012

(5) **Fuel**
a. *Primary Fuel* Uranium
b. Alternate Fuel ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data *,****

Book Life (Years):	22	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2010 Nuclear Cost recovery filing.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Cape Canaveral Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,210 MW
b. Winter 1,355 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2011
b. Commercial In-service date: 2013

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 43 Acres

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%
Forced Outage Factor (FOF):	1.1%
Equivalent Availability Factor (EAF):	96.5%
Resulting Capacity Factor (%):	Approx. 90 % (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,484 Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2013 $/kW):	921
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	98
Escalation ($/kW):	
Fixed O&M ($/kW-Yr): (2013 $)	13.29
Variable O&M ($/MWH): (2013 $)	0.16
K Factor:	1.484

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Riviera Beach Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,212 MW
b. Winter 1,344 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2012
b. Commercial In-service date: 2014

(5) **Fuel**
a. Primary Fuel — Natural Gas
b. Alternate Fuel — Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** *Once-through* cooling water

(8) **Total Site Area:** 33 Acres

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.5%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,480	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,**,*****

Book Life (Years):	30	years
Total Installed Cost (2014 $/kW):	1,053	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	121	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2014 $)	13.67	
Variable O&M ($/MWH): (2014 $)	0.13	
K Factor:	1.509	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Space Center Next Generation Solar Energy Center (PV)

The new Space Center Next Generation Solar Energy Center (PV) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

West County Energy Center Unit 3

(1)	Point of Origin and Termination:	New Sugar Substation – Corbett Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL - Owned
(4)	Line Length:	1 mile
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: May 2009 End date: November 2010
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$11,300,000
(8)	Substations:	New Sugar Substation and Corbett Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

St. Lucie 1 Nuclear (Uprate)

The St. Lucie 1 Nuclear (Uprate) does not require any “new” transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point 3 Nuclear (Uprate)

The Turkey Point 3 Nuclear (Uprate) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

St. Lucie 2 Nuclear (Uprate)

The St. Lucie 2 Nuclear (Uprate) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point 4 Nuclear (Uprate)

The Turkey Point 4 Nuclear (Uprate) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Cape Canaveral Next Generation Clean Energy Center (Projected Modernization)

The Cape Canaveral Next Generation Clean Energy Center, that would be the result of the projected modernization of the exiting Cape Canaveral power plant site, does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Riviera Beach Next Generation Clean Energy Center (Projected Modernization)

The Riviera Beach Energy Center Modernization, that would be the result of the projected *modernization of the existing* Riviera Beach power plant site, does not require any "new" transmission lines. Several lines will be extended and reconfigured to accommodate the increased capacity.

Schedule 11.1

Existing FIRM and NON-FIRM Capacity and Energy by Primary Fuel Type
Actuals for the Year 2009

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	Summer (MW)	Summer (%)	Winter (MW)	Winter (%)	GWh [2]	%
(1)	Coal	900	3.3%	902	3.2%	6,362	5.7%
(2)	Nuclear	2,939	10.9%	3,013	10.6%	22,893	20.6%
(3)	Residual	6,764	25.0%	6,818	23.9%	4,560	4.1%
(4)	Distillate	1,908	7.1%	2,160	7.6%	21	0.0%
(5)	Natural Gas	11,993	44.4%	12,942	45.3%	62,728	56.4%
(6)	*FPL Existing Units Total [1]:*	*24,504*	*90.7%*	*25,835*	*90.5%*	*96,565*	*86.8%*
(7)	Renewables (Purchases)- Firm	111.0	0.4%	162.0	0.6%	1,036	0.9%
(8)	Renewables (Purchases)- Non-Firm	Not Applicable		Not Applicable		416	0.4%
(9)	*Renewable Total:*	*111.0*	*0.4%*	*162.0*	*0.6%*	*1,452*	*1.30%*
(10)	*Purchases Other :*	*2,404.0*	*8.9%*	*2,542.0*	*8.9%*	*13,288*	*11.9%*
(11)	*Total :*	*27,019.4*	*100.0%*	*28,539.0*	*100.0%*	*111,304*	*100.0%*

Note:
(1) FPL Existing Units Total should match Total System found on Schedule 1 for summer and winter.
(2) Net Energy for Load GWH should match Schedule 6.1 the actual value.

Schedule 11.2

Existing NON-FIRM Self-Service Renewable Generation Facilities
Actuals for the Year 2009

(1) Type of Facility	(2) Installed Capacity DC (MW)	(3) Renewable Projected Annual Output (MWh)	(4) Annual Energy Purchased from FPL (MWh)	(5) Annual Energy Sold to FPL (MWh)	(6) = (3+4) - (5) Projected Annual Energy Used by Customer (MWh)
Customer-Owned PV (0 kW to 10 kW)	2.525	2,095	42,634.0	30.0	44,698.9
Customer-Owned PV (> 10 kW to 100 kW)	1.085	865	12,938	54.0	13,749.1
Customer-Owned PV (> 100 kW - 2 MW)	2.846	379	29,739	0.0	30,118.5
Total	6.456	3,339.1	85,311.3	84.0	88,566.5

Notes:

(1) There were approximately 645 customer-owned operating PV facilities interconnected with FPL during 2009.
(2) The Installed Capacity value is the sum of the nameplate ratings (DC MW) for all of the customer-owned PV facilities connected as of Dec. 31,2009.
(3) The Projected Annual Output value is based on NREL's PV Watts program and the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.
(3) The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2009.
(4) The Annual Energy Sold to FPL is an actual value from FPL's metered data for 2009.
(5) *The Projected Annual Energy Used by Customers* is a projected value that equals:
(Renewable Projected Annual output + Annual Energy Purchased) minus the Annual Energy Sold to FPL.

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered or threatened plant and animal species. FPL competes for air, land, and water resources that are necessary to meet the demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

FPL has been recognized for many years as one of the leaders among electric utilities for its commitment to the environment. For example, FPL has one of the lowest CO_2 emission rates in the nation. The environmental leadership of FPL and its parent company, FPL Group, has been heralded by many outside organizations as demonstrated by a few recent examples. In 2009, FPL Group was ranked first among electric and gas utilities in FORTUNE® magazine's, "America's Most Admired Companies" edition. This is the third consecutive year that FPL Group scored number one in each of the eight attributes considered: innovation, people management, use of corporate assets, social responsibility, quality of management, financial soundness, long-term investments, and quality of products and services. According to *Fortune*, America's Most Admired Companies is "the definitive report card on corporate reputations".

FPL Group was named, for the fifth time, one of the Global 100 Most Sustainable Corporations in the World by Corporate Knights, Inc., a Canadian media company. Some 1,800 companies from a wide range of sectors were evaluated regarding effective management of environmental, social, and governance risks and opportunities. FPL Group was one of only three United States utility companies, or utility parent companies, to make the list of 100.

FPL Group's commitment to acknowledging the risks of climate change and effectively reducing its greenhouse gas emissions was again recognized when the company was named to the Carbon Disclosure Leadership Index for 2009. FPL Group was one of only three U.S. companies to be so named. The Carbon Disclosure Leadership Index is produced annually by the Carbon Disclosure Project (CDP), a not-for-profit organization that reports on the business risks and opportunities of climate change for investors. CDP represents 475 institutional investors with $55 trillion in assets under management. Compiled by PricewaterhouseCoopers on behalf of CDP, the Carbon Disclosure Leadership Index highlights companies within the S&P 500 Index that excel in the area of climate change awareness and action.

FPL Group was named to the 2009 Dow Jones Sustainability Index (DJSI) of the leading companies in North America for corporate sustainability. The DJSI North America selects the top 20 percent of companies in sustainability performance from the 600 largest companies in North America. According to Dow Jones, corporate sustainability leaders achieve long-term shareholder value by "gearing their strategies and management to harness the market's potential for sustainability products and services while successfully reducing and avoiding sustainability costs and risks."

The 11th Annual Sustainable Florida Best Practice Awards were announced on June 9, 2009 in Orlando, Florida. FPL was named a finalist in the large business category for its "initiative and leadership in the voluntary development of three state-of-the-art clean, renewable, emissions-free solar energy facilities." The awards are presented by the Council for Sustainable Florida, the premier statewide organization committed to balancing the economic interests of the state with the need to be socially and environmentally responsible. The Sustainable Florida Award recognizes organizations for protecting and preserving Florida's environment for the future while building markets for Florida's business.

In 2009, FPL received the Business of the Year Award from Martin County for efforts related to the construction of three solar energy facilities in Florida, including one in Martin County.

In recognition of the company's leadership role in using low-carbon vehicles, FPL earned the 2008 National Biodiesel Board's Eye on Innovation award for the early and substantive use of biodiesel, the 2008 National Association of Fleet Administrator's Green Fleet Award, and the 2007 Council for Sustainable Florida Large Business Best Practice Award.

In May 2007, FPL Group was included on the KLD Global Climate 100SM Index for the third time since the Global Climate 100 was launched in 2005. The Global Climate 100 is designed to promote investment in public companies whose activities demonstrate the greatest potential for reducing the social and economic consequences of climate change.

The Global Climate 100 Index includes a mix of 100 global companies that demonstrate leadership in providing near-term solutions to climate change through renewable energy, alternative fuels, clean technology, and efficiency.

In 2006, FPL and the Palm Beach County-based Arthur R. Marshall Foundation joined as "partners for the environment." FPL's support included a $25,000 donation to the non-profit organization for educational and restoration programs, including the planting of native Florida wetland trees. In 2007, FPL volunteers returned to the site of the tree plantings to help take care of the growing saplings.

FPL has also been the recipient of earlier environmental awards and recognition. In 2001, FPL was awarded Edison Electric Institute's National Land Management Award for its stewardship of 25,000 acres surrounding its Turkey Point Plant. In 2001, FPL was awarded the 2001 Waste Reduction and Pollution Prevention Award from the Solid Waste Association of North America. FPL received the 2001 Program Champion Award from the Environmental Protection Agency's Wastewise Program. The Florida Department of Environmental Protection named FPL a "Partner for Ecosystem Protection" in 2001 for its emission-reducing "repowering" projects at its Fort Myers and Sanford Plants. FPL won the Council for Sustainable Florida's award in 2002 for its sea turtle conservation and education programs at its St. Lucie Plant. Finally, FPL has been recognized by numerous federal and state agencies for its innovative endangered species protection programs which include such species as manatees, crocodiles, and sea turtles.

As mentioned above, FPL Group has taken a leadership role to address climate change and the call for action for a national climate change policy. The decision to step into the forefront of this issue goes hand-in-hand with FPL Group's longtime commitment to managing operations with sensitivity to the environment.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Commitment in 1992 to clearly define its position. This statement reflects how FPL incorporates environmental values into all aspects of its activities and serves as a framework for new environmental initiatives throughout the company. FPL's Environmental Statement is:

It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:

- Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
- Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
- Encourage the wise use of energy to minimize the impact on the environment.
- Communicate effectively on environmental issues.
- Conduct periodic self-evaluations, report performance, and take appropriate actions.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an environmental management system to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program that is discussed below. Other components include: executive management support and commitment, a dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to evaluate environmental performance, verify compliance with corporate policy as well as legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and FPL policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2009 environmental outreach activities are noted in Table IV.E.1. In 2009 and 2010, FPL launched web cams at three facilities in order to increase public awareness of ongoing solar projects and the warm water refuge for manatees provided by power plants. The "solar cams" provide the public with a glimpse of the PV installation at the Space Coast Next Generation Solar Energy Center and the solar thermal installation at the Martin Next Generation Solar Energy Center. Additionally, the "manatee cam" provides the public a glimpse of hundreds of manatees that gather in the warm waters near the FPL Riviera Plant each Winter during the cold weather. In the first two months the manatee cam has been operational, the cam has received over 78,000 page views on-line. These web cam addresses, respectively, are:

http://www.fpl.com/environment/solar/spacecoast_cam.shtml),
(http://www.fpl.com/environment/solar/martin_cam.shtml),
http://www.fpl.com/environment/plant/riviera_cam.shtml).

In 2009 FPL also initiated efforts to recommence tours of the Barley Barber Swamp at the Martin Power Plant. Public tours are expected to begin by the end of 2010.

Table IV.E.1: 2009 FPL Environmental Outreach Activities

Activity	# of Participants (Approx.)
Visitors to FPL's Energy Encounter at St. Lucie	20,000
Visitors to Manatee Park	180,000
Number of visits to FPL's Environmental Website	103,000
Number of pieces of Environmental literature distributed	>60,000
Solar Schools Program (# of schools participating)	13

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified seven Preferred Sites and ten Potential Sites for future generation additions. Preferred Sites are those locations where FPL has conducted significant reviews and has either taken action, or is currently committed to take action, to site new generation capacity. Potential Sites are those sites that have attributes that support the siting of generation and are under consideration as a location for future generation. Some of these sites are currently in use as existing generation sites and some are not. The identification of a Potential Site does not indicate that FPL has made a definitive decision to pursue generation (or generation expansion in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of a generator has been determined. The Preferred Sites and Potential Sites are discussed in separate sections below.

As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other Greenfield sites.

IV.F.1 Preferred Sites

FPL identifies seven Preferred Sites in this Site Plan: the West County Energy Center (WCEC) adjacent to the existing Corbett FPL substation, the existing St. Lucie plant site, the existing Turkey Point plant site, the existing Cape Canaveral plant site, the existing Riviera plant site, and two locations for new solar power generation: Brevard County and the existing Martin plant site.

The West County Energy Center site is the location for one CC capacity addition FPL will make in 2011. The St. Lucie site is the location for nuclear capacity uprates that FPL will make in 2011 and 2012. The St. Lucie site is also the location for a proposed wind generation addition. The Turkey Point site is the location for nuclear capacity uprates that FPL will make in 2011 and 2012. (Turkey Point is also the site for two new nuclear units, Turkey Point Units 6 & 7, for which FPL is pursuing licensing approvals. Current projections for these new, nuclear units' in-service dates are beyond the 2010-2019 reporting time frame of this document.). The Cape Canaveral and Riviera sites are the locations for potential modernizations of existing power plant sites that are projected in this document. And, as previously mentioned, the other two sites, Brevard County and Martin County, are the sites for new solar energy facilities.

The seven Preferred Sites are discussed below.

Preferred Site # 1: West County Energy Center, Palm Beach County

FPL has identified the property adjacent to the existing Corbett Substation property in unincorporated western Palm Beach County as a Preferred Site for the addition of new generating capacity. The site was selected for the addition of another CC natural gas unit (Unit 3) with ultra-low sulfur light fuel oil (distillate) as a backup fuel. WCEC Units 1 & 2 were constructed on this site and went into commercial operations on August 27, 2009, and November 3, 2009, respectively. WCEC Unit 3, which began construction in March 2009, was approved by both the FPSC and the Secretary of the Florida Department of Environmental Protection (FDEP) and is anticipated to go into commercial operation in June of 2011. Unit 3 will be identical to Units 1 & 2 in regard to technology and capacity.

The existing site is accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections. The facility will use natural gas as the primary fuel and state-of-the-art combustion controls.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the West County Energy Center (WCEC) plant site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the general layout of the WCEC generating facilities at the site is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

The site was undeveloped until February 2007 when construction of WCEC Units 1 & 2 was initiated. The site was previously dedicated to industrial (mining) and agricultural use. The site had been excavated, back-filled, and totally re-graded to an elevation of approximately 10 feet above the surrounding land surface. Prior to the initiation of power plant construction, no structures were present on the site and vegetation was virtually non-existent. Units 1 & 2 are completed and are now in commercial operation.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The plant site had been significantly altered by the construction and operation of a limestone mine where vegetation had been cleared and removed. The surrounding land use is predominantly sugar cane, agriculture, and limestone mining. FPL's existing Corbett substation is located north of the site. The Arthur R. Marshall Loxahatchee National Wildlife Refuge is located to the south of the site.

2. Listed Species

Construction and operation of Unit 3 at the site will not affect any rare, endangered, or threatened species. Wildlife utilization of the property is minimal as a result of the prior mining activities. Common wading birds can be observed on areas adjacent to, and occasionally within, the property. The property is adjacent to areas that have been identified as potential habitats for wood stork.

3. Natural Resources of Regional Significance Status

The construction and operation of another gas-fired CC generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands including the Arthur R. Marshall Loxahatchee National Wildlife Refuge. Construction will not result in any onsite wetland impacts under federal, state, or local agency permitting criteria.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design of Unit 3 comprises the following: one 1,219 MW (Summer capacity) unit consisting of: three combustion turbines (CT), three heat recovery steam generators (HRSG), and a new steam turbine. Natural gas delivered via pipeline is the primary fuel type for this facility with ultra-low sulfur light fuel oil (distillate) serving as a backup fuel.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the project site is "Rural Residential" according to the Palm Beach County Future Land Use Map. Designations for the area under the Palm Beach County Unified Land Development Code classified the project site and surrounding area as Special Agricultural District. The site has been granted conditional use for electrical power facilities under a General Industrial zoning district.

h. **Site Selection Criteria Process**

The site has been selected as a Preferred Site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues.

i. **Water Resources**

WCEC Units 1 & 2 are currently operating using water from the Floridan Aquifer for cooling, service, and process water. Potable water is purchased from the Palm Beach County water municipality.

The primary water source for the entire site will be reclaimed (reuse) water that will come from Palm Beach County Water Utilities Department once Unit 3 is complete. FPL has obtained the necessary approvals to also supply WCEC Units 1 & 2 using reclaimed water once WCEC Unit 3 is operational. Reclaimed water will be used for cooling, service, and process water. Backup water sources include utilizing the Floridan Aquifer allocation permitted for WCEC Units 1, 2, & 3.

j. **Geological Features of Site and Adjacent Areas**

The site is underlain by approximately 13,000 feet of sedimentary rock strata. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks. Little information is known about these rocks due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine in origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, clay, and phosphate grains. The deepest formation in Palm Beach County on which significant published data are available is the Eocene Age Avon Park. Limited information is available from wells penetrating the underlying

Oldsmar formation. The published information on the sediments comprising the formations below the Avon Park Limestone is based on projections from deep wells in Okeechobee, St. Lucie, and Palm Beach counties.

Testing during construction of Exploratory Well 2 (EW-2) demonstrated the presence of a highly permeable zone (Boulder Zone) below a depth of 2,790 feet below pad level (bpl) overlain by a thick confining interval from approximately 2,000 to 2,790 feet bpl. The base of the Underground Source of Drinking Water (USDW) was identified between the depths of 1,932 and 1,959 feet bpl through interpretation of packer tests, water quality data, and geophysical logs. Injection testing has confirmed that the hydrogeology of the EW-2 site is favorable for disposal of fluids via a deep injection well system.

k. <u>Projected Water Quantities for Various Uses</u>

The estimated quantity of water required for industrial processing and cooling for all 3 units is approximately 29 million gallons per day (mgd). Cooling water for the three generating units would be cycled through cooling towers. Water quantities needed for other uses such as potable water are estimated to be approximately 35,000 gallons per day (gpd) for the entire WCEC site.

l. <u>Water Supply Sources by Type</u>

WCEC Units 1 & 2 will use available ground water as the source of cooling water until Unit 3 comes on line. Cooling towers will act as a heat sink for the facility auxiliary cooling system. Such needs for cooling and process water will comply with the existing SFWMD regulations for consumptive water use.

WCEC Unit 3, and eventually Units 1 & 2, will use reclaimed water as the primary source of cooling water for the cooling tower. The cooling tower will also act as a heat sink for the facility auxiliary cooling system. Such needs for cooling and process water will comply with the existing SFWMD regulations for consumptive water use. In addition, reclaimed water used at WCEC must meet all relevant requirements of Chapter 62-610, F.A.C., Part III, for use in cooling towers.

m. <u>Water Conservation Strategies Under Consideration</u>

The use of reclaimed water is a water conservation strategy because it is a beneficial use of wastewater. Impacts on the surficial aquifer would be minimized and used only for potable water, if necessary. Water from the Floridan Aquifer will be used for cooling purposes as a backup water source and cooling towers will be utilized. In addition, captured stormwater may be reused in the cooling tower whenever feasible. Stormwater captured in the stormwater ponds will also recharge the surficial aquifer.

n. Water Discharges and Pollution Control

Heat will be dissipated in the cooling towers. Blowdown water from the cooling towers, along with other wastestreams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Storm water runoff will be collected and used to recharge the surficial aquifer via a storm water management system. Design elements will be included to capture suspended sediments. In addition, captured stormwater may be reused in the cooling towers, whenever feasible. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is serviced by a new natural gas transmission pipeline that is capable of providing a sufficient quantity of gas to the entire site. Ultra-low sulfur light fuel oil (distillate) will be received by truck and stored in above-ground storage tanks to serve as backup fuel for the WCEC generating units.

p. Air Emissions and Control Systems

The use of natural gas and ultra-low sulfur light fuel oil (distillate) and combustion controls will minimize air emissions from these units and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminants. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil (distillate) as backup fuel. These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of the WCEC generating units incorporate features that will make them among the most efficient and cleanest power plants in the State of Florida.

q. **Noise Emissions and Control Systems**

Noise expected to be caused by construction at the site is expected to be below current noise levels for the residents nearest the site. Noise from the operation of the new unit will be within allowable levels.

r. **Status of Applications**

In regard to WCEC Unit 3, a Site Certification Application (SCA) was filed in December 2007 and received Site Certification by the Secretary of the FDEP, in lieu of the Governor and Cabinet, in November 2008. A Prevention of Significant Deterioration (PSD) air permit was filed in December 2007. The permit was issued by FDEP in July 2008. FPL initiated construction in March 2009 and anticipates an in-service date of mid-2011. WCEC Unit 3 will utilize the underground injection control (UIC) system permitted for the entire site.

Preferred Site # 2: St. Lucie Plant, St. Lucie County

FPL's St. Lucie Plant is located in St. Lucie County on Hutchinson Island on an FPL-owned 1,130-acre site. The plant site is bordered by the Atlantic Ocean to the east and the Indian River Lagoon to the west. Located on the site are two nuclear-powered generating units, St. Lucie Units 1 & 2, which have been in operation since 1976 and 1983, respectively. The St. Lucie site has been selected as a Preferred Site for the addition of two types of new generating capacity.

The first type of generating capacity addition is an increase in the capacity of the two existing nuclear generating units that is used to serve FPL's customers of approximately 103 MW for St. Lucie Unit 1 and 88 MW for St. Lucie Unit 2. This difference is due to FPL's 100% ownership share of St. Lucie 1 and its 85% ownership share of St. Lucie Unit 2. This work will involve changes to several existing main components within the existing facilities to increase their capability to produce steam for the generation of electricity. No new facilities are required as part of this capacity "uprate." This capacity uprate, along with a similar capacity uprate of FPL's existing Turkey Point nuclear units, was approved by the FPSC in January 2008. The capacity uprates at St. Lucie for the two nuclear units sited there are projected to be in-service in late 2011 and 2012.

The second type of generating capacity addition is the proposed installation of FPL wind generation turbines at the plant site. In 2007, FPL began the St. Lucie County land use approval process, and soon after applied for the necessary federal and state permitting. However, a decision by the state and federal agencies on the St. Lucie Wind project's permitting won't be finalized until the local land use approval process is completed. The in-service date will depend on the approval and permitting process. Six wind turbines are being proposed that, in total, would have a maximum output of approximately 13.8 MW.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the FPL St. Lucie Nuclear site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the general layout of the proposed generating facilities at the site is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

St. Lucie Units 1 & 2 are pressurized water reactors, each having two steam generators. The prominent structures, enclosed facilities, and equipment associated with St. Lucie Units 1 & 2 include the containment building, the turbine generator building, the auxiliary building, and the fuel handling building.

Prominent features beyond the power block area include the intake and discharge canals, switchyard, spent-fuel storage facilities, technical and administrative support facilities, and public education facilities (the Energy Encounter and the College of Turtle Knowledge). Significant features surrounding the St. Lucie Units 1 & 2 are predominately undeveloped land and water bodies including; Big Mud Creek, the Atlantic Ocean, Herman's Bay, and Indian River Lagoon.

In regard to the nuclear capacity uprates, the only changes will be modifications to the existing power generation facilities within the power block area, modifications to the switchyard facilities, and modifications to the transmission lines from St. Lucie to Midway substation. None of the other existing facilities at the plant will change as a result of the uprates. No changes to the nuclear power generation facilities are projected as a result of the proposed wind turbine additions.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

FPL's St. Lucie Plant is located in St. Lucie County on Hutchinson Island on an FPL-owned 1,130-acre site. The St. Lucie Plant includes the reactor buildings, turbine buildings, access/security building, auxiliary building, maintenance facilities, and miscellaneous warehouses and other buildings associated with the operation of Units 1 & 2. The site includes adjacent undeveloped mangrove areas. As a result of the approved capacity uprates, the site characteristics will not change.

The proposed wind turbines would also be located on the FPL-owned site. Impacts to the site characteristics are projected to be minimal from the proposed wind turbines.

2. Listed Species

Some listed species known to occur in the area of the plant location are Atlantic sturgeon, smalltooth sawfish, loggerhead sea turtle (*Caretta caretta*), green sea turtle (*Chelonia mydas)*, leatherback sea turtle (*Dermochelys coriacea*), hawksbill sea turtle (*Eretmochelys imbriccata*), gopher tortoise (*Gopherus polyphemus*), kemp's ridley sea turtle (*Lepidochelys kempi*), wood stork (*Mycteria americana*), black skimmer (*Rynchops niger*), and least tern (*Sterna antillarum*).

In regard to the nuclear capacity uprates, neither the development work, nor the continued operation of the two nuclear units after the uprate work has been completed, are expected to adversely affect any rare, endangered, or threatened species. No changes in wildlife populations at the adjacent undeveloped areas are anticipated, including listed species. Noise and lighting impacts will not change and it is expected that wildlife will continue to use the undeveloped areas within the St. Lucie Plant boundary.

In regard to the wind turbines, some changes to the adjacent undeveloped areas are anticipated. Noise and lighting impacts will not change and the wind turbines are not anticipated to deter the continued use by wildlife of the undeveloped areas within the St. Lucie Plant boundary or any adjacent areas.

3. **Natural Resources of Regional Significance Status**

Significant features surrounding the St. Lucie Units 1 & 2 are predominately undeveloped land and water bodies including; Big Mud Creek, the Atlantic Ocean, Herman's Bay, and Indian River Lagoon.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. It is a once-through system. The effects of the discharge of cooling water via these discharge structures were evaluated and mixing zones were established to allow compliance with thermal water quality standards as a part of the Plant's NPDES (Permit No. FL0002208). These mixing zones include the volume of water beyond the discharge structures, at the edge of which the water temperature is no greater than 17°F above the ambient temperature of the intake water.

In regard to the nuclear capacity uprates, the once-through system will continue to be used for the nuclear units. In regard to the wind turbines, no water will be required.

g. **Local Government Future Land Use Designations**

St. Lucie Units 1 & 2 are located in unincorporated St. Lucie County, Florida. The County has adopted a comprehensive plan, which is updated on a periodic basis. The County Comprehensive Plan incorporates a map that depicts the future land use categories of all property falling within the unincorporated portions of the County. The St. Lucie Plant has a Future Land Use category of Transportation/Utilities (T/U) according to the St. Lucie County Future Land Use Map. The T/U category is described in the St. Lucie County Comprehensive Plan Future Land Use Element Future Land Use.

In regard to the wind turbines, FPL has submitted an application to St. Lucie County to rezone the land that would serve as the footprint of the turbines to the T/U category.

h. **Site Selection Criteria Process**

The site has been selected as a Preferred Site for the nuclear capacity uprates because it is an existing nuclear plant site and, therefore, offers the opportunity for increased nuclear capacity. The site has been selected as a Preferred Site for the wind turbines because of the available wind resource at that location.

i. **Water Resources**

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. The once-through system flow will not change as a result of the nuclear uprates. No water will be required to operate the wind turbines. Due to the existing nature of the St. Lucie Plant, surrounding surface waters will not be adversely affected by either of the generation capacity additions. Stormwater will be handled by the existing facilities and no new areas will be impacted. Wetlands, groundwater, and nearby surface waters will not be impacted.

j. **Geological Features of Site and Adjacent Areas**

Beneath the land surface, there is a peat layer 4 to 6 feet thick. Below this layer is the Anastasia Formation, a sedimentary rock formation composed of clay lenses, sandy limestone, and silty fine to medium sand with fragmented shells. This highly permeable stratum extends 35 to 90 feet below mean sea level (msl). Underlying this stratum there is a semi-permeable zone, The Hawthorn Formation, consisting of slightly clayey and very fine silt which extends 600 feet below msl.

The original surficial deposits at the St. Lucie Plant were excavated to a depth of 60 feet and backfilled with Category I or II fill. The fill is underlain by the Anastasia formation, a sequence of partially cemented sand and sandy limestone, which extend to an average depth of about 145 feet. The Anastasia is underlain to a depth of about 600 to 700 feet by the partially cemented and indurated sands, clays, and sandy limestones of The Hawthorn Formation. Underlying these surface strata are about 13,000 feet of Jurassic through Tertiary Formations, primarily carbonate rocks. These formations have a relatively gentle slope to the southeast.

k. **Projected Water Quantities for Various Uses**

In regard to the nuclear capacity uprates, no change is expected in the quantity or characteristics of industrial wastewaters generated by the facility. Therefore, no change in that compliance achievement status is expected. The capacity uprates will not cause any changes in hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow. The St. Lucie Plant does not directly withdraw groundwater under its current operations and it will not withdraw groundwater after the capacity uprates work is completed. The use of water supplied by the City of Fort Pierce, which does withdraw groundwater, will remain unchanged and there will be no changes to the groundwater discharges. There will be no quality, quantity, or hydrological changes, either by withdrawal or discharge to a drinking water source. Therefore, there will be no impacts on drinking water.

The wind turbines will not require water for operations and will not cause any changes in the hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow.

l. **Water Supply Sources by Type**

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. General plant service water, fire protection water, process water, and potable water are obtained from City of Fort Pierce. Process water uses include demineralizer regeneration, steam cycle makeup, and general service water use for washdowns.

The existing St. Lucie Plant water use is projected to be unchanged as a result of the nuclear capacity uprates. The wind turbines will not require water for operations.

m. **Water Conservation Strategies Under Consideration**

The existing water resources will not change as a result of the nuclear capacity uprates. The wind turbines will not require water for operations.

n. **Water Discharges and Pollution Control**

St. Lucie Units 1 & 2 use once-through cooling water from the Atlantic Ocean to remove heat from the main (turbine) condensers via the Circulating Water System (CWS), and to remove heat from other auxiliary equipment via the Auxiliary Equipment Cooling Water System (AECWS). The great majority of this cooling water is used for the CWS.

Under emergency conditions, water can be withdrawn from Big Mud Creek via the Emergency Intake Canal through two 54-inch pipe assemblies in the barrier wall that separates the Creek from the Canal. FPL does not use this intake during normal operations, but does test this system quarterly.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants. The wind turbines will not require water for operations. Consequently, there will be no water discharge as a result of these turbines.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

St. Lucie Units 1 & 2 are licensed for uranium-dioxide fuel that is slightly enriched uranium-235. The uranium-dioxide fuel is in the form of pellets contained in Zircaloy tubes with welded end plugs to confine radionuclides. The tubes are fabricated into assemblies designed for loading into the reactor core. Each reactor core includes 217 fuel assemblies.

FPL currently replaces approximately one-third of the fuel assemblies in each reactor at intervals of approximately 18 months. FPL operates the reactors such that the average fuel usage by the reactors is approximately 47,000 megawatt-days per metric ton uranium. In regard to the nuclear capacity uprates, more nuclear fuel will be used due to the increased capacity of each generating unit. No changes in the fuel-handling facilities are required. The addition of the wind turbines will have no fuel-related impact; i.e., no impacts from fuel delivery, storage, waste, or pollution control. Used fuel assemblies are stored in the onsite Nuclear Regulatory Commission (NRC) approved spent fuel storage facilities. Following completion of the uprates, approximately 11 percent more nuclear fuel will be used to increase the capacity of each unit. No changes in the fuel-handling facilities are required.

Diesel fuel is used in a number of emergency generators that include four main plant generators, two building generators, and various general purpose diesel engines. The main plant emergency generators will not be changed as a result of either of the two types of generation capacity additions. These emergency generators are for standby use only and are tested to assure reliability and for maintenance. Diesel fuel is delivered to the St. Lucie Plant by truck as needed, and stored in tanks with secondary containment.

p. Air Emissions and Control Systems

The St. Lucie Plant is classified as a minor source of air pollution, since FDEP has issued a Federally Enforceable State Operating Permit (FESOP) to keep emissions less than 100 tons per year for any air pollutant regulated under the Clean Air Act.

The applicable units at the St. Lucie Plant consist of eight large main plant diesel engines, two smaller diesel engines, and various general-purpose diesel engines. The air emissions from these engines are limited by the use of 0.05-percent sulfur diesel fuel and good combustion practices. Best Available Control Technology (BACT) is not applicable to these existing emission units.

Nitrogen oxide (NO_x) emissions from the operation of the diesel engines comprise the limiting pollutant for these diesel units at the St Lucie Plant. The FDEP FESOP limits NO_x emissions to 99.4 tons, which includes fuel use limits on the large main plant emergency diesel engines of 97,000 gallons in any 12-month consecutive period and the smaller building and general purpose diesel engines of 190,000 gallons in any 12-month consecutive period. Also, the Plant may choose to combine the diesel units' fuel-tracking, which then limits the NO_x totals for a 12-month consecutive period to a maximum of 80 tons. There will be no change in the operation or emissions of the diesel engines resulting from either the nuclear capacity uprates or the wind turbines.

In addition, neither of these types of generation capacity additions will result in an increase of carbon dioxide (CO_2) or other greenhouse gas emissions. In fact, both of these increases in generation capacity are projected to result in decreased FPL system-wide emissions of CO_2.

q. <u>Noise Emissions and Control Systems</u>

A field survey and impact assessment of noise expected to be caused by construction activities at the site was conducted for both types of generation capacity additions. Predicted noise levels are not expected to result in adverse noise impacts in the vicinity of the site during construction or operation of either generating capacity additions.

r. <u>Status of Applications</u>

In regard to the nuclear capacity uprates, a Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act was filed in December 2007 and a final order issued in September 2008. The FPSC voted to approve the need for the St. Lucie (and Turkey Point) nuclear capacity uprates and the final order approving the need for these capacity additions was issued in January 2008. In regard to the wind turbines, a Site Certification Application is not required. Individual permit applications were submitted for an Environmental Resource Permit (ERP) and the Army Corps of

Engineers Permits in May 2008 and the Coastal Construction Control Line in July 2008. In September of 2007, FPL submitted an application to St. Lucie County for a Conditional Use, Rezoning, and Height Amendment. The local approvals process is ongoing. However, the state and federal permitting process is on hold awaiting completion of local permitting.

Preferred Site # 3: Turkey Point Plant, Miami-Dade County

The Turkey Point Plant site is located on the west side of Biscayne Bay, 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. Public access to the plant site is limited due to the nuclear units located there. The land surrounding the site is owned by FPL and acts as a buffer zone. The site is comprised of two nuclear units (Units 3 & 4), two natural gas/oil conventional boiler units (Units 1 & 2), one CC natural gas unit (Unit 5), nine small diesel generators, the cooling canals, an FPL-maintained natural wildlife area, and wetlands that have been set aside as the Everglades Mitigation Bank (EMB).

Turkey Point Units 3 & 4 have been in operation since 1972 and 1973, respectively. The Turkey Point site has been selected as a Preferred Site for the increase in the capacity of its two existing nuclear generating units by approximately 103 MW each. This work will involve changes to several existing main components within the existing facilities to increase their capability to produce steam for the generation of electricity. No new or expanded facilities are required as part of this capacity "uprate." This capacity uprate, along with a similar capacity uprate of FPL's existing St. Lucie nuclear units, was approved by the FPSC in January 2008. The capacity uprates at Turkey Point are projected to be in-service in 2012.

As previously mentioned, FPL is pursuing licensing for two new nuclear units at the Turkey Point site. Each of these two units would provide 1,100 MW of capacity. Current projections for the in-service dates of these two units, Turkey Point Units 6 & 7, are beyond the 2010-2019 reporting time frame of this document. At the time this document is being prepared, FPL is evaluating what the revised in-service dates for Turkey Point 6& 7 should be for planning purposes. FPL will address those revised in-service dates for planning purposes in its May 3, 2010 cost recovery filing to the FPSC.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Turkey Point plant site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the Turkey Point Units 3 and 4 generating facility at the site is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The five existing power generation units and support facilities occupy approximately 150 acres of the 11,000-acre Turkey Point Plant site. Support facilities include service buildings, an administration building, fuel oil tanks, water treatment facilities, circulating water intake and outfall structures, wastewater treatment basins, and a system substation. The cooling canal system occupies approximately 5,900 acres. The two 400-megawatt (MW) (nominal) fossil fuel-fired steam electric generation units at the Turkey Point Plant have been in service since 1967 (Unit 1) and 1968 (Unit 2). These units currently burn residual fuel oil and/or natural gas with a maximum equivalent sulfur content of 1 percent. The two 700-MW (nominal) nuclear units have been in service since 1972 (Unit 3) and 1973 (Unit 4). Turkey Point Units 3 and 4 are pressurized water reactor (PWR) units. Turkey Point Unit 5 is a nominal 1,150-MW CC unit that began operation in 2007. Significant features in the vicinity of the site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The prominent structures and enclosed facilities and equipment associated with Units 3 & 4 include: the containment building, which contains the nuclear steam supply system, including the reactor, steam generators, reactor coolant pumps, and related equipment; the turbine generator building, where the turbine generator and associated main condensers are located; the auxiliary building, which contains waste management facilities, engineered safety components, and other facilities; and the fuel handling building, where the spent fuel storage pool and storage facilities for new fuel are located. Prominent features beyond the power block area include the intake system, cooling canal system, switchyard, spent fuel storage facilities, and technical and administrative support facilities.

2. **Listed Species**

The construction during the uprating of the units, and operation of the units after the capacity uprating is completed, are not expected to adversely affect any rare, endangered, or threatened species. Listed species known to occur at the site and in the nearby Biscayne National Park that could potentially utilize the site include the peregrine falcon *(Falco peregrinus)*, wood stork *(Mycteria americana)*, American crocodile *(Crocodylus acutus)*, mangrove rivulus *(Rivulus marmoratus)*, roseate spoonbill (*Ajaja ajaja)*, limpkin *(Aramus guarauna)*, little blue heron *(Egretta caerulea)*, snowy egret *(Egretta thula)*, American oystercatcher *(Haematopus palliates)*, least tern *(Sterna antillarum)*, the white ibis *(Eudocimus albus)*, and bald eagle *(Haliaeetus leucocephalus)*. No bald eagle nests are known to exist in the vicinity of the site. The federally listed, threatened American Crocodile thrives at the Turkey Point site, primarily in and around the southern end of the cooling canals which lie south of the project area. The entire site is considered crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American crocodile and is attributed with survival improvement and the downlisting of the American Crocodile from endangered to threatened.

3. **Natural Resources of Regional Significance Status**

Significant features in the vicinity on the site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park. Biscayne National Park contains 180,000 acres, approximately 95 percent of which is open water interspersed with more than 40 keys. The Biscayne National Park headquarters is located approximately 2 miles north of the Turkey Point plant and is adjacent to the Miami-Dade County Homestead Bayfront Park which contains a marina and day-use recreational facilities.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

Turkey Point Units 3 & 4 uses cooling water from a closed-cycle cooling canal system to remove heat from the main (turbine) condensers, and to remove heat from other auxiliary equipment. The existing cooling canals will accommodate the increase in heat load that is associated with the increased capacity from the uprates. The maximum predicted increase in water temperature entering the cooling canal system from the units resulting from the uprates is predicted to be about 2.5°F, from 106.1°F to 108.6°F. The associated maximum increase in water temperature returning to the units is about 0.9°F, from 91.9°F to 92.8°F.

g. <u>Local Government future Land Use Designations</u>

Local government future land use plan designates most of the site as IU-3 "Industrial, Unlimited Manufacturing District." There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. <u>Site Selection Criteria Process</u>

The site has been selected as a Preferred Site for the nuclear capacity uprates because it is an existing nuclear plant site and, therefore, offers the opportunity for increased nuclear capacity.

i. <u>Water Resources</u>

Unique to the Turkey Point plant site is the self-contained cooling canal system that supplies water to condense steam used by the plant's turbine generators. The canal system consists of 36 interconnected canals. The cooling canals occupy an area approximately two miles wide by five miles long (5,900 acres), approximately four feet deep. The system performs the same function as a giant radiator. The water is circulated through the canals in a two-day journey, ending at the plant's intake pumps.

j. <u>Geological Features of Site and Adjacent Areas</u>

The Turkey Point Plant lies upon the Floridian Plateau, a partly-submerged peninsula of the continental shelf. The peninsula is underlain by approximately 4,000 to 15,000 feet of sedimentary rocks consisting of limestone and associated formations that range in age from Paleozoic to Recent. Little is known about the basement complex of Paleozoic igneous and metamorphic rocks due to their great depth.

Generally in Miami-Dade County, the surficial aquifer (Biscayne Aquifer) consists of a wedge-shaped system of porous clastic and carbonate sedimentary materials, primarily limestone and sand deposits of the Miocene to late Quaternary age. The Biscayne Aquifer is thickest along the eastern coast and varies in thickness from 80 to 200 feet thick. The surficial aquifer is typically composed of Pamlico Sand, Miami Limestone (Oolite), the Fort Thompson and Anastasia Formations (lateral equivalents), Caloosahatchee Marl, and the Tamiami formation. The lower confining layers below the surficial aquifer range in thickness from 350 to 600 feet and are composed of the Hawthorn Group. Beneath the Hawthorn Group, the Floridan Aquifer System ranges from 2,800 to 3,400 feet thick and consists of Suwannee Limestone, Avon Park Limestone, and the Oldsmar Formations.

k. Projected Water Quantities for Various Uses

The addition of nuclear generating capacity as a result of the uprates will not cause any changes in the quantity or characteristics of industrial wastewaters generated by the facility; therefore, no change in that compliance achievement status is expected. The uprates will not cause any changes in hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow. The Turkey Point Plant does not directly withdraw groundwater under its current operations and it will not do so after the capacity uprates. Locally, groundwater is present beneath the site in the surficial or Biscayne Aquifer and in deeper aquifer zones that are part of the Floridan Aquifer System. There will be no effects on those deeper aquifer zones from the capacity uprates.

l. Water Supply Sources and Type

The source of cooling water for Turkey Point Units 3 & 4 is the cooling canal system. There will be no increase in the amount of water withdrawn as a result of the capacity uprates. General plant service water, fire protection water, process water, and potable water are obtained from Miami-Dade County. Process water uses include demineralizer regeneration, steam cycle makeup, and general service water use for washdowns. The water use for the facility will not change as a result of the capacity uprates.

m. Water Conservation Strategies

The existing water resources will not change as a result of the uprates.

n. Water Discharges and Pollution Control

Heated water discharges are dissipated using the existing closed cooling water system and the cooling canal system.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

Turkey Point Units 3 & 4 utilize uranium-dioxide fuel that is slightly enriched uranium-235. The uranium-dioxide fuel is in the form of pellets contained in Zircaloy tubes with welded end plugs to confine radionuclides. The tubes are fabricated into assemblies designed for loading into the reactor core. Used fuel assemblies are stored in the onsite NRC-approved spent fuel storage facilities.

FPL currently replaces approximately one-third of the fuel assemblies in each reactor at refueling intervals of approximately 18 months. FPL operates the reactors such that the average fuel usage by the reactors is approximately 45,000 megawatt-days per metric ton of uranium. Following completion of the uprates, more nuclear fuel will be used to increase the capacity of each unit. No changes in the fuel handling facilities are required. Following completion of the uprates, approximately 11 percent more nuclear fuel will be used to increase the capacity of each unit. No changes in the fuel-handling facilities are required.

Diesel fuel is used in a number of emergency generators that include four main emergency generators, five smaller emergency generators and various general purpose diesel engines. The emergency generators will not be changed as a result of the capacity uprates. These emergency generators are for stand-by use only and only operated for testing purposes to assure reliability and for maintenance. Diesel fuel for the emergency generators is delivered to the Turkey Point Plant by truck as needed, and stored in tanks with secondary containment.

p. **Air Emissions and Control Systems**

The normal operation of Turkey Point Units 3 & 4 does not create fossil fuel-related air emissions. However, there are 9 emergency generators associated with Units 3 & 4. Four of these nine emergency generators are main plant emergency generators which are rated at 2.5 MW each. The remaining five are smaller emergency generators which are associated with the security system. In addition, various general purpose diesels are used as needed for Units 3 & 4.

Turkey Point Plant Units 3 & 4's associated emergency generators and diesel engines, together with Units 1, 2, & 5, are classified as a major source of air pollution. FDEP has issued a separate Title V Air Operating Permit for the Turkey Point Nuclear Plant (Permit Number 0250003-004-AV). There are no operating limits for the emergency generators or diesel engines. Emergency diesel generators are limited to ultra-low sulfur distillate (0.0015% sulfur). NOx emissions are regulated under Reasonably Available Control Technology (RACT) requirements in Rule 62-296.570(4)(b)7 F.A.C., which limit NO_x emissions to 4.75 lb/MMBtu. The use of 0.05 percent sulfur diesel fuel and good combustion practices serve to keep NO_x emissions under this limit.

q. **Noise Emissions and Control Systems**

A field survey and impact assessment of noise expected to be caused by activities associated with the uprates was conducted. Predicted noise levels are not expected to result in adverse noise impacts in the vicinity of the site.

r. **Status of Applications**

A Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act was filed in January 2008 and a final order was issued in October 2008. The FPSC voted to approve the need for the Turkey Point (and St. Lucie) uprates and the final order approving the need for this additional nuclear capacity was issued in January 2008.

Preferred Site # 4: Cape Canaveral Plant, Brevard County

This site is located on the existing FPL Cape Canaveral Plant property in unincorporated Brevard County. The site is bound to the east by the Indian River Lagoon and on the west by a four lane highway (US. 1). The city of Port St. Johns is located less than a mile away. A rail line is located near the plant.

The existing 788 MW (summer) of generating capacity at FPL's Cape Canaveral site occupies a portion of the 43 acres that are wholly owned by FPL. The generating capacity is made up of steam units (Units 1 & 2).

The Cape Canaveral Plant site has been listed as a Potential Site in previous FPL Site Plans for both CC and simple cycle generation options. FPL is proposing, for resource planning purposes, to modernize the existing Cape Canaveral Plant, to be renamed the

Cape Canaveral Next Generation Clean Energy Center (CCEC), by replacing the existing generating units with a modern, highly efficient, lower-emission next-generation clean energy center using the latest CC technology. The existing two (2) steam units will first be dismantled and removed from the site and will be replaced by a single new CC unit.

a. Geological Survey (USGS) Map

A USGS map of the Cape Canaveral Plant site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the CCEC generating facilities at the site is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing land uses on the site are primarily dedicated to electrical generation; i.e., FPL's existing Cape Canaveral Units 1 & 2. The existing land uses that are adjacent to the site consist of single- and multi-family residences to the south and southwest, commercial property to the northwest, utility systems to the west, and a private medical/office facility to the north.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The natural environment surrounding the site includes the Indian River Lagoon to the east and upland scrub, pine and hardwoods to the north and south. Vegetation with the approximately 45-acre offsite construction laydown and parking area (located west of U.S. Highway 1) consists of open land, upland scrub, pine, hardwoods along with exotic plant species.

2. Listed Species

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the Site, due to the existing developed nature of the Site and lack of suitable onsite habitat for listed species. Federal- or state-listed terrestrial plants and animals inhabiting the offsite construction laydown and parking area are limited to the state-listed gopher tortoise and the state- and federally-listed scrub jay. The warm water discharges from the plant attract manatees, an endangered species. FPL is working closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process and upon operation of the new plant. FPL will be complying with several manatee related conditions of certification to ensure the protection of the manatees during this time.

3. **Natural Resources of Regional Significance Status**

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design option is to replace the existing steam generating units (Units 1 & 2) with one new 1,219 MW (approximate) CC unit consisting of three new combustion turbines (CT), three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit would be in-service in mid-2013. Natural gas delivered via pipeline is the primary fuel type for this unit with ultra-low sulfur light oil serving as a backup fuel.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the site is "Public Utilities" and the area has been rezoned to GML-U. Designations for the surrounding area are primarily "Community Commercial" and "Residential". The Indian River Lagoon is to the east of the site.

h. **Site Selection Criteria Process**

The Cape Canaveral Plant has been selected as a preferred site for a site modernization due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of replacing the existing steam units with a new CC unit including a significant reduction in system air emissions and improved aesthetics at the site.

i. **Water Resources**

Condenser cooling for the steam cycle portion of the new plant and auxiliary cooling will come from the existing cooling water intake system. Process, potable, and irrigation water for the new plant will come from the existing City of Cocoa's potable water supply.

j. **Geological Features of Site and Adjacent Areas**

FPL's Cape Canaveral Plant is located on the Atlantic Coastal Ridge and is at an approximate elevation of 12 feet above mean sea level (msl). The land consists primarily of fine to medium sand that parallels the coast. There is a lack of shell as it was deposited during a time of transgression. The base of the sedimentary rocks is made up of a thick, primarily carbonate sequence deposited during the Jurassic age through the Pleistocene age. Starting in the Miocene age and continuing through the Holocene age, siliciclastic sedimentation became more predominant. The basement rocks in this area consist of low-grade metamorphic and igneous intrusives, which occur several thousand feet below land surface and are Precambrian, Paleozoic, and Mesozoic in age.

k. **Projected Water Quantities for Various Uses**

The estimated quantity of water required for processing is approximately 0.232 million gallons per day (mgd) for uses such as process water and service water. Approximately 619 million gallons per day (mgd) of cooling water would be cycled through the once-through cooling water system. Potable water demand is expected to average .001 mgd.

l. **Water Supply Sources by Type**

The new plant will continue to use the Indian River Lagoon water as the source of once-through cooling water. Such needs for cooling water will comply with the existing St. John's River Water Management District (SJRWMD) Consumptive Use Permit (CUP). Process, potable, and irrigation water for the new plant will come from the existing City of Cocoa's potable water supply.

m. **Water Conservation Strategies Under Consideration**

No additional water sources will be required as a result of the modernization project.

n. Water Discharges and Pollution Control

The modernized site will utilize portions of the existing once-through cooling water systems for heat dissipation. The heat recovery steam generator blowdown will be mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit would be transported to the site via a pipeline. New on-site gas compressors may be installed to raise the gas pressure of the existing pipeline for the new unit. Ultra-low sulfur light fuel oil would be received by truck or barge from Port Canaveral and stored in an existing above-ground storage tank.

p. Air Emissions and Control Systems

The emission rates of CCEC would decrease by almost 100-fold from the existing Cape Canaveral Plant, resulting in substantial annual emissions reductions and increased air quality benefits. The use of natural gas and ultra-low sulfur light fuel oil and combustion controls would minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of the new CCEC plant will incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise from the operation of the new unit will be within allowable levels.

r. Status of Applications

The FPSC voted to approve the need for the modernization project and the need order was issued in September 2008. The project received final state certification on October 9, 2009, through the issuance of a final order signed by the Secretary of the DEP.

Preferred Site # 5: Riviera Plant, Palm Beach County

This site is located on the existing FPL Riviera Plant property primarily within Riviera Beach, Palm Beach County (with a small portion of the Site in West Palm Beach). The site is bound to the east by the Lake Worth Lagoon (Intracoastal Waterway) and on the west by a four lane highway (US. 1). The site has barge access via the Port of Palm Beach. A rail line is located near the plant.

The current site generating capacity is made up of two (2) operational 300 MW (approximate) steam generating units (Units 3 & 4). Units 1 & 2 have been retired and dismantled and are no longer on the plant site.

The Riviera Plant site has been listed as a Potential Site in previous FPL Site Plans for both CC and simple cycle generation options. FPL is proposing, for resource planning purposes, to modernize the existing Riviera Plant, to be renamed the Riviera Beach Next Generation Clean Energy Center (RBEC), by replacing the existing generating units with a modern, highly efficient, lower-emission next-generation clean energy center using the latest CC technology. The existing two steam units will first be removed from the site and will be replaced by a single new CC unit.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Riviera site is found at the end of this chapter.

b. Proposed Facilities Layout

A general layout of the RBEC generating facilities is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing Riviera Plant currently consists of two 300 MW (approximate) units with conventional dual-fuel fired steam boilers and steam turbine units. The plant site includes minimal vegetation and a landscape buffer area south of the power plant. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of facilities related to electric power generation for the existing Riviera Plant. The site is located on the Intracoastal waterway which provides warm water refugia for manatees during cold winter days.

2. Listed Species

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the Site, due to the existing developed nature of the Site and lack of suitable onsite habitat for listed species. The warm water discharges from the plant attract manatees, an endangered species. FPL is working closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process and upon operation of the new plant. FPL will be complying with several manatee related conditions of certification to ensure the protection of the manatees during this time.

3. Natural Resources of Regional Significance Status

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option is to replace the existing units (Units 3 & 4) with one new 1,219 MW (approximate) unit consisting of three new combustion turbines (CT), three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit would be in service in mid-2014. Natural gas delivered via pipeline is the primary fuel type for the unit with ultra-low sulfur light oil serving as a backup fuel.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the site is "Utility". The Port of Palm Beach is to the north of the site. Designation to the west of the site is "Commercial". To the south of the site is "Residential" and is in the City of West Palm Beach.

h. **Site Selection Criteria Process**

The Riviera plant has been selected as a Preferred Site to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of replacing the existing steam units with a new CC unit including a significant reduction in system air emissions and improved aesthetics at the site.

i. **Water Resources**

Water from the Lake Worth Lagoon (Intracoastal waterway) is currently used for once-through cooling water. The new plant will utilize portions of the existing once through cooling water intake and discharge structures. Water for cooling pump seals and irrigation will come from three onsite surficial aquifer wells. Process and potable water for the converted plant will come from the existing City of Riviera Beach potable water supply.

j. **Geological Features of Site and Adjacent Areas**

FPL's Riviera Plant site is underlain by the surficial aquifer system. The Surficial aquifer system in eastern Palm Beach County is primarily composed of sand, sandstone, shell, silt, calcareous clay (marl), and limestone deposited during the Pleistocene and Pliocene Epochs. The sediments forming the aquifer system are the Pamlico Sand, Fort Thompson Formation (Pleistocene) and the Caloosahatchee Marl (Pleistocene and Pliocene). Permeable sediments in the upper part of the Tamiami Formation (Pliocene) are also part of the aquifer system. The sediments in the eastern portion of the county are appreciably more permeable than in the west due to better sorting and less silt and clay content.

The surficial aquifer is underlain by at least 600 feet the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing is approximately 0.232 million gallons per day (mgd) for uses such as process water and service water. Approximately 600 mgd of cooling water would be cycled through the once-through cooling water system. Potable water demand is expected to average .001 mgd.

l. Water Supply Sources by Type

The new plant will continue to use the Lake Worth Lagoon water as the source of once-through cooling water. Water for cooling pump seals and irrigation will come from on-site surficial aquifer wells currently permitted by SFWMD. Process and potable water for the new plant will come from the existing City of Riviera Beach's potable water supply.

m. Water Conservation Strategies Under Consideration

No additional water sources will be required as a result of the modernization project.

n. Water Discharges and Pollution Control

The new plant will utilize portions of the existing once-through cooling water system for heat dissipation. The heat recovery steam generator blowdown will be mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system prior to discharge. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit would be transported to the site via a pipeline. New gas compressors may be installed to raise the gas pressure of the existing pipeline to the appropriate level for the converted unit. Ultra-low sulfur light fuel oil would be received by truck, pipeline or barge and stored in a new above-ground storage tank.

p. **Air Emissions and Control Systems**

The regulated air emissions at the new plant would be more than 90 percent lower than the existing Riviera Plant's emissions are, resulting in significant annual emissions reductions and air quality benefits. The use of natural gas and ultra-low sulfur light fuel oil and combustion controls would minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of RBEC would incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q. **Noise Emissions and Control Systems**

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. **Status of Applications**

The FPSC voted to approve the need for the modernization project and the need order was issued in September 2008. The project received final state certification on November 24, 2009, through the issuance of a final order signed by the Secretary of the DEP.

Preferred Site #6: Space Coast Next Generation Solar Energy Center, Brevard County

The Space Coast site is located at Section 13, Township 23 South, and Range 36 East, North of North Courtenay Parkway. FPL is leasing approximately 60 acres from Kennedy Space Center in Brevard County. This Space Coast site has been selected as a Preferred Site for the addition of a 10 MW PV generation facility. The Space Coast Next Generation Solar Energy Center is expected to be in operation by the end of 2010. This

Site has the potential to expand by another 10 MW. Also, FPL is evaluating the potential for expansion beyond the existing site.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the Space Coast Next Generation Solar Energy Center plant site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the general layout of the Space Coast Next Generation Solar Energy Center generating facility is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

The site is inactive. The site was previously dedicated to agricultural use as citrus groves. There are no structures on the site and the majority of the vegetation is citrus grove.

e. **General Environment Features On and In the Site Vicinity**

1. **Natural Environment**

The surrounding land use is predominantly agriculture. FPL was able to design the PV facility to avoid most of the impacts to natural wetlands.

2. **Listed Species**

Wildlife resources at the site were evaluated in February 2008 through pedestrian surveys. There were no listed species observed.

3. **Natural Resources of Regional Significance Status**

The construction and operation of a PV generating facility at this location is not expected to have any adverse impacts on parks or recreation areas. Construction will result in minimal wetland impacts under federal, state, or local agency permitting criteria.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design consists of 10 MW of PV technology. No mitigating options are deemed necessary at the site.

g. **Local Government future Land Use Designations**

Future land use designation for the site is Spaceport Management as designated by the Brevard County Future Land Use Map.

h. **Site Selection Criteria Process**

The site has been selected as a Preferred Site for the installation of a PV technology due to consideration of various factors including its suitability for a PV facility of this magnitude and the cooperation of the Kennedy Space Center.

i. **Water Resource**

No water will be required at the PV facility except the small amount that may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water would be brought to the site by truck.

j. **Geological Features of the Site and Adjacent Areas**

The surface and near-surface deposits of east-central Florida range from surficial unconsolidated sands to well indurated limestones and dolomites at depth. In ascending order the four main geologic units present in east-central Florida are: (i) Eocene limestones; (ii) Lower and Middle Miocene compact silt and clays; (iii) Upper Miocene and Pliocene silty and clayey sands; and (iv) Pleistocene and Recent age sands with interbedded shell layers.

k. **Projected Water Quantities for Various Uses**

The projected water use for the PV facility is expected to be minimal with water being used occasionally only to clean the PV panels.

l. **Water Supply Sources and Type**

At this time, it is expected that natural rainfall will be sufficient to keep the solar panels clean. In the event that additional water is required, a small amount of water may be occasionally trucked in to clean the PV panels.

m. **Water Conservation Strategies**

FPL constructed this PV facility knowing it would not use water for operation and would only need a minimal amount for cleaning the PV panels.

n. **Water Discharges and Pollution Control**

There will not be any water discharges or pollution as a result of this facility

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

The facility will use the sun for fuel. Therefore, there will not be any fuel delivery, storage, waste, or pollution at this site.

p. **Air Emissions and Control Systems**

No air emissions will be emitted from this facility.

q. **Noise Emissions and Control Systems**

Noise expected during construction is expected to be below noise levels allowed by Brevard County. No noise will be emitted from this facility during operation.

r. **Status of Applications**

FPL received an Environmental Resource Permit (ERP) from the St. Johns Water Management District in April 2009 and a U.S. Army Corps of Engineers permit in December 2008 for the 10 MW site. .

Preferred Site #7: Martin Next Generation Solar Energy Center, Martin County

The Martin Next Generation Solar Energy Center (MSEC) is located on the existing FPL Martin Plant site in unincorporated Martin County, Florida. The Martin Plant site is located in southwestern Martin County about 40 miles northwest of West Palm Beach and about 1.3 miles east of Lake Okeechobee (Figure 2.1-1). The Martin Plant site is bounded by State Road (SR) 710 and a CSX Railroad line (east and north), a Florida East Coast Railway line and SFWMD L-65 Canal (west), and the St. Lucie Waterway (south).The MSEC Project will be constructed in an approximately 600-acre area (Project Area) within FPL's existing 11,300-acre Martin Plant site. The land surrounding the site is owned by FPL and acts as a buffer zone.

The site has been selected as a Preferred Site for the addition of approximately 75 MW of solar thermal generation. The facility will produce steam that will replace steam that would otherwise have been produced by burning natural gas in one of the existing CC units at the site, Martin Unit 8. The Martin Next Generation Solar Energy Center is expected to be in operation by the end of 2010.

There also is potential for an additional 75 MW of photovoltaic or solar thermal on the Martin Plant Property in the future. Adjacent farmlands are also being considered for additional photovoltaic facilities.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the Martin Next Generation Solar Energy Center plant site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the general layout of the Martin Next Generation Solar Energy Center generating facility is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

Total acreage for the existing Martin Plant site is approximately 11,300 acres, which represents land owned by FPL. The Martin Plant site consists of a 6,800-acre cooling pond (6,500 acres of water surface and 300 acres of embankment) and approximately 400 acres for existing Units 1 through 4, Unit 8, and associated facilities. Units 1 & 2 are nominal 800-MW steam electric generating units that use natural gas and low-sulfur residual oil. Units 3 & 4 are nominal 500-MW natural gas-fired CC units. Unit 8 is a natural gas fired 4-on-1 CC unit with a nominal capacity of 1,100 MW that began operation in 2005. Light oil is used as backup in Unit 8. The other onsite facilities include water and wastewater treatment facilities, residual and light fuel oil storage, switchyards and transmission lines, offices, warehouses, maintenance buildings, and other miscellaneous uses.

Adjacent areas include agricultural uses such as croplands, pastures, and groves account for much of the land use and cover within 5 miles of the Martin Plant site. Three types of wetlands, forested freshwater, non-forested freshwater, and mixed forested and forested freshwater also account for a great deal of nearby land use.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The portions of the Martin Plant site that will be affected by the construction of the MSEC are about 550 acres that will be utilized for solar arrays and construction facilities. The solar arrays will be located east of the existing Unit 8. Activities associated with construction will occupy about 100 acres. This will include construction laydown, parking, and trailers. These areas will be cleared of any vegetation. The area for the heat exchangers will be near Unit 8 and this area has been previously impacted by the construction of Units 3, 4, and 8.

2. Listed Species

Threatened and endangered species within the project area are limited to avian species and gopher tortoise. No listed species of plants were identified within the MSEC project area. Due to the presence of large areas of similar habitat both within the Northwest Mitigation Area and areas north of the existing transmission line right-of-way (ROW) adjacent to the project area, and the highly mobile nature of protected avian species, no significant adverse impacts to federally or state listed animals are expected. Creation of wood stork foraging ponds and sandhill crane habitat within the Northwest Mitigation Area provides suitable habitat to offset the loss of shallow hydroperiod wetlands within the project area.

Gopher tortoises are classified as threatened by the Florida Fish and Wildlife Conservation Commission (FFWCC), but are not listed federally by the U.S. Fish and Wildlife Service (USFWS). Gopher tortoise burrows were observed in the palmetto prairie and woodland pasture. Other listed species are known to utilize gopher tortoise burrows (commensal species), including the Eastern indigo snake (*Drymarchon corais couperi*; federally and state threatened), gopher frog (*Rana capito*; state species of special concern), and Florida mouse (*Podomys floridanus*; state species of special concern). A permit was obtained to relocate the gopher tortoises and any commensal species. Construction and operation at the site is not expected to affect any rare, endangered, or threatened species.

3. Natural Resources of Regional Significance Status

The construction and operation of a solar thermal facility at this location is not expected to have any adverse impacts on parks or recreation areas.

Construction will result in minimal wetland impacts under federal, state, or local agency permitting criteria.

4. **Other Significant Features**

The Florida Department of State, Division of Historical Resources, has determined that no significant archaeological or historical sites are recorded or are likely to be present within the project area. As a result no construction impacts on historic properties listed or eligible for listing in the National Register of Historic Places, or otherwise of historical or archaeological value, are anticipated.

f. **Design Features and Mitigation Options**

The design consists of approximately 75 MW of solar thermal technology. FPL has already undertaken an extensive wetland mitigation program on a 1,130-acre parcel northwest of the existing Martin Plant generating units. That mitigation program was deemed successful by the SFWMD in 2001. All wetland impacts associated with the MSEC have been fully mitigated through this now-successful wetland and upland mitigation effort.

g. **Local Government future Land Use Designations**

The Martin Plant site that includes Units 1 & 2 was developed prior to the county's adoption of a future land use map. In 1982, at the time of the original land use plan map adoption, the portion of the Martin Plant site surrounding the existing units was designated Industrial. The Electric Utility Element of the Comprehensive Plan acknowledged FPL's then current plans to construct two integrated coal gasification combined cycle (IGCC) plants at the Martin Plant site and encouraged the facilities to be developed under the industrial planned unit development [PUD(i)] zoning designation. In September 1988, FPL requested a comprehensive plan land use amendment to industrial for the licensing of the Martin Coal Gasification/Combined Cycle (CG/CC) Project Area and a rezoning of that area to PUD(i). In August 1989, the Martin County Board of County Commissioners (BOCC) approved the comprehensive plan amendment and the rezoning request. In June 2008, with the BOCC approval of the rezoning, a PUD Zoning Agreement was executed between Martin County and FPL in which development standards and special conditions were addressed. Most of the special conditions were addressed during earlier phases of developing the Martin Plant site. An amendment of the PUD Zoning Agreement was requested by FPL to allow renewable energy facilities to be located within the PUD area. Subsequent to the certification of the CG/CC project, which includes the area of the MSEC, Martin County has amended its future land use element and map to designate 7,300 acres in the Martin Plant site as Public Utilities – Major Public Power Generation Facilities.

h. Site Selection Criteria Process

The site has been selected as a Preferred Site due to consideration of various factors including available land area and proximity to an existing generating unit (Martin Unit 8) to which the steam generated by the solar thermal facility could be fed.

i. Water Resource

There will be no water used at the solar thermal facility except the small amount needed to occasionally clean the solar mirrors. The additional water needed for mirror cleaning is already within the previously approved allocation of water for the Martin Plant site.

j. Geological Features of the Site and Adjacent Areas

Borings drilled in the area just east of the existing Unit 8 show that the predominant soil type is sand from the ground surface [approximately 30 feet above mean sea level (ft-msl)] to −70 ft-msl (negative number denotes feet below sea level). The sands vary in color from light to dark gray and brown. Clayey sand and sandy clay seams from a few inches to several feet in thickness are generally found at 10 ft-msl. A thin layer of greenish-gray sandy clay was found in the borings at approximately −25 ft-msl. The Pamlico and Anastasia Formations extend from the ground surface (20 to 30 ft-msl) to an average of −3 ft-msl. These strata consist of fine sands and silty sands with shell fragments. Thin beds of limestone and cemented sand occur sporadically at depths ranging from 2 to 4.5 ft-msl in localized areas; this zone may represent the boundary between the Pamlico and Anastasia Formations. In areas where the cemented sands and limestone are absent, it is not possible to differentiate the two formations.

The underlying Caloosahatchee Group extends to an average −80 ft-msl. This formation can be subdivided into two units, namely an upper limestone interbedded with sand and shell present to an average −12 ft-msl, and a lower unit of silty sand with shell fragments and shell beds to −80 ft-msl. The Tamiami Formation underlies the Caloosahatchee from −105 ft-msl to −150 ft-msl. This formation consists of silty sand varying with depth to clayey sand from −72 ft-msl. The color of the formation also varies from gray in the sands to predominantly green in the clayey zone.

The top of the Hawthorn Group occurs at approximately −105 ft-msl to −150 ft-msl. These elevations are based on the logs of test wells and exploratory borings drilled in the area. The Hawthorn, approximately 550 ft thick, consists predominantly of greenish clay with subordinate amounts of shell, limestone, silt, and sand. Major limestone zones generally occur near the base of the formation. Due to very low vertical permeability, the Hawthorn acts as a confining bed overlying the Floridan Aquifer.

k. Projected Water Quantities for Various Uses

Washing mirrors requires about 50 gallons per 120 mirrors (i.e., a 50 meter section). Based on the amount of mirrors for the MSEC, about 75,000 gallons per washing will be required. This amount of water is estimated to be no more than about 2 million gallons per year for cleaning mirrors.

l. Water Supply Sources and Type

The plant water use for MSEC can be accommodated by the current authorization for water in the Conditions of Certification (PA89-27L). The amount of water required by the MSEC is estimated to not exceed about 2 million gallons per year for cleaning mirrors, or an annual average of about 5 gallons per minute (gpm). The usage will be intermittent, with maximum usage of about 75,000 gallons every 1 or 2 weeks during periods without rain and depending upon the reflectivity of the mirrors. The source of water for the MSEC is the existing demineralized water system.

m. Water Conservation Strategies

FPL plans to construct this solar thermal facility knowing it will use very little water for operation.

n. Water Discharges and Pollution Control

There will not be any water discharges or pollution as a result of this facility.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The facility will use the sun for fuel. Therefore, there will not be any fuel delivery, storage, waste, or pollution at the site from the operation of the solar thermal facility.

p. Air Emissions and Control Systems

There will be no SO_2, NO_x, or CO_2 emissions from the solar thermal facility and its operation will result in reductions of FPL system emissions for all three types of emissions.

There will be minor amounts of volatile organic compounds (VOCs) released from the expansion tanks as a result of decomposition products of heat transfer fluids (HTF). Based on reported values from FPL Energy SEGS facilities in California, the VOC emissions from the MSEC will be about 0.8 tons per year (TPY). This amount would classify these emissions as insignificant activities and the amount is well below the threshold requiring permitting under FDEP rules in 62-210.300, F.A.C. A generic exemption is that emissions of any regulated pollutant be less than 5 TPY. The 5 TPY applies to the "potential-to-emit" for the emission unit, which would be 8,760 hours/year unless restricted as an enforceable permit condition in a permit. The exemption covers the requirement to obtain construction permits required pursuant to Rule 62-210.300(1), F.A.C.

q. Noise Emissions and Control Systems

Noise during construction is expected to be below noise level allowed by Martin County. There will not be any noise from the solar thermal facility during operation.

r. Status of Applications

FPL submitted an application for a Site Certification Modification for the Martin Next Generation Solar Energy Center to the FDEP in May 2008. FPL received the site certification modification approval in August 2008.

IV.F.2 Potential Sites for Generating Options

Ten (10) sites are currently identified as Potential Sites for near-term future generation additions to meet FPL's capacity and energy needs.[4]

These sites have been identified as Potential Sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies.

Each of these Potential Sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that will require further definition

[4] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other greenfield sites. Greenfield sites that FPL currently does not own, or for which FPL has not currently secured the necessary rights to, are not specifically identified as Potential Sites in order to protect the economic interests of FPL and its customers.

and attention. Solely for the purpose of estimating water requirements for each site, it was assumed that either one dual-fuel (natural gas and light oil) simple cycle combustion turbine (CT) or a natural gas-fired CC unit would be constructed at the Potential Sites unless otherwise noted. A simple cycle CT would require approximately 50 gallons per minute (gpm) for both process and cooling water (assuming air cooling). A CC unit would require approximately 150 gpm for service and process water and approximately 14 million gallons per day (mgd) for cooling water depending upon the water source and associated water quality. If an existing power plant site is ultimately selected for converting an existing unit(s), the water requirements discussed above for a CC unit would be approximately correct for the converted unit. If a renewable energy generating technology, such as photovoltaic or solar thermal, is ultimately selected for one of these sites, the water requirements would be less than those for CT or CC facilities.

Permits are presently considered to be obtainable for each of these sites. No significant environmental constraints are currently known for any of these sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time, FPL considers each site to be equally viable.

Potential Site # 1: Babcock Ranch , Charlotte County

This site is located within the Babcock Ranch Community on the north side of Truckers Grade, approximately 10.5 miles north of the intersection of SR-80 and SR-31 and 1.1 miles east of SR-31. The project is bordered on the north by the Babcock Ranch Reserve owned by the State of Florida. The site is within the SFWMD and, therefore, the drainage would be in accordance with the SFWMD Basis of Review. Permitting of the surface water management system would be through the Florida Department of Environmental Protection (FDEP) - South District based on a pre-application meeting. This site is a possibility for an FPL photovoltaic (PV) facility.

a. U.S. Geological Survey (USGS) Map

A map of this site is found at the end of this chapter.

b. Land Uses

Existing Land Use on the site is agricultural. FPL would attempt to re-zone the property to PD-P1 which will allow for electrical generation.

c. **Environmental Features**

FPL anticipates mitigating for any panther and/or wetland impacts as a result of the project.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**

No water will be required at the PV facility except the small amount that may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water would be brought to the site by truck.

Potential Site # 2: DeSoto Solar Expansion, DeSoto County

The DeSoto site is located at 4051 Northeast Karson Street approximately 0.3 miles east of US 17 and immediately north of Bobay Road in Arcadia, Florida. The site is located in Sections 26, 27, & 35, Township 36 South, and Range 25 East. FPL owns an approximate 13,000 acre parcel in DeSoto County. FPL has designated approximately 1,523 acres for development of a photovoltaic (PV) facility. The land surrounding the site is owned by FPL and acts as a buffer zone.

The DeSoto site was previously selected as the site for the addition of a 25 MW PV facility, which is currently operational. There is also a potential to create an additional 275 MW PV generating facility which would be implemented in phases on the additional land.

a. **U.S. Geological Survey (USGS) Map**

A map of this site is found at the end of this chapter.

b. **Land Uses**

Existing Land Use on the site is agricultural.

c. **Environmental Features**

There are no significant environmental features on the site.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**

No water will be required at the PV facility except the small amount that may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water would be brought to the site by truck.

Potential Site # 3: Florida Heartland Solar, Glades County

This site is located within Glades County, Florida off of SR 78. This site is a possibility for an FPL PV facility.

a. **U.S. Geological Survey (USGS) Map**

A map of this site is found at the end of this chapter.

b. **Land Uses**

The existing land uses on the site is agriculture.

c. **Environmental Features**

FPL anticipates mitigating for any panther and/or wetland impacts as a result of the project.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**

No water will be required at the PV facility except the small amount that may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water would be brought to the site by truck.

Potential Site # 4: Fort Myers Plant, Lee County

FPL's existing 460-acre Fort Myers property is located just east of Interstate 75 in Lee County and is adjacent to the Caloosahatchee River. The existing facilities on the site include one 1,440 MW (approximate) CC unit, 12 gas turbines, each with an approximate capacity of 54 MW, and two combustion turbines, each with an approximate capacity of 160 MW.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the Fort Myers plant site is found at the end of this chapter.

b. **Land Uses**

The land on the site is currently dedicated to industrial use with surrounding grassy and landscaped areas. Much of the site has been used in recent years for direct plant construction activities. The adjacent land uses include light commercial and retail to the east of the property, plus some residential areas located toward the west.

c. **Environmental Features**

Mixed scrub with some hardwoods can be found to the east and further south. The Caloosahatchee River is designated as critical habitat for manatees.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

The available water source is the Caloosahatchee River and the available groundwater source is the sandstone aquifer. FPL is aware that the Caloosahatchee River provides habitat for a variety of listed species. Prior to definitive site selection, FPL will take into account impingement and entrainment impacts as well as potential water quality impacts as a result of any new generating unit addition.

Potential Site # 5: Hendry County

FPL is currently evaluating potential sites in Hendry County for a future photovoltaic facility for up to 100 MW. Sites currently under investigation are approximately 1500 acres. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

Not available because a specific site has not been selected at this time.

b. **Land Uses**

Hendry County is predominantly agricultural land use.

c. **Environmental Features**

Not available because a specific site has not been selected at this time.

d. **Water Quantities**

Minimal amounts of water would be required for a photovoltaic facility.

e. **Supply Sources**

No water will be required at the PV facility except the small amount that may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water would be brought to the site by truck.

Potential Site # 6: Lauderdale Plant, Broward County

The Lauderdale site is located in Eastern Broward County approximately 5 miles inland from Dania Beach and less than 2 miles west of Ft. Lauderdale International Airport. The site is bounded on the south by Dania Cutoff Canal, on the east by S.W. 30th Avenue, and on the North by I-595.

The existing approximately 1,700 MW of generating capacity at FPL's Lauderdale site occupies a portion of the approximately 210 acres that are wholly owned by FPL. The generating capacity is made up of two CC units (Units 4 & 5), and 24 simple cycle gas turbine (GT) units.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site is found at the end of this chapter.

b. **Land Uses**

The existing power plant facilities are located on approximately 130 acres. The existing site has been in use since the 1920s and is adjacent to a county resource recovery project.

c. **Environmental Features**

To the north of the power plant is an area of mixed uplands with a scattering of small wetlands. Manatees are known to inhabit the waters nearby the plant.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

Existing groundwater or the municipal water supply are potential water sources. FPL will also consider the potential for alternative water development options at this site.

Potential Site # 7: Manatee Plant, Manatee County

The existing FPL Manatee Plant 9,500-acre site is located in unincorporated north-central Manatee County. The existing power generating facilities are located in all or portions of Sections 18 and 19 of Township 33S, Range 20-E. The plant site lies approximately 5 miles east of Parrish, Florida. It is approximately 5 miles east of U.S. 301 and 9.5 miles east of Interstate Highway 75 (I-75). The existing plant is approximately 2.5 miles south of the Hillsborough-Manatee County line; a portion of the north property boundary of the plant site abuts the county line. State Road 62 (SR 62) is about 0.7 mile south of the plant, with the plant entrance road going north from that highway. This site is a possibility for an FPL PV or solar thermal facility.

a. **U.S. Geological Survey (USGS) Map**

A map of the site is found at the end of this chapter.

b. **Land Uses**

Existing Land use on the site is agricultural. FPL is attempting to rezone the property to PD-PI which will allow for electrical generation.

c. **Environmental Features**

FPL anticipates mitigating for any gopher tortoise and/or wetland impacts as a result of the project.

d. **Water Quantities**

Minimal amounts of water would be required for a solar thermal facility.

e. **Supply Sources**

The existing water supply could be used for the water required to clean the mirrors for a solar thermal facility.

Potential Site # 8: Northeast Okeechobee County

This site is located within Okeechobee County, Florida. The northeastern portion of Okeechobee County has been identified as an area with the potential to provide a project site that requires strategic consideration. Further assessments of NE Okeechobee County are anticipated to determine suitability of a specific site.

a. **U.S. Geological Survey (USGS) Map**

Not available because a specific site has not been selected at this time.

b. **Land Uses**

Northeast Okeechobee County is predominantly agricultural land use.

c. **Environmental Features**

Not available because a specific site has not been selected at this time.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

Existing groundwater is a potential water source.

Potential Site # 9: Southwest Indian River County

This site is located within Indian River County, Florida. The southwestern portion of Indian River County has been identified as an area with the potential to provide a project site that requires strategic consideration. Further assessments of SW Indian River County are anticipated to determine suitability of a specific site.

a. **U.S. Geological Survey (USGS) Map**

Not available because a specific site has not been selected at this time.

b. **Land Uses**

Southwestern Indian River County is predominantly agricultural land use.

c. **Environmental Features**

Not available because a specific site has not been selected at this time.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

Existing groundwater is a potential water source.

Potential Site # 10: West Broward, Broward County

FPL has identified the Andytown Substation property in western unincorporated Broward County as a potential site for the addition of new generating capacity and FPL refers to this potential site as the West Broward site. Current facilities on-site include an electric substation. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site has been included at the end of this chapter.

b. **Land Uses**

The land uses for the site were designated as agricultural use.

c. **Environmental Features**

Extensive low-quality wetlands are present on the site. Construction and operation of a new facility on this site would not be expected to adversely affect any rare, endangered, or threatened species.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for both process and cooling water (assuming air cooling) and up to 14 million gallons per day (mgd) for cooling water.

e. **Supply Sources**

Groundwater from the shallow aquifer or a local source of reclaimed (reuse) water has been identified as potential water sources. The Floridan Aquifer has also been identified as a potential cooling water source. FPL will also consider the potential for alternative water development options at this site.

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Environmental and Land Use Information: Supplemental Information

Preferred Site#1: West County Energy Center

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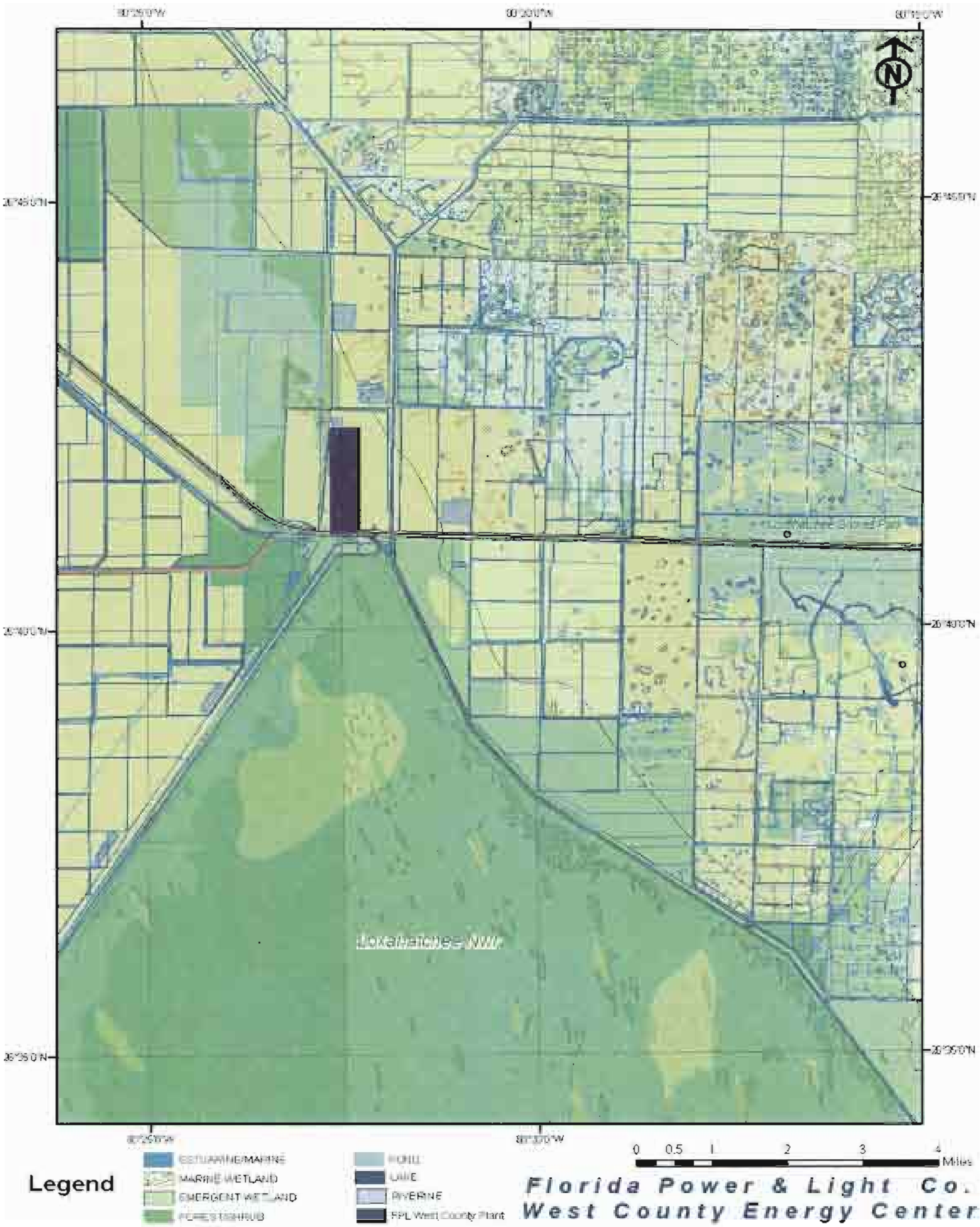
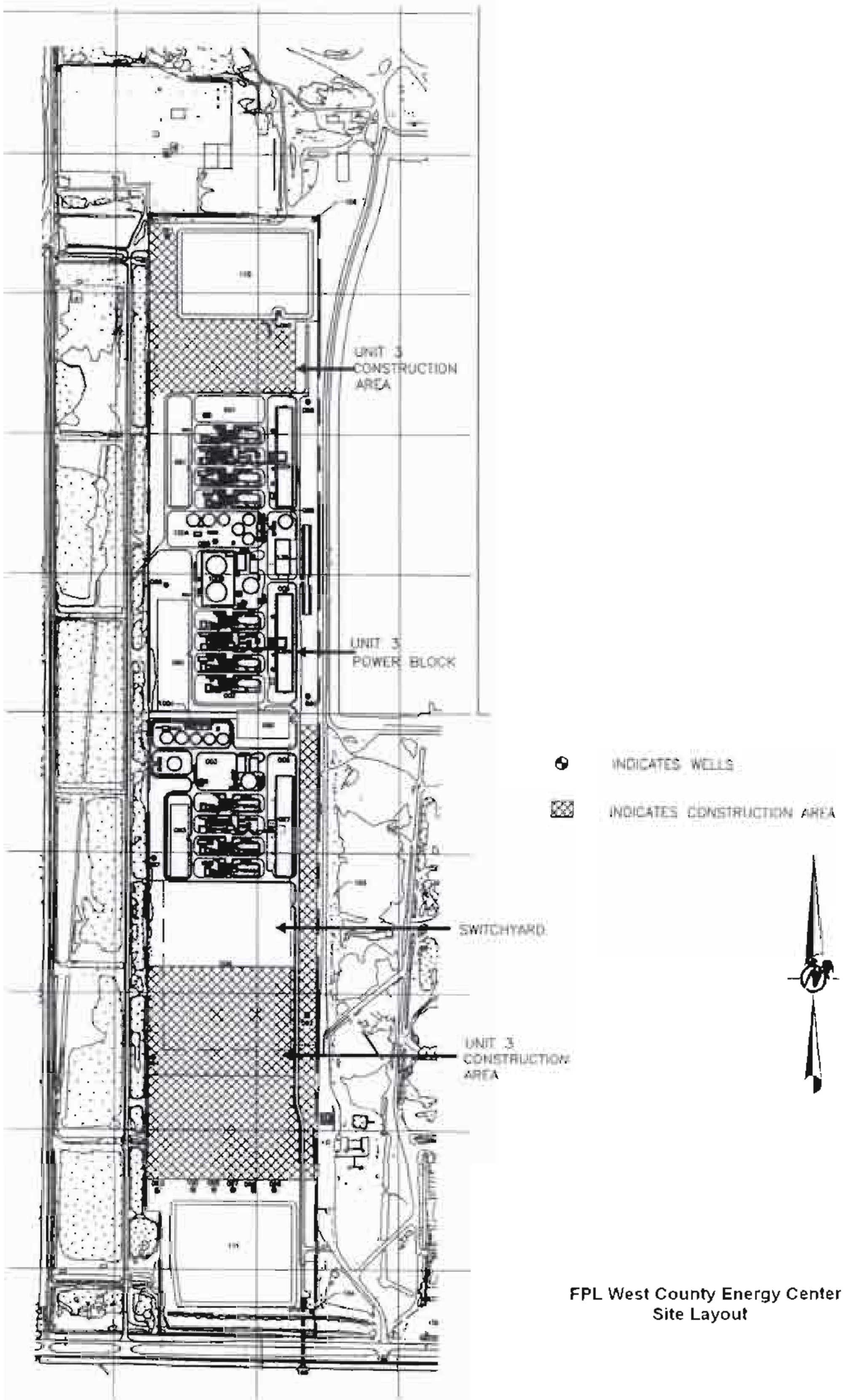
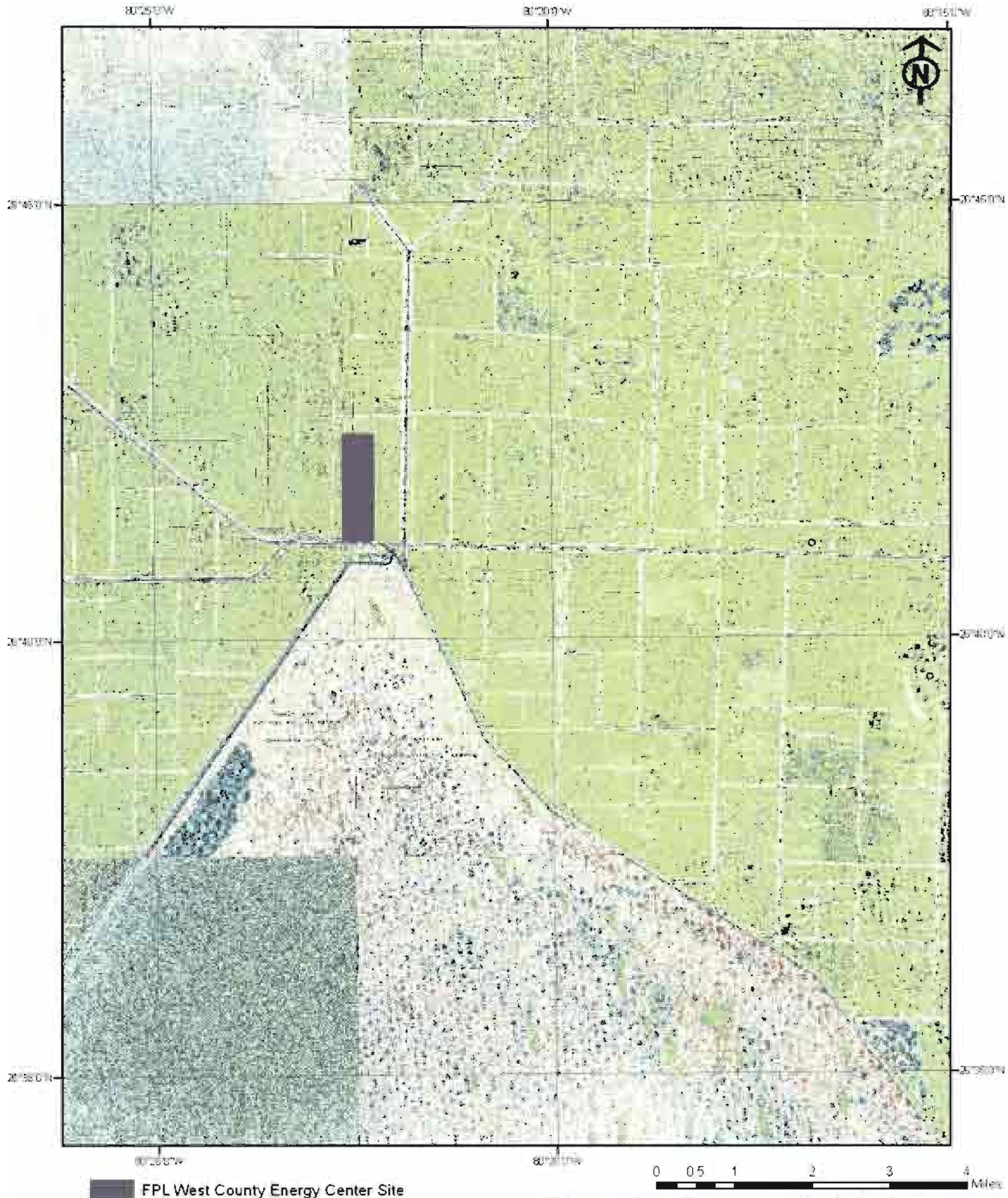

Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FORESTSHRUB
POND
LAKE
RIVERINE
FPL West County Plant
0 0.5 1 2 3 4 Miles
Florida Power & Light Co.
West County Energy Center



FPL West County Energy Center
Site Layout



Florida Power & Light Co.
West County Energy Center

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Environmental and Land Use Information: Supplemental Information

Preferred Site #2: St. Lucie Plant

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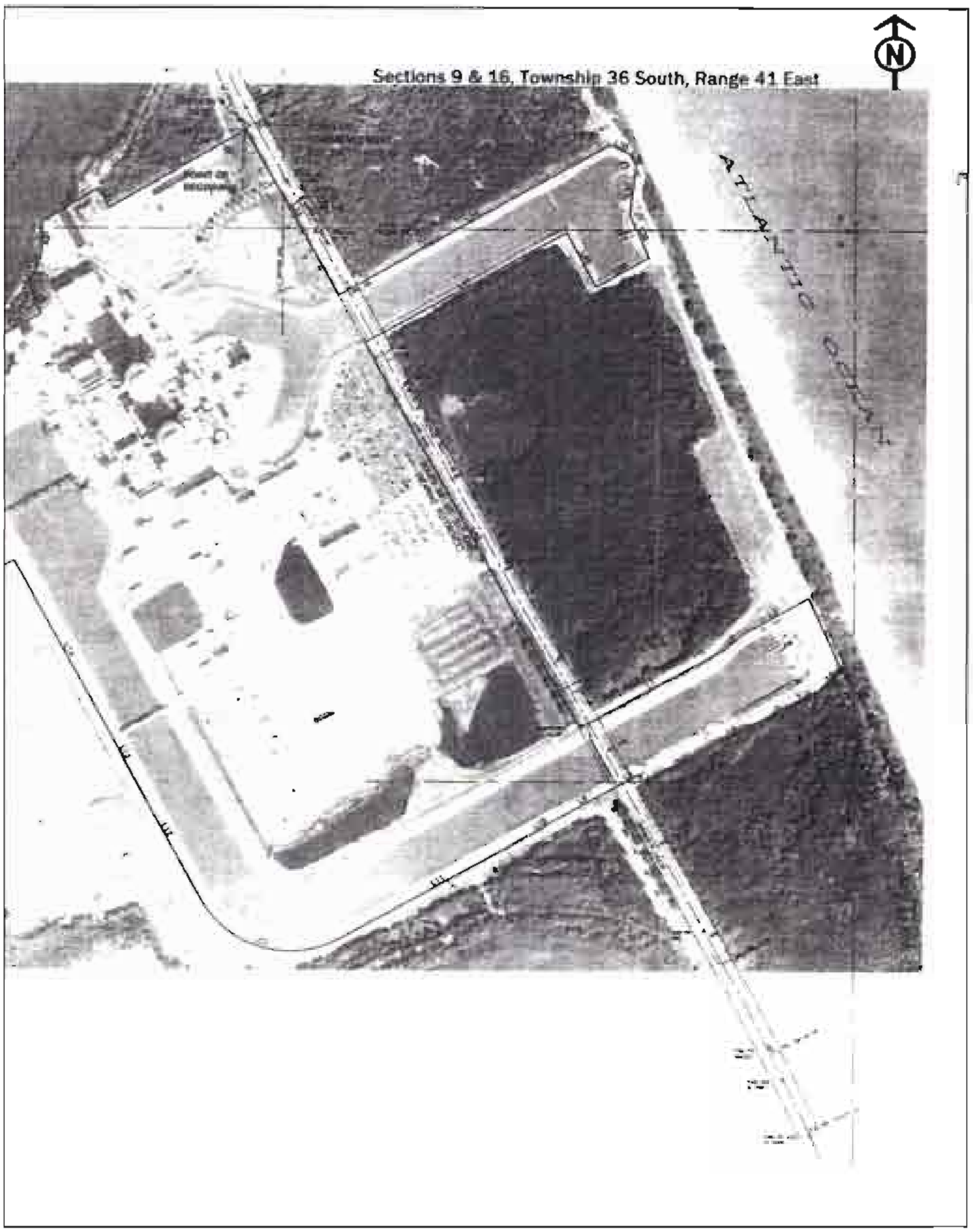

St. Lucie Site Layout

Florida Power & Light Co.
St. Lucie Power Plant


Florida Power & Light Co.
St. Lucie Power Plant
FPL St. Lucie Plant
Miles

Florida Power & Light Co.
St. Lucie Power Plant

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Environmental and Land Use Information: Supplemental Information

Preferred Site #3: Turkey Point Plant

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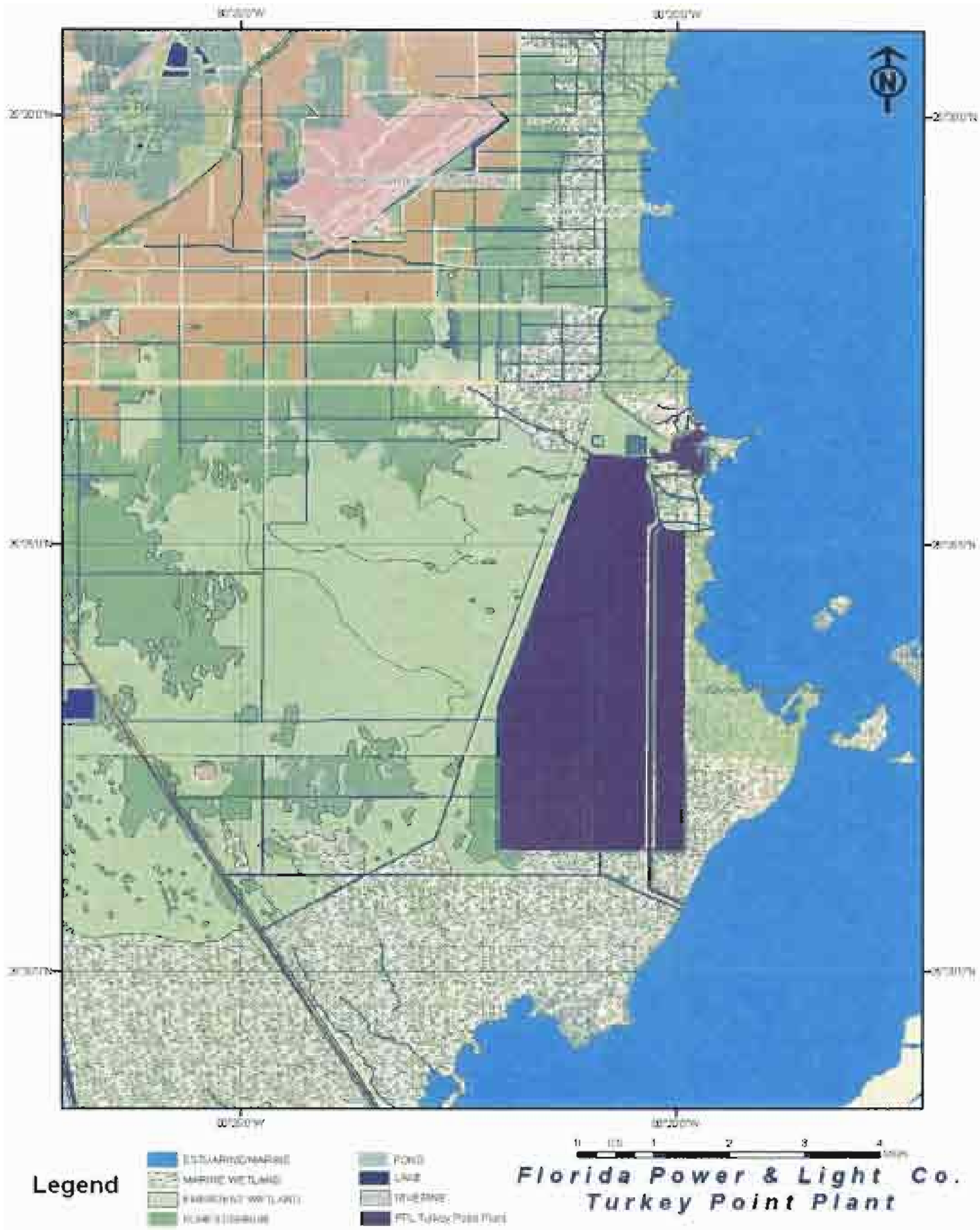
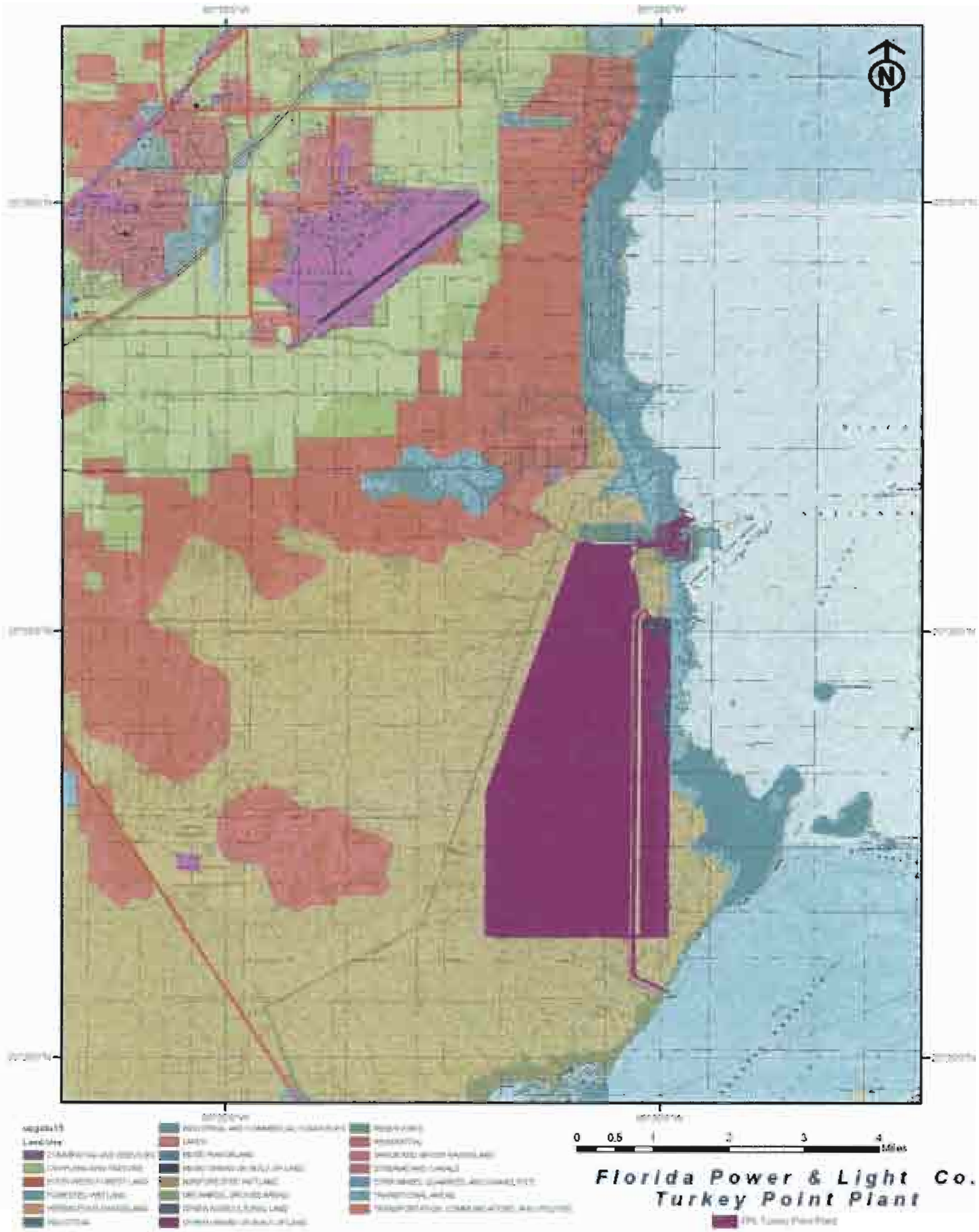
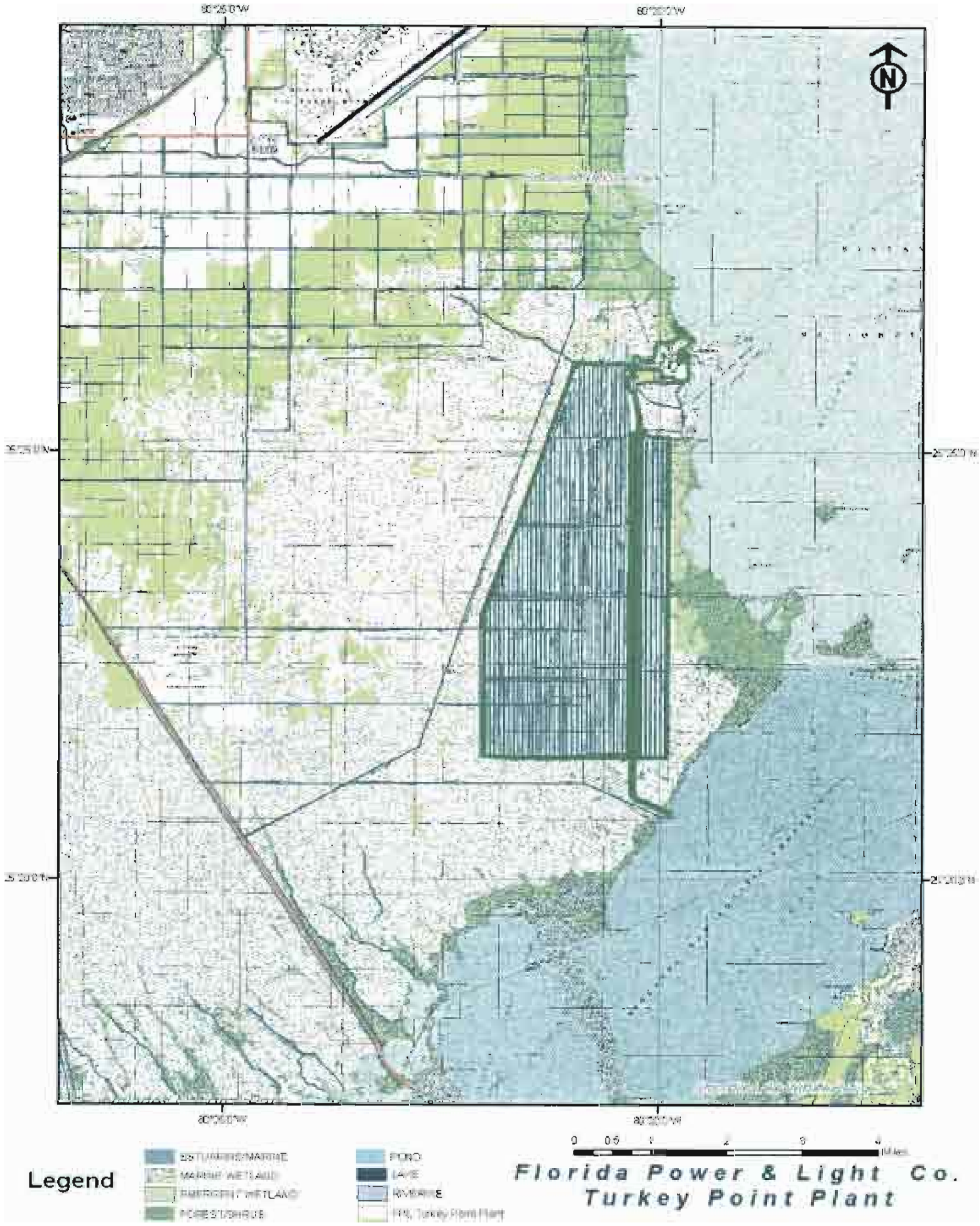

Legend
ESTUARINE/MARINE
MARINE WETLAND
POND
LAKE
RIVERINE
Florida Power & Light Co.
Turkey Point Plant


0 0.5 1 2 3 4
Miles
Florida Power & Light Co.
Turkey Point Plant


Legend
ESTUARINE/MARINE
MARINE WETLAND
EMERGENT WETLAND
FOREST/SHRUB
POND
LAKE
RIVERINE
FPL Turkey Point Plant
0 0.5 1 2 3 4
Miles
Florida Power & Light Co.
Turkey Point Plant

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Environmental and Land Use Information: Supplemental Information

Preferred Site #4: Cape Canaveral Plant

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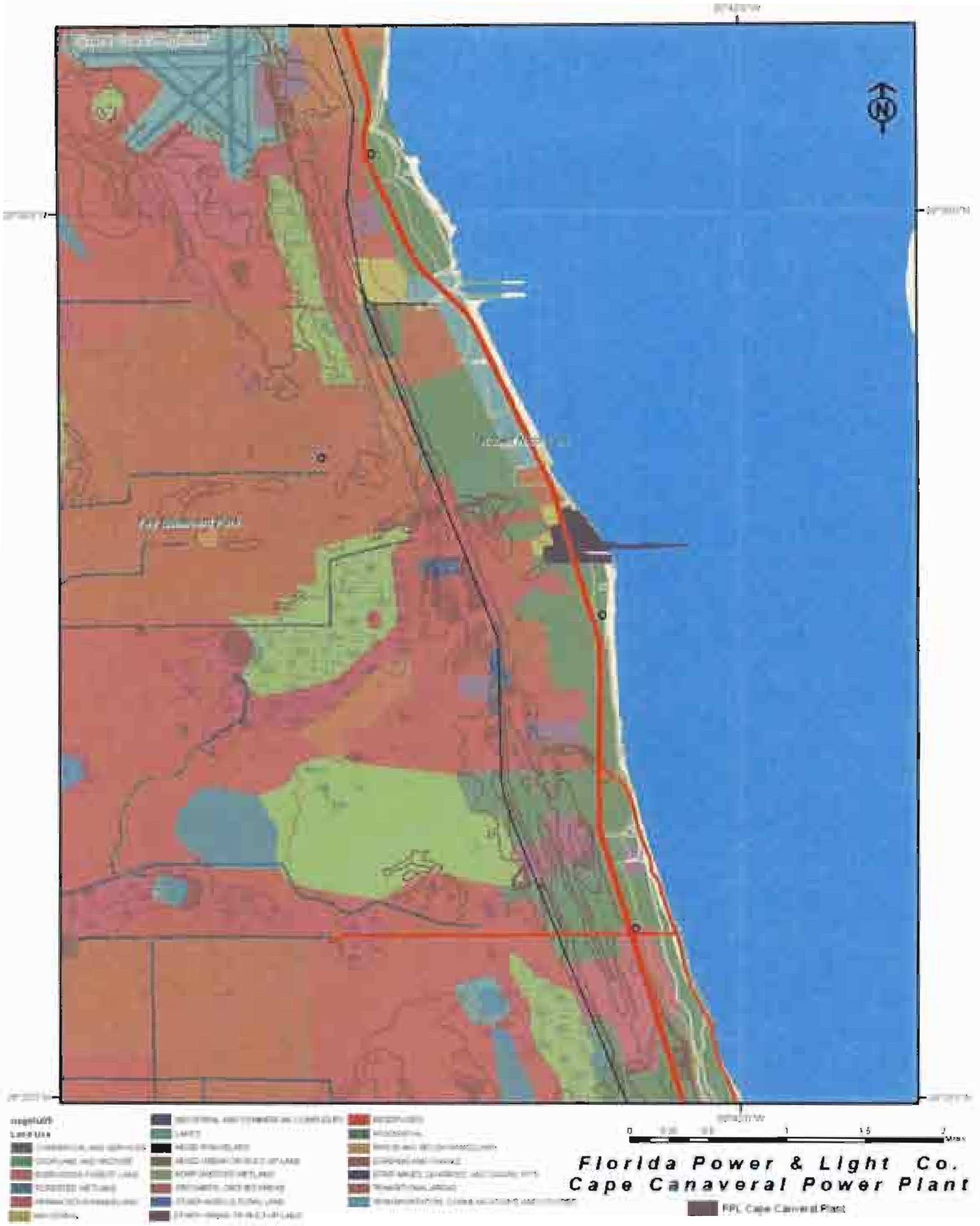
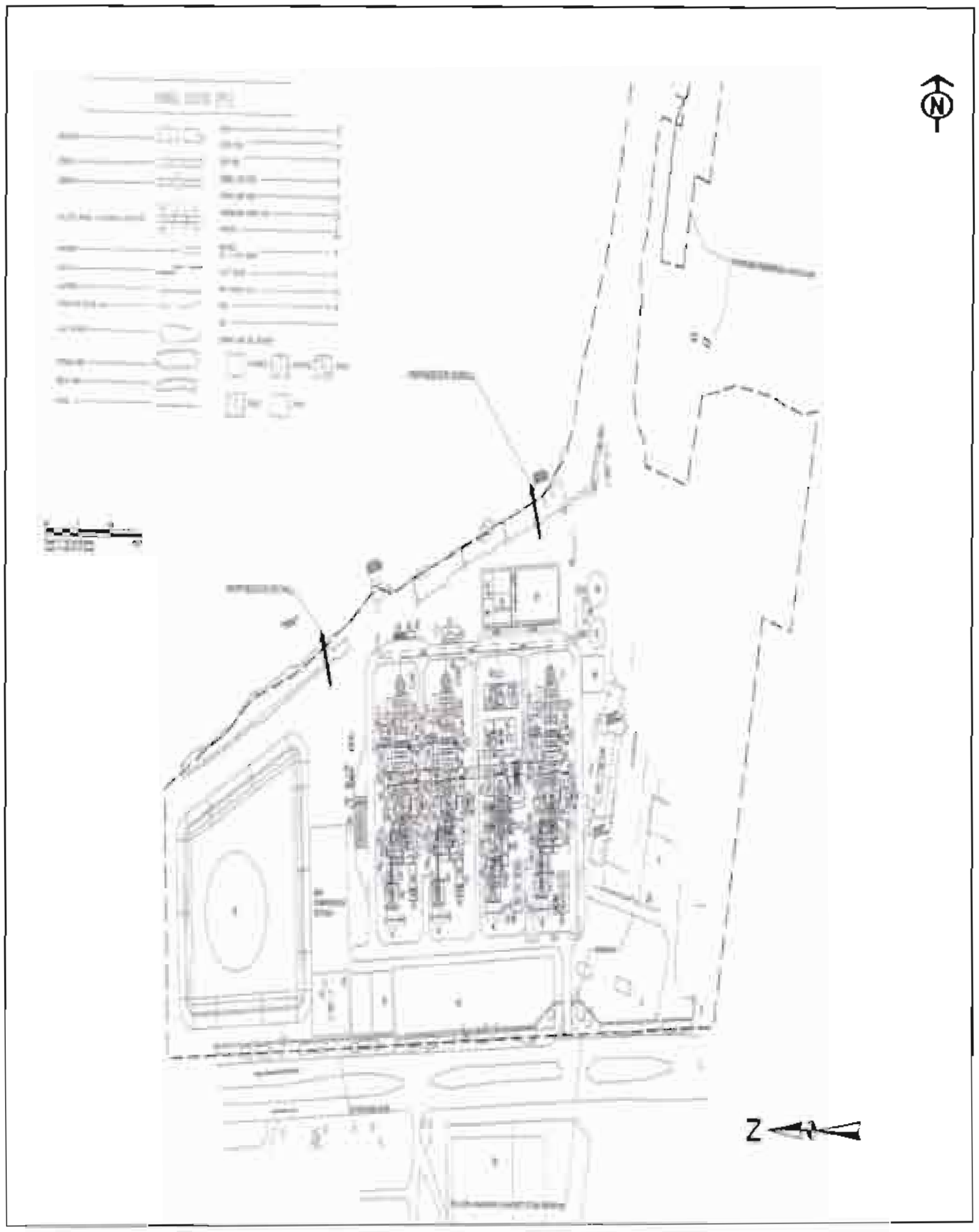
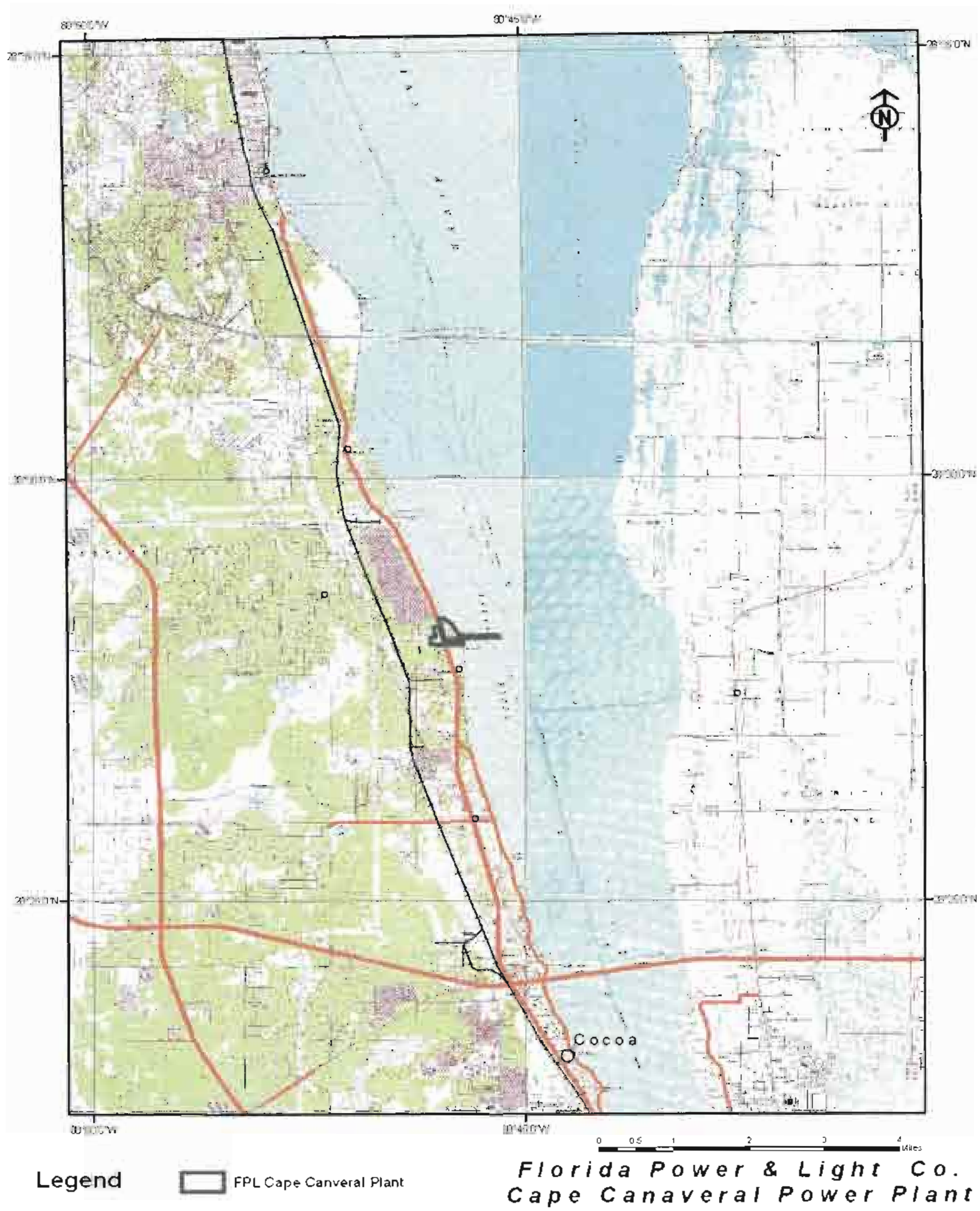

Florida Power & Light Co.
Cape Canaveral Power Plant
FPL Cape Canaveral Plant



Cape Canaveral Plant
Facility Layout

Florida Power & Light Co.
Cape Canaveral Power Plant


Cocoa
Legend
FPL Cape Canveral Plant
Florida Power & Light Co.
Cape Canaveral Power Plant

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Environmental and Land Use Information:
Supplemental Information
Preferred Site #5: Riviera Plant

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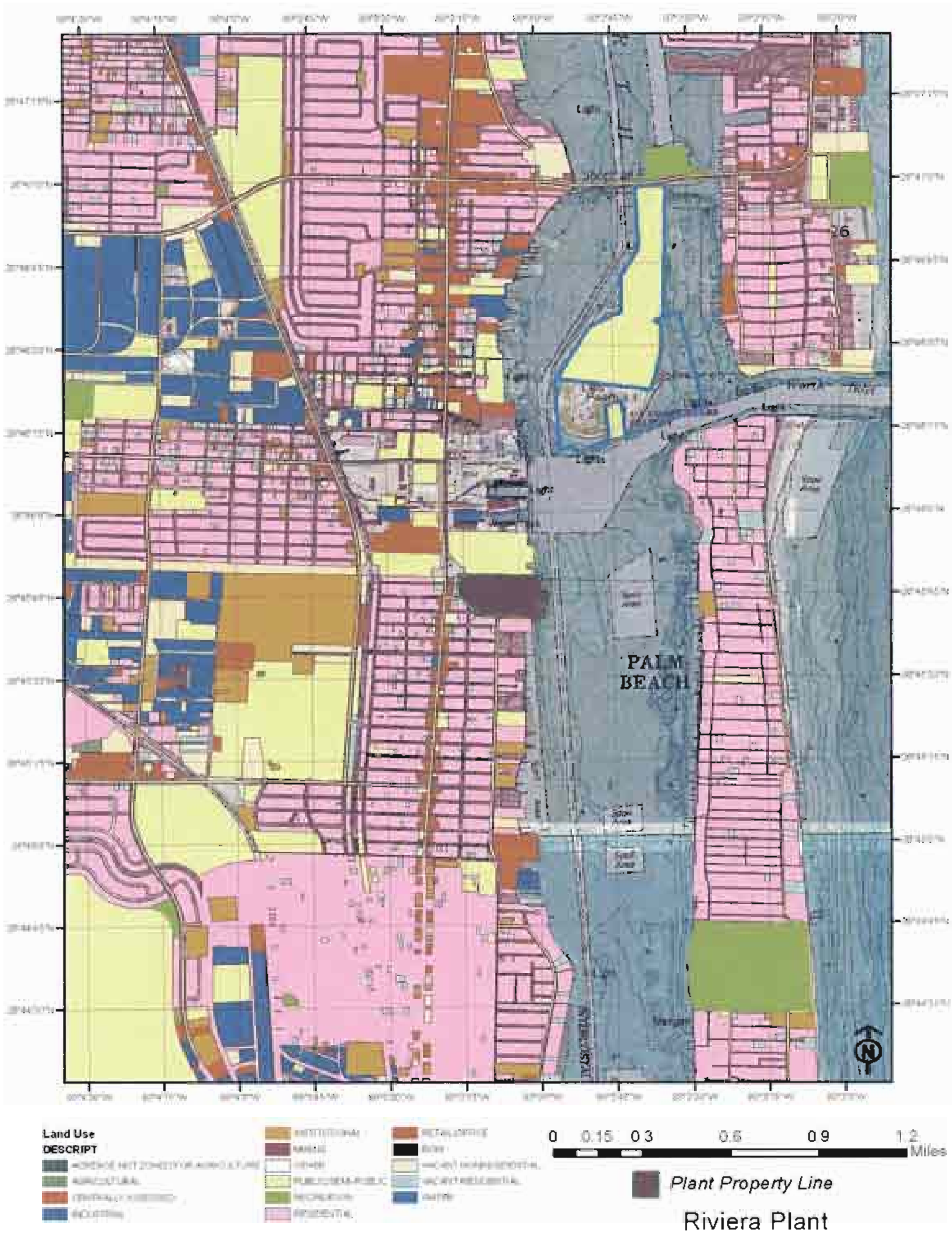
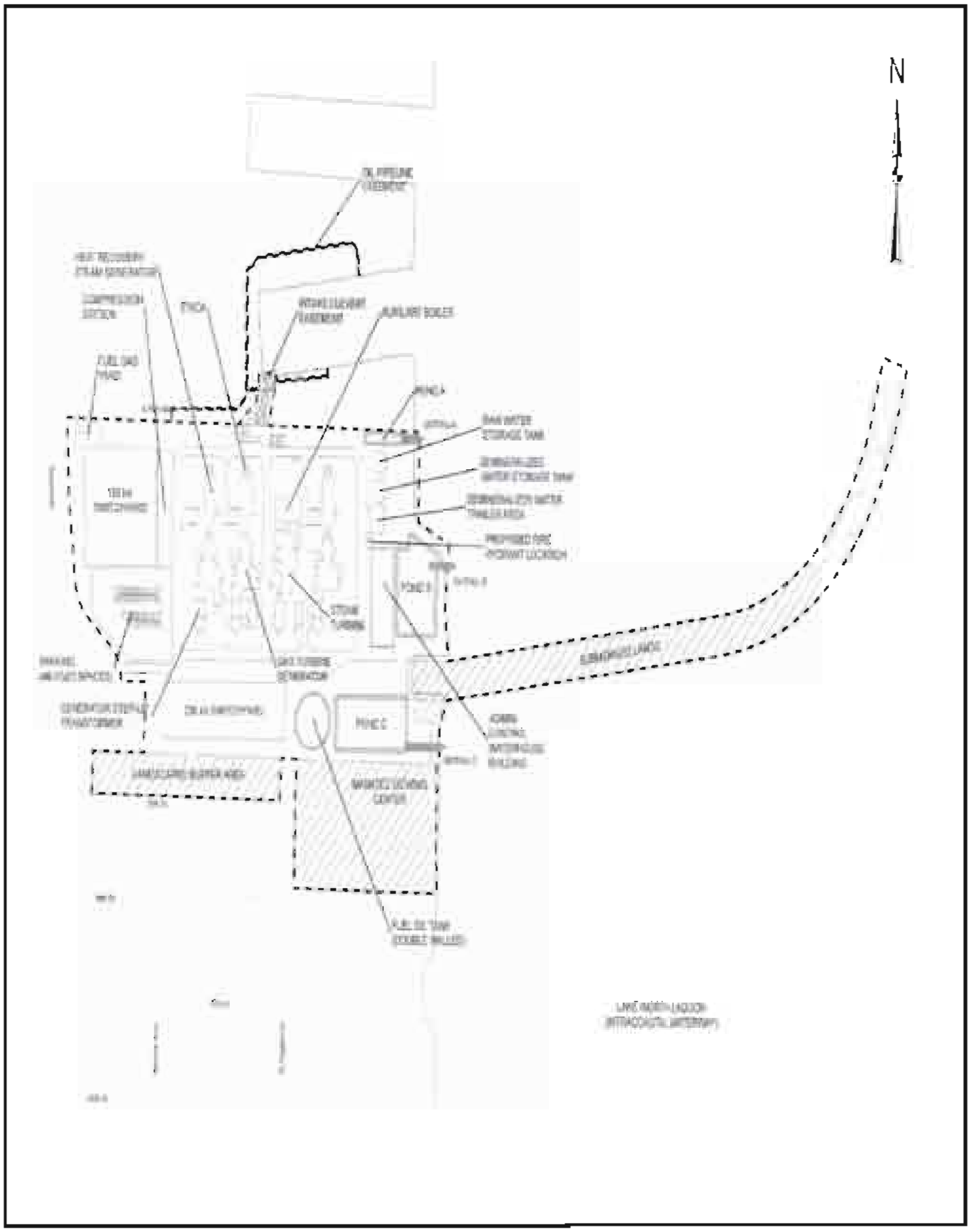
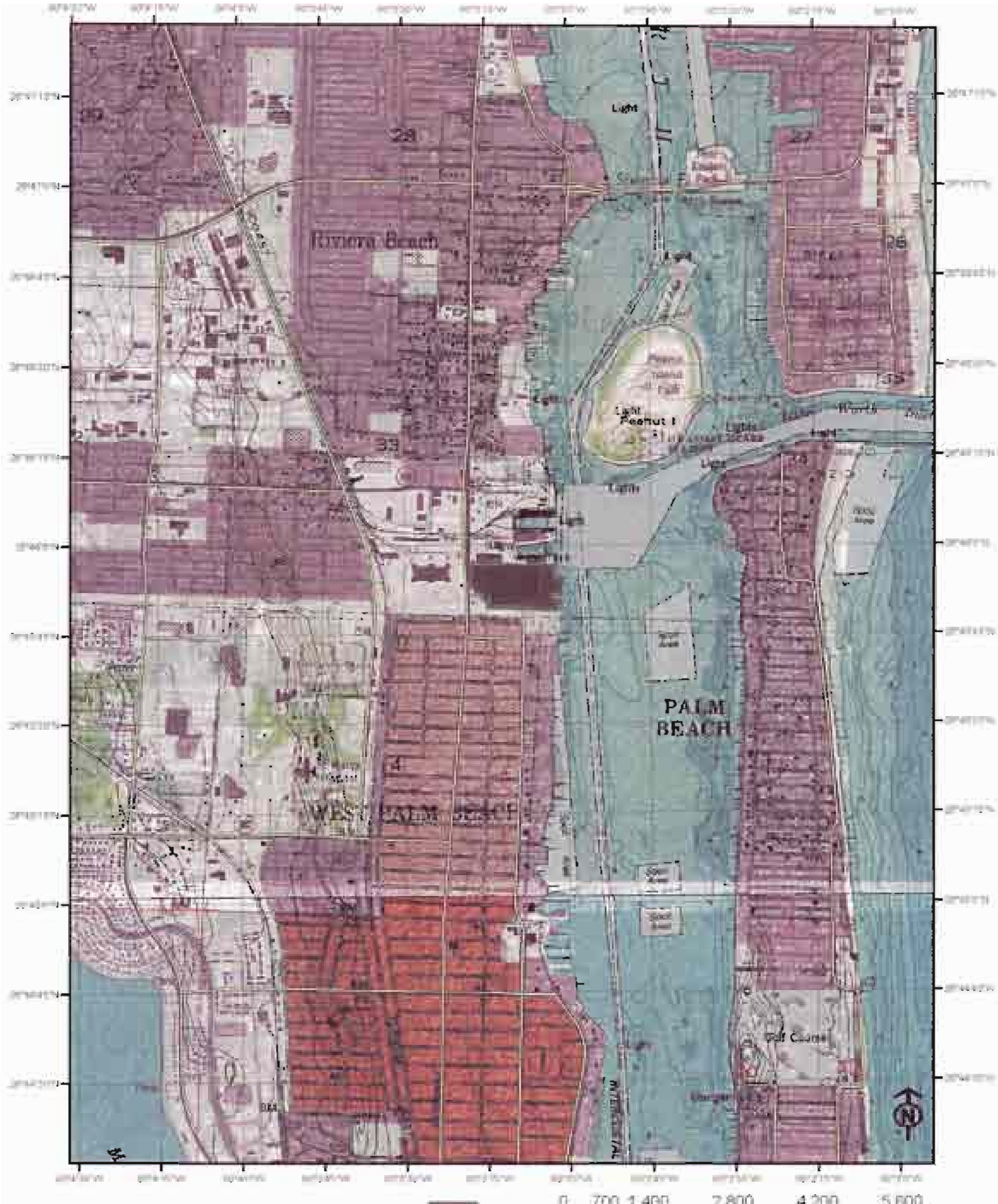


Riviera Plant



Riviera Plant Facility Layout

Florida Power & Light Co.
Riviera Plant



Riviera Plant *Plant Property Line*

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Environmental and Land Use Information: Supplemental Information

Preferred Site #6: Space Coast Next Generating Solar Energy Center

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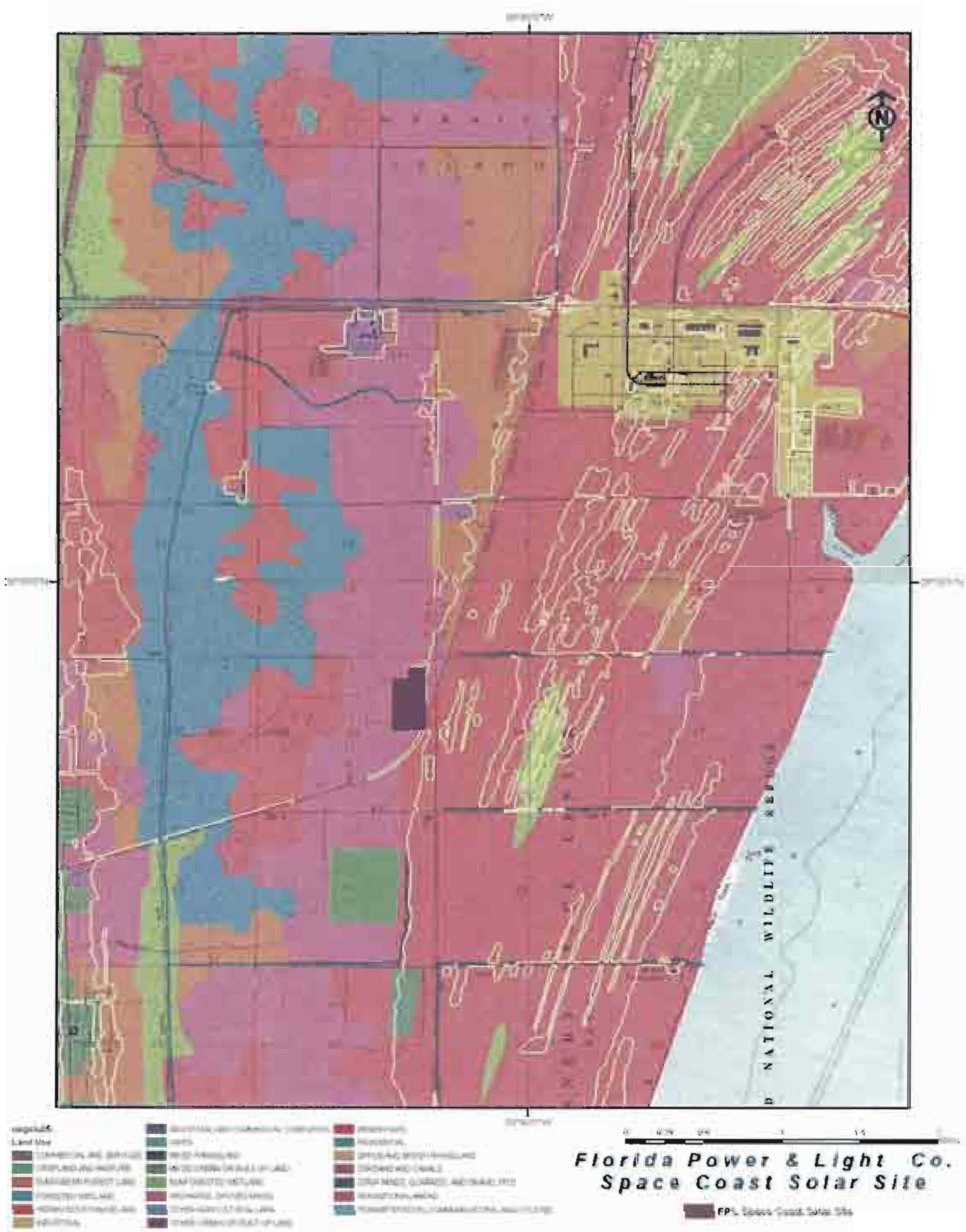
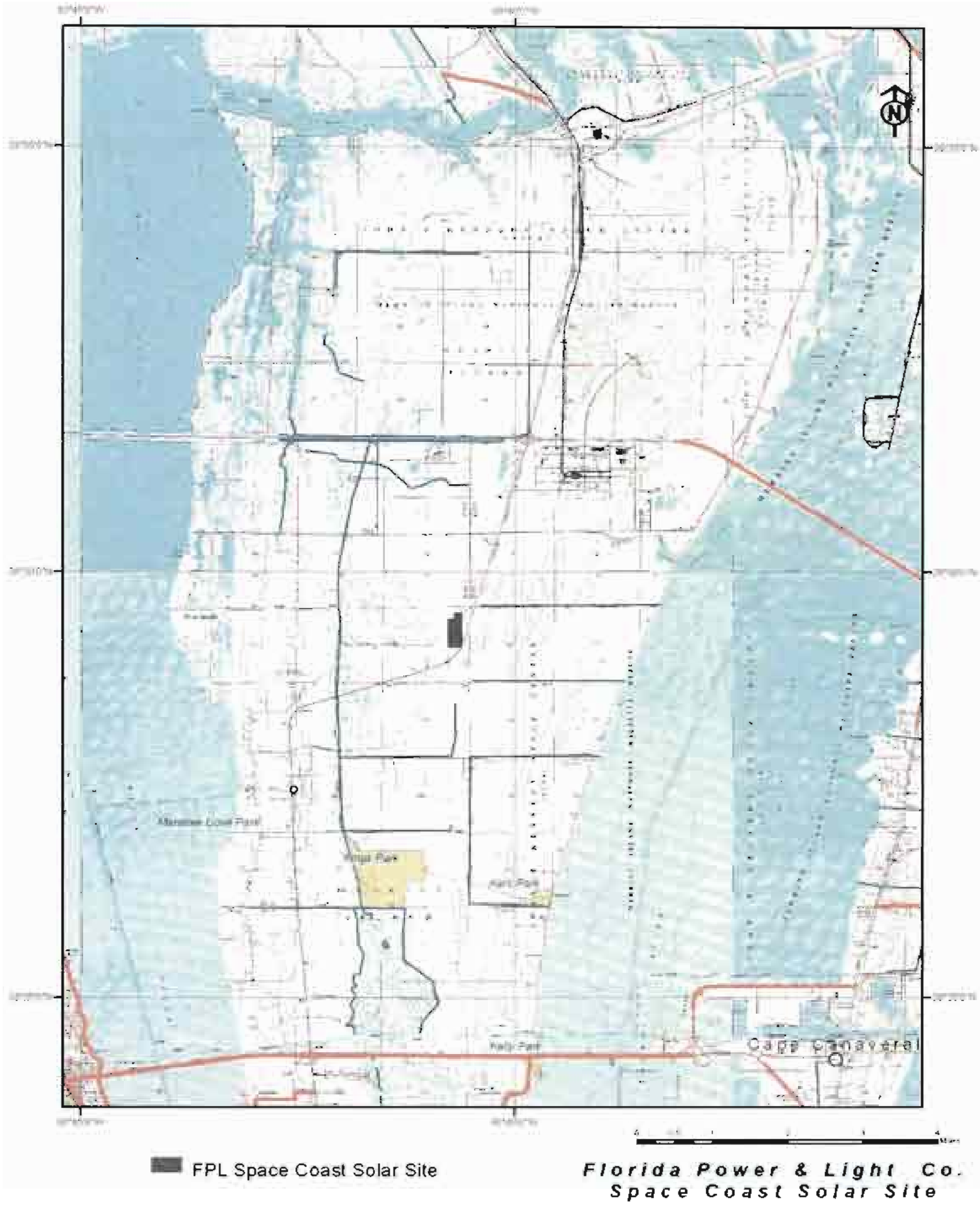
FPL Space Coast Solar Site Layout


Florida Power & Light Co.
Space Coast Solar Site


Cape Canaveral
FPL Space Coast Solar Site
Florida Power & Light Co.
Space Coast Solar Site

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Environmental and Land Use Information: Supplemental Information

Preferred Site #7: Martin Next Generation Solar Energy Center

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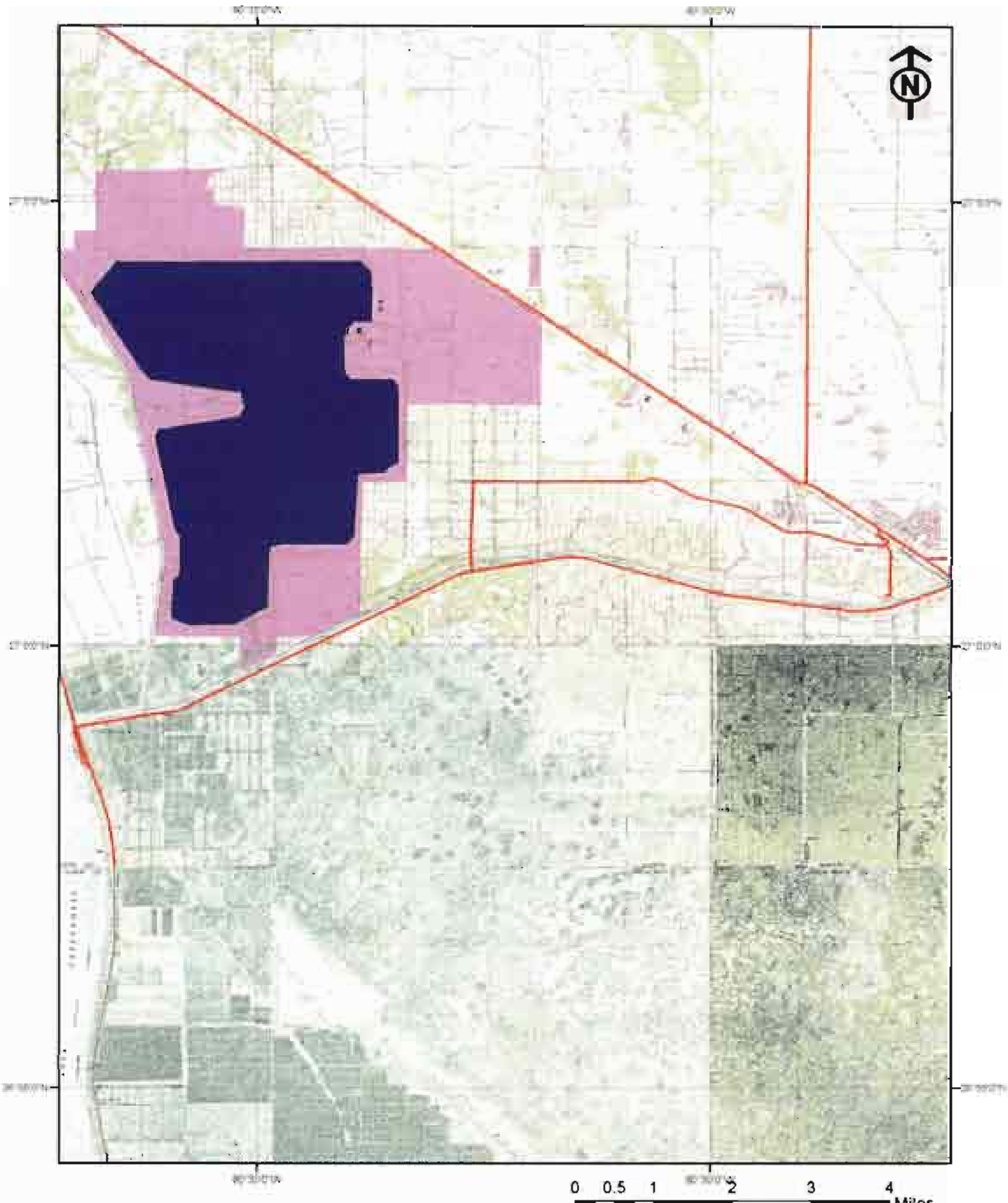
0 0.125 0.25 0.5 0.75 1
Miles

Martin Plant Facility Layout

FPL Martin Plant Site
Facility Structures
Solar Thermal Plant

Florida Power & Light Co.
Martin Plant

Florida Power & Light Co.
Martin Plant



Martin Plant USGS TOPO

Florida Power & Light Co.
Martin Plant

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Environmental and Land Use Information: Supplemental Information

Potential Site #1: Babcock Ranch

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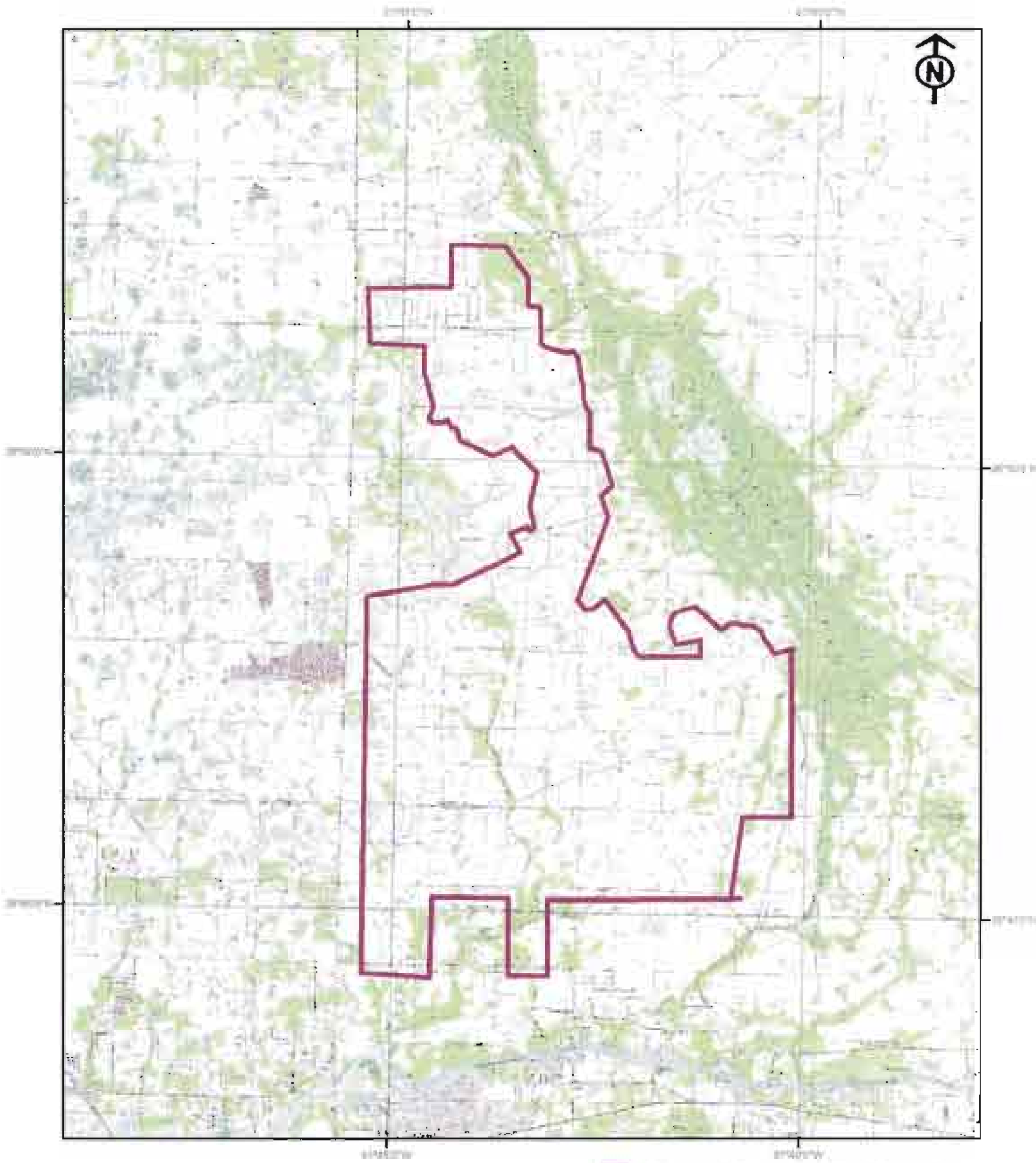
Legend
Forrest/Brush
Agriculture
Wetland
Surface Water
Other Built-Up
Transitional
Industrial
Mining
Vacant NonResidential
Commercial
Residential
Utilities/Transportation
Babcock Ranch Site Boundary
0 850 1,700 3,400 5,100 6,800
Miles
Florida Power & Light Co.
Babcock Ranch Plant Site



Florida Power & Light Co.
Babcokc Ranch Plant Site

Environmental and Land Use Information: Supplemental Information

Potential Site #2: Desoto Solar Expansion

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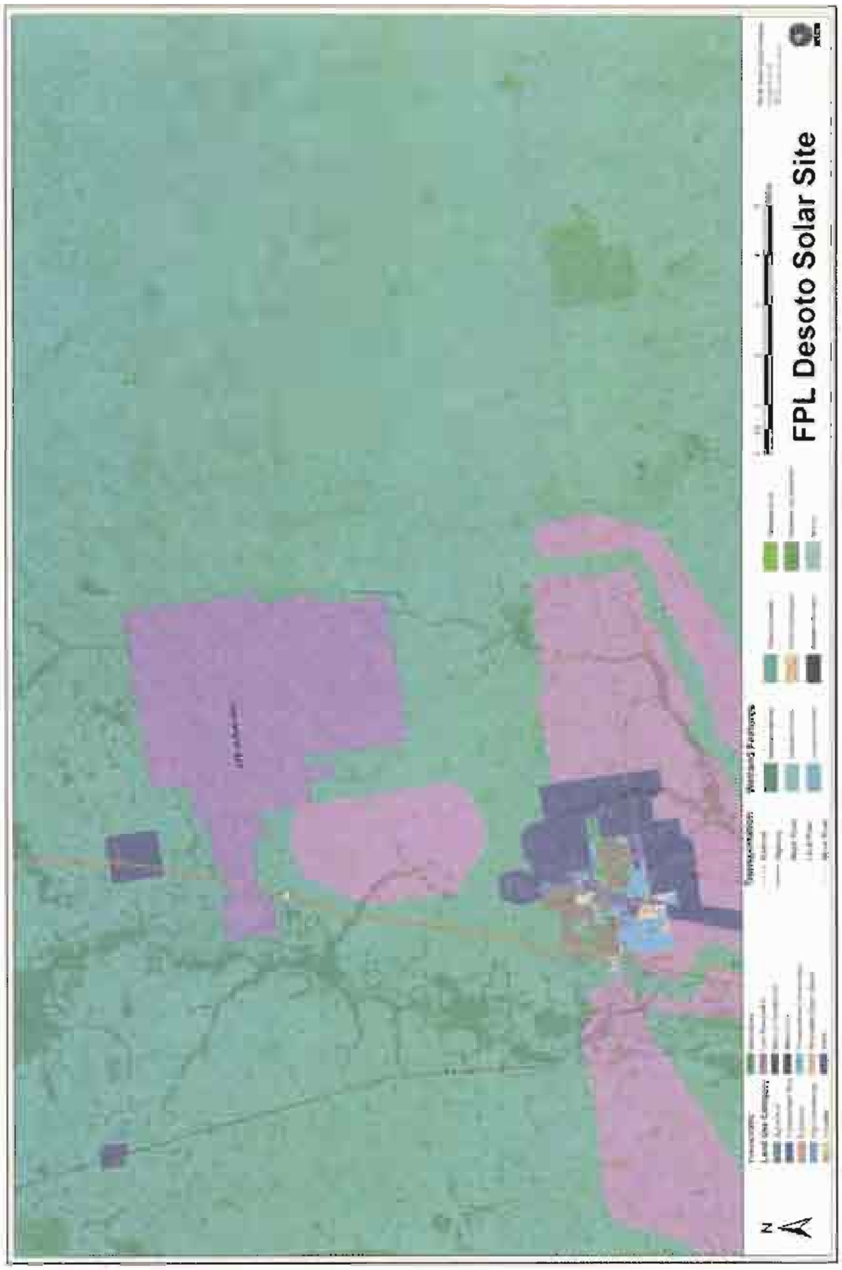
FPL Desoto Solar Site


74
27
68
FPL Desoto Site Boundary
Solar Site Layout
Florida Power & Light Co.
Desoto Solar Site Layout

Environmental and Land Use Information: Supplemental Information

Potential Site #3: Florida Heartland Solar

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Florida Heartland Solar
Glades County

Florida Power & Light Co.

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Environmental and Land Use Information: Supplemental Information

Potential Site # 4: Ft. Myers Plant

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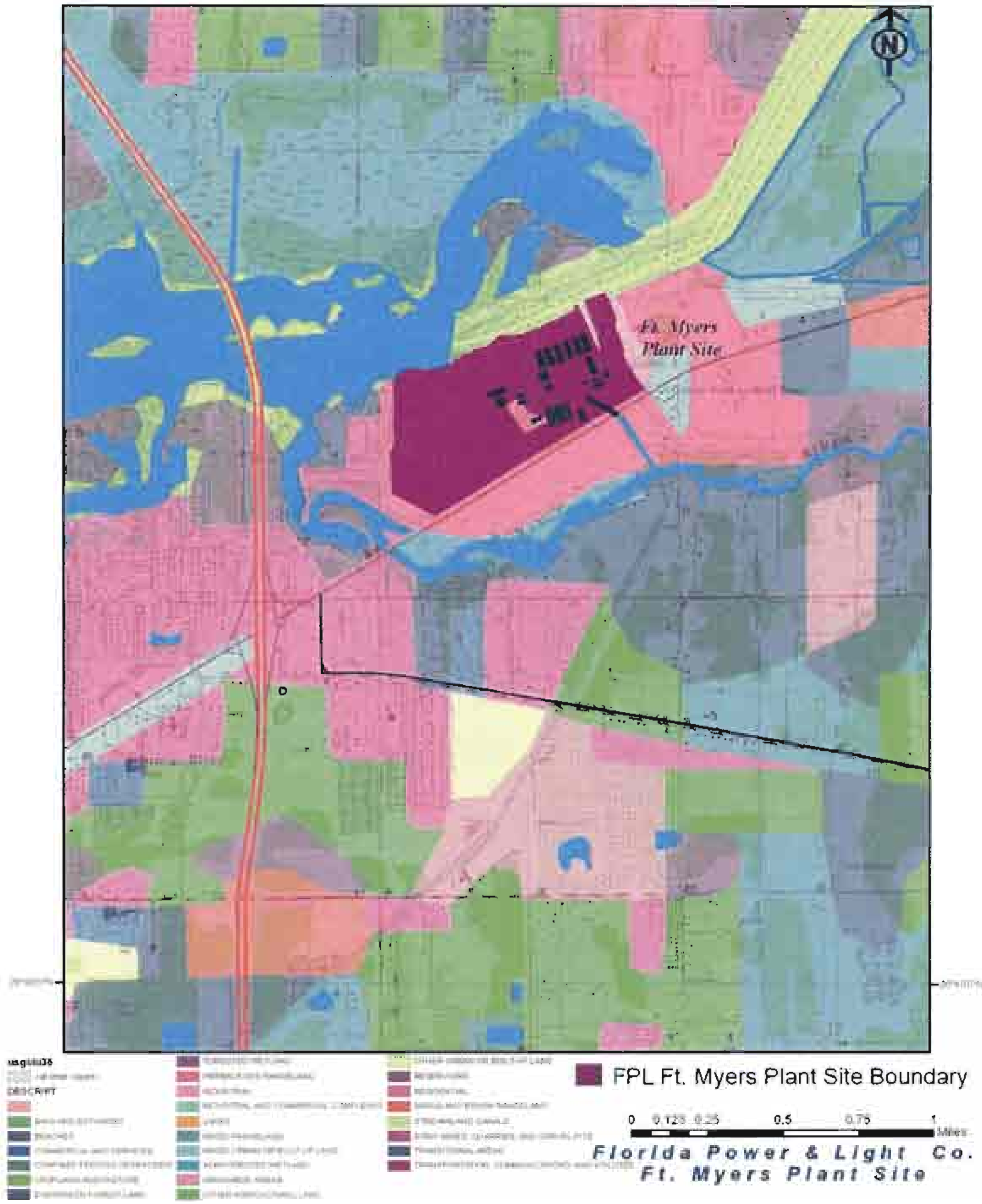
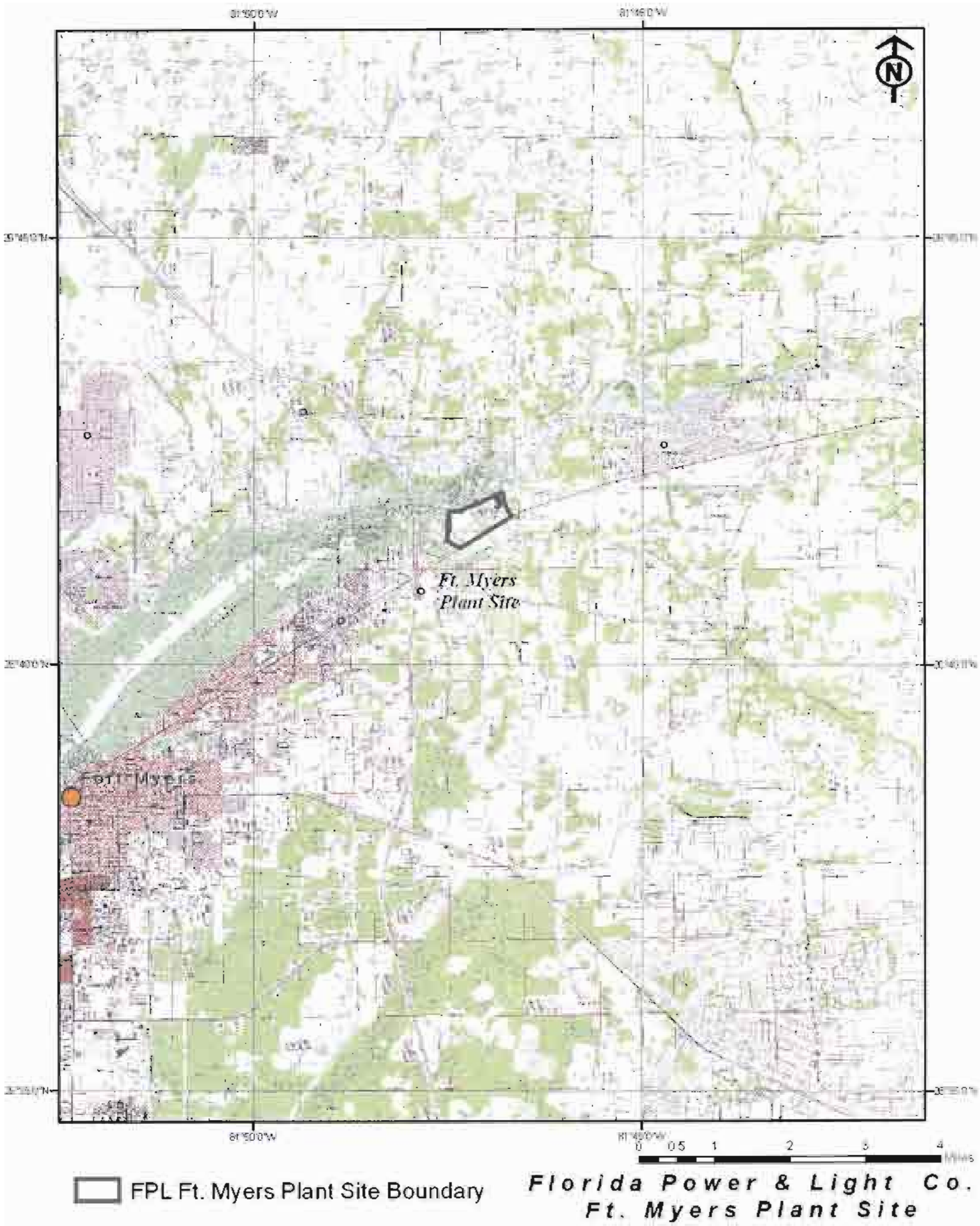

Ft. Myers
Plant Site
N
FPL Ft. Myers Plant Site Boundary
0 0.125 0.25 0.5 0.75 1
Miles
Florida Power & Light Co.
Ft. Myers Plant Site


Ft. Myers
Plant Site
Fort Myers
FPL Ft. Myers Plant Site Boundary
Florida Power & Light Co.
Ft. Myers Plant Site

Environmental and Land Use Information: Supplemental Information

Potential Site #5: Hendry County

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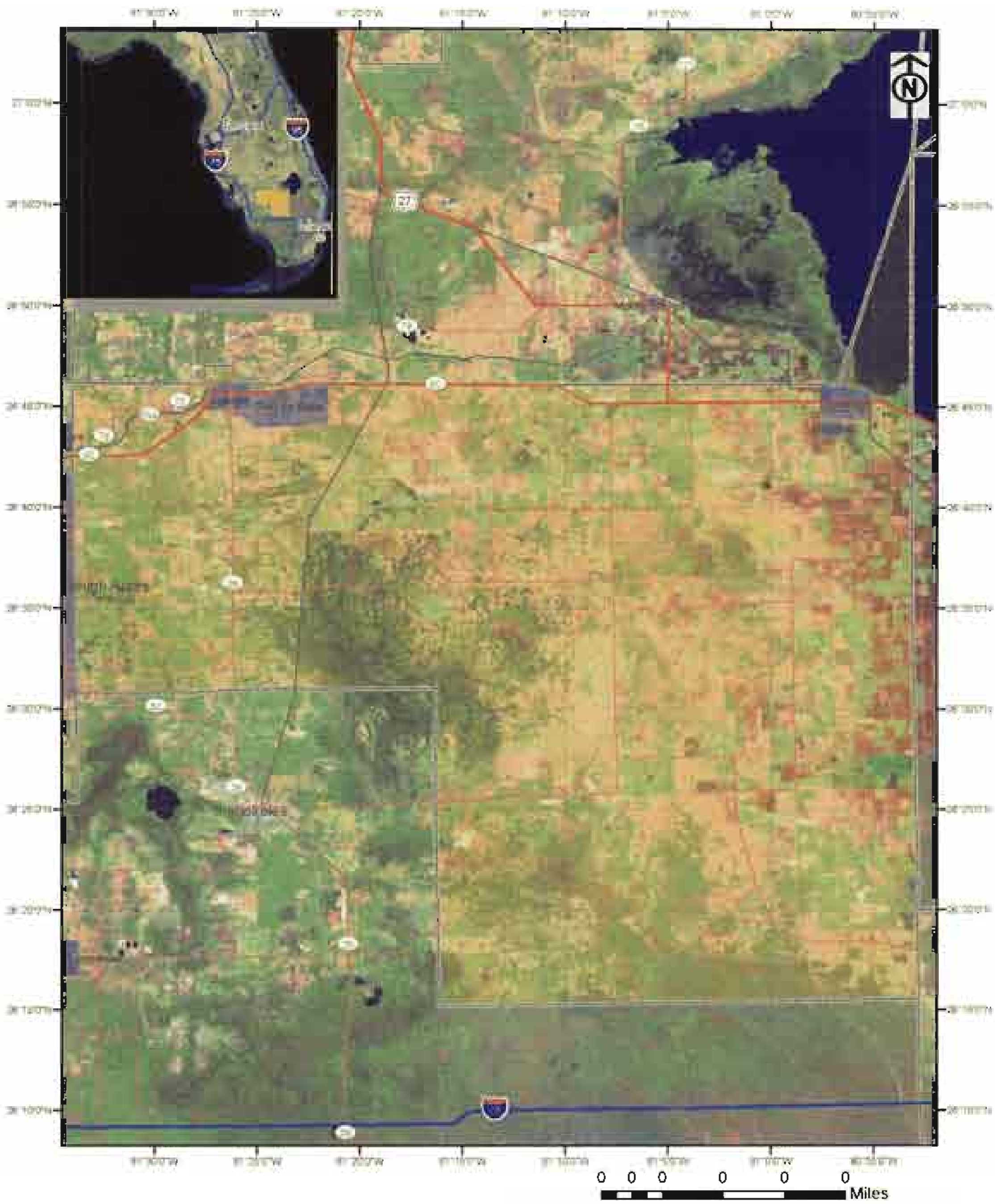

Hendry County Florida

Florida Power & Light Co.

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Environmental and Land Use Information: Supplemental Information

Potential Site #6: Lauderdale Plant

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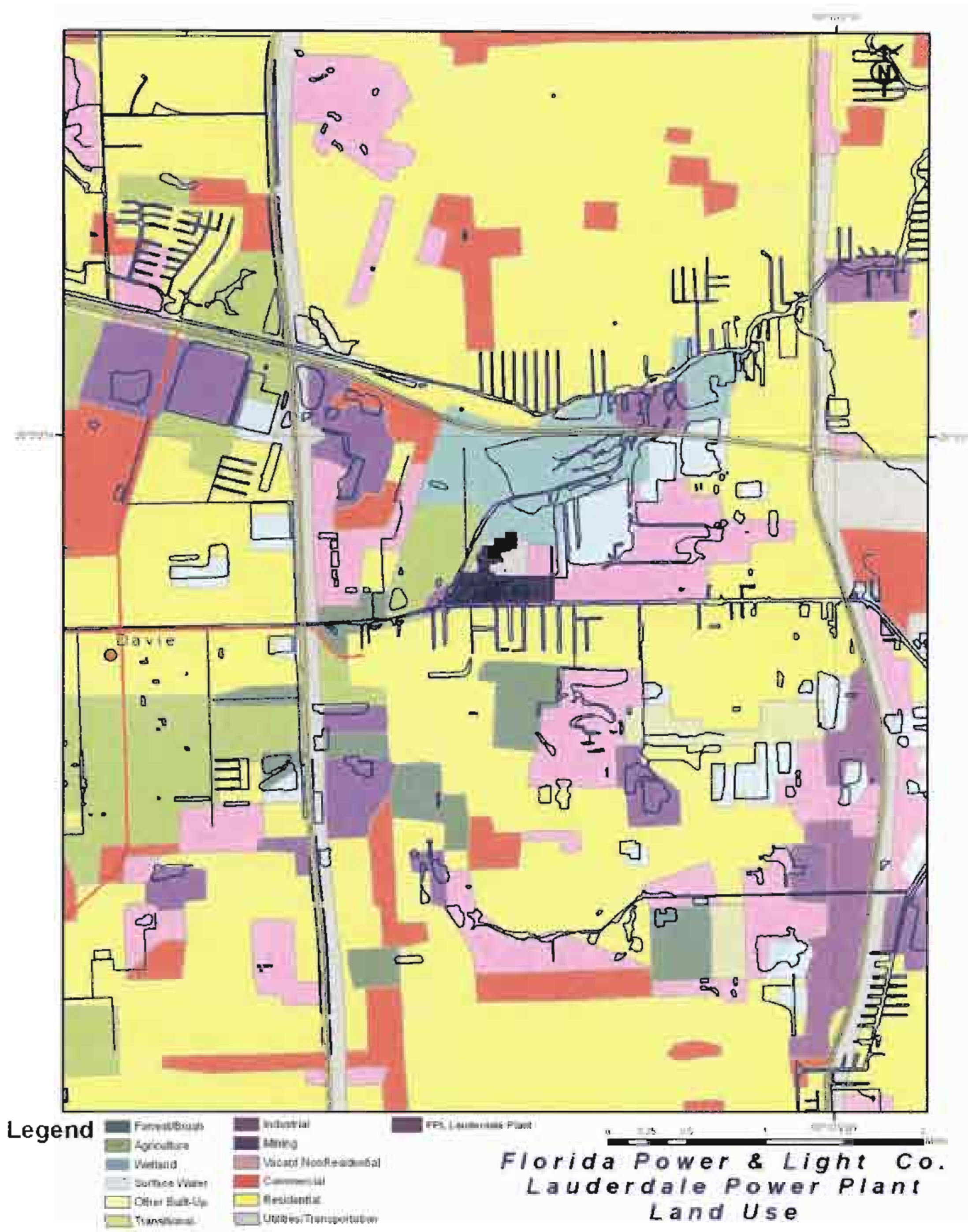
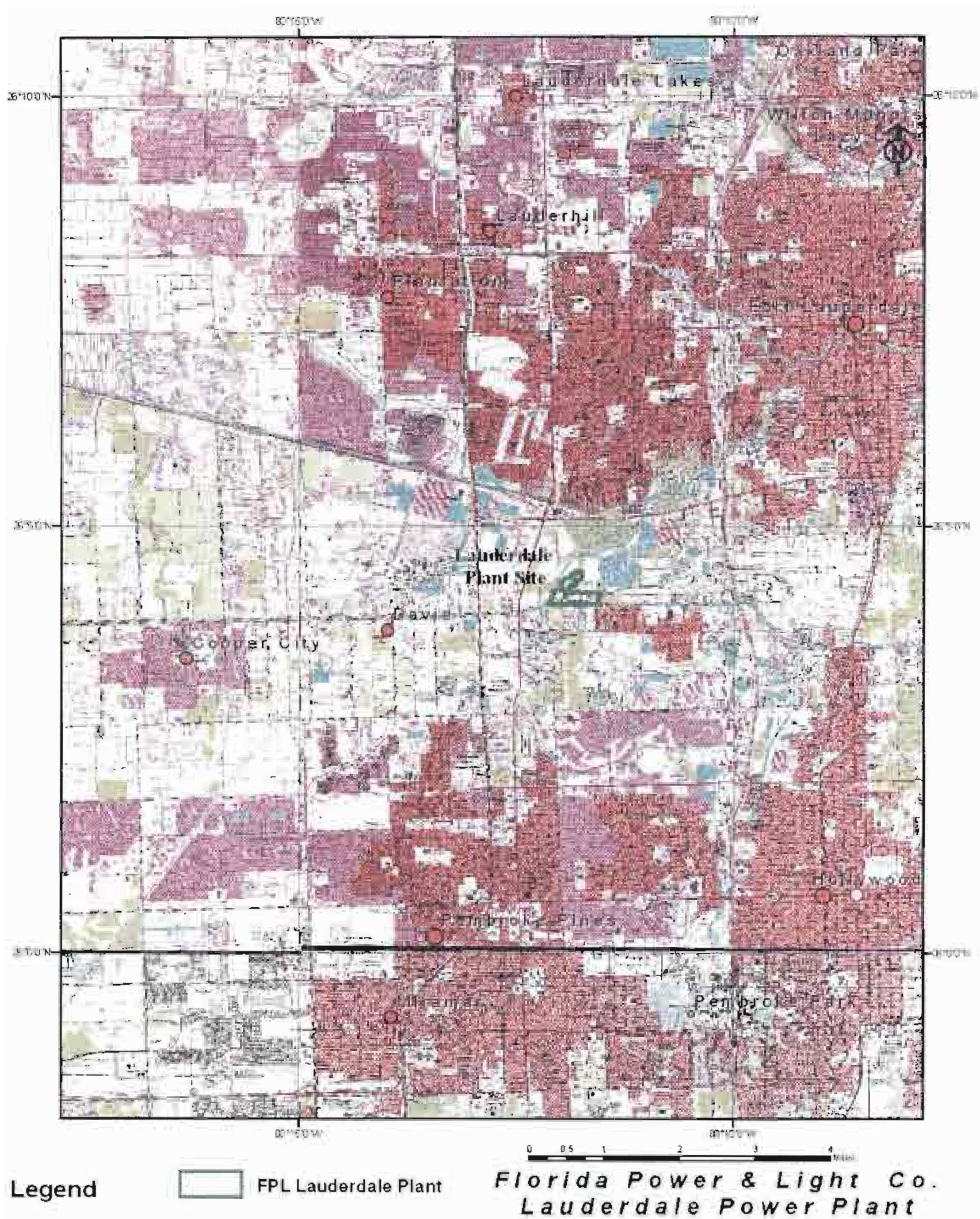

Davie
Legend
Forest/Brush
Agriculture
Wetland
Surface Water
Other Built-Up
Transitional
Industrial
Mining
Vacant NonResidential
Commercial
Residential
Utilities/Transportation
FPL Lauderdale Plant
Florida Power & Light Co.
Lauderdale Power Plant
Land Use


Lauderdale Lakes
Lauderhill
Cooper City
Davie
Lauderdale Plant Site
Pembroke Pines
Hollywood
Legend
FPL Lauderdale Plant
Florida Power & Light Co.
Lauderdale Power Plant

Environmental and Land Use Information: Supplemental Information

Potential Site #7: Manatee Plant

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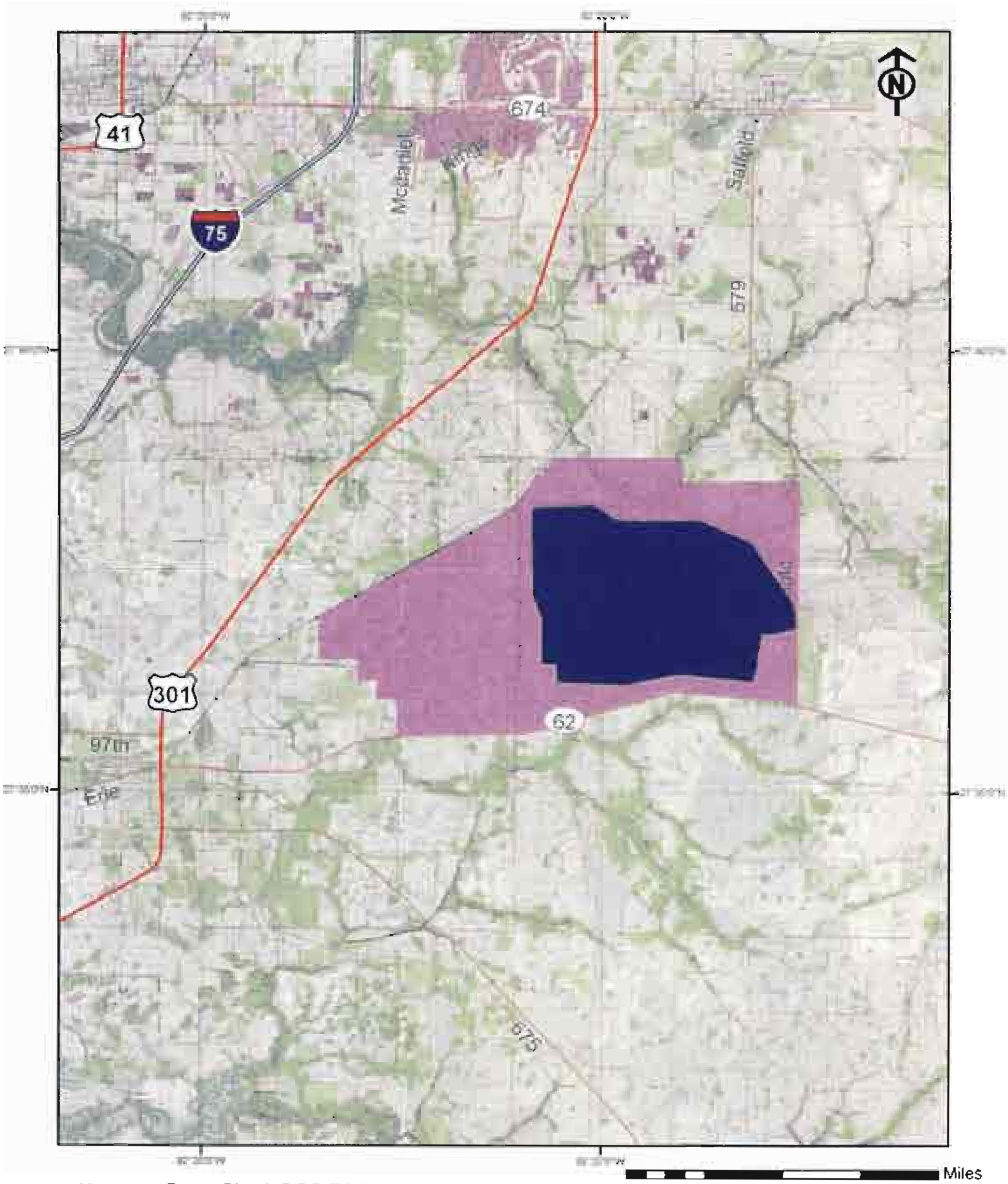
N
Legend
Forest/Brush
Agriculture
Wetland
Surface Water
Other Built-Up
Transitional
Industrial
Mining
Vacant NonResidential
Commercial
Residential
Utilities/Transportation
FPL Manatee Plant Site
Power Plant Site
Reservoir
0 0.5 1 2 3 4
Miles
Florida Power & Light Co.
Manatee Plant



Manatee Plant Site USGS TOPO

Florida Power & Light Co.
Manatee Plant

Environmental and Land Use Information: Supplemental Information

Potential Site #8: Northeast Okeechobee County

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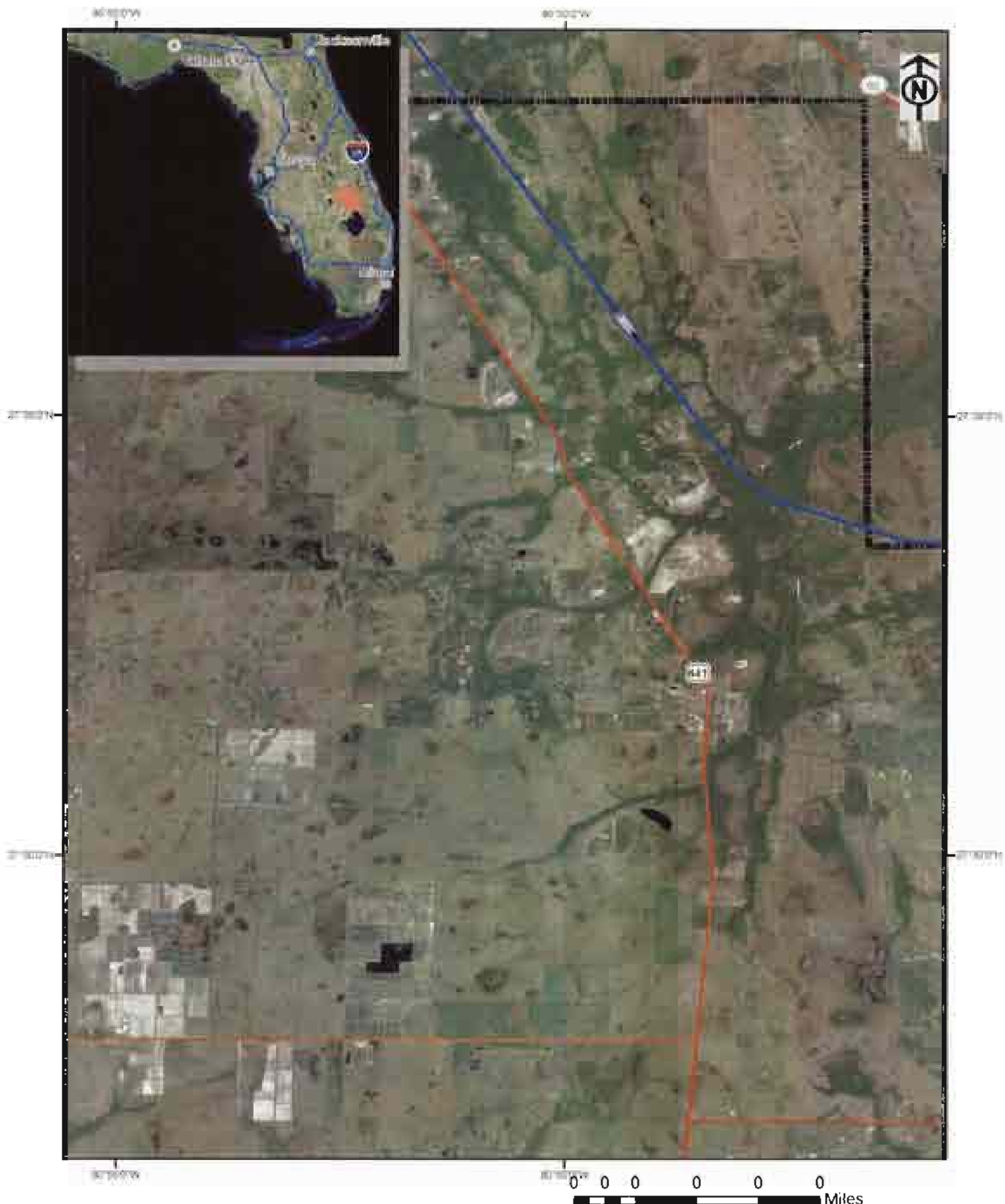

NE Okeechobee Florida

Florida Power & Light Co.

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Environmental and Land Use Information: Supplemental Information

Potential Site #9: Southwest Indian River County

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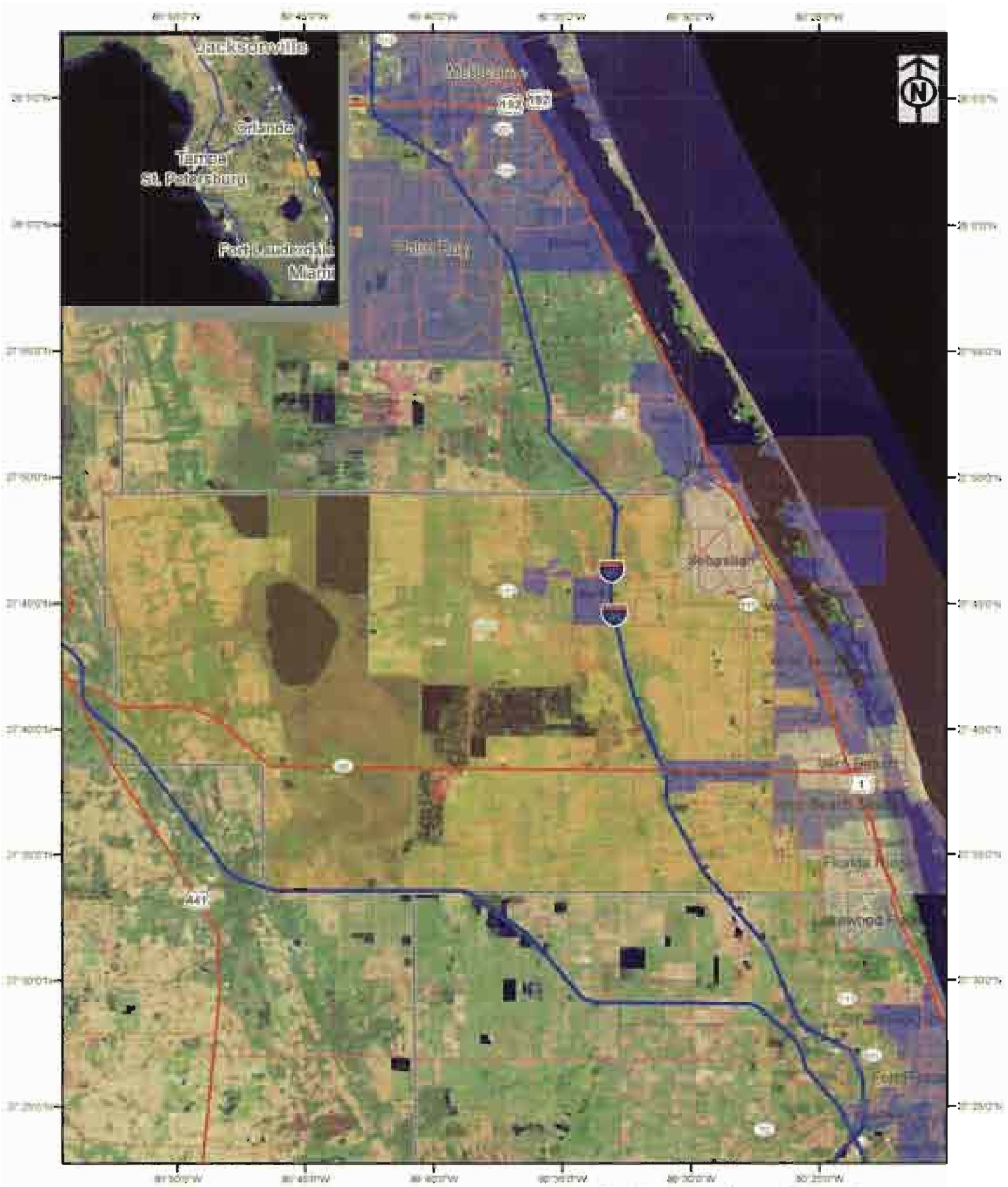

0 0 0 0 0 0 Miles

Indian River County Florida

Florida Power & Light Co.

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Environmental and Land Use Information: Supplemental Information

Potential Site #10: West Broward

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Weston
West Broward Site Area
Florida Power & Light Co.
West Broward Potential Site

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CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information". These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints: external limitations and internal limitations. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important since they affect the development of assumptions for the amount of external assistance that is available to the FPL system as well as the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In the loss of load probability (LOLP) portion of its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new units that minimize adverse impacts to the flow of electricity within FPL's system. The internal transmission limitations are also addressed by developing the direct costs for siting new units at different locations and by evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system.

Both of these site- and system-related transmission costs are developed for each different unit/unit location option or groups of options. In addition, transfer limits for capacity and energy that can be imported into the Southeastern region of FPL's system are also developed for use in FPL's production costing analyses. (A further discussion of the Southeastern Florida region and the need to maintain a regional balance between generation and transmission contributions is found in Chapter III.)

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's planned transmission facilities to interconnect and integrate FPL's resource plans and those that must be certified under the Transmission Line Siting Act are presented in Chapter III.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements for the FPL system.[4]

The load forecast that is presented in FPL's 2010 Site Plan was developed in February 2010. FPL has not performed sensitivity analyses on forecasts that differ from this recently developed load forecast.

[4] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis (i.e., when only new generating options are considered), the lowest rate basis and the lowest system revenue requirements basis are identical. In such cases FPL evaluates options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its fuel price forecasts are discussed in Chapter III of this document. FPL used three fuel and four environmental compliance cost forecasts in the 2009 nuclear cost recovery filings. FPL utilized one of these fuel cost forecasts, and one of these environmental compliance cost forecasts in its DSM Goals analyses.

The resource plan presented in this Site Plan is based, in part, on those prior analyses. For that reason, this resource plan, with the recently developed February 2010 load forecast, has not been further tested for different fuel cost forecasts.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item # 3, FPL used up to three fuel cost forecasts in its 2009 resource planning analyses. While these forecasts did not represent a constant cost differential between oil/gas and coal, a variety of fuel cost differentials were represented in these forecasts.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 in Chapter I, and Schedule 8 in Chapter III, present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options in its resource planning work. A summary of this information for the new capacity options FPL projects to add over the planning horizon is presented on the Schedule 9 forms in Chapter III.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

In its 2009 resource planning work, FPL used the following financial assumptions: (i) a capital structure of 44.2% debt and 55.8% equity; (ii) a 7.03% cost of debt; (iii) a 12.5% return on equity; and (iv) an after-tax discount rate of 8.89%. In this work, FPL performed no sensitivity analyses that used varying financial assumptions.

In its new resource planning analysis work in 2010, financial assumptions such as these will change due to the outcome of FPL's recent base rate case.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item # 2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective are identical when DSM levels are unchanged between competing plans. Therefore, in planning work in which DSM levels were unchanged, the equivalent cumulative present value of revenue requirements perspective was utilized.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses two system reliability criteria in its resource planning work that addresses generation, purchase, and DSM options. One of these is a minimum 20% Summer and Winter reserve margin. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability analysis work, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the Reliability Standards established by the North American Electric Reliability Council (NERC). The *NERC Reliability Standards* are available on the internet site (http://www.nerc.com/).

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Facility Rating Methodology* document that are also available on the internet under the FPL OATT Documents directory at https://www.oatioasis.com/FPL/index.html.

Generally, FPL limits its transmission facilities to 100% of the applicable thermal rating. The normal and contingency voltage criteria for FPL stations are provided below:

	Normal/Contingency	
Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09
Turkey Point (*)	1.01/1.01	1.06/1.06
St. Lucie (*)	1.00/1.00	1.06/1.06

(*) Voltage range criteria for FPL's Nuclear Power Plants

There may be isolated cases for which FPL may have determined that it is acceptable to deviate from the general criteria stated above. There are several factors that could influence this criteria, such as the overall number of potential customers that may be impacted, the probability of an outage actually occurring, or transmission system performance, as well as others.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The impact of FPL's DSM programs on demand and energy consumption is revised periodically. Engineering models, calibrated with field-metered data, are updated when significant efficiency changes occur in the marketplace. Participation trends are tracked for all of the FPL DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants.

Survey data is collected from non-participants in order to establish the baseline efficiency. Participant data is compared against non-participant data to establish the demand and energy saving benefits of the utility program versus what would be installed in the absence of the program. For these DSM measures which involve the utilization of load management, FPL conducts periodic tests of the load control equipment to ensure that it is functioning correctly.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The Executive Summary chapter provides a discussion of two system concerns that are typically addressed in FPL's resource planning work: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida. In addition, two other relatively recent items will also influence FPL's resource planning efforts. One of these items is the Executive Orders directive issued in 2007 by Governor Crist calling for reduction in greenhouse gas emissions and greater contribution from renewable energy sources. As previously discussed in both the Executive Summary chapter and Chapter III, FPL's resource planning has already taken positive steps in regard to both of these issues. The other item that could affect FPL's resource planning is the possibility of the establishment of a Florida standard for renewable energy, or clean energy, contributions to a utility system. A Renewable Portfolio Standard (RPS) proposal was prepared by the FPSC, and then sent to the Florida Legislature for consideration, with a possible change to a Clean Portfolio Standard (CPS), during the 2009 legislative session. However, no RPS or CPS legislation was enacted during the 2009 legislative session. RPS or CPS legislation, or other legislative initiatives regarding renewable or clean energy contributions, may occur in the future. If such legislation is enacted in 2010 or later years, FPL will then determine what steps need to be taken to address the legislation. Such steps would then be discussed in FPL's Site Plan in the year following the enactment of such legislation.

In addition to these system concerns/issues, there are other strategic factors FPL typically considers when choosing between resource options. These include the following: (1) technology risk; (2) environmental risk, and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology, which has not achieved general commercial acceptance, has a higher risk than a technology in wide use and, therefore, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the FPL system, including environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for a plan are those which minimize environmental impacts for the FPL system as a whole through highly efficient fuel use and state of the art controls.

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decisions, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As has been previously discussed in prior FPL Site Plans, elements of FPL's recent and future capacity additions include the construction of new generating capacity at the West County Energy Center (WCEC) site, WCEC Units 1, 2, & 3. These generation construction projects were selected after evaluating competing bids received in response to Requests for Proposals (RFP) issued by FPL. The FPSC subsequently approved FPL's decision to construct these new combined cycle (CC) units in Determination of Need dockets.

In regard to the Modernization projects at FPL's existing Cape Canaveral and Riviera plants, these projects were also evaluated using the competing bids received in response to the RFP issued for WCEC Unit 3. In addition, bids from competing vendors were also evaluated for FPL's new solar thermal and PV projects.

The nuclear capacity additions, both the nuclear uprates and the new nuclear units, do not lend themselves to an RFP approach involving bids from third parties who would build new nuclear generation capacity. In addition, nuclear capacity additions are exempted from the Commission's Bid Rule by section 403.519 (4) (c). For these nuclear projects, FPL's procurement activities were conducted to ensure the best combination of quality and cost for the delivered products.

Construction capacity addition decisions for non-nuclear generation for years beyond those presented in this document are expected to be conducted in a manner consistent with the Commission's Bid Rule.

Identification of self-build options, beyond those units already approved by the FPSC and Governor and Siting Board or units for which FPL may be then seeking approval, in future FPL Site Plans will not be an indication that FPL has pre-judged any capacity solicitation it may conduct. The identification of future generating units is required of FPL in its Site Plan filings and represents those alternatives that appear to be FPL's best, most cost-effective self-build options at the time. FPL reserves the right to refine its planning analyses and to identify other self-build options. Such refined analyses have the potential to yield a variety of self-build options, some of which might not require an RFP. If an RFP is issued for Supply options, FPL reserves the right to choose the best alternative for its customers, even if that option is not an FPL self-build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

(1) FPL has identified the need for a new 230kV transmission line that required certification under the Transmission Line Siting Act which was issued in April 2006. The new line is to be completed in two phases connecting FPL's St. Johns Substation to FPL's Pringle Substation (also shown on Table III.E.1 in Chapter III). Phase 1 was completed in May 2009 and consisted of a new line connecting Pringle

to a new Pellicer Substation. Phase 2 is planned to connect St. Johns to Pellicer and is scheduled to be complete by December 2013. The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

(2) FPL has identified the need for a new 230kV transmission line (by December 2012) that required certification under the Transmission Line Siting Act which was issued on November 2008. The new line will connect FPL's Manatee Substation to FPL's proposed BobWhite Substation (also shown on Table III.E.1 in Chapter III). The construction of this line is necessary to serve existing and future customers in the Manatee and Sarasota areas in a reliable and effective manner.

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FPL.

Jessica Cano
Principal Attorney
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(561) 691-7135 (Facsimile)

October 19, 2010

VIA OVERNIGHT DELIVERY
Ms. Ann Cole
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

Re: Docket No. 100000; Corrections to FPL's Ten Year Power Plant Site Plan

Dear Ms. Cole:

Please find enclosed an original and 25 copies of three replacement pages for FPL's 2010-2019 Ten Year Power Plant Site Plan, originally filed on April 1, 2010, reflecting corrected information. Revisions are in bold, red font.

Specifically, pages 45, 46, and 47 are being replaced and contain the following corrections:

- Page 45 – Schedule 3.1: Residential Load Management and Conservation and C/I Load Management and Conservation values for years 2010 – 2019 were corrected and the footnote for Cols (5) – (9) was revised.
- Page 46 – Schedule 3. 2: Residential Load Management and Conservation and C/I Load Management and Conservation values for years 2010 – 2019 were corrected and the footnote for Cols (5) – (9) was revised.
- Page 47 – Schedule 3.3: Historical Actual Total Billed Retail Energy Sales (GWh) and the Load Factor (%) for 2009 were corrected; Residential Conservation and C/I Conservation GWh values for years 2010 – 2019 were corrected; and the footnote for Projected Values Cols (3) and (4) was revised.

Please contact me if you or your Staff have any questions regarding this filing.

Sincerely,

Jessica Cano

Jessica Cano

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CLK Dorothy cc: Katherine Fleming
(2)

Rev: 09-30-10

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
August of Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2000	17,808	161	17,647	0	719	645	467	451	16,622
2001	18,754	169	18,585	0	737	697	488	481	17,529
2002	19,219	261	18,958	0	770	755	489	517	17,960
2003	19,668	253	19,415	0	781	799	577	554	18,310
2004	20,545	258	20,287	0	783	847	588	578	19,174
2005	22,361	264	22,097	0	790	895	600	611	20,971
2006	21,819	256	21,563	0	809	948	635	640	20,375
2007	21,962	261	21,701	0	954	982	715	683	20,293
2008	21,060	181	20,879	0	974	1035	735	708	19,351
2009	22,351	212	22,139	0	985	1084	793	734	20,573
2010	21,922	381	21,541	0	1,030	130	866	93	19,804
2011	21,788	386	21,402	0	1,043	200	886	120	19,539
2012	22,139	391	21,748	0	1,059	284	910	154	19,731
2013	22,332	352	21,980	0	1,077	377	938	191	19,749
2014	23,575	1,178	22,397	0	1,095	474	966	230	20,810
2015	23,924	1,200	22,724	0	1,113	568	993	268	20,983
2016	24,344	1,225	23,119	0	1,129	653	1,018	302	21,242
2017	24,774	1,253	23,521	0	1,144	731	1,040	333	21,526
2018	25,328	1,283	24,045	0	1,158	801	1,061	361	21,948
2019	25,785	1,314	24,470	0	1,170	866	1,080	387	22,282

Historical Values (2000 - 2009):

Col. (2) - Col. (4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) for 2000 through 2009 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values **except for 2009 values which are August values.**
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC), CILC and Commercial /Industrial Demand Reduction (CDR).

Col. (11) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (11) is derived by the formula:Col. (10) = Col.(2) - Col.(6) - Col.(8).

Projected Values (2010 - 2019):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation, cumulative load management, or **incremental load management.**

Col. (5) - Col. (9) represent **cumulative** load management, and incremental **conservation and** load management. **All** values are projected August values. **The 2010 values are based on IRP projections through the end of 2009 and FPL's new DSM Goals for 2010. In the projections for 2011 through 2019, FPL used cumulative values from the new DSM Goals with estimated breakouts into the residential, C/I, load management, and conservation categories.**

Col (8) represents FPL's Business On Call, CDR,CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

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Rev: 09-30-10

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1) January of Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2000	17,057	142	16,915	0	741	434	438	176	15,878
2001	18,199	150	18,049	0	791	459	448	183	16,960
2002	17,597	145	17,452	0	811	500	457	196	16,329
2003	20,190	246	19,944	0	847	546	453	206	18,890
2004	14,752	211	14,541	0	857	570	532	230	13,363
2005	18,108	225	17,883	0	862	583	542	233	16,704
2006	19,683	225	19,458	0	870	600	550	240	18,263
2007	16,815	223	16,592	0	894	620	577	249	15,344
2008	18,055	163	17,892	0	879	644	635	279	16,541
2009	20,081	162	19,919	0	951	678	764	295	18,366
2010	20,550	376	20,174	0	937	72	767	41	18,733
2011	20,647	381	20,266	0	943	87	774	55	18,788
2012	20,861	386	20,475	0	949	107	783	72	18,949
2013	21,138	392	20,746	0	957	131	793	93	19,163
2014	22,152	1,060	21,092	0	966	157	805	116	20,108
2015	22,745	1,284	21,461	0	975	185	817	141	20,627
2016	23,118	1,311	21,807	0	984	212	829	164	20,929
2017	23,488	1,341	22,147	0	993	237	840	186	21,232
2018	23,889	1,374	22,514	0	1,000	260	850	206	21,573
2019	24,293	1,409	22,884	0	1,007	281	859	225	21,921

Historical Values (2000 - 2009):

Col. (2) - Col. (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) for 2000 through 2009 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC), CILC and Commercial /Industrial Demand Reduction (CDR).

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (11) is derived by the formula:Col. (10) = Col.(2) - Col.(6) - Col.(8) - Col.(9).

Projected Values (2010 - 2019):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2010 are incorporated into the load forecast.

Col. (5) - Col. (9) represent **cumulative** load management, and incremental **conservation and** load management. **All** values are projected August values. **The 2010 values are based on IRP projections through the end of 2009 and FPL's new DSM Goals for 2010. In the projections for 2011 through 2019, FPL used cumulative values from the new DSM Goals with estimated breakouts into the residential, C/I, load management, and conservation categories.**

Col (8) represents FPL's Business On Call, CDR,CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Rev: 9-30-10

Schedule 3.3
History of Annual Net Energy for Load - GWh: Base Case
(All values are "at the generator" values except for Col (8))

(1) Year	(2) = (5) + (3) + (4) Total Net Energy For Load without DSM	(3) Residential Conservation	(4) C/I Conservation	(5) **Actual** Net Energy For Load	(6) Sales for Resale GWh	(7) Utility Use & Losses	(8) = (5) - (6) - (7) **Actual** Total Billed Retail Energy Sales (GWh)	(9) Load Factor(%)
2000	99,097	1,674	1,434	95,989	970	7,059	87,959	61.4%
2001	101,739	1,789	1,545	98,404	970	7,222	90,212	59.9%
2002	107,755	1,917	1,639	104,199	1,233	7,443	95,523	61.9%
2003	112,160	2,008	1,759	108,393	1,511	7,386	99,496	62.9%
2004	112,034	2,106	1,834	108,093	1,531	7,467	99,095	59.9%
2005	115,440	2,205	1,934	111,301	1,506	7,498	102,296	56.8%
2006	117,490	2,312	2,041	113,137	1,569	7,909	103,659	59.2%
2007	118,894	2,373	2,206	114,315	1,499	7,401	105,415	59.4%
2008	115,755	2,485	2,267	111,004	993	7,092	102,919	60.0%
2009	116,221	2,581	2,336	111,304	1,155	7,394	102,755	56.8%

Historical Values (2000 - 2009):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5).

Col.(3) & Col.(4) for 2000 through 2009 are DSM values starting in January 1988 and are annual (12-month) values. Col. (3) and Col. (4) for 2009 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWh reductions actually experienced each year .

Col. (5) is the **actual** Net Energy for Load (NEL) for years 2000 - 2009.

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (5)*1000) / ((Col.(2) * 8760) Adjustments are made for leap years.

Forecast of Annual Net Energy for Load - GWh: Base Case
(All values are "at the generator"values except for Col (8))

(1) Year	(2) **Forecasted** Net Energy For Load without DSM	(3) Residential Conservation	(4) C/I Conservation	(5) = (2) - (3) - (4) Net Energy For Load Adjusted for DSM	(6) Sales for Resale GWh	(7) Utility Use & Losses	(8) = (2) - (6) - (7) **Forecasted** Total Billed Retail Energy Sales (GWh) without DSM	(9) Load Factor(%)
2010	109,886	61	41	109,784	2,046	7,172	100,668	57.2%
2011	111,634	211	141	111,282	2,145	7,150	102,340	58.5%
2012	113,516	408	272	112,837	2,166	7,372	103,979	58.4%
2013	115,899	633	422	114,845	2,059	7,493	106,347	59.2%
2014	122,471	868	579	121,025	4,846	8,068	109,558	59.3%
2015	124,742	1,094	729	122,918	5,484	7,980	111,278	59.5%
2016	125,672	1,298	865	123,510	5,513	8,070	112,089	58.8%
2017	127,236	1,477	984	124,775	5,555	8,173	113,508	58.6%
2018	129,665	1,636	1,091	126,938	5,602	8,370	115,693	58.4%
2019	131,712	1,781	1,187	128,744	5,648	8,468	117,596	58.3%

Projected Values (2010 - 2019):

Col. (2) represents Forecasted Net Energy for Load w/o DSM values. The values are extracted from Schedule 2.3, Col. (19).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation and are mid-year (6-month) values **reflecting DSM signups occurring evenly thoughout each year.**
The effects of conservation implemented prior to 2010 are incorporated into the load forecast.

Col. (5) is the forecasted Net Energy for Load (NEL) after adjusting for DSM impacts DSM for years 2010 - 2019. Col.(5) = Col.(2) - Col.(3) - Col.(4)

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760) Adjustments are made for leap years.

FPL

Florida Power & Light Company, 215 S. Monroe Street, Suite 810, Tallahassee, FL 32301

Jessica Cano
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5226
(561) 691-7135 (Facsimile)

April 1, 2011

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REC.
COMMISSION CLERK

VIA HAND DELIVERY

Ms. Ann Cole
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

RE: Florida Power & Light Company's 2011 Ten Year Power Plant Site Plan

Dear Ms. Cole:

In accordance with Rule 25-22.071, F.A.C., please find enclosed for filing the original and twenty-five (25) copies of Florida Power & Light Company's 2011-2020 Ten Year Power Plant Site Plan.

Sincerely,

Lynne R. Adams
for Jessica A. Cano

Enclosures

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 46
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-K

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Ten Year Power Plant Site Plan
2011 – 2020

FPL

FPL.

Florida Power & Light Company, 215 S. Monroe Street, Suite 810, Tallahassee, FL 32301

Jessica Cano
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April 1, 2011

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Ms. Ann Cole
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FPL

Ten Year Power Plant Site Plan

2011-2020

Submitted To:

Florida Public Service Commission

Miami, Florida
April 2011

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Table of Contents

List of Figures and Tables

List of Schedules

Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan. This plan should include an estimate of the utility's future electric power generating needs, a projection of how these estimated generating needs might be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The information contained in this Site Plan is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

This Ten Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) integrated resource planning (IRP) analyses that were carried out in 2010 and that were on-going in the first Quarter of 2011. The forecasted information presented in this plan addresses the years 2011 through 2020.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information and all of this information is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, based on FPL's IRP work in 2010 and

early 2011.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as Preferred and Potential site locations for additional electric generation facilities.

Chapter V – *Other Planning Assumptions and Information*

This chapter addresses twelve "discussion items" which pertain to additional information that is included in a Site Plan filing.

FPL
List of Abbreviations
Used In FPL Forms

Reference	*Abbreviation*	*Definition*
Unit Type	BIT	Bituminous Coal
	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	IC	Internal Combustion
	NP	Nuclear Power
	PV	Photovoltaic
	ST	Steam Unit
Fuel Type	UR	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	Solar	Solar
	SUB	Sub Bituminous Coal
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	P	Planned Unit
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	ESP	Electrostatic Precipitators

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Executive Summary

Florida Power & Light Company's (FPL) 2011 Ten Year Power Plant Site Plan (Site Plan) presents FPL's current plans to augment and enhance its electric generation capability (owned or purchased) as part of its efforts to meet its projected incremental resource needs for the 2011 - 2020 time period. By design, the primary focus of this document is on supply side additions; i.e., electric generation capability and the sites for these additions. The supply side additions discussed in this document are resources projected to be needed after accounting for FPL's demand side management (DSM) efforts and the significant energy efficiency contributions from the current federal appliance and lighting efficiency standards. The projected impacts of the federal appliance and lighting efficiency standards are already reflected in FPL's load forecast which is discussed in Chapter II. The projected impacts of FPL's DSM efforts are addressed as projected reductions to the forecasted load.

The resource plan that is presented in FPL's 2011 Site Plan contains a number of key similarities to the resource plan presented in FPL's 2010 Site Plan. On the other hand, there are specific factors that are driving changes in FPL's resource plans and which will continue to influence FPL's on-going resource planning work. A brief discussion of these similarities, factors, and changes is provided below. Additional information regarding many of these topics is presented in Chapter III.

I. Similarities to the Resource Plan Previously Presented in FPL's 2010 Site Plan:

There are six key similarities in the current resource plan presented in this document compared to the resource plan presented in the 2010 Site Plan.

Similarity # 1: A third highly efficient combined cycle (CC) generating unit at the West County Energy Center site will be added to FPL's system in 2011.

One similarity to FPL's 2010 Site Plan is the addition of a third new highly efficient natural gas-fired CC generating unit at FPL's West County Energy Center (WCEC) site in 2011. FPL placed in-service two 1,219 MW (Summer) CC units at the WCEC site in 2009. These units are identified as WCEC Units 1 and 2. The WCEC Units 1 and 2 were approved by the Florida Public Service Commission (FPSC) in June 2006 in Order No. PSC-06-0555-FOF-EI. Site Certification for these units under the Florida Electric Power Plant Siting Act was approved by the Governor and the Cabinet serving as the Siting Board in December 2006 in Order No. DEP 06-1755.

FPL is currently constructing the third new CC unit, WCEC Unit 3, at this site. This new CC unit is projected to go into commercial operation by June 2011. The WCEC Unit 3 was approved by the FPSC in September 2008 in Order No. PSC-08-0591-FOF-EI and Site Certification for this unit was obtained in November 2008 in Order No. DEP 08-1204.

Similarity # 2: FPL's 2011 Site Plan continues to project that the DSM Goals imposed by FPSC for FPL will be met.

In late 2009, the FPSC imposed new DSM Goals for FPL for the years 2010 through 2019. As was the case in its 2010 Site Plan, FPL continues to project that these DSM Goals will be met.

However, there are several aspects of the new DSM Goals that are cause for concern. One issue is that, in imposing DSM Goals for FPL, the approach used by the FPSC in 2009 deviated from prior practice in ways that resulted in electric rates for FPL's customers being higher than would otherwise have been the case. In addition, this high level of DSM Goals means that FPL is becoming increasingly dependent upon DSM resources for reserves needed to maintain system reliability. This concern is mentioned again later in this Executive Summary and is discussed in more detail in Chapter III.

Similarity # 3: Generating capacity at FPL's four existing nuclear generation units will increase in the 2011 – 2013 time frame.

FPL will be adding approximately 450 MW of increased generating capacity from its existing Turkey Point and St. Lucie nuclear power plants. This increased capacity is currently scheduled to come in-service between March 2011 and January 2013. The need for these nuclear capacity "uprates" was approved by the FPSC in January 2008 in Order No. PSC-08-0021-FOF-EI. The Final Order for the Site Certification was issued in September 2008 for the St. Lucie uprates in Order No. DEP 08-0942 and in October 2008 for the Turkey Point uprates in Order No. DEP 08-1141. (There are some relatively small changes in the schedules for the increased nuclear capacity that are discussed in Chapter III.)

Similarity # 4: FPL continues to pursue licenses, permits, and approvals that would be necessary for future construction and operation of two new nuclear generating units at its Turkey Point site.

FPL is continuing its work to obtain all of the licenses, permits, and approvals that would be necessary to construct and operate two new nuclear units at its Turkey Point site in the future.

These licenses, permits, and approvals will provide FPL with the option to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units. A decision regarding construction of these new units will be made once the licenses and permits are granted. (Based on the current estimated time for construction, the earliest practical deployment dates for the two new units would be beyond the 10-year reporting period for this Site Plan. Therefore, these units are not shown in this document.)

Similarity # 5: A number of existing generating units have been placed on Inactive Reserve.

In 2009, FPL began to take a number of its existing generating units out of active service and place them on Inactive Reserve status. That process is continuing in early 2011. The specific generating units that have been placed on Inactive Reserve status are discussed in Chapter III of this document. However, there are changes in regard to FPL's current plans for these units that are discussed later in this Executive Summary and in more detail in Chapter III.

Similarity # 6: The modernizations of FPL's existing Cape Canaveral and Riviera plant sites is underway and are projected to be completed in 2013 and 2014, respectively.

FPL's 2010 Site Plan projected that the modernizations of FPL existing generating units at these two sites would occur in 2013 (Cape Canaveral) and 2014 (Riviera). FPL received need determination approval from the FPSC for both of these modernizations in September 2008 in Order No. PSC-08-0591-FOF-EI. Site Certification was received for Cape Canaveral in October 2009 in Order No. DEP 09-1015. , Site Certification was received for Riviera in November 2009 in Order No. DEP O9-1245. These modernizations are underway and are again reflected in this Site Plan.

II. Factors That Are Driving Changes in FPL's Resource Plan:

There are two primary factors that are driving the changes in FPL's 2011 resource plan compared to the resource plan presented in FPL's 2010 Site Plan. These factors, and their impacts on the resource plan, are summarized below and are addressed in more detail in Chapter III of this document.

Factor # 1: The costs of returning units from Inactive Reserve status are projected to be high.

Recent detailed evaluation of the specific costs of returning generating units from their current Inactive Reserve status, and then operating those units after they are returned to service, indicate that such costs are projected to be high. These cost projections require further analysis to determine when, and if, these units will be returned to active service.

Factor # 2: The growing number of combined cycle units on FPL's system will require that planned maintenance outages for FPL's fleet of fossil-fueled generating units be scheduled throughout the year, including Summer and Winter peak load months .

Combined cycle units are based on advanced combustion turbines whose planned maintenance outages must be strictly tied to their operating hours. Therefore, there is relatively little flexibility regarding when planned maintenance for the combined cycle units can be scheduled. This makes it more difficult to schedule planned maintenance for these units, plus all of FPL's other fossil-fueled generating units, solely in non-peak load months.

III. Resulting Changes in FPL's Resource Plan Compared to the Resource Plan Previously Presented in FPL's 2010 Site Plan:

The combined effect of the factors discussed above contribute to three significant changes in FPL's resource plan presented in this document compared to the resource plan previously presented in FPL's 2010 Site Plan. The changes are summarized below and are discussed in more detail in Chapter III.

Resulting Change # 1: FPL's 2011 Site Plan does not specify a permanent return to active service of the existing generating units placed in Inactive Reserve.

The effect of the projected high costs of returning these units to active status, and subsequently operating these units, are reflected in the resource plan that FPL presents in its 2011 Site Plan. Based on these cost projections, and the comparatively lower projected system costs of new combined cycle capacity, this resource plan does not show the permanent return to service of any of these generating units in the ten-year period addressed in this document.

FPL currently expects that three of these generating units, Cutler 5 & 6 and Sanford 3, will be retired by 2012. FPL will be examining other potential uses for these sites, including their potential use as sites for new renewable energy facilities. The four steam units at FPL's Port Everglades site will remain available to return to service at least until 2014. Two of these four steam units, Port Everglades Units 3 & 4, are currently scheduled to be returned to active service in 2012 and then return to Inactive Reserve status at least until the "modernized" units at Cape Canaveral and Riviera are in normal operation (i.e., until mid-2014). The other two steam units, Port Everglades Units 1 & 2, are currently scheduled to remain on Inactive Reserve status during this time period. The remaining unit on Inactive Reserve status, Turkey Point 2, will remain on Inactive Reserve status, but will operate as a synchronous condenser (which provides reactive power support for FPL's transmission system in Southeastern Florida) rather than as provider of electricity. This unit is capable of returning to active service in the future to provide MW and MWh. (Further discussion of the units on Inactive Reserve status is provided in Chapter III.)

FPL will continue to evaluate the relative economics of returning the Port Everglades and Turkey Point 2 units from Inactive Reserve compared to adding new combined cycle capacity at Greenfield/Brownfield sites and/or modernizing generation facilities at existing sites.

Resulting Change # 2: For planning purposes consistent with the objectives of this reporting document, the resource plan presented in this Site Plan shows the addition of two new Greenfield CC units.

With the assumption that none of the units currently in Inactive Reserve status will be permanently returned to active service during the ten-year period addressed in this document, and consistent with all other assumptions (new load forecast, DSM Goals, etc.), FPL currently projects that it will have its next resource need in 2016. Consistent with two of the objectives of this document, which are to provide a preview of what types of generating units FPL projects would be added, and when FPL projects that those additions would be made, FPL is projecting that this resource need would be met by the addition of one new CC unit similar to the new CC units being added as part of the modernizations of the Cape Canaveral and Riviera sites. An additional resource need is then projected by the year 2020. For planning purposes, FPL currently projects that this subsequent resource need would also be met by the addition of another new CC unit of the same type. No specific sites have been designated for these two new CC units and they are referred to as Greenfield CC units throughout this document.

As previously mentioned, and as part of FPL's ongoing resource planning process, FPL will continue to evaluate how best to meet future resource needs; i.e., through new CC capacity and/or the return of Inactive Reserve units to active service. These analyses will also examine the potential for modernizing additional existing power plants such as is being done at the Cape

Canaveral and Riviera sites. For example, the existing Port Everglades site is a potential site for modernization. Other existing sites may also emerge in the ongoing analyses as potential candidates for modernization. Analyses of any modernization candidates would include evaluation of numerous factors including: fuel delivery costs/issues, transmission impacts (especially in the Southeastern region of Florida as will be discussed later), system reliability issues due to the removal of existing units from active service prior to the construction of new capacity at the site, overall system economics, etc.

Resulting Change # 3: *FPL's resource plan reflects that planned maintenance must be scheduled during Summer and Winter peak months.*

Due to the previously discussed requirement that combustion turbine maintenance take place on a strict schedule based on operating hours, FPL must schedule planned maintenance during peak load months. This is reflected in this Site Plan as MWs of capacity that are projected to be out-of-service in Summer and Winter reserve margin calculations (as presented in Schedules 7.1 through 7.4 in Chapter III.) One effect of this change is that it increases FPL's projected resource needs in future years.

IV. Additional Factors Influencing FPL's Resource Planning Work:

In addition to the two factors specifically described above (projected high costs of returning units in Inactive Reserve to active service and the need to schedule planned maintenance in peak load months) that are driving changes in FPL's resource plans, there are additional factors that also influence FPL's resource planning work. Among these other additional factors are two that FPL typically refers to as on-going system concerns that FPL has considered in its resource planning work for a number of years. These two on-going system concerns are: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward counties.

A third factor that could affect FPL's resource planning is the possibility of the establishment of a Florida standard for renewable energy or clean energy. A Renewable Portfolio Standard (RPS) proposal was prepared by the FPSC, and then sent to the Florida Legislature for consideration, with a possible change to a Clean Portfolio Standard (CPS), during the 2009 legislative session. However, no RPS or CPS legislation was enacted during the 2009 or 2010 legislative sessions. RPS or CPS legislation, or other legislative initiatives regarding renewable or clean energy contributions, may occur in the future. If such legislation is enacted during 2011 or in later years, FPL will then determine what steps need to be taken to address the legislation. Such steps would then be discussed in FPL's Site Plan in the year following the enactment of such legislation.

A fourth factor that will affect FPL's resource planning is the issue of how best to reliably obtain additional natural gas for FPL's system which is projected to continue to add more natural gas-fired generating capacity after the modernizations of Cape Canaveral and Riviera are completed.

A fifth factor or issue that will affect FPL's resource planning was previously mentioned in this Executive Summary: the extent to which FPL's reserves will become increasingly dependent upon DSM resources as opposed to generation resources. This projected imbalance in future reserves is becoming more pronounced, in part, because of higher DSM Goals requirements.

Each of these factors will continue to be examined in FPL's on-going resource planning work during the rest of 2011 and in future years.

Table ES-1 presents a current projection of major changes to specific generating units and firm capacity purchases for 2011 – 2020 in terms of Summer MW. Table ES-2 then expands upon the information presented in Table ES-1 by adding projections of Winter MW impacts, Summer reserve margins, Winter reserve margins, etc. (Although neither table specifically identifies the impacts of the new DSM Goals on FPL's resource needs and resource plan, the DSM Goals have been fully accounted for in the resource plan presented in this Site Plan.)

Table ES-1: Projected Capacity & Firm Purchase Power Changes

*Year **	*Projected Capacity & Firm Purchase Power Changes*	*Summer MW*	*Date*
2011	Riviera Unit 3 & 4 - removed for modernization	(565)	February-11
	St. Lucie Unit 2 Uprates - interim increase	17	April-11
	West County Unit # 3	1,219	June-11
	Total of MW changes to Summer reserve margin:	**671**	
2012	Inactive Reserve Unit (PE Units 3 & 4) - active service	761	January-12
	St. Lucie Unit 1 Uprates - completed	122	March-12
	Palm Beach SWA - PPA extension	55	April-12
	Oleander PPA - contract ends	(155)	May-12
	St. Lucie Unit 2 outage	(731)	June-12
	Turkey Point Unit 3 Uprates - completed	109	June-12
	Total of MW changes to Summer reserve margin:	**161**	
2013	St. Lucie Unit 2 Uprates - completed	93	October-12
	Inactive Reserve Unit (PE Units 3 & 4) - inactive status	(761)	November-12
	Turkey Point Unit 4 Uprates - completed	109	February-13
	Cape Canaveral Next Generation Clean Energy Center	1,210	June-13
	Martin 1 ESP - outage	(826)	June-13
	Total of MW changes to Summer reserve margin:	**(175)**	
2014	Martin 2 ESP - outage	(826)	March-14
	Riviera Beach Next Generation Clean Energy Center	1,212	June-14
	Total of MW changes to Summer reserve margin:	**386**	
2015	Palm Beach SWA PPA - additional	90	April-15
	Total of MW changes to Summer reserve margin:	**90**	
2016	UPS Replacement	(931)	December-15
	SJRPP	(375)	April-16
	Greenfield 3x1 Combined Cycle	1,191	June-16
	Total of MW changes to Summer reserve margin:	**(115)**	
2017			
	Total of MW changes to Summer reserve margin:	**0**	
2018			
	Total of MW changes to Summer reserve margin:	**0**	
2019			
	Total of MW changes to Summer reserve margin:	**0**	
2020	Greenfield 3x1 Combined Cycle	1,191	June-20
	Total of MW changes to Summer reserve margin:	**1,191**	

* Year shown reflects when the MW change begins to be accounted for in reserve margin calculations.

Table ES-2: Projected Capacity Changes and Reserve Margins for FPL

Projected Capacity Changes and Reserve Margins for FPL (1)					
		Net Capacity Changes (MW)		Reserve Margin (%) After Maintenance (2)	
Year	Projected Capacity Changes	Winter (3)	Summer (4)	Winter	Summer
2011	Inactive Reserve of Existing Units - offline (8)	(775)	(1,922)		
	Riviera Plant - offline for modernization	—	(565)		
	Scherer Plant Upgrade	—	26		
	St. Lucie Unit 2 Partial Uprate (7)	—	17		
	St. Lucia Unit 2 Uprate Peak Outage (7)	(726)	—		
	West County Unit 3 (6)	—	1,219	25.7%	22.7%
2012	Changes to Existing Purchases (5)	—	(100)		
	St. Lucie Unit 1 Uprates	—	122		
	Turkey Point Unit 3 Uprates	—	109		
	Inactive Reserve of Existing Units - offline (8)	(394)	—		
	Inactive Reserve Unit (PE Units 3 & 4) - online	765	761		
	Manatee 2 ESP Peak Outage (8)	(822)	—		
	Riviera Plant - offline for modernization	(571)	—		
	Scherer Plant upgrade	26	—		
	St. Lucie Unit 1 Uprate Paak Outage (7)	(853)	—		
	St. Lucie Unit 2 Partial Uprate (7)	17	—		
	St. Lucie Unit 2 Uprate Peak Outage (7)	—	(731)		
	Turkey Point Unit 3 Uprata Peak Outage (7)	(717)	—		
	West County Unit 3 (6)	1,335	—	19.6%	23.4%
2013	Cape Canaveral Next Generation Clean Energy Center (6)	—	1,210		
	St. Lucie Unit 1 Uprates	122	—		
	St. Lucie Unit 2 Uprates	110	93		
	Turkey Point Unit 3 Uprates	109	—		
	Turkey Point Unit 4 Upratas	—	109		
	Inactive Reserve Unit (PE Units 3 & 4) - offline (9)	(765)	(761)		
	Manatee Unit 1 ESP Peak Outage (8)	(822)	—		
	Martin Unit 1 ESP Peak Outage (8)	-	(828)		
	St. Lucie Unit 2 Partial Uprate	(17)	—	24.2%	25.4%
2014	Cape Canaveral Next Generation Clean Energy Center (6)	1,355	—		
	Turkey Point Unit 4 Uprates	109	—		
	Martin Unit 1 ESP Peak Outage (8)	(832)	—		
	Martin Unit 2 ESP Peak Outage (8)	—	(826)		
	Riviera Beach Next Generation Clean Energy Center (6)	—	1,212	26.7%	24.8%
2015	Change to Existing Qualifying Facilities (5)	—	90		
	Riviera Beach Next Generation Clean Energy Center (6)	1,344	—	35.1%	25.9%
2016	Changes to Existing Purchases (5)	(841)	(1,306)		
	Change to Existing Qualifying Facilities (5)	—	—		
	Greenfield 3x1 Combined Cycle (6)	—	1,191	30.1%	23.8%
2017	Changes to Existing Purchases (5)	(383)	—		
	Greenfield 3x1 Combined Cycle (6)	1,351	—	33.8%	22.2%
2018	—	—	—	32.7%	21.6%
2019	—	—	—	31.6%	20.0%
2020	Greenfield 3x1 Combined Cycle (6)	—	1,191	30.4%	23.1%

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) The Summer and Winter reserve margins reflect an additional 350 MW in summer and 550 MW in winter of units scheduled to be out during those peak periods. Saa Section III.C.1 in Chapter 3 for more details.
(3) Winter values are forecasted values for January of the year shown.
(4) Summer values are forecasted values for August of the year shown.
(5) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(6) All new unit additions are scheduled to be in-service in June of the year shown. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.
(7) Outages for uprate work.
(8) Outages for ESP work.
(9) A number of existing FPL power plants have been removed from service and placed on Inactive Reserve status. See Chapter 3 for a discussion of the units on Inactive Reserves.

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CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 8.7 million people. FPL served an average of 4,520,328 customer accounts in thirty-five counties during 2010. These customers were served from a variety of resources including: FPL-owned fossil-fueled, renewable, and nuclear generating units, non-utility owned generation, demand side management (DSM), and interchange/purchased power.

I.A. FPL-Owned Resources

The existing FPL generating resources are located at sixteen generating sites distributed geographically around its service territory and also include partial ownership of one unit located in Georgia and two units located in Jacksonville, Florida. The current electrical generating facilities consist of four nuclear units, three coal units, fourteen combined cycle (CC) units, fifteen fossil steam units, forty-eight combustion gas turbines, one simple cycle combustion turbine, and two photovoltaic facilities[1]. The locations of these eighty-seven generating units are shown on Figure I.A.1 and in Table I.A.1. Table I.A.2 provides a "break down" of the capacity provided by the combustion turbine (CT) and steam turbine (ST) components of FPL's existing CC units.

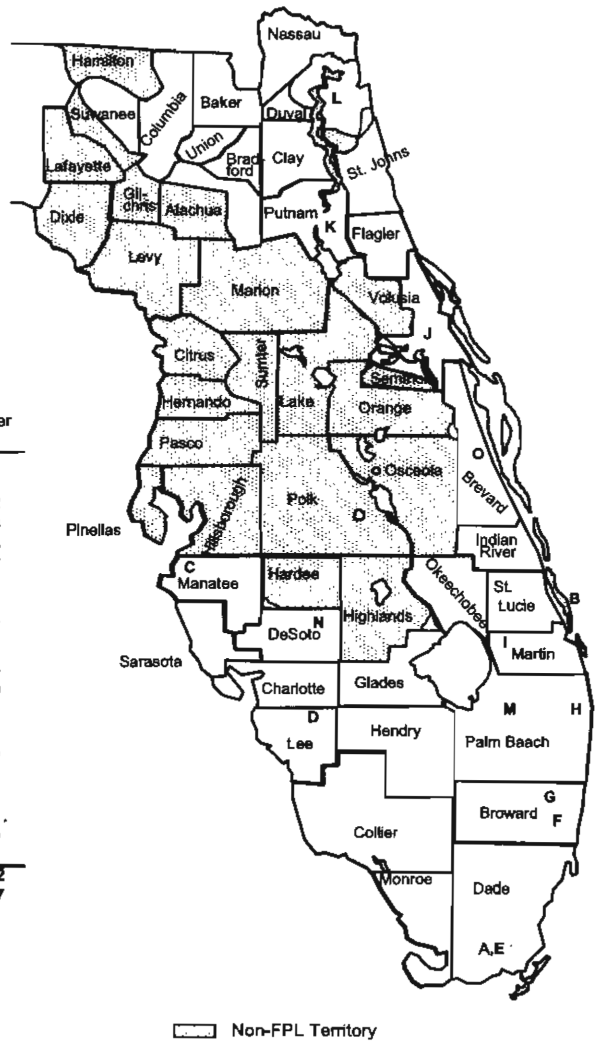
FPL's bulk transmission system is comprised of 6,721 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 586 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3 shows FPL's interconnection ties with other utilities.

[1] FPL also has one 75 MW solar thermal facility at its Martin plant site. This facility does not generate electricity as the other units mentioned above do. Instead, it produces steam that reduces the use of fossil fuel to produce steam.

FPL Generating Resources by Location

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	5	3,322
B	St. Lucie *	2	1,553
C	Manatee	3	2,735
D	Fort Myers	2	1,747
E	Cutler	2	205
F	Lauderdale	2	884
G	Port Everglades	4	1,187
H	Riviera	2	565
I	Martin	5	3,695
J	Sanford	3	2,050
K	Putnam	2	498
L	SJRPP **	2	254
M	West County	2	2,438
N	DeSoto ***	1	25
O	Space Coast ***	1	10
	Scherer ****	1	646
	Gas Turbines	48	1,906
	Total System Generation =	**87**	**23,722**
	System Firm Generation =	**85**	**23,687**



* Represents FPL's ownership share: St Lucie nuclear: 100% unit 1, 85% unit 2: St. Johns River: 20% of two units.

** SJRPP = St. John's River Power Park

*** The 25 MW of PV at DeSoto and the 10 MW of Space Coast are considered as non-firm generating capacity.

**** The Scherer unit is located in Georgia and is not shown on this map.

Figure I.A.1: Capacity Resources by Location (as of December 31, 2010)

Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2010)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Nuclear				
Turkey Point	Florida City, FL	2	Nuclear	1,386
St. Lucie *	Hutchinson Island, FL	2	Nuclear	1,553
Total Nuclear		**4**		**2,939**
Coal Steam				
SJRPP **	Jacksonville, FL	2	Coal	254
Scherer	Monroe County, Ga	1	Coal	646
Total Coal Steam		**3**		**900**
Combined-Cycle ***				
Martin	Indiantown,FL	2	Gas	938
Sanford	Lake Monroe, FL	2	Gas	1,912
Fort Myers	Fort Myers, FL	1	Gas	1,432
Manatee	Parrish,FL	1	Gas	1,111
Turkey Point	Florida City, FL	1	Gas	1,146
Lauderdale	Dania, FL	2	Gas/Oil	884
Martin	Indiantown,FL	1	Gas/Oil	1,105
Putnam	Palatka, FL	2	Gas/Oil	498
West County	Palm Beach County,FL	2	Gas/Oil	2,438
Total Combined Cycle		**14**		**11,466**
Oil/Gas Steam				
Cutler	Miami, FL	2	Gas	205
Manatee	Parrish, FL	2	Oil/Gas	1,624
Martin	Indiantown,FL	2	Oil/Gas	1,652
Port Everglades	Port Everglades, FL	4	Oil/Gas	1,187
Riviera	Riviera Beach, FL	2	Oil/Gas	565
Sanford	Lake Monroe, FL	1	Oil/Gas	138
Turkey Point	Florida City, FL	2	Oil/Gas	788
Total Oil/Gas Steam		**15**		**6,159**
Gas Turbines(GT)/Diesels(IC)				
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Fort Myers (GT)	Fort Myers, FL	12	Oil	848
Total Gas Turbines/Diesels		**48**		**1,908**
Combustion Turbines ***				
Fort Myers ****	Fort Myers, FL	1	Gas/Oil	315
Total Combustion Turbines		**1**		**315**
PV				
DeSoto *****	DeSoto, FL	1	Solar Energy	25
Space Coast *****	Brevard County,FL	1	Solar Energy	10
Total PV		**2**		**35**
Total System Genaration as of December 31, 2010 =		**87**		**23,722**
System Firm Generation as of December 31, 2010 =		**85**		**23,687**

* Total capability of each unit is 853/839 MW. FPL's ownership share of St. Lucie 1 and 2 is 100% and 85%, respectivaly. Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.

** Represents FPL's ownership share: SJRPP coal: 20% of two units

*** The Combined Cycles and Combustion Turbines are broken down by components on Table 1.A.2.

**** This unit consists of two combustion turbines.

***** The 25 MW of PV at DeSoto and the 10 MW at Space Coast are considered non-firm generating capacity.

Table I.A.2: Combined Cycle and Combustion Turbine Components

Combined-Cycle

Plant Name/ Unit No.	Summer MW * CT A	CT B	CT C	CT D	CT E	CT F	Steam 1	Steam 2	BOP Aux	Total Unit MW
Ft Myers 2	158	158	158	158	158	158	60	447	(20)	1,432
Lauderdale 4	161	161	—	—	—	—	125	—	(5)	442
Lauderdale 5	161	161	—	—	—	—	125	—	(5)	442
Manatee 3	162	162	162	162	—	—	483	—	(18)	1,111
Martin 3	164	164	—	—	—	—	148	—	(6)	469
Martin 4	164	164	—	—	—	—	148	—	(6)	469
Martin 8	161	161	161	161	—	—	482	—	(22)	1,105
Putnam 1	71	71	—	—	—	—	113	—	(5)	249
Putnam 2	71	71	—	—	—	—	113	—	(5)	249
Sanford 4	160	160	160	160	—	—	332	—	(13)	958
Sanford 5	159	159	159	159	—	—	330	—	(13)	954
Turkey Point 5	174	174	174	174	—	—	477	—	(26)	1,148
West County 1	250	250	250	—	—	—	495	—	(27)	1,219
West County 2	250	250	250	—	—	—	495	—	(27)	1,219

Combustion Turbines

Plant Name/ Unit No.	CT A	CT B	CT C	CT D	CT E	CT F	Steam 1	Steam 2	BOP Aux	Total Unit MW
Ft. Myers 3	158	158	—	—	—	—	—	—	(1)	315

This table shows the breakdown of total MW for each unit by CT and steam component.

* The total MW values shown in this table may differ slightly from values shown in other tables due to rounding of per-component values.

Table 1.A.3: Purchase Power Resources by Contract (as of December 31, 2010)

	Location (City or County)	Fuel	Summer MW
I. Purchases from QF's: Cogeneration/Small Power Production Facilities			
Cedar Bay Generating Co.	Duval	Coal (Cogen)	250
Indiantown Cogen., LP	Martin	Coal (Cogen)	330
Broward South	Broward	Solid Waste	4
Broward North	Broward	Solid Waste	56
		Total:	**640**
II. Purchases from Utilities:			
UPS from Southern Company	Various in Georgia	Coal	931
SJRPP	Jacksonville, FL	Coal	375
		Total:	**1,306**
III. Other Purchases:			
Oleander (Extension)	Brevard	Gas	155
			155
	Total Net Firm Generating Capability:		**2,101**

Non-Firm Energy Purchases (MWH)

Plant Name	Location (City or County)	Fuel	Energy (MWH) Delivered to FPL in 2010
Okeelanta	Palm Beach	Bagasse/Wood	256,627
Broward South	Broward	Garbage	349,171
Tomoka Farms	Volusia	Landfill Gas	24,527
Waste Managemen t- Renewable Energy	Broward	Landfill Gas	55,438
Tropicana	Manatee	Natural Gas	43,827
Calnetix	Palm Beach	Natural Gas	0
Georgia Pacific	Putnam	Paper by-product	2,548
Rothenbach Park	Sarasota	PV	259
Customer - Owned PV & Wind	Various	PV/Wind	482
Palm Beach SWA	Palm Beach	Solid Waste	114,195

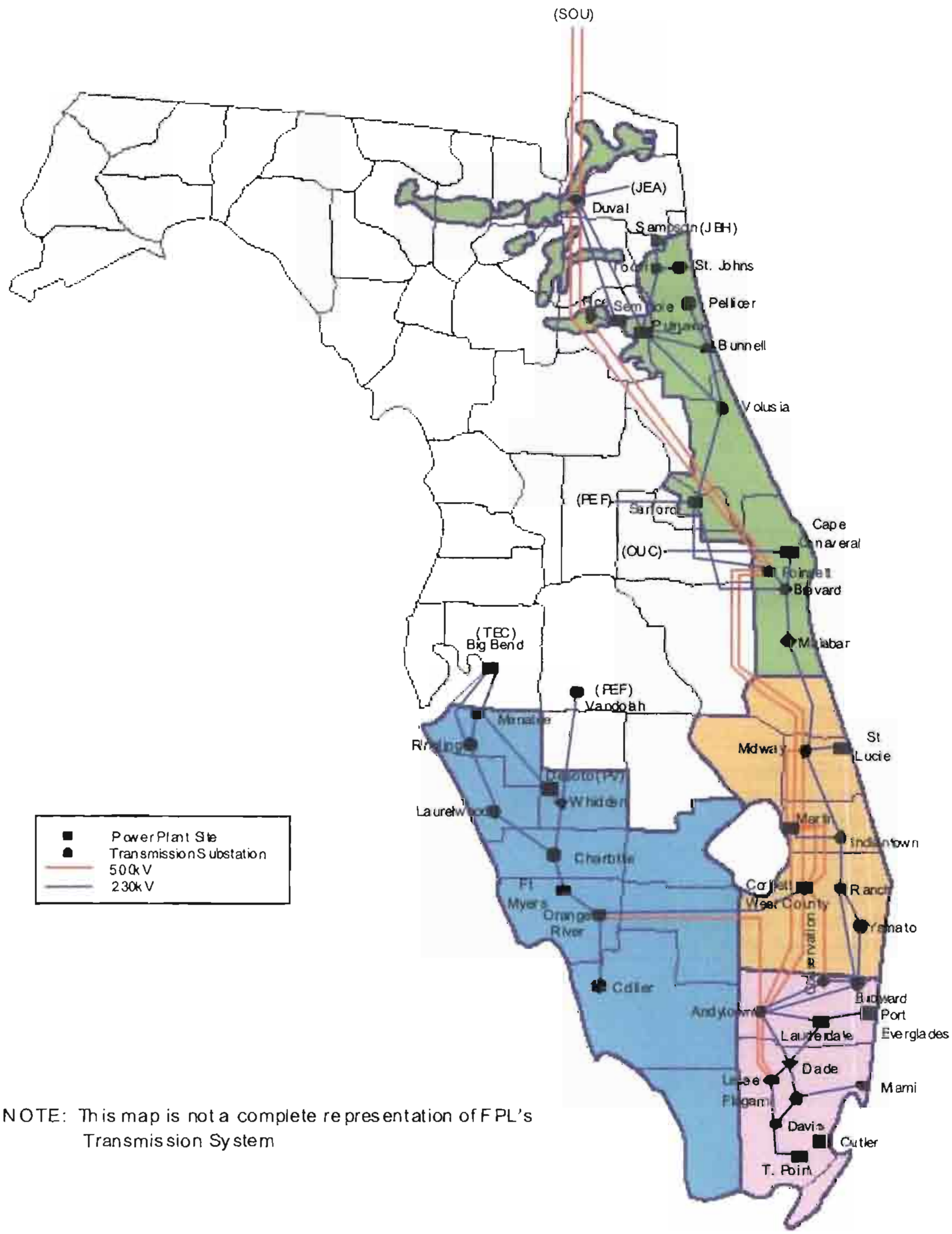


Figure I.A.2: FPL Substation and Transmission System Configuration

FPL Interconnection Diagram

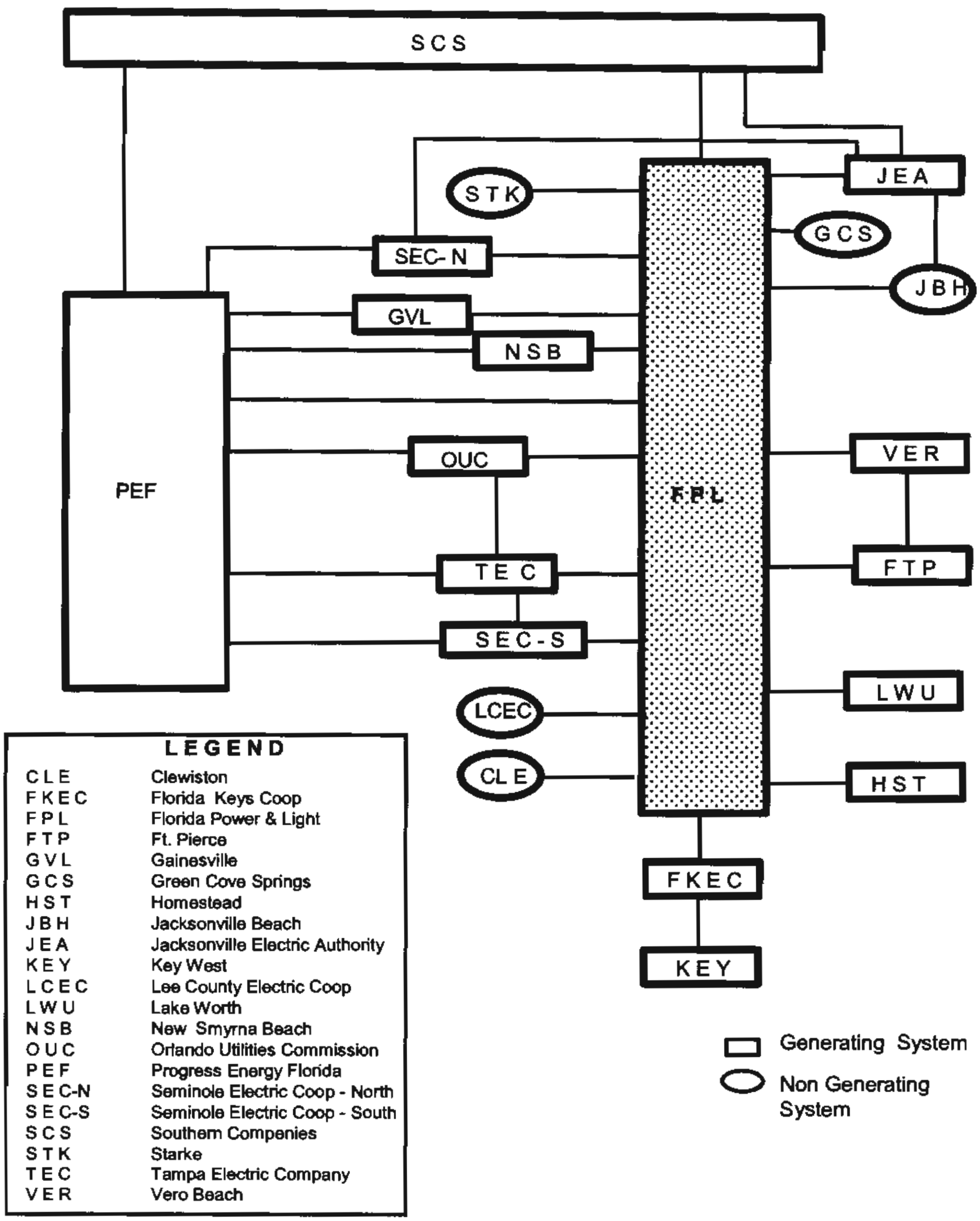


Figure I.A.3: FPL Interconnection Diagram

I.B Firm Capacity Power Purchases

Purchases from Qualifying Facilities (QF):

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has contracts with five qualifying facilities; i.e., cogeneration/small power production facilities, to purchase firm capacity and energy as shown in Table I.A.2, Table I.B.1, and I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

Purchases from Utilities:

FPL has a Unit Power Sales (UPS) contract to purchase 931 MW from the Southern Company (Southern) through the end of December 2015. This capacity will be supplied by Southern from a mix of gas-fired and coal-fired units.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 375 MW (Summer) and 383 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. However, due to Internal Revenue Service (IRS) regulations, the total amount of energy that FPL may receive from this purchase is limited. FPL currently assumes, for planning purposes, that this limit will be reached in the first half of 2016. Once this limit is reached, FPL will be unable to receive firm capacity and energy from these purchases. (However, FPL will continue to receive firm capacity and energy from its ownership portion of the SJRPP units.)

These purchases are shown in Table I.A.3, Table I.B.1, and Table I.B.2. FPL also has ownership interest in the SJRPP units. The ownership amount is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.

Other Purchases:

FPL has another firm capacity purchase contract with a non-QF, non-utility supplier. This purchase contract runs through May 2012. Table I.B.1 and I.B.2 present the Summer and Winter MW, respectively, resulting from this contract.

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Broward South	1/1/1993	12/31/2026	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	1/1/1997	12/31/2026	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	1/1/1993	12/31/2026	7	7	7	7	7	7	7	7	7	7
Broward North	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	1/1/1997	12/31/2026	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	1/25/1994	12/31/2024	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/1995	12/1/2025	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA - extension	4/1/2012	4/1/2032	0	55	55	55	55	55	55	55	55	55
Palm Beach SWA - additional	4/1/2015	4/1/2032	0	0	0	0	90	90	90	90	90	90
		QF Purchases Sub Total:	**595**	**650**	**650**	**650**	**740**	**740**	**740**	**740**	**740**	**740**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
UPS Replacement	6/1/2010	12/31/2015	931	931	931	931	931	0	0	0	0	0
SJRPP	4/2/1982	4/1/2016 *	375	375	375	375	375	0	0	0	0	0
		Utility Purchases Sub Total:	**1,306**	**1,306**	**1,306**	**1,306**	**1,306**	**0**	**0**	**0**	**0**	**0**
		Total of QF and Utility Purchases =	**1,901**	**1,956**	**1,956**	**1,956**	**2,046**	**740**	**740**	**740**	**740**	**740**

III. Other Purchases:

	Contract Start Date	Contract End Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oleander (Extension)	6/1/2007	5/31/2012	155	0	0	0	0	0	0	0	0	0
		Other Purchases Sub Total:	**155**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total "Non-QF" Purchase Sub-Total =	**1,461**	**1,306**	**1,306**	**1,306**	**1,306**	**0**	**0**	**0**	**0**	**0**

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Summer Firm Capacity Purchases Total MW:	**2,056**	**1,956**	**1,956**	**1,956**	**2,046**	**740**	**740**	**740**	**740**	**740**

* Contract End Date shown does not represent the actual contract end date. Instead, this date represents a projection of the date at which FPL's ability to receive further capacity and energy from this purchase will be suspended due to IRS regulations.

Table I.B.2: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Start Date	End Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA - extension	4/1/2012	4/1/2032	0	0	55	55	55	55	55	55	55	55
Palm Beach SWA - additional	4/1/2015	4/1/2032	0	0	0	0	0	90	90	90	90	90
		QF Purchases Sub Total:	**595**	**595**	**650**	**650**	**650**	**740**	**740**	**740**	**740**	**740**

II. Purchases from Utilities:

	Start Date	End Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
UPS Replacement	06/01/10	12/31/15	931	931	931	931	931	0	0	0	0	0
SJRPP	04/02/82	4/1/2016 *	383	383	383	383	383	383	0	0	0	0
		Utility Purchases Sub Total:	**1,314**	**1,314**	**1,314**	**1,314**	**1,314**	**383**	**0**	**0**	**0**	**0**

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total of QF and Utility Purchases =	**1,909**	**1,909**	**1,964**	**1,964**	**1,964**	**1,123**	**740**	**740**	**740**	**740**

III. Other Purchases:

	Contract Start Date	Contract End Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oleander (Extension)	06/01/07	05/31/12	180	180	0	0	0	0	0	0	0	0
		Other Purchases Sub Total:	**180**	**180**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
"Non-QF" Purchase Sub-Total =	**1,494**	**1,494**	**1,314**	**1,314**	**1,314**	**383**	**0**	**0**	**0**	**0**

	2011	2012	2013	2014	2015	2016	2017	2016	2019	2020
Winter Firm Capacity Purchases Total MW:	**2,089**	**2,089**	**1,964**	**1,964**	**1,964**	**1,123**	**740**	**740**	**740**	**740**

* Contract End Date shown does not represent the actual contract end date. Instead, this date represents a projection of the date at which FPL's ability to receive further capacity and energy from this purchase will be suspended due to IRS regulations.

I.C Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. Table I.C.1 shows the amount of energy purchased in 2010 from these facilities.

Table I.C.1: As-Available Energy Purchases From Non-Utility Generators in 2010

Project	County	Fuel	In-Service Date	Energy (MWH) Delivered to FPL in 2010
Okeelanta	Palm Beach	Bagasse/Wood	11/95	256,627
Broward South	Broward	Garbage	9/09	349,171
Tomoka Farms	Volusia	Landfill Gas	7/98	24,527
Waste Management - Renewable Energy	Broward	Landfill Gas	1/10	55,438
Tropicana	Manatee	Natural Gas	2/90	43,827
Calnetix	Palm Beach	Natural Gas	7/05	0
Georgia Pacific	Putnam	Paper by-product	2/94	2,548
Rothenbach Park	Sarasota	PV	10/07	259
Customer - Owned PV & Wind	Various	PV/Wind	Various	482
Palm Beach SWA	Palm Beach	Solid Waste	4/10	114,195

I.D. Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include a number of conservation/energy efficiency and load management initiatives. FPL's DSM efforts through 2010 have resulted in a cumulative Summer peak reduction of approximately 4,371 MW at the generator and an estimated cumulative energy saving of approximately 55,462 Gigawatt-hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2010 have eliminated the need to construct the equivalent of more than 13 new 400 MW generating units. DSM is discussed further in Chapter III.

Schedule 1

Existing Generating Facilities
As of December 31, 2010

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability [1] Winter MW	(14) Net Capability [1] Summer MW
Cape Canaveral [2]		Brevard County											
		19/24S/36F									0	0	0
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Jun-10	0	0	0
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Jun-10	0	0	0
Cutler [3]		Miami Dade County											
		27/55S/40E									236,500	207	205
	5		ST	NG	No	PL	No	Unknown	Nov-54	Jan-12	75,000	69	68
	6		ST	NG	No	PL	No	Unknown	Jul-55	Jan-12	161,500	138	137
DeSoto [4]		DeSoto County											
		27/36S/25E									25,000	25	25
	1		PV	N/A	N/A	N/A	N/A	Unknown	Oct-09	Unknown	25,000	25	25
Fort Myers		Lee County											
		35/43S/25E									2,895,890	2,552	2,395
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,775,390	1,490	1,432
	3A & B		CT	NG	FO2	PL	PL	Unknown	Jun-03	Unknown	376,380	352	315
	1-12		GT	FO2	No	PL	No	Unknown	May-74	Unknown	744,120	710	646
Lauderdale		Broward County											
		30/50S/42E									1,673,968	1,864	1,724
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	483	442
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	483	442
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,734	459	420
Manatee		Manatee County											
		18/33S/20E									2,951,110	2,812	2,735
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	822	812
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	822	812
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,186	1,111
Martin		Martin County											
		29/29S/36E									4,317,510	3,804	3,695
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	832	826
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	832	826
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	489	469
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	489	469
	8 [5]		CC	NG	FO2	PL	PL	Unknown	Jun-05	Unknown	1,224,510	1,162	1,105

1/ These ratings are peak capability.
2/ The Cape Canaveral modernization project has resulted in the removal of the two steam units previously at the Canaveral site to clear the site for the introduction of a new combined cycle generating unit. This new unit is projected to go into service in June 2013.
3/ These generating units were on Inactive Reserve status as of 12/31/2010.
4/ The capacity shown for the PV facility at DeSoto is considered as non-firm generating capacity due to the intermittent nature of the solar resource.
5/ Martin 8 is also partially fueled by a 75 MW solar thermal facitility that supplies steam when adequate sunlight is available, thus reducing fossil fuel use.

Schedule 1

Existing Generating Facilities
As of December 31, 2010

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability [1/] Winter MW	(14) Net Capability [1/] Summer MW
Port Everglades		City of Hollywood 23/50S/42E									1,665,334	1,652	1,607
	1 [2/]		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	225,250	214	213
	2 [2/]		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	225,250	214	213
	3 [2/]		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	389	387
	4 [2/]		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	376	374
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	459	420
Putnam		Putnam County 16/10S/27E									580,008	530	498
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,004	265	249
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,004	265	249
Riviera		City of Riviera Beach 33/42S/43E									620,840	571	565
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Feb-11	310,420	280	277
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Feb-11	310,420	291	288
Sanford		Volusia County 16/19S/30E									2,533,970	2,217	2,050
	3 [2/]		ST	FO6	NG	WA	PL	Unknown	May-59	Jan-12	156,250	140	138
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,860	1,040	958
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	1,037	954
Scherer [3/]		Monroe, GA									680,368	652	646
	4		BIT	SUB	No	RR	No	Unknown	Jul-89	Unknown	680,388	652	646
Space Coast [4/]		Brevard County 13/23S/36E									10,000	10	10
	1		PV	N/A	N/A	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10

1/ These ratings are peak capability.

2/ These generating units were on Inactive Reserve status as of 12/31/2010.

3/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.

4/ The capacity shown for the PV facility at Space Coast is considered as non-firm generating capacity due to the intermittent nature of the solar resource.

Schedule 1

Existing Generating Facilities
As of December 31, 2010

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability [1/] Winter MW	(14) Net Capability [1/] Summer MW
St. Johns River Power Park [2/]		Duval County 12/15/28E (RPC4)									271,836	250	254
	1		BIT	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	125	127
	2		BIT	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	125	127
St. Lucie [3/]		St. Lucie County 16/36S/41E									1,573,775	1,579	1,553
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	850,000	853	839
	2		NP	UR	No	TK	No	Unknown	Jun-83	Unknown	723,775	726	714
Turkey Point		Miami Dade County 27/57S/40E									3,548,550	3,382	3,322
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	398	396
	2 [4/]		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	394	392
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	759,970	717	693
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	759,970	717	693
	5		CC	NG	FO2	PL	PL	Unknown	May-07	Unknown	1,224,510	1,156	1,148
West County		Palm Beach County 29&32/43S/40E									2,733,600	2,670	2,438
	1		CC	NG	FO2	PL	PL	Unknown	Aug-09	Unknown	1,366,800	1,335	1,219
	2		CC	NG	FO2	PL	PL	Unknown	Nov-09	Unknown	1,366,800	1,335	1,219
Total System Generating Capacity as of December 31, 2010 [5/] =												24,797	23,722
System Firm Generating Capacity as of December 31, 2010 [6/] =												24,762	23,687

1/ These ratings are peak capability.

2/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No. 1 and No. 2, excluding the Jacksonville Electric Authority (JEA) share of 80%.

3/ Total capability of each unit is 853/839 MW. FPL's ownership share of St. Lucie 1 and 2 is 100%(853/839) and 85% (714/726) respectively as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.

4/ This generating unit was on Inactive Reserve status as of 12/31/2010.

5/ The Total System Generating Cpacity value shown includes FPL-owned firm and non-firm generating capacity.

6/ The System Firm Generating Capacity value shown includes only firm generating capacity.

CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

II. A. Overview of the Load Forecasting Process

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are typically developed on an annual basis for resource planning work at FPL. New long-term forecasts were developed by FPL in early 2011 that replaced the previous long-term load forecasts that were used by FPL during 2010 in much of its resource planning work and which were presented in FPL's 2010 Site Plan. These new load forecasts are utilized throughout FPL's 2011 Site Plan. These forecasts are a key input to the models used to develop FPL's integrated resource plan.

The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads. Consistent with past forecasts, the primary drivers to develop these forecasts include economic conditions and weather.

The projections for the national and Florida economies are obtained from the consulting firm IHS Global Insight. Population projections are obtained from the Florida Legislature's Office of Economic and Demographic Research (EDR). These projections are developed, in conjunction with the Bureau of Economic and Business Research (BEBR) of the University of Florida. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects FPL's energy sales and peak demand. Two sets of weather variables are developed and used in FPL's forecasting models:

1. Cooling and Heating Degree-Hours are used to forecast energy sales.
2. Temperature data, along with Cooling and Heating Degree-Hours, are used to forecast Summer and Winter peaks.

The Cooling and Heating Degree-Hours are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. A composite hourly temperature profile is derived using hourly temperatures across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained. In developing the composite hourly profile, these regional temperatures are weighted by regional energy sales. This composite temperature is used to derive projected Cooling and Heating Degree-Hours, which are based on starting point temperatures of 72° F and 66° F degrees, respectively.

Similarly, composite temperature and hourly profiles of temperatures are used for the Summer and Winter peak models.

II. B. Comparison of FPL's Current and Previous Load Forecasts

FPL's current load forecast is generally in line with the load forecast presented in its 2010 Site Plan. There are three primary factors that are driving the current load forecast: projected population growth, a projection of gradual recovery following the economic recession in Florida, and a somewhat lower projected long-term price of electricity. The net impact of these three factors is that the current load forecast is similar to the 2010 Site Plan forecast in most years between 2011 and 2020.

The customer forecast is based on recent population projections. Population projections are derived from the EDR's February 2011 Demographic Estimating Conference. This forecast is slightly higher than the prior projection. During the recent recession, net migration into Florida fell to record lows. Historically low rates of net migration are expected to continue until around 2012 - 2013 due to the weakened housing market and other lingering effects from the recession which make it difficult for people to relocate.

As population growth recovers, a modest rebound in customer growth is projected in 2012 and 2013. However, population growth is not expected to reach the level historically experienced in Florida until 2014 - 2015. As a result of the higher than expected customer growth in 2010, the total number of customers projected in the current load forecast is above the levels projected in FPL's 2010 Site Plan.

Consistent with the economic assumptions incorporated into the 2010 Site Plan, the state's economy continues to suffer the lingering effects of an economic recession. Beginning in mid-2010, Florida began seeing an annual increase in employment for the first time in three years. Since December 2009, Florida has gained nearly 44,000 jobs. However, Florida is still a long way from recovering. Since the recession began, Florida had lost over 800,000 jobs. Foreclosures are still a problem for the state, with Florida being second only to California in the number of mortgage foreclosures. The severity of the recession and current economic conditions suggests that Florida's economic recovery will be gradual. By 2013, the state's economy is projected to resume a more historically typical rate of growth. The real price of electricity in the current forecast is somewhat lower than that utilized in last year's Site Plan. A delay in carbon pricing, combined with lower projected fuel costs, are two factors driving the relatively lower forecasted price of electricity.

Consistent with the forecast presented in FPL's 2010 Site Plan, the total growth projected for the ten-year reporting period of this document is significant. The Summer peak is projected to increase to 26,193 MW by 2020, an increase of 3,937 MW over the 2010 actual Summer peak. Likewise, NEL is projected to reach 133,121 GWH in 2020, an increase of 18,747 GWH from the actual 2010 value.

II.C. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for each revenue class and are adjusted to match the NEL forecast. The results of these sales forecasts for the years 2011 - 2020 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and NEL forecast are outlined below.

1. Residential Sales

Residential electric usage per customer is estimated by using an econometric model. Residential sales are a function of: Cooling Degree-Hours, Heating Degree-Hours, lagged Cooling Degree-Hours, lagged Heating Degree-Hours, consecutive minimum temperature days square, real price of electricity (a 12-month moving average), Florida real per capita income, a variable designed to reflect the impact of empty homes, and a dummy variable for the month of January. The impact of weather is captured by the Cooling Degree-Hours, Heating Degree-Hours, the one month lag of these variables, and the consecutive minimum temperature variable. The price of electricity plays a role in explaining electric usage, because electricity, like all other goods and services, will be used in greater or lesser quantities depending upon its price. To capture economic conditions, the model includes Florida's real per capita income. The housing crisis has also had an impact on use per customer. Consequently, the model includes a variable designed to capture the impact of empty homes. A dummy variable for January is included to reflect a different usage pattern for this month. Residential energy sales are forecasted by multiplying the residential use per customer forecast by the number of residential customers forecasted.

2. Commercial Sales

The commercial sales forecast is also developed using an econometric model. Commercial sales are a function of the following variables: Florida real per capita income, commercial real price of electricity, Cooling Degree-Hours, Heating Degree-Hours, lagged Cooling Degree-Hours, a variable designed to reflect the impact of empty homes, a dummy variable for the month of December and for the specific month of January 2007, and an autoregressive term. Cooling Degree-Hours, Heating Degree-Hours, and the one month lag of Cooling Degree-Hours are used to capture weather-sensitive load in the commercial sector.

3. Industrial Sales

The industrial class is comprised of two distinct groups; very small accounts (those with less than 20 kW of demand) and large, traditionally industrial customers. As such, the forecast is developed using a separate econometric model for each group of industrial customers. The small industrial sales model utilizes the following variables: Florida Housing Starts, Cooling Degree-Hours, Heating Degree-Hours, and an autoregressive term. The Cooling and Heating Degree-Hours are used to capture the weather-sensitive load in this group of industrial customers. Florida Housing Starts are reflective of construction activity which comprises a significant portion of this group. The large industrial sales model utilizes the following variables: Florida population, and the industrial real price of electricity (a 24-month moving average).

4. Railroad and Railways Sales and Street and Highway Sales

The projections for railroad and railways sales are based on historical average use per customer which is multiplied by the forecasted number of customers. This class consists solely of Miami-Dade County's Metrorail system.

The forecast for street and highway sales is developed by using a trended use per customer, which is multiplied by the number of forecasted customers.

5. Other Public Authority Sales

This revenue class is a closed class with no new customers being added. This class consists of sports fields and a government account. The forecast for this class is based on historical knowledge of its usage characteristics.

6. Total Sales to Ultimate Customer

Sales forecasts by revenue class are summed to produce a total sales forecast.

7. Sales for Resale

Sales for resale (wholesale) customers are composed of municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers. Currently there are four customers in this class: the Florida Keys Electric Cooperative; City of Key West; Metro-Dade County; and Lee County Electric Cooperative. In addition, FPL will begin making sales to Seminole Electric Cooperative in June 2014 under a long term agreement[2].

FPL provides service to the Florida Keys Electric Cooperative under a long-term partial requirements contract. The sales to Florida Keys Electric Cooperative are forecasted using a regression model.

FPL's sales to the City of Key West are expected to terminate in 2013. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor.

Metro-Dade County sells 60 MW to Progress Energy Florida. Line losses are billed to Metro-Dade under a wholesale contract.

Lee County has contracted with FPL for FPL to supply a portion of their load through 2013, then to begin serving their entire load beginning in 2014 through 2033. This contract began in January 2010. Forecasted sales to Lee County are based on assumptions regarding their contract demand and expected load factor.

A new contract with Seminole Electric Cooperative is included in the forecast which includes delivery of 200 MW beginning in June 2014.

II.D. Net Energy for Load (NEL)

An econometric model is developed to produce a NEL per customer forecast. The inputs to the model include the real price of electricity (a 12-month moving average), and Florida real per capita income. The model also includes three weather variables: Cooling Degree Hours using a base temperature of 72 degrees, Heating Degree Days using a base of 66 degrees, and an additional heating degree variable for extreme cold weather

[2] FPL is currently evaluating the possibility of serving the Vero Beach electrical load at the time the 2011 Site Plan is being prepared. Because this possibility is still being evaluated, the load forecast presented in this Site Plan does not include this potential load.

using a base of 45 degrees. In addition, the model also includes variables for mandated energy efficiency and a variable designed to capture the impact of empty homes. Seasonal dummy variables are included for the months of February, May, July, October, and December.

The mandated energy efficiency variables are included to capture the impacts of the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and compact florescent light bulbs. The estimated impact of these factors for the 2011 to 2020 time period is a reduction, on average, of 10,447 GWh per year. The increase in the number of empty homes resulting from the current housing slump has affected use per customer and is captured in a separate variable. The forecast was also adjusted for additional load estimated from hybrid vehicles, beginning in 2010, which resulted in an increase of approximately 2,052 GWh by the end of the ten-year reporting period.

The NEL forecast is developed by multiplying the NEL per customer forecast by the total number of customers forecasted. Once the NEL forecast is obtained, total billed sales are computed using a historical ratio of sales to NEL. The sales by class forecasts previously discussed are then adjusted to match the total billed sales. The forecasted NEL values for 2011 - 2020 are presented in Schedule 3.3 that appears at the end of this chapter.

II.E. System Peak Forecasts

The rate of absolute growth in FPL system peak load has been a function of the size of the customer base, varying weather conditions, projected economic conditions, changing patterns of customer behavior (including an increased stock of electricity-consuming appliances), and more efficient appliances and lighting. FPL developed the peak forecast models to capture these behavioral relationships. Impacts of the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the impact of compact fluorescent light bulbs are taken into account in developing the peak forecast. The estimated impact of these federal mandates for the 2011 to 2020 time frame is a reduction of approximately 909 MW (Summer) and 454 MW (Winter) in 2011, and approximately 2,268 MW (Summer) and 1,315 MW (Winter) by 2020. The forecast was also adjusted for additional load estimated from hybrid vehicles which resulted in an increase of approximately 261 MW in the Summer and 114 MW in the Winter by the end of the ten-year reporting period.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2011 – 2020 are presented at the end of this chapter in Schedules 3.1 and 3.2, and in Chapter III in Schedules 7.1 through 7.4.

1. **System Summer Peak**

   The Summer peak forecast is developed using an econometric model. The variables included in the model are the real price of electricity, Florida real per capita income, Cooling Degree-Hours in the day prior to the peak, the maximum temperature on the day of the peak, and a variable for mandated energy efficiency. The model is based on the Summer peak contribution per customer and is, therefore, multiplied by total customers, and adjusted to account for incremental loads resulting from hybrid vehicles and new wholesale contracts, to derive FPL's system Summer peak.

2. **System Winter Peak**

   Like the system Summer peak model, this model is also an econometric model. The model consists of two weather-related variables: the minimum temperature on the peak day and Heating Degree-Hours for the prior day square. The model also includes a dummy variable for winter peaks occurring on weekends and an autoregressive term. The forecasted results are adjusted for the impact of mandated energy efficiency. The model is based on the Winter peak contribution per customer and is, therefore, multiplied by total customers, and adjusted to account for incremental loads resulting from hybrid vehicles and new wholesale contracts, to derive FPL's system Winter peak.

3. **Monthly Peak Forecasts**

   The forecasting process for monthly peaks consists of the following actions:

   a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to the appropriate seasonal peak.

   b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.F. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2011 - 2020 are produced using a System Load Forecasting "shaper" program. This model uses years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

II.G. Uncertainty

In order to address uncertainty in the forecasts of aggregate peak demand and NEL, FPL first evaluates the assumptions underlying the forecasts. FPL takes a series of steps in evaluating the input variables, including comparing projections from different sources, identifying outliers in the series, and assessing the series' consistency with past forecasts. In addition, FPL reviews factors which may affect the input variables. This may require reviewing data from local economic development boards or from FPL's own Customer Service Business Unit. Other factors which may be considered include demographic trends and housing characteristics such as starts, size, and vintage of homes.

Uncertainty is also addressed in the modeling process. Generally, econometric models are used to forecast the aggregate peak demand and NEL. During the modeling process, the relevant statistics (goodness of fit, F-statistic, P-values, mean absolute deviation (MAD), mean absolute percentage error (MAPE), etc.) are scrutinized to ensure that the models adequately explain historical variation. Once a forecast is developed, it is compared with past forecasts. Deviations from past forecasts are examined in light of changes in input assumption to ensure that the drivers underlying the forecast are well understood. Finally, forecasts of aggregate peak demand and NEL are compared with their actual values as they become available. An ongoing process of variance analyses is performed. To the extent that the variance analysis identifies large unexplained deviations between the forecast and actual values, revisions to the econometric model may be considered.

The inherent uncertainty in load forecasting is addressed in different ways in regard to FPL's overall resource planning and operational planning work. In regard to FPL's resource planning work, FPL's utilization of a 20% reserve margin criterion (approved by the FPSC) is designed, in part, to maintain reliable electric service to FPL's customers in light of forecasting uncertainty. In regard to operational planning, an extreme weather load forecast for the projected Summer peak day is produced based on maximum historical temperatures on the day of the Summer peak. Likewise, an extreme weather Winter peak forecast is developed by considering minimum historical temperatures at the time of the Winter peak. Statistical analysis on the distribution of historical weather data is performed to evaluate and understand the impact of extreme weather on the peaks and on NEL, and the likelihood of experiencing extreme weather.

II.H. DSM

The effects of FPL's DSM energy efficiency programs implementation through 2010 are assumed to be imbedded in the actual usage data for forecasting purposes. Any change in usage pattern, be it the impact of FPL's DSM energy efficiency efforts, price impact, or weather impact, is reflected in the actual observed load data. Therefore, energy efficiency impacts, whether market-driven or as a result of FPL's DSM programs, are assumed to be included in the historical usage data for peaks and NEL.

The impacts of incremental energy efficiency that FPL plans to implement in the future, plus the impacts of FPL's cumulative and incremental load management programs, are accounted for as "line item reductions" to the forecasts as part of the IRP process as shown in Schedules 7.1 and 7.2. After making these adjustments to the load forecasts, the resulting "firm" load forecast is then used in FPL's IRP work.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class
(Historical)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2001	7,754,846	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,898,628	2.21	50,865	3,566,167	14,263	40,029	435,313	91,955
2003	8,079,316	2.21	53,485	3,652,663	14,643	41,425	444,650	93,163
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,620,855	2.21	54,570	3,906,267	13,970	44,487	478,867	92,901
2007	8,729,806	2.19	55,138	3,981,451	13,849	45,921	493,130	93,121
2008	8,771,694	2.20	53,229	3,992,257	13,333	45,561	500,748	90,987
2009	8,732,591	2.19	53,950	3,984,490	13,540	45,025	501,055	89,860
2010	8,739,209	2.18	56,343	4,004,366	14,070	44,544	503,529	88,464

Historical Values (2001 - 2010):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent actual energy sales including the impacts of existing conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve month values.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class
(Projected)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2011	8,873,003	2.20	54,364	4,033,183	13,479	44,188	504,216	87,637
2012	8,965,719	2.20	54,932	4,075,327	13,479	44,496	505,886	87,956
2013	9,106,253	2.20	56,399	4,139,206	13,626	45,134	510,436	88,423
2014	9,263,516	2.20	58,257	4,210,689	13,836	46,214	517,941	89,226
2015	9,418,816	2.20	59,326	4,281,280	13,857	47,089	526,406	89,455
2016	9,564,956	2.20	60,382	4,347,707	13,888	47,869	534,487	89,560
2017	9,700,967	2.20	61,118	4,409,530	13,860	48,660	542,273	89,733
2018	9,830,014	2.20	61,828	4,488,188	13,837	49,456	549,902	89,937
2019	9,955,509	2.20	62,480	4,525,231	13,807	50,385	557,399	90,393
2020	10,080,541	2.20	63,575	4,582,064	13,875	51,512	564,827	91,199

Projected Values (2011 - 2020):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent forecasted energy sales that do not include the impact of incremental conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption And Number of Customers by Customer Class (Historical)

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads & Railways	Street & Highway Lighting	Sales to Public Authorities	Sales to Ultimate Consumers
Year	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	GWh	GWh	GWh
2001	4,091	15,445	264,872	86	419	67	90,212
2002	4,057	15,533	261,199	89	420	63	95,523
2003	4,004	17,029	235,135	93	425	64	99,496
2004	3,964	18,512	214,139	93	413	58	99,095
2005	3,913	20,392	191,873	95	424	49	102,296
2006	4,036	21,211	190,277	94	422	49	103,659
2007	3,774	18,732	201,499	91	437	53	105,415
2008	3,587	13,377	268,168	81	423	37	102,919
2009	3,245	10,084	321,796	80	422	34	102,755
2010	3,130	8,910	351,318	81	431	28	104,557

Historical Values (2001 - 2010):

Col. (10) and Col.(14) represent actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve month values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.2
History and Forecast of Energy Consumption And Number of Customers by Customer Class (Projected)

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads & Railways	Street & Highway Lighting	Sales to Public Authorities	Sales to Ultimate Consumers
Year	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	GWh	GWh	GWh
2011	3,152	8,848	356,191	82	442	30	102,257
2012	3,082	9,306	331,150	91	452	30	103,083
2013	3,037	9,733	312,057	92	463	30	105,155
2014	3,018	10,054	300,163	92	475	30	108,085
2015	3,013	10,241	294,231	92	487	30	110,038
2016	3,015	10,437	288,893	92	500	30	111,888
2017	3,004	10,527	285,355	92	514	30	113,418
2018	2,992	10,516	284,534	92	529	30	114,928
2019	2,987	10,545	283,288	92	544	30	116,518
2020	2,981	10,598	281,312	92	560	30	118,749

Projected Values (2011 - 2020):

Col. (10) and Col.(14) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (11) represents the ennual average of the twelve month values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class
(Historical)

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2001	970	7,222	98,404	2,722	3,935,281
2002	1,233	7,443	104,199	2,792	4,019,805
2003	1,511	7,386	108,393	2,879	4,117,221
2004	1,531	7,467	108,093	3,029	4,224,509
2005	1,506	7,498	111,301	3,156	4,321,895
2006	1,569	7,909	113,137	3,218	4,409,563
2007	1,499	7,401	114,315	3,276	4,496,589
2008	993	7,092	111,004	3,348	4,509,730
2009	1,155	7,394	111,303	3,439	4,499,067
2010	2,049	7,768	114,373	3,523	4,520,328

Historical Values (2001 - 2010):

Col. (19) represents actual energy sales including the impacts of existing conservation.

Col. (19) = Col. (16) + Col. (17) + Col. (18). Historical NEL includes the impacts of existing conservation and agrees to Col. (5) on schedule 3.3.

Col. (20) represents the annual average of the twelve month values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class
(Projected)

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2011	2,142	6,776	111,175	3,590	4,549,837
2012	2,142	7,292	112,517	3,672	4,594,191
2013	2,047	7,445	114,647	3,756	4,663,131
2014	4,935	6,014	121,035	3,845	4,742,529
2015	5,566	8,006	123,610	3,940	4,821,867
2016	5,599	8,106	125,593	4,041	4,896,672
2017	5,625	8,208	127,251	4,147	4,966,477
2018	5,672	8,310	128,910	4,258	5,032,864
2019	5,717	8,443	130,679	4,373	5,097,548
2020	5,770	8,601	133,121	4,493	5,161,981

Projected Values (2011 - 2020):

Col. (19) represents forecasted energy sales that do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

Col. (19) = Col. (16) + Col. (17) + Col. (18).

Col. (20) represents the annual average of the twelve month values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 3.1
History and Forecast of Summer Peak Demand (MW)
(Historical)

(1) Year	(2) Total	(3) Wholesele	(4) Retail	(5) Interruptible	(6) Res. Loed Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2001	18,754	169	18,585	0	635	516	483	469	17,436
2002	19,219	261	18,958	0	670	576	483	506	17,866
2003	19,666	253	19,415	0	885	618	566	541	18,217
2004	20,545	258	20,287	0	695	665	586	566	19,064
2005	22,361	264	22,097	0	898	715	592	599	20,871
2006	21,819	258	21,563	0	910	770	607	634	20,302
2007	21,962	261	21,701	0	941	608	676	672	20,345
2008	21,060	181	20,879	0	986	861	734	697	19,360
2009	22,351	249	22,102	0	976	902	760	719	20,595
2010	22,256	419	21,837	0	991	982	816	747	16,720

Historical Values (2001 - 2010):

Col. (2) - Col. (4) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) represent ectual DSM capebilities starting from January 1988 end are ennuel (12-month) values except for 2010 values which are August values. Note thet the values for FPL's former Interruptible Rete are incorporated into Col. (8), which elso includes Business On Call (BOC), CILC, end Commercial /Industrial Demand Reduction (CDR).

Col. (10) represents a HYPOTHETICAL "Net Firm Demend" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.1
History and Forecast of Summer Peak Demand (MW)
(Projected)

(1) August of Year	(2) Total	(3) Wholesela	(4) Retail	(5) Interruptible	(6) Res. Load Manegement	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2011	21,679	383	21,295	0	1,005	79	858	39	19,697
2012	21,853	385	21,468	0	1,017	154	676	93	19,712
2013	22,155	343	21,812	0	1,023	244	698	154	19,837
2014	23,452	1,129	22,322	0	1,041	343	934	216	20,917
2015	24,172	1,136	23,037	0	1,044	442	952	272	21,462
2016	24,605	1,143	23,463	0	1,047	536	971	316	21,734
2017	25,025	1,150	23,875	0	1,050	625	989	353	22,006
2016	25,266	1,157	24,109	0	1,053	711	1,007	378	22,117
2019	25,690	1,165	24,526	0	1,056	792	1,026	397	22,419
2020	26,193	1,172	25,022	0	1,060	837	1,042	412	22,823

Projected Values (2011 - 2020):

Col. (2) - Col. (4) represent FPL's forecasted peak w/o incrementel conservation, cumulative load management, or Incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values ere projected August values. The 2011 values are based on IRP projections after the 2010 Summer peak and FPL's new DSM Goals for 2011. The projections for 2012 through 2020 ere besed on FPL's DSM Goels.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation end assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case
(Historical)

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2001	18,199	150	18,049	0	749	500	448	196	17,002
2002	17,597	145	17,452	0	768	546	457	206	16,373
2003	20,190	246	19,944	0	802	587	453	227	18,935
2004	14,752	211	14,541	0	814	583	535	233	13,403
2005	18,108	225	17,883	0	816	600	542	240	16,750
2006	19,683	225	19,458	0	822	620	549	249	18,312
2007	16,815	223	16,592	0	849	644	579	279	15,387
2008	18,055	163	17,892	0	668	666	638	285	16,551
2009	20,081	207	19,874	0	884	687	680	291	18,517
2010	24,346	500	23,846	0	895	718	721	303	21,709

Historical Values (2001 - 2010):

Col. (2) - Col. (4) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) for 2001 through 2010 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC), CILC, and Commercial /Industrial Demand Reduction (CDR).

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case
(Projected)

(1) January of Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2011	21,443	376	21,067	0	911	31	754	15	19,732
2012	21,491	378	21,113	0	922	63	769	47	19,689
2013	21,683	380	21,303	0	932	104	784	69	19,774
2014	22,584	1,015	21,569	0	956	158	817	134	20,518
2015	23,048	1,222	21,826	0	959	214	832	177	20,866
2016	23,302	1,229	22,073	0	961	267	846	215	21,014
2017	23,543	1,237	22,308	0	963	314	860	244	21,161
2018	23,794	1,245	22,550	0	986	358	874	286	21,331
2019	24,044	1,252	22,792	0	968	398	889	282	21,506
2020	24,305	1,260	23,045	0	970	431	902	293	21,709

Projected Values (2011 - 2020):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected January values. The 2011 values are based on IRP projections after the 2010 Winter peak and FPL's new DSM Goals for 2011. The projections for 2012 through 2020 are based on FPL's DSM Goals.

Col. (6) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.3
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))
(Historical)

(1) Year	(2) Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Actual Net Energy For Load GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Total Billed Retail Energy Sales (GWh)	(9) Load Factor(%)
2001	101,364	1,554	1,405	98,404	970	7,222	90,212	59.9%
2002	107,380	1,682	1,499	104,199	1,233	7,443	95,523	61.9%
2003	111,784	1,773	1,619	108,393	1,511	7,386	99,496	62.9%
2004	111,659	1,872	1,693	108,093	1,531	7,487	99,095	59.9%
2005	115,065	1,970	1,793	111,301	1,506	7,498	102,296	56.8%
2006	117,116	2,078	1,901	113,137	1,569	7,909	103,659	59.2%
2007	116,518	2,138	2,066	114,315	1,499	7,401	105,415	59.4%
2008	115,379	2,249	2,126	111,004	993	7,092	102,919	60.0%
2009	115,844	2,345	2,196	111,303	1,155	7,394	102,755	56.8%
2010	119,119	2,487	2,259	114,373	2,049	7,768	109,302	61.1%

Historical Values (2001 - 2010):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5).

Col. (3) & Col. (4) are DSM values starting in January 1988 and are annual (12-month) values. Col. (3) and Col. (4) for 2010 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWh reductions experienced each year .

Col. (5) is the actual Net Energy for Load (NEL) for years 2001 - 2010.

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760) Adjustments are made for leap years.

Schedule 3.3
History of Annual Net Energy for Load (GWh)
(All values are "at the generator"values except for Col (8))
(Projected)

(1) Year	(2) Forecasted Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Net Energy For Load Adjusted for DSM GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Forecasted Total Billed Retail Energy Sales w/o DSM GWh	(9) Load Factor(%)
2011	111,175	73	75	111,026	2,142	6,776	102,257	58.5%
2012	112,517	230	245	112,041	2,142	7,292	103,083	58.6%
2013	114,647	408	442	113,797	2,047	7,445	105,155	59.1%
2014	121,035	601	641	119,793	4,935	8,014	108,085	58.9%
2015	123,610	798	822	121,991	5,568	8,006	110,038	58.4%
2016	125,593	986	972	123,634	5,599	8,106	111,888	58.1%
2017	127,251	1,185	1,092	124,994	5,625	8,208	113,418	58.0%
2018	128,910	1,335	1,186	126,387	5,672	8,310	114,928	58.2%
2019	130,879	1,497	1,267	127,915	5,717	8,443	116,516	58.1%
2020	133,121	1,657	1,329	130,135	5,770	8,801	118,749	58.0%

Projected Values (2011 - 2020):

Col. (2) represents Forscasted Net Energy for Load w/o DSM values. The values are extracted from Schedule 2.3, Col. (19).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation and are mid-year (6-month) values reflecting DSM signups occurring evenly thoughout each year.The effects of conservation implemented prior to 2011 are incorporated into the load forecast values in Col. (2).

Col. (5) is the forecasted Net Energy for Load (NEL) after adjusting for impacts DSM for years 2011 - 2020 using the formula:
Col. (5) = Col. (2) - Col. (3) - Col. (4)

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7).
These values are at the meter.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760) Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2010 ACTUAL		2011 FORECAST		2012 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	24,346	9,410	21,443	8,191	21,491	8,301
FEB	16,488	7,470	17,558	7,365	17,596	7,449
MAR	17,748	8,001	17,460	8,239	17,499	8,328
APR	15,480	8,179	17,160	8,368	17,299	8,449
MAY	19,217	9,950	19,255	9,905	19,410	9,992
JUN	21,901	11,619	20,557	10,336	20,723	10,423
JUL	21,633	11,215	21,155	11,101	21,326	11,199
AUG	22,256	11,651	21,679	11,218	21,853	11,323
SEP	20,738	11,094	20,917	10,424	21,086	10,543
OCT	19,116	9,020	19,582	9,728	19,740	9,872
NOV	17,052	8,145	17,922	8,099	18,082	8,255
DEC	21,153	8,619	17,787	8,202	17,946	8,383
TOTALS		114,373		111,175		112,517

Cols. (4) - (7) do not include the impacts of cumulative load management, incremental conservation, and incremental load management and are consistent with values shown in Col. (19) of Schedule 2.3 and Col. (2) of Schedule 3.3.

CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990s and has since utilized this approach, in whole or in part as analysis needs warranted, to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of new power plants, the primary subjects of this document, are determined as part of the IRP process work.

This section describes FPL's basic IRP process. Some of the key assumptions, in addition to a new load forecast, that were used in developing the resource plan presented in this Site Plan are also discussed.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental steps to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Evaluate the competing options and resource plans in regard to system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

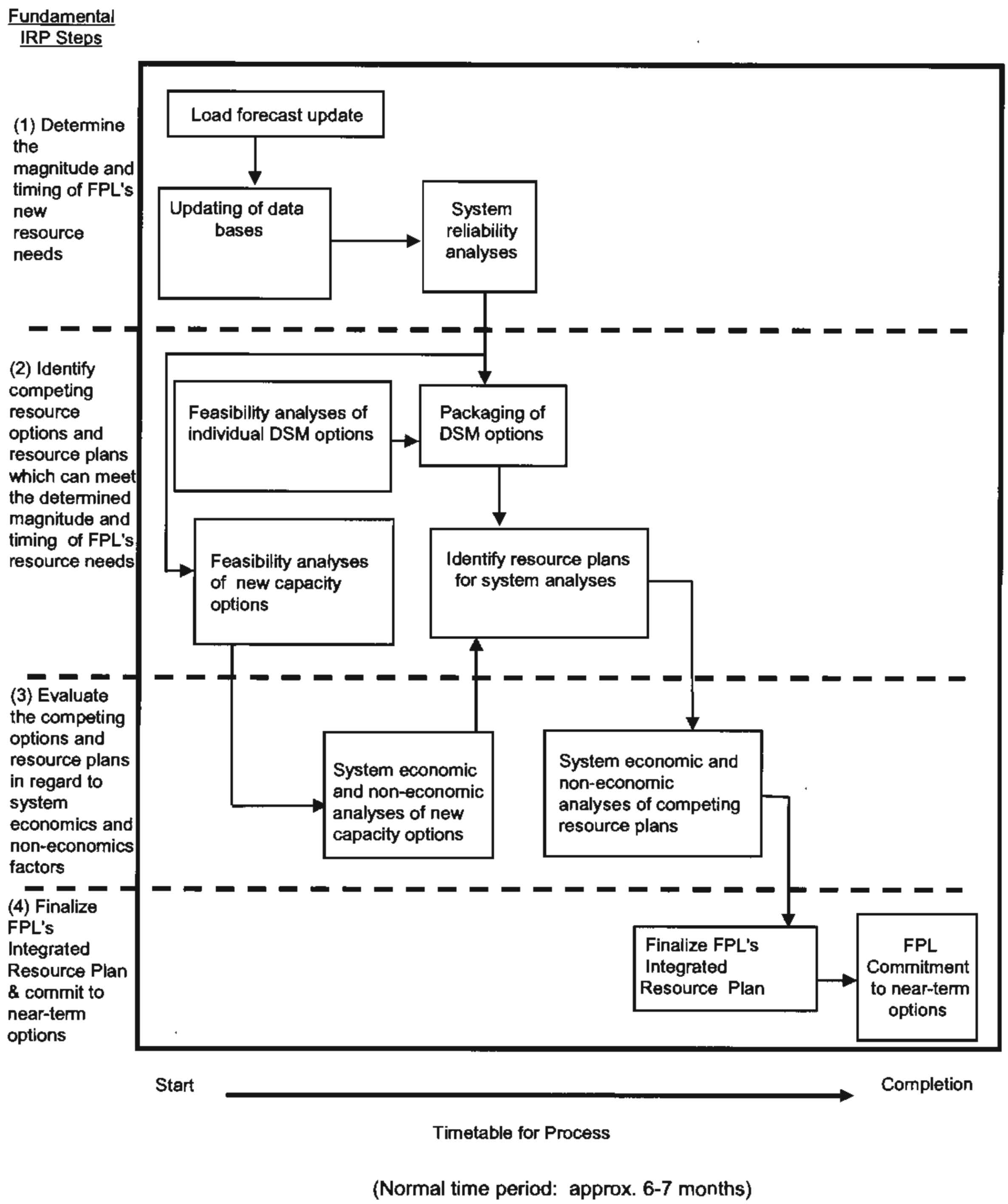

Figure III.A.1: Overview of FPL's IRP Process

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of the four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed to maintain system reliability. Also determined in this step is when the MWs are needed to meet FPL's reliability criteria. This step is often referred to as a reliability assessment, or resource adequacy, analysis for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include, but are not limited to: delivered fuel price projections, current financial and economic assumptions, and power plant capability and reliability assumptions. FPL also includes key assumptions regarding three specific resource areas: (1) near-term construction capacity additions, (2) firm capacity power purchases, and (3) DSM implementation.

The first of these assumptions is based on new generating capacity additions that have been approved by the Florida Public Service Commission (FPSC) through Determination of Need proceedings that evaluated both the need for, and the cost-effectiveness of, each of the new capacity additions. These generating capacity additions have also received the necessary Site Certification approvals from either the Secretary of the Florida Department of Environmental Protection (FDEP) or the Governor and Cabinet (acting as the Siting Board). (There is also work in progress to obtain the necessary federal and state licenses, permits, and approvals for construction and operation of two new nuclear units whose earliest practical deployment dates are outside of the 2011 – 2020 reporting period of this Site Plan.)

Several new generating unit additions will occur in the 2011 – 2020 reporting time frame of this document. These generating unit additions include:

- The completion of a third gas-fired CC unit at FPL's West County Energy Center (WCEC) site which is scheduled to come in-service in June 2011. This new unit, WCEC Unit 3, will add approximately 1,219 MW (Summer) of generation capacity.

FPSC approval for this unit was obtained in September 2008 and site certification was granted in November 2008.

- Two existing generating plant sites, each featuring two older fossil fuel-fired steam generating units, are in the process of being modernized by removing the existing generating units and replacing them with one new, highly efficient CC unit. The new CC plant at FPL's Cape Canaveral site is projected to be placed in-service in 2013. This new CC unit is projected to have a peak output of 1,210 MW and will be called the Cape Canaveral Next Generation Clean Energy Center. The new plant at FPL's Riviera site is projected to be placed in-service in 2014 and it is expected to have a peak output of 1,212 MW. This new plant will be called the Riviera Beach Next Generation Clean Energy Center. These modernizations were approved by the FPSC in September 2008. The site certification application for Cape Canaveral was granted in October 2009. The site certification application for Riviera Beach was granted in November 2009.
- In addition, FPL will be adding approximately 450 MW of generating capacity at its existing nuclear power plants at the Turkey Point and St. Lucie sites. This added capacity is scheduled to come in-service in the 2011 – 2013 time period. These capacity "uprates" were approved by the FPSC in January 2008. The Final Order for the Site Certification was issued in September 2008 for the St. Lucie uprates and in October 2008 for the Turkey Point uprates.

These new generating units and generating capacity additions were selected for a variety of reasons including cost-effectiveness, significant system fuel savings, fuel diversity, and significant system emission reductions, including greenhouse gas emission reductions.

The second of these assumptions involves firm capacity power purchases. FPL's current projection of firm capacity purchases is generally similar to the projection shown in FPL's 2010 Site Plan. However, FPL's current projection does include an additional 90 MW from the Palm Beach Solid Waste Authority (SWA). FPL and SWA are currently seeking FPSC approval for this capacity addition. In total, the projected firm capacity purchases are from a combination of utility and independent power producers. Details, including the annual total capacity values for these purchases, are presented in Chapter I in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's resource planning work.

The third of these assumptions involves a projection of the amount of additional demand side management (DSM) that is anticipated to be implemented annually over the ten-year period. Since 1994, FPL's resource planning work has assumed that, at a minimum, the DSM MW called for in FPL's approved DSM Goals will be achieved as planned. The resource plan presented in FPL's 2011 Site Plan fully accounts for the new DSM goals.

These key assumptions, plus the other updated information described above, are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's future resource needs. This determination is accomplished by system reliability analyses which for FPL are currently based on dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry.

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss-of-load probability or LOLP. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of the "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

The result of the first fundamental step of resource planning is a projection of how many new MW of resources are needed to meet both reserve margin and LOLP criteria, and thus maintain system reliability, and of when the MW are needed. Information regarding the timing and magnitude of these resource needs is then used in the second fundamental step: identifying resource options and resource plans that can meet the determined magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, preliminary economic screening analyses of new capacity options are often conducted to determine which new capacity options appear to be the most competitive on FPL's system. This preliminary analysis work can also help identify capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. Similarly, preliminary economic screening analyses of new DSM options and/or continued growth in existing DSM options are typically conducted.

FPL typically utilizes the P-MArea production cost model and a Fixed Cost Spreadsheet, and/or the Strategist model, as well as spreadsheet analyses, to perform the preliminary economic screening of generation resource options. For the preliminary economic screening analyses of DSM resource options, FPL typically uses its DSM cost-effectiveness model which is an FPL spreadsheet model utilizing the FPSC's approved methodology for performing preliminary cost-effectiveness screening of individual DSM measures and programs. FPL also utilizes its non-linear programming model for analyzing the potential for lowering system peak loads through additional load management capacity. Then FPL typically utilizes its linear programming model to develop DSM portfolios that are subsequently used in developing resource plans for final system analyses of DSM-based resource plans.

The individual new resource options emerging from these preliminary economic screening analyses are then typically "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's projected new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet and/or dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans in Regard to System Economics and Non-Economic Factors:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for evaluating these resource options and resource plans in final, or system, economic analyses that attempt to account for all of the impacts to the FPL system from the competing resource options/resource plans. (These system impacts are typically not accounted for in preliminary economic screening analyses.) In FPL's 2010 and early 2011 resource planning work, once the resource plans were developed, FPL utilized the P-MArea production cost model and a Fixed Cost Spreadsheet, and/or the Strategist model, to perform the system economic analyses.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the objective generally being to minimize FPL's projected leveled system average rate (i.e., a Rate Impact Measure or RIM methodology). In cases in which the DSM contribution was assumed as a given and the only competing options were new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. Consequently, the competing options and plans in such cases were evaluated on a cumulative present value revenue requirement (CPVRR) basis.

Other factors are also included in FPL's evaluation of resource options and resource plans. While these factors may have an economic component or impact, they are often discussed in quantitative, but non-economic terms, such as percentages, tons, etc. rather than in terms of dollars. These factors are often referred to by FPL as "system concerns" that include (but are not necessarily limited to) maintaining/enhancing fuel diversity in the FPL system, system emission levels, and maintaining a regional balance between load and generating capacity, particularly in the Southeastern Florida counties of Miami-Dade and Broward. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL's system, both the economic and non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps are typically used to develop the current resource plan. This plan is presented in the following section.

III.B Projected Incremental Resource Additions/Changes

FPL's projected incremental generation capacity additions/changes for 2011 through 2020 are depicted in Table III.B.1. These capacity additions/changes result from a variety of actions that primarily consist of: (i) changes to existing units (which are frequently achieved as a result of plant component replacements during major overhauls), (ii) the construction of an approved third new generating unit at the West County Energy Center (WCEC), (iii) increases in generating capacity at FPL's four existing nuclear units, (iv) the temporary return of certain generating units from Inactive Reserve status to active service, then returning these units to Inactive Reserve status, (v) changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, (vi) the projected modernizations of FPL's existing Cape Canaveral and Riviera sites by the removal of the steam generating units that were previously on the sites and the addition of one new, very fuel-efficient CC generating unit at each site, and (vii) the projected addition of new, very fuel-efficient new CC generating capacity at sites yet to be determined.[3]

[3] These new CC capacity additions may take the form of new CC units at Greenfield sites, Brownfield sites, and/or through modernizations at existing sites. These decisions have not yet been made at the time the 2011 Site Plan was being developed. For reference purposes, these additions are referred to in the 2011 Site Plan as "Greenfield CC units".

Although the DSM additions that are consistent with the DSM goals imposed by the FPSC through 2020 are not explicitly presented in this table, these DSM additions have been fully accounted for in all of FPL's resource planning work reflected in this document. In addition, the projected MW reductions from these DSM additions are reflected in the projected reserve margin values shown in the table below and in Schedules 7.1 and 7.2 presented later in this chapter.

Table III.B.1: Projected Capacity Changes for FPL

Projected Capacity Changes for FPL (1)			
		Net Capacity Changes (MW)	
Year	Projected Capacity Changes	Winter (3)	Summer (4)
2011	Inactive Reserve of Existing Units - offline (8)	(775)	(1,922)
	Riviera Plant - removed for modernization	---	(565)
	Scherer Plant - Upgrade	---	26
	St. Lucie Unit 2 Uprate - Outage (7)	---	17
	St. Lucie Unit 2 - Interim Increase (7)	(726)	---
	West County Unit 3 (6)	---	1,219
2012	Changes to Existing Purchases (5)	---	(100)
	St. Lucie Unit 1 Uprates - Completed	—	122
	Turkey Point Unit 3 Uprates - Completed	—	109
	Inactive Reserve of Existing Units - offline (8)	(394)	---
	Inactive Reserve Units (PE Units 3 & 4) - active status	765	761
	Manatee 2 ESP - Outage (8)	(822)	---
	Riviera Plant - removed for modernization	(571)	---
	Scherer Plant - upgrede	26	---
	St. Lucie Unit 1 Uprate - Outage (7)	(853)	---
	St. Lucie Unit 2 - Interim Increase (7)	17	---
	St. Lucie Unit 2 Uprate - Outage (7)	---	(731)
	Turkey Point Unit 3 Uprate - Outage (7)	(717)	—
	West County Unit 3 (6)	1,335	---
2013	Cape Canaveral Next Generation Clean Energy Center (6)	—	1,210
	St. Lucie Unit 1 Uprates - Completed	122	---
	St. Lucie Unit 2 Uprates - Completed	93	93
	Turkey Point Unit 3 Uprates - Completed	109	---
	Turkey Point Unit 4 Uprates - Completed	—	109
	Inactive Reserve Unit (PE Units 3 & 4) - inactive status (9)	(765)	(761)
	Manatee Unit 1 ESP - Outage (8)	(822)	---
	Martin Unit 1 ESP - Outage (8)	--	(826)
2014	Cape Canaveral Next Generation Clean Energy Center (6)	1,355	---
	Turkey Point Unit 4 Uprates - Completed	109	---
	Martin Unit 1 ESP - Outage (8)	(832)	---
	Martin Unit 2 ESP - Outage (8)	—	(826)
	Riviera Beach Next Generation Clean Energy Center (6)	—	1,212
2015	Change to Existing Qualifying Facilities (5)	—	90
	Riviera Beach Next Generation Clean Energy Center (6)	1,344	---
2016	Changes to Existing Purchases (5)	(841)	(1,306)
	Change to Existing Qualifying Facilities (5)	—	---
	Greenfield 3x1 Combined Cycle (6)	—	1,191
2017	Changes to Existing Purchases (5)	(383)	---
	Greenfield 3x1 Combined Cycle (6)	1,351	---
2018	—	---	---
2019	—	---	---
2020	Greenfield 3x1 Combined Cycle (6)	---	1,191

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) The Summer and Winter reserve margins reflect an additional 350 MW in Summer and 550 MW in Winter of unspecified average capacity scheduled to be out during those peak periods. See Chapter III for more details.
(3) Winter values are forecasted values for January of the year shown.
(4) Summer values ara forecasted values for August of the yeer shown.
(5) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(6) All new unit additions are scheduled to be in-service in June of the year shown. All additions essumed to stert in June ere included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the naxt year.
(7) Outages for uprete work.
(8) Outages for ESP work. (Assumes EPA final Toxics Rula requires ESPs, thus necessitating outages.)
(9) A number of existing FPL power plants heve been removed from service and placed on Inactive Reserve status. See Chapter III for e discussion of the units on Inactive Reserves.

III.C Discussion of the Projected Resource Plan and Issues Impacting FPL's Resource Planning Work

As indicated in the Executive Summary, FPL's resource planning efforts in 2010 and early 2011 were influenced by a number of factors. Furthermore, these factors are expected to continue to influence FPL's resource planning work for the foreseeable future. There are 7 such factors that are of primary importance:

1) Growing difficulty in scheduling fossil-fueled power plant maintenance;
2) High projected costs of returning generating units on Inactive Reserve status to active service;
3) Securing additional natural gas (and doing so in a manner that enhances the reliability of the natural gas supply system);
4) Maintaining/enhancing fuel diversity in the FPL system;
5) Maintaining a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward counties;
6) Growing dependence upon DSM resources to maintain FPL system reliability; and,
7) Possible establishment of "Clean Energy Standards" or another mechanism to promote large scale utilization of renewable energy.

These 7 factors, and their various impacts on FPL's resource planning efforts including the current resource plan that is presented in this Site Plan, are briefly discussed below.

1. Growing Difficulty in Scheduling Fossil-Fueled Power Plant Maintenance:

FPL's fleet of fossil generation units is increasingly made up of CC units. These units have the desirable attributes of being very fuel-efficient and operating with very low air emissions. However, the key components of each CC unit are combustion turbines (CT). The maintenance schedule for the CT components is directly tied to the CT's operating hours. When operating hour thresholds are reached, scheduled maintenance of the CTs must take place. This fact reduces flexibility in scheduling planned maintenance of CC units, and, in turn, reduces flexibility in scheduling planned maintenance of other fossil-fueled generating units on FPL's system.

FPL has historically attempted to avoid scheduling planned maintenance of its generating units during its peak load months of January and August. However, as the number of CC units on its system has increased (and will continue to increase with the addition of WCEC 3, the modernizations, etc.), this scheduling of planned maintenance outside of the peak months has become more difficult to do. Compounding this issue is the fact that the Winter peak can occur in months other than January such as December or February, and the Summer peak can occur in months other than August such as June or July. FPL already schedules planned maintenance during these other months.

Consequently, FPL will now begin scheduling planned maintenance during the months of January and August. For reserve margin projection purposes, FPL is now projecting that, on average, 550 MW will be out of service for planned maintenance during its Winter peak months and 350 MW will be out of service for planned maintenance during its Summer peak months. These projections are based on averages of currently planned maintenance in Winter peak months other than January, and on averages of currently planned maintenance in Summer peak months other than August.

This projection of scheduled planned maintenance during peak months is now reflected in Schedules 7.1 through 7.4 which present, respectively, the projected Summer and Winter reserve margins. (In practice, the actual number of MW that will be out of service on any day in January and/or August will likely vary from these average amounts.) One effect of this change is that it increases FPL's projected resource needs in future years.

2. Projected High Costs of Returning Generating Units on Inactive Reserve Status to Active Service:

In FPL's 2010 Site Plan, FPL's then-current resource plan (reflecting FPL's 2009 and early 2010 resource planning work) assumed that the generating units that were being placed on Inactive Reserve status would begin to be returned to active service as needed to maintain system reliability. No economic analyses had been done at that time to compare this option to other alternatives. FPL's recent analyses of these generating units, particularly regarding the projected high costs of returning them to active service in comparison with the net system costs of new generation options, indicate that the addition of new generation will be less costly.

In comparison with new CC capacity, FPL's ongoing analyses currently show that it is projected to be more cost-effective for FPL's customers to add new CC capacity rather than to return the Inactive Reserve units to active service. As a result, FPL currently projects the following in regard to the units currently on Inactive Reserve status:

- Sanford 3 and Cutler 5 & 6 are projected to be retired by 2012. FPL will be examining other potential uses for these sites, including their potential use as sites for new renewable energy facilities.
- Turkey Point 2 operation has been changed from a unit that provides electricity to the grid to a synchronous condenser that provides voltage support for the transmission system in Southeastern Florida. Turkey Point 2 is currently projected to continue serving in this role for the foreseeable future.
- Two of the four steam units at FPL's Port Everglades site, Port Everglades units 3 & 4, are currently scheduled to be returned to active service in 2012, then to return to Inactive Reserve status until the modernized units at Cape Canaveral and Riviera are in normal operation (i.e., until mid-2014). A decision on the future role of these two units will be made at that time or at a later date.
- The remaining units on Inactive Reserve, Port Everglades 1 & 2, will remain on Inactive Reserve status for the immediate future. A decision on their future roles will be made at a later date.

FPL's current projections indicate that the Inactive Reserve units are not the economic choice with which to meet FPL's future resource needs. FPL currently projects that it will have resource needs beginning in 2016 and increasing each year through 2020, the last year of the reporting period of this document.

For planning purposes, FPL's 2011 Site Plan shows the addition of one new "Greenfield" CC unit in 2016 and another new Greenfield CC unit in 2020. These new CC units are currently projected to be the same type of unit that is being added in the modernizations of Cape Canaveral and Riviera. These projected in-service dates are subject to change as a result of FPL's on-going resource planning work.

As mentioned previously in a footnote, FPL has not yet made a decision regarding the site for new CC capacity additions. Therefore, new CC capacity could be added at a Greenfield site, a Brownfield site, and/or at an existing site as part of a modernization similar to those currently taking place at FPL's Cape Canaveral and Riviera sites.

In regard to potential modernization of existing sites, there are a number of factors that must be analyzed including: fuel delivery costs/issues, transmission impacts (especially in the Southeastern region of Florida as will be discussed later), system reliability issues due to the removal of existing units from active service prior to construction of new capacity at the site, overall system economics, etc. FPL's analyses to-date have identified Port Everglades as a potential candidate for modernization. This site, plus other Greenfield and Brownfield sites, is being evaluated in FPL's on-going analyses. These potential sites are discussed in detail in Chapter IV.

3. Securing Additional Natural Gas:

The recent trend of increasing reliance upon natural gas to produce electricity for FPL's customers is projected to continue with the addition of WCEC 3, the Cape Canaveral modernization, and the Riviera modernization, plus the projection of new CC capacity starting in 2016. Therefore, FPL will need to secure more natural gas supply and more gas transportation capacity. The issue is how to secure these additional natural gas resources in a manner that is economical for FPL's customers and which maintains and/or enhances the reliability of natural gas supply and deliverability to FPL's generating units.

FPL has historically purchased the gas transportation capacity required for new natural gas supply from two existing natural gas pipeline companies. As more natural gas is delivered through two pipelines entering Florida, the impact of a supply disruption on either pipeline becomes more problematic. Therefore, FPL sought approval in 2009 from the FPSC for the construction of a new, third natural gas pipeline into Florida capable of serving future gas-fired generation needs for FPL and others in the state. Such a third pipeline was projected to have benefits for FPL and its customers by increasing the diversity of FPL's fuel supply sources, increasing the physical reliability of the pipeline delivery system, and enhancing competition among pipelines. However, the application for an FPL-owned pipeline was denied by the FPSC in 2009. FPL is continuing to evaluate how additional significant amounts of natural gas can best be delivered to its system in the future and FPL will be addressing this issue with the FPSC in 2011.

4. **Maintaining/Enhancing System Fuel Diversity;**

FPL is currently dependent upon using natural gas to generate more than half of the electricity it delivers to its customers. In the future, the percentage of FPL's electricity that is generated by natural gas is projected to steadily increase. Therefore, FPL is continually seeking opportunities to maintain and enhance the fuel diversity of its system.

In 2007, FPL sought approval from the FPSC to add two new advanced technology coal units to its system. These two new units would have been placed in-service in 2013 and 2014. However, in part due to concerns over potential greenhouse gas emission legislation/regulation, FPL was unable to obtain approval for these units. Consequently, FPL does not believe that new advanced technology coal units are viable fuel diversity enhancement options in Florida for the foreseeable future.

Therefore, FPL has turned its attention to nuclear energy and renewable energy to enhance its fuel diversity, and to using natural gas more efficiently. In regard to nuclear energy, FPL obtained approval to increase capacity at each of its four existing nuclear units. In total, these capacity "uprates" will add approximately 450 MW of nuclear capacity and energy for FPL's customers beginning in the 2011 - 2013 time period. In 2008, the FPSC approved the need for these uprates and authorized FPL to recover uprates-related expenditures. The schedule for this additional nuclear capacity has changed slightly from that projected in FPL's 2010 Site Plan. An "interim" capacity increase of approximately 17 MW (FPL's share) from St. Lucie 2 is now projected to become available by April 2011. No such "interim" capacity increase was projected in the 2010 Site Plan. Another projected change involves the schedule for St. Lucie 1. The completion of the uprates work is now projected to occur several months later than originally projected, primarily due to delays in federal licensing for this project. Smaller delays in the completion of the uprate projects at St. Lucie 2 and Turkey Point 3 are also now projected.

FPL is continuing its work to obtain all of the licenses, permits, and approvals that would be necessary to construct and operate two new nuclear units at its Turkey Point site in the future. These licenses, permits, and approvals will provide FPL with the option to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units. A decision regarding construction of these new units will be made once the licenses and permits are granted. (Based on the current estimated time for construction, the earliest practical deployment dates for the two new units would be beyond the 10-year reporting period for this Site Plan. Therefore, these units are not shown in this document.)

FPL also has been involved in activities to investigate adding or maintaining renewable resources as a part of its generation supply. One of these activities is a variety of discussions with the owners of existing facilities aimed at maintaining or extending current agreements that are scheduled to end during the ten-year reporting period of this document. Also FPL sought and received approval from the FPSC in 2008 to add 110 MW through three new FPL-owned solar facilities, one solar thermal facility and two photovoltaic (PV) facilities. One 25 MW PV facility began commercial operation in 2009. The remaining two solar facilities, a 10 MW PV facility and a 75 MW solar thermal steam generating facility, began commercial operation in 2010. The addition of these renewable energy facilities was made possible due to enabling legislation from the Florida Legislature in 2008. FPL remains strongly supportive of Federal and/or State legislation that enables electric utilities to add renewable energy resources and authorize the utilities to recover costs for these resources.

In regard to using natural gas more efficiently, FPL received approvals in 2008 from the FPSC to build a third highly efficient CC unit at its West County Energy Center site (WCEC Unit 3) and to modernize the existing Cape Canaveral and Riviera plant sites with new, highly efficient CC units that replace the former steam units. WCEC Unit 3 is currently projected to go in-service in 2011. The modernizations of Cape Canaveral and Riviera are currently projected to go in-service in 2013 and 2014, respectively.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity. FPL also plans to maintain the ability to utilize fuel oil at those existing units that have that capability, although cost factors currently limit the expected use of this fuel. Furthermore, as previously discussed, FPL continues to evaluate the potential for greater diversity in the delivery of natural gas through a new, third natural gas pipeline. A third pipeline would result in a more reliable, and more economic, natural gas supply for FPL's customers.

5. Maintaining a Balance Between Load and Generation in Southeastern Florida:

In recent years, an imbalance was projected to develop between regionally installed generation and regional peak load in Southeastern Florida. With such an imbalance, a significant amount of energy required in the Southeastern Florida region during peak periods would need to be provided either by operating less efficient generating units located in Southeastern Florida out of economic dispatch, or by importing the energy through the transmission system from plants located outside the region. FPL's prior planning work concluded that either additional installed generating capacity in this region, or additional installed transmission capacity capable of delivering electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location, four recent capacity addition decisions (Turkey Point Unit 5 and WCEC Units 1, 2, & 3) were evaluated as the most cost-effective options to meet FPL's capacity needs in the near-term. Adding these units contributes to reducing the imbalance between generation and load in Southeastern Florida.

In addition, FPL will be adding increased capacity at FPL's existing two nuclear units at Turkey Point in 2012 and 2013 and will increase the generating capacity at its Riviera site through a modernization of that site in 2014. These generating unit additions in Southeastern Florida are expected to address the imbalance for most, if not all, of the 2011 - 2020 reporting period addressed in this document.

However, because of the combination of a number of factors including: (i) the projected retirement of the Cutler 5 & 6 units, (ii) placing the Port Everglades steam units (Units 1 – 4) on Inactive Reserve status for most of this reporting period, (iii) dedicating Turkey Point 2 to a transmission support role, plus (iv) projected growth in electrical demand in the region, FPL still projects that an imbalance between generation and load in the region will eventually occur. The recent WCEC unit additions, and the modernization of the Rivera site, have had the effect of effectively "shrinking" the region of concern regarding imbalance. The former area of concern included Miami-Dade County, Broward County, and parts of Palm Beach County. After these capacity additions in Palm Beach County, the region of concern regarding a load-generation imbalance for the foreseeable future now consists of Miami-Dade and Broward counties, which is south of the former area of concern.

The Southeastern Florida imbalance issue will remain a consideration in FPL's on-going resource planning work, particularly as FPL's planning analyses in future years begin to increasingly focus on the 2020-on time frame.

6. Growing Dependence Upon DSM Resources to Maintain System Reliability:

In late 2009, the FPSC imposed significantly higher DSM Goals than had been deemed appropriate in previous DSM Goals dockets. One result of the higher amounts of DSM is that it will result in higher electric rates for all of FPL's customers.

Another result is that FPL is projected to become increasingly dependent upon DSM, instead of generation resources, to maintain system reliability. In order to demonstrate this point, FPL has added two new schedules, Schedule 7.3 and 7.4, to its 2011 Site Plan. These new schedules are presented in the back portion of this chapter. Both of the new schedules use Schedule 7.1, which presents FPL's projected Summer reserve margins, as a starting point.

In Schedule 7.3, Column (14), FPL projects what a "generation-only" reserve margin would be for each year in the 10-year reporting period by making two changes in Schedule 7.1. First, the projected DSM values in Column (8) have been zeroed out to remove the projected contribution from DSM. Second, the projected additions of one Greenfield CC unit in both 2016 and 2020 have been removed. These two changes result in a projection of reserve margins that are based solely on generation resources that currently exist or which have been approved by the FPSC.

The result is a projected generation-only reserve margin in the range of approximately 11% to 12% through 2015, but which would decrease significantly thereafter. It decreases to 4.5% in 2016 and becomes negative by 2020.

In Schedule 7.4, the projected additions of the 2016 and 2020 Greenfield CC units have been added back in as indicated by the values in Column (1). The projected generation-only reserve margin for the year 2016 increases to 9.3%. Although substantially higher than the 4.5% value for 2016 projected in Schedule 7.3, the 9.3% value is also considerably lower than the 11% to 12% range for the years 2011 through 2015. In the years after 2016, the projected generation-only reserve margin steadily decreases to less than 5% by 2019. Even with the projected addition of another new CC unit in 2020, this generation-only reserve margin does increase again, but only slightly above 7%.

Therefore, FPL's projected system reserves, already dependent to a significant degree upon DSM resources, are becoming increasingly more dependent upon DSM. Stated another way, the FPL system's ability to continue to provide reliable electricity service to FPL's customers is becoming increasingly dependent upon DSM. FPL currently believes that generation-only reserves at these projected low levels may not be adequate, and FPL will continue to evaluate the appropriateness of a minimum generation-only requirement as part of its on-going resource planning work.

7. Possible Establishment of "Clean Energy Standards":

At the time this document is being prepared, neither the United States nor the State of Florida has established a "Clean Energy Standard" which would require that a certain amount of energy be supplied by "clean" energy sources. A similar "Renewable Portfolio Standard" proposal was prepared by the FPSC and sent to the Florida Legislature for their consideration, including an option to change the standard to a Clean Energy Standard, during the 2009 legislative session. However, no such legislation was enacted during either the 2009 or 2010 session. Such legislation, or other legislative initiatives regarding clean energy contributions, may occur in the future. If such legislation is enacted in 2011 or in a later year, FPL will then determine what steps need to be taken to comply with the legislation. Such steps would then be discussed in FPL's Site Plan in the year following the enactment of such legislation.

III.D Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include both conservation initiatives and load management. FPL's DSM efforts through 2010 have resulted in a cumulative Summer peak reduction of approximately 4,371 MW (Summer) at the generator and an estimated cumulative energy saving of approximately 55,462 Gigawatt Hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2010 have eliminated the need to construct more than 13 new 400 MW generating units.

As previously discussed in Chapter I and earlier in this chapter, the FPSC in late 2009 imposed significantly higher DSM Goals for FPL for 2010 – 2019 than were deemed appropriate in prior DSM Goals dockets. The DSM Goals recently imposed by the FPSC have three components: Summer MW reductions, Winter MW reductions, and GWh reductions. Table III.D.1 presents the cumulative Summer MW reduction component of these goals. (The Summer MW component, and to a much lesser degree the Winter MW reduction component, impacts FPL's need for future resources such as those discussed in this document. The GWh reduction component has no impact on FPL's need for future resources.)

Table III.D.1: FPL's Summer MW Reduction Goals for DSM
(at the Generator)

Year	Cumulative Summer MW DSM Goals for FPL (at Generator)
2010	110
2011	253
2012	419
2013	599
2014	783
2015	955
2016	1,111
2017	1,251
2018	1,379
2019	1,498

The next step in regard to FPL's DSM efforts is to obtain FPSC approval for a DSM Plan with which it proposes to meet the DSM Goals. At the time this Site Plan is being prepared, FPL has not received FPSC approval for a DSM Plan. Consequently, FPL does not yet know with certainty what its portfolio of approved DSM programs will be. FPL expects to have an approved DSM Plan later in 2011. (Assuming this is the case, FPL expects to provide a description of its approved DSM programs in its 2012 Site Plan.) Nonetheless, FPL's resource planning work in 2010 and early 2011, reflected in this document, assumed that the FPSC-approved DSM Goals would be met.

FPL has consistently been among the leading utilities nationally in DSM achievement. For example, according to the U.S. Department of Energy's 2009 data (the last year for which the DOE data was available at the time this Site Plan is being developed), FPL ranked # 2 nationally in cumulative DSM demand reduction. And, importantly, FPL has achieved these significant DSM accomplishments while seeking to lessen the DSM-based impact on electric rates for all of its customers.

In regard to DSM, FPL's intent is to meet the FPSC's DSM Goals and to continue its national leadership role in DSM consistent with efforts both to continue to lessen the DSM-based impact on electric rates for all of FPL's customers, and to ensure that FPL's system reliability does not become too dependent upon DSM resources.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy to FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV bulk transmission lines that must be certified under the Transmission Line Siting Act.

Table III.E.1: List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	St. Johns 1/	Pringle	25	Dec - 16	230	759
FPL	Manatee 2/	BobWhite	30	Dec - 15	230	1190

1/ Final order certifying the corridor was issued on April 21, 2006. This project is to be completed in two phases. Phase I consisted of 4 miles of new 230kV line (Pringle to Pellicer) and was completed in May-2009. Phase II consists of 21 miles of new 230kV line (St. Johns to Pellicer) and is scheduled to be completed by Dec-2016.

2/ Final order certifying the corridor was issued on November 6, 2008. This project consists of 30 miles of new 230kV line (Manatee to Bobwhite) and is scheduled to be completed by Dec-2015

In addition, there will be transmission facilities needed to connect several of FPL's projected generating capacity additions to the system transmission grid. These transmission facilities for the projected generating capacity additions at the West County Energy Center site Unit 3, the capacity increases (uprates) at the existing St. Lucie and Turkey Point nuclear sites, and the Cape Canaveral and Riviera Beach modernizations are described on the following pages.

In regard to the existing generating units that have been placed on Inactive Reserve status, there are no projected impacts to FPL's transmission system from these units.

III.E.1 Transmission Facilities for West County Energy Center (WCEC) Unit 3

The work required to connect West County Energy Center (WCEC) Unit 3 in 2011 to the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with four breakers to connect the three combustion turbines (CT), and one steam turbine (ST).
2. Build new Sugar 230 kV Substation on WCEC site.
3. Construct two string busses to connect the collector busses to Sugar 230kV Substation.
4. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
5. At Corbett Substation, relocate Germantown 230 kV line terminal from Corbett to Sugar Sub.
6. At Corbett Substation, relocate Broward/Yamato 230 kV line terminal from Corbett to Sugar Sub.
7. At Corbett Substation, install new Sugar 230 kV line terminal in Bay 2W.
8. At Corbett Substation, install one 5-ohm inductor on the 230 kV side of the 500/230 kV autotransformer.
9. Add relays and other protective equipment.

II. Transmission:

1. Relocate Germantown 230 kV line from Corbett to Sugar.
2. Relocate Broward/Yamato 230 kV line from Corbett to Sugar.
3. Construct one mile 230 kV 1190 MVA line from Sugar to Corbett.

III.E.2 Transmission Facilities for St. Lucie Units 1 & 2 Capacity Uprates

The work required to address the St. Lucie Units 1 & 2 uprates in 2011 for Unit 1 and in 2012 for Unit 2, in regard to the FPL grid is projected to be as follows:

I. Substation:

1. At Midway Substation, replace eleven 230 kV disconnect switches, and remove six wave traps. Also upgrade associated jumpers, bus work and equipment connections.
2. At St. Lucie Switchyard, replace eighteen 230 kV disconnect switches and remove six wave traps.
3. Uprate the Unit 1A and 1B main step-up transformers to 635 MVA. Unit 1B main step-up transformer is to be replaced by the uprated spare main step-up transformer. Existing Unit 1B main step-up transformer is to become the new station spare
4. Uprate the spare main step-up transformer to 635 MVA to replace Unit 2A main step-up transformer.
5. Replace the Unit 2A and Unit 2B main step-up transformer with new one rated at 635 MVA.
6. Add fiber optic relays and other protective equipment.

II. Transmission:

1. Upgrade the three existing St. Lucie-Midway 230 kV lines with spacers between the conductors to achieve a normal (continuous) rating of 2790 Amperes.
2. Replace one existing overhead ground wire on each of the three existing St. Lucie Midway 230kV line with fiber optic overhead ground wire for protective relay communication.

III.E.3 Transmission Facilities for Turkey Point Units 3 & 4 Capacity Uprates

The work required to address the Turkey Point Units 3 & 4 uprates in 2012 in regard to the FPL grid is projected to be as follows:

I. Substation:

1. At Turkey Point Switchyard, install two 5-Ohm series phase inductors combined with external shunt capacitors on the southeast and southwest 230 kV operating busses.
2. At Turkey Point Switchyard, replace twelve 230 kV disconnect switches. Also upgrade associated jumpers, bus work and equipment connections.
3. Uprate the Unit 3 and Unit 4 main step-up transformers to 970 MVA.
4. Replace spare main step-up transformer with 1028 MVA transformer.
5. Add relays and other protective equipment.
6. Replace breaker failure panels at Davis Substation.
7. Replace breaker failure panels at Flagami Substation.

II. Transmission:

1. Upgrade the existing string busses for both Units 3 & 4 between the main step-up transformers and the switchyard with spacers between the conductors.

III.E.4 Transmission Facilities for Cape Canaveral Next Generation Clean Energy Center (Projected Modernization)

The work required to connect the projected Cape Canaveral Next Generation Clean Energy Center in 2013 to the FPL grid is forecasted to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with four breakers to connect the three combustion turbines (CT), and one steam turbine (ST).
2. Construct two string busses to connect the collector busses to Cape Canaveral 230kV Substation.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. At Cape Canaveral Switchyard replace eight 230 kV disconnect switches. Also upgrade associated jumpers, bus work and equipment connections.
5. Expand switchyard relay vault and add relays and other protective equipment.

II. Transmission:

1. Relocate the Cape Canaveral-Grissom 115 kV line.

III.E.5 Transmission Facilities for Riviera Beach Next Generation Clean Energy Center (Projected Modernization)

The work required to connect the projected Riviera Beach Next Generation Clean Energy Center in 2014 to the FPL grid is forecasted to be as follows:

I. Substation:

1. Expand the Riviera 230 kV Switchyard five breakers to accommodate terminals for one combustion turbine (CT), and one steam turbine (ST).
2. Construct a new 138 kV Riviera Switchyard - five bays, 14 breakers with terminals to connect two CT units and seven 138 kV lines.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. Add relays and other protective equipment.
5. At Ranch Substation, add a new 230 kV bay 5 and upgrade bay 4 to 3000 Amperes.
6. Breaker replacements:
   Ranch Substation – Replace one 230 kV breaker
   Broward Substation – Replace one 230 kV breaker

II. Transmission:

1. Break the Indiantown-Riviera 230kV and extend each of the line segments south (approx. 4 miles) to connect to the Ranch 230 kV Substation forming Indiantown-Ranch and a Ranch-Riviera 230 kV circuits.
2. Remove Corbett-Ranch #2 230 kV line at Ranch and:
   a. extend to meet the Cedar-Lauderdale 230 kV line N/S corridor (approx. 10 miles).
3. Break Cedar -Corbett 230 kV (near Ranch Sub in Corbett-Jog section) and:
   a. Extend Cedar side to Riviera, (approx. 15 miles) creating new Cedar-Riviera 230 kV.
   b. Extend Corbett side to meet the Cedar-Lauderdale 230 kV N/S corridor (approx. 10 miles).
4. Break Cedar-Lauderdale 230 kV (near 230 corridor running N/S)
   a. Connect Cedar side to meet 3.b. to create a Cedar to Corbett 230 kV.
   b. Connect Lauderdale side to meet 2.a. to create a Corbett to Lauderdale 230 kV.
5. Upgrade the existing IBM-Yamato 138 kV line to 1200 Amperes.
6. New underground 138 kV tie line between new Riviera 138 kV Switchyard and 560 MVA, 230/138 kV autotransformer in the expanded Riviera 230 kV Substation.
7. Relocate six existing 138 kV lines from existing Riviera 138 kV Switchyard to new Riviera 138 kV Switchyard.

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to effectively utilize renewable energy technologies to serve its customers. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. For purposes of discussing FPL's renewable energy efforts in this document, those efforts will be placed into five categories.

1) **Early Research & Development Efforts:**

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970s in demonstrating the first residential solar photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-kilowatt (kW) system was placed into operation in 1984. (The system was removed in 1990 to make room for substation expansion once testing of this PV installation had been completed.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. This FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's early "green pricing" efforts.

2) **Demand Side & Customer Efforts:**

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program ended (due to the fact that it was no longer cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for six passive home designs with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the FPSC to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test were deemed to be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, and various customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

FPL has since continued to analyze and promote the utilization of PV. These efforts have included a PV research, development, and education project, and participation in the State of Florida's PV for Schools program. With resources from the FPL Group Foundation, FPL contributed 30 kw of PV to schools and educational non-profits in its service area during 2010. This initiative also delivers teacher training and curriculum that is tied to the Sunshine Teacher Standards in Florida. Additionally, it provides teacher grants to promote and fund projects in the classrooms. As part of its green pricing research efforts, 2 kw PV arrays were placed in each of 4 schools, and in the Miami Science Museum, for a total of 10 kw of PV in educational facilities. FPL's green pricing efforts also resulted in a 250 kw PV array at Rothenbach Park in Sarasota.

FPL has also been investigating fuel cell technologies through monitoring of industry trends, discussions with manufacturers, and direct field trials. From 2002 through the end of 2005, FPL conducted field trials and demonstration projects of Proton Exchange Membrane (PEM) fuel cells with the objectives of serving customer end-uses while evaluating the technical performance, reliability, economics, and relative readiness of the PEM technology. The demonstration projects were conducted in partnership with customers and included 5 locations. The research projects were useful to FPL in identifying specific issues that can occur in field applications and the current commercial viability of this technology. FPL will continue to monitor the progress of these technologies and conduct additional field evaluations as significant developments in fuel cell technologies occur.

In addition, FPL assists customers who are interested in installing PV equipment at their facilities. Consistent with Florida Administrative Code Rule 25-6.065, Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned PV systems. Through December 2010, approximately 1,074 customer systems (predominantly residential) have been interconnected.

Finally, as part of its DSM Goals decision, the FPSC imposed a requirement for Florida's investor-owned utilities to spend up to a set, not-to-exceed amount of money annually to facilitate demand side solar water heater and photovoltaic applications. FPL's not-to-exceed annual amount of money for these applications is approximately $15.5 million. These expenditures will be made in accordance with the solar water heater and PV aspects of FPL's DSM Plan once FPL receives approval for its Plan.

3) **Supply Side Efforts – Power Purchases:**

FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy, and as-available energy, have been purchased by FPL from these types of facilities. (Please refer to Tables I.B.1, I.B.2, and Table I.C.1 in Chapter I).

Periodically, FPL invites renewables suppliers to provide proposals for renewable power and energy at or below avoided costs in response to FPL's Requests for Proposals (RFPs). FPL issued Renewable RFPs in 2007 and 2008 soliciting proposals to provide firm capacity and energy, and energy only, at or below avoided costs from renewable generators. FPL also promptly responds to inquiries for information from prospective renewable energy suppliers either by e-mail or phone.

With regard to existing contracts that have recently ended, FPL and the Solid Waste Authority of Palm Beach (SWA) recently agreed to extend their contract that expired March 31, 2010 for a 20-year term from April 1, 2012 through April 1, 2032. In addition, a new contract for an additional 90 MW between FPL and SWA has been signed and has been submitted to the FPSC for approval. Also, the firm capacity and energy contract with Broward South that expired August 2009 was not renewed, but Broward South continues as an as-available supplier of renewable energy to FPL.

4) **Supply Side Efforts – FPL Facilities:**

With regard to solar projects, FPL has completed construction of three solar facilities: (i) a 75 MW steam generation solar thermal facility in Martin County (the Martin Next Generation Solar Energy Center); (ii) a 25 MW PV electric generation facility in DeSoto County (the DeSoto Next Generation Solar Energy Center); and (iii) a 10 MW PV electric generation facility in Brevard County at NASA's Kennedy Space Center (the Space Coast Next Generation Solar Energy Center). The DeSoto County project was completed in 2009 and the other two projects were completed in 2010. These three projects were completed in response to the Florida Legislature's House Bill 7135 which was signed into law by then-Governor Crist in June 2008. House Bill 7135 (hereafter referred to as the 2008 Energy Bill), was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in the State of Florida. Specifically, the 2008 Energy Bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land, zoning, and transmission rights in place. FPL's three solar projects met the specified criteria, and were granted approval for cost recovery in 2008. Each of the three solar projects is discussed below.

a. **The Martin Next Generation Solar Energy Center:**

This facility began commercial operation in 2010 and provides 75 MW of solar thermal capacity in an innovative way that directly displaces fossil fuel usage on the FPL system. This facility consists of solar thermal technology which generates steam that is integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired CC plant. This project is the first "hybrid" solar plant in the world, the second largest solar facility in the world, and the largest solar plant of any kind in the U.S. outside of California.

b. **The DeSoto Next Generation Solar Energy Center:**

This PV facility began commercial operation in 2009 and provides up to 25 MW of non-firm capacity and energy, making it the second largest PV facility in the U.S. The facility utilizes a tracking array that is designed to follow the sun as it traverses across the sky.

c. **The Space Coast Next Generation Solar Energy Center:**
Located at the Kennedy Space Center, this facility is part of an innovative public/private partnership with NASA. This non-tracking PV facility began commercial operation in 2010 and provides up to 10 MW of non-firm capacity and energy.

Each of these facilities is a significant and innovative renewable generating plant in its own right. Collectively, these Next Generation Solar Energy Centers are expected to produce a total of approximately 225,000 megawatt-hours (MWh) of electricity each year, and at peak production provide enough energy to serve the requirements of more than 15,000 homes.

For resource planning purposes, FPL projects that the output from these renewable facilities will be "as available", non-firm energy only. This is due to several factors. First, the Martin solar thermal facility is a "fuel-substitute" facility, not a facility that provides additional capacity and energy. The solar thermal facility displaces the use of fossil fuel to produce steam on the FPL system when the solar thermal facility is operating. Second, in regard to the two PV facilities, the intermittent nature of the solar resource makes it difficult to accurately determine what contribution the PV facilities at these specific locations can consistently make at FPL's late Summer afternoon and early Winter morning peak load hours. Once site-specific operating data has been gathered for an appropriate amount of time, FPL will then re-evaluate the actual output from each PV facility to determine what portion, if any, of its output can be projected as firm capacity at the projected peak hours in FPL's resource planning work.

In addition to these three approved projects, FPL is currently in the process of identifying other potential solar sites in the state in the event that a future Renewable Portfolio Standard (RPS), Clean Energy Portfolio Standard (CPS), or other legislation is enacted by the Florida legislature that enables FPL to construct and recover costs for additional solar generation. FPL is evaluating existing FPL generation sites along with potential Greenfield sites within FPL's service territory. These potential FPL and Greenfield sites are discussed further in Chapter IV.

FPL remains hopeful of developing a wind generation project on South Hutchinson Island in St. Lucie County. This project is known as the St. Lucie Wind Project and it would consist of up to six wind turbine generators capable of generating up to approximately 13.8 MW. In 2007, FPL began the St. Lucie County land use approval process, and soon after applied for the necessary federal and state permitting. However, a decision by the state and federal agencies on the St. Lucie Wind Project's permitting will not be finalized until the local land use approval process is completed. At the time this Site Plan is being developed, the local land use approval process has not been completed. An in-service date for the project is dependent upon a successful outcome to the local approval and permitting process.

5) **Ongoing Research & Development Efforts:**

FPL has developed alliances with several Florida universities to promote development of emerging technologies. For example, an alliance has been established with the newly formed Southeast National Marine Renewable Energy Center (SNMREC) at Florida Atlantic University (FAU), which will focus on the commercialization of ocean current, ocean thermal (i.e., energy conversion as well as cold water air conditioning), and hydrogen technologies. FPL has been taking the lead in assisting FAU with the discussions being held with the U.S. Department of the Interior's Minerals Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE). BOEMRE is working to establish the permitting process for ocean energy development on the outer continental shelf.

FPL has also developed an alliance with the University of Florida to support its biomass-related studies to determine improved vegetative management techniques for use in minimizing maintenance costs at FPL's current and future solar sites and to perform wind studies within the state. In addition, FPL has partnered with the Florida Institute of Technology on fuel cell technology and with the Florida State Universities Center for Applied Power System in regard to grid integration of ocean energy and other renewables.

FPL has also developed a "Living Lab" to demonstrate FPL's solar energy commitment to employees and visitors at its Juno Beach facility. FPL is evaluating multiple solar technologies and applications for the purpose of developing a renewable business model resulting in the most cost-effective and reliable uses of solar energy for FPL customers. FPL will expand the Living Lab as new solar products come to market.

FPL has also been in discussions with several private companies on multiple emerging technology initiatives including ocean current, ocean thermal, hydrogen, fuel cell technology, biomass, biofuels, and energy storage.

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil-fired generation. In the early 1980s, FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership and additional purchases from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit 4 which began serving FPL's customers in 1991. Starting in 1997, petroleum coke was added to the fuel mix as a blend stock with coal at SJRPP.

The trend since the early 1990s has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective CC generating units and the ready availability of natural gas. This planning document reflects an evolution in that trend in recognition that, although efficient gas-fired generation continues to provide significant benefits to FPL's customers, adding natural gas-fired additions exclusively would, in the long term, create an unbalanced generation portfolio. In 2009, FPL placed into commercial operation two new gas-fired CC units at the West County Energy Center (WCEC) site. A third new CC unit will be added to the WCEC site in 2011. In addition, FPL is currently modernizing its existing Cape Canaveral and Riviera plant sites by removing the steam generating units previously on the sites and replacing them with two highly efficient new CC units, one at each site. These new CC units will provide highly efficient generation that will dramatically improve FPL's overall system generation efficiency.

In addition, FPL is increasing its utilization of nuclear energy through capacity uprates of its four existing nuclear units. These uprates will add a total of approximately 450 MW of nuclear generation capacity in the 2011 – 2013 time period. (FPL is also pursuing plans to obtain licenses, permits, and approvals to construct and operate two new nuclear units at its existing Turkey Point site that, in total, would add approximately 2,200 MW of new nuclear generating capacity. The earliest dates by which those new nuclear units could practically be deployed are outside of the ten-year reporting time frame of this document.)

In regard to utilizing renewable energy, FPL has added 110 MW of solar generating capacity through a 75 MW solar thermal facility at FPL's existing Martin site, a 25 MW PV facility in DeSoto County, and a 10 MW PV facility in Brevard County. The 25 MW PV facility was placed into commercial operation in 2009. The other two solar facilities were placed into commercial operation in 2010.

FPL's future resource planning work will continue to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance FPL's long-term fuel diversity. These fuel diverse alternatives may include: the purchase of power from renewable energy facilities, additional FPL-owned renewable energy facilities, obtaining access to diversified sources of natural gas such as liquefied natural gas (LNG) and natural gas from the Mid-Continent unconventional reserves, preserving FPL's ability to utilize fuel oil at its existing units, and increased utilization of nuclear energy. (As previously discussed, new advanced technology coal generating units are not currently considered as viable options in Florida in the ten-year reporting period of this document due, in part, to concerns over greenhouse gas emissions legislation/regulation.) The evaluation of the feasibility and cost-effectiveness of these, and other possible alternatives, will be part of on-going resource planning efforts.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2020 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

2. FPL's Fossil Fuel Cost Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future resource needs. FPL's forecasts are generally consistent with other published contemporary forecasts.

Future oil and natural gas prices, and to a lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short-and long-term price of oil, natural gas, coal, and petroleum coke. These drivers include:

a. Current and projected worldwide demand for crude oil and petroleum products;

b. Current and projected worldwide refinery capacity/production;

c. Expected worldwide economic growth, in particular in China, and other Pacific Rim countries;

d. Organization of Petroleum Exporting Countries (OPEC) production, the availability of spare OPEC production capacity and the assumed growth in spare OPEC production capacity;

e. Non-OPEC production and expected growth in non-OPEC production;

f. The geopolitics of the Middle East, West Africa, the Former Soviet Union, Nigeria, Venezuela, etc., as well as, the uncertainty and impact upon worldwide energy consumption related to U. S. and worldwide environmental legislation, politics, etc.;

g. Current and projected North American natural gas demand;

h. Current and projected U.S., Canadian, and Mexican natural gas production;

i. The worldwide supply and demand for LNG; and

j. The growth in solid fuel generation on a U. S. and worldwide basis.

The inherent uncertainty and unpredictability in these factors today and tomorrow clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal and petroleum coke) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed and utilized Low, Medium, and High price forecasts for fossil fuels in some of its 2010 and early 2011 resource planning work, particularly in regard to nuclear cost recovery filing work.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

a. For 2011 through 2013, the methodology used the January 14, 2011 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil, ultra low sulfur diesel fuel oil, and Henry Hub natural gas commodity prices;

b. For the next two years (2014 and 2015), FPL used a 50/50 blend of the January 14, 2011 forward curve and the most current projections at the time from The PIRA Energy Group;

c. For the 2016 through 2025 period, FPL used the annual projections from The PIRA Energy Group, and;

d. For the period beyond 2025, FPL used the real rate of escalation provided in the Energy Information Administration (EIA) *Annual Energy Outlook 2011 Early Release* publication. FPL assumed a 2.5% annual rate of escalation to convert real prices to nominal prices prior to 2025, with no escalation from 2025 forward. In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach:

a. The price forecasts for Central Appalachian coal (CAPP), Powder River Basin (PRB), South American coal, and petroleum coke were provided by JD Energy;

b. The marine transportation rates from the loading port for coal and petroleum coke to an import terminal were also provided by JD Energy;

c. The coal price forecast for SJRPP and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for oil, natural gas, coal, and petroleum coke prices were based on the historical volatility of the 12-month forward price, one year ahead. FPL developed these forecasts to account for the uncertainty which exists within each commodity as well as across commodities. These forecasts reflect a range of reasonable forecast outcomes.

3. Nuclear Fuel Cost Forecast

This section reviews the various steps needed to fabricate nuclear fuel for delivery to the nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

a) Steps Required for Nuclear Fuel to be delivered to FPL's Plants

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

(1) Mining: Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U3O8 (sometimes referred to as yellowcake).

(2) Conversion: During the second step, the U3O8 is chemically converted into UF6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

(3) Enrichment: The third step is called enrichment. Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 3% to as high as 5%). The output of this enrichment process is enriched uranium in the form of UF6.

(4) Fabrication: During the last step, fuel fabrication, the enriched UF6 is changed to a UO2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) Mining: There is some volatility in the current uranium market. Current demand continues to be rather stable and outputs from production facilities have been increasing steadily. The following are the current major contributors that led to some volatility in the prices for uranium:

- Hedge funds are now back in the market, now that the recent financial crisis is resolving itself. This causes more speculative demand, not tied to market fundamentals, and causes the market price to move according to news potentially affecting potential future supply/demand balance, or news regarding current suppliers.
- The large inventory from the U.S. Department of Energy (DOE) is being withheld from the market due to political pressure from suppliers. Some of this uranium finds its way into the market periodically to fund cleanup of certain Department of Energy facilities.
- The U.S. Department of Commerce (DOC) has imposed restrictions on the import of nuclear fuel from France and Russia.
- Although a limited number of new nuclear units is scheduled to start production in the US during the next 5 to 10 years, other countries, more specifically China, has announced a significant increase in construction of new units which has caused short term increase in uranium market price.

Over a 10 year horizon, FPL expects the market to be more consistent with market fundamentals The supply picture is more stable, with laws enacted to resolve the import of Russian-enriched uranium, by allowing some imports of Russian-enriched uranium to about 20-25% of needs for currently operating units, but with no restriction on the first core for new units and no restrictions after 2020. New and current facilities continue to add capacity to meet demands. Actual demand tends to grow over time because of the long lead time to build nuclear units. However, FPL cannot discount the possibility of future periodic sharp increase in prices, but believes such occurrences will likely be temporary in nature.

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies.

(2) Conversion: FPL's price forecast considers the construction of new nuclear units. Just like for raw uranium, an increase in demand for conversion services would result from this need. Insufficient planned production is currently forecasted after 2013 to meet the higher demand scenario. As with additional raw uranium production, supply will expand beyond current level once more firm commitments are made including commitments to building new nuclear units.

(3) Enrichment: With no new production capacity, the current tight market supply for economically produced enrichment services will continue until 2013. The current diffusion plants, which use significant amount of electricity, can make up any gaps in supply of enrichment services now that prices for electricity have decreased. In addition, there are a number of new facilities coming on-line through 2013, using more efficient and proven processes such as the use of centrifuges for enrichment of uranium. As with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand. Meanwhile, world supply and demand will continue to be balanced such that FPL expects adequate supply of enrichment services. The tight supply/demand will most likely causes the price of enrichment services to continue to rise in the future.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the Nuclear Regulatory Commission (NRC), not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand is expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) **Other Comments Regarding FPL's Nuclear Fuel Cost Forecast**

The calculations for the nuclear fuel cost forecasts used in FPL's 2010 and early 2011 resource planning work were performed consistent with the method then used for FPL's Fuel Clause filings, including the assumption of refueling outages every 18 months. The costs for each step to fabricate the nuclear fuels were added to come up with the total costs of the fresh fuel to be loaded at each refueling (acquisition costs). The acquisition cost for each group of fresh fuel assemblies were then amortized over the energy produced by each group of fuel assemblies. FPL also added 1 mill per kilowatt hour net to reflect payment to DOE for spent fuel disposal.

Schedule 5
Fuel Requirements
(for FPL only)

		Actual 1/		Forecasted									
Fuel Requirements	**Units**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
(1) Nuclear	Trillion BTU	250	250	257	217	276	292	269	290	295	290	290	296
(2) Coal	1,000 TON	3,577	3,191	3,570	3,250	3,959	3,645	3,956	3,655	3,951	3,599	3,932	3,633
(3) Residual (FO6) - Total	1,000 BBL	7,489	6,754	2,489	1,455	845	712	907	1,066	1,256	1,213	1,376	1,240
(4) Steam	1,000 BBL	7,489	6,754	2,469	1,455	845	712	907	1,068	1,256	1,213	1,376	1,240
(5) Distillate (FO2) - Total	1,000 BBL	47	522	121	2	5	0	15	19	71	47	63	2
(6) Steam	1,000 BBL	0	4	0	0	0	0	0	0	0	0	0	0
(7) CC	1,000 BBL	6	194	100	2	4	0	0	0	0	0	0	0
(8) CT	1,000 BBL	40	324	21	0	1	0	15	19	71	47	63	2
(9) Natural Gas - Total	1,000 MCF	461,428	504,996	529,619	542,420	505,993	538,762	541,899	575,212	589,224	605,055	612,589	626,151
(10) Steam	1,000 MCF	81,260	56,729	40,917	27,439	13,860	11,609	13,620	16,789	19,179	18,634	21,159	19,608
(11) CC	1,000 MCF	395,703	443,108	487,142	514,015	491,405	526,628	527,571	557,375	567,865	584,757	589,172	605,395
(12) CT	1,000 MCF	4,462	5,159	1,559	966	728	544	709	1,048	2,180	1,864	2,258	1,148

1/ Source: A Schedules.
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

Schedule 6.1
Energy Sources

			Actual 1/		Forecasted									
	Energy Sources	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Annual Energy Interchange 2/	GWH	9,508	8,333	5,797	5,947	5,274	5,163	5,082	1,728	0	0	0	0
(2)	Nuclear	GWH	22,893	22,850	20,758	19,718	25,388	26,720	28,406	26,567	28,981	26,591	26,491	27,058
(3)	Coal	GWH	6,362	5,721	6,738	6,230	7,446	6,903	7,440	6,926	7,426	6,795	7,390	6,873
(4)	Residual(FO6) -Total	GWH	4,560	4,081	1,627	964	559	467	602	704	829	801	909	820
(5)	Steam	GWH	4,560	4,081	1,627	964	559	467	802	704	829	801	909	820
(6)	Distillate(FO2) -Total	GWH	21	279	93	2	4	0	5	6	25	15	20	1
(7)	Steam	GWH	3	2	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	3	143	84	2	4	0	0	0	0	0	0	0
(9)	CT	GWH	15	134	9	0	0	0	5	8	25	15	20	1
(10)	Natural Gas -Total	GWH	62,728	66,771	73,272	75,939	71,971	77,352	78,200	83,199	85,127	87,618	88,496	90,766
(11)	Steam	GWH	8,705	5,041	3,984	2,711	1,365	1,134	1,347	1,655	1,894	1,838	2,087	1,935
(12)	CC	GWH	53,636	61,304	69,186	73,151	70,549	76,174	78,797	81,464	83,071	85,651	66,241	88,742
(13)	CT	GWH	387	426	123	77	57	44	56	81	163	126	169	90
(14)	Solar 3/	GWH	0	69	228	227	226	225	225	225	224	224	222	221
(15)	PV	GWH	0	69	73	73	72	71	71	71	70	70	69	69
(16)	Solar Thermal 4/	GWH	0	0	155	155	154	154	154	154	154	154	153	152
(17)	Other 5/	GWH	5,231	6,339	2,663	3,489	3,780	4,204	5,650	8,239	6,836	6,869	7,149	7,380
	Net Energy For Load 6/	GWH	111,304	114,373	111,176	112,517	114,647	121,035	123,610	125,593	127,250	128,910	130,879	133,121

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP end the Southern Companies (UPS contract).
3/ Represents output from FPL's PV end solar thermal facilities.
4/ Estimated projected values.Solar thermal does not produce GWh, but produces steam that displaces fossil fuel-derived steam. Actual solar thermal contribution for 2010 was relatively small due to the fact that the facility did not begin commercial operation until late 2010. Its 2010 contribution to the Martin 8 CC GWh output is rolled into row (12) for reporting purposes. Its projected contributions for 2011 - 2020 are provided separately on row (18).
5/ Represents e forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
6/ Net Energy For Load values for the years 2011 - 2020 are also shown in Schedule 2.3.

Schedule 6.2
Energy Sources % by Fuel Type

	Energy Source	Units	Actual 1/		Forecasted									
			2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Annual Energy Interchange 2/	%	8.5	7.3	5.2	5.3	4.6	4.3	4.1	1.4	0.0	0.0	0.0	0.0
(2)	Nuclear	%	20.6	20.0	18.7	17.5	22.1	22.1	21.4	21.2	21.2	20.6	20.3	20.3
(3)	Coal	%	5.7	5.0	6.1	5.5	6.5	5.7	6.0	5.5	5.8	5.3	5.7	5.2
(4)	Residual (FO6) -Total	%	4.1	3.6	1.5	0.9	0.5	0.4	0.5	0.6	0.7	0.8	0.7	0.6
(5)	Steam	%	4.1	3.6	1.5	0.9	0.5	0.4	0.5	0.6	0.7	0.8	0.7	0.6
(6)	Distillate (FO2) -Total	%	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CC	%	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	CT	%	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	56.4	58.4	65.9	67.5	62.8	63.9	63.3	66.2	66.9	68.0	67.7	68.2
(11)	Steam	%	7.8	4.4	3.6	2.4	1.2	0.9	1.1	1.3	1.5	1.4	1.6	1.5
(12)	CC	%	48.2	53.6	62.2	65.0	61.5	62.9	62.1	64.9	65.3	66.4	66.0	66.7
(13)	CT	%	0.3	0.4	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
(14)	Solar 3/	%	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(15)	PV	%	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(16)	Solar Thermal 4/	%	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(17)	Other 5/	%	4.7	5.5	2.4	3.1	3.3	3.5	4.6	5.0	5.2	5.3	5.5	5.5
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies (UPS contract).
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Estimated projected values.Solar thermal does not produce GWh, but produces steam that displaces fossil fuel-derived steam.
Actual solar thermal contribution for 2010 was ratetively small due to the fact that the facility did not begin commercial operation until late 2010. Its 2010 contribution to the Martin 8 CC GWh output is rolled into row (12) for reporting purposes. Its projected contributions for 2011 - 2020 are provided separately on row (16).
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
6/ Net Energy For Load values for the years 2011 - 2020 are also shown in Schedule 2.3.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2011	22,462	1,461	0	595	24,518	21,679	1,981	19,698	4,819	24.5	350	4,469	22.7
2012	23,437	1,306	0	650	25,393	21,853	2,141	19,712	5,681	28.8	1,064	4,617	23.4
2013	24,105	1,306	0	650	26,061	22,155	2,317	19,838	6,223	31.4	1,176	5,047	25.4
2014	25,317	1,306	0	650	27,273	23,452	2,534	20,918	6,354	30.4	1,176	5,178	24.8
2015	25,317	1,306	0	740	27,363	24,172	2,710	21,462	5,900	27.5	350	5,550	25.9
2016	26,508	0	0	740	27,248	24,605	2,871	21,734	5,514	25.4	350	5,164	23.8
2017	26,508	0	0	740	27,248	25,025	3,016	22,009	5,239	23.8	350	4,889	22.2
2018	26,508	0	0	740	27,248	25,266	3,149	22,117	5,130	23.2	350	4,780	21.6
2019	26,508	0	0	740	27,248	25,690	3,271	22,419	4,828	21.5	350	4,478	20.0
2020	27,699	0	0	740	28,439	26,193	3,371	22,822	5,616	24.6	350	5,266	23.1

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MWs are generelly considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2011 load forecast without incremental DSM or cumulative load management.
Col. (8) represents cumulative load management capability, plus incremental conservation, from 1/2011-on intended for use with the 2011 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of: (i) an assumed value of 350 MW on average of capacity that will be out-of-service for planned maintenance during the Summer months for all years; (ii) an additional 714 MW (at St. Lucie 2) of nuclear capacity that will be out-of-service during part of Summer in 2012 due to an extended planned outage as part of the capacity uprates project; and (iii) an additional 826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin 1) and in the Summer of 2014 (at Martin 2) due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled
Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
January of Year	Firm Installed Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintananca MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2011	23,987	1,494	0	595	26,076	21,443	1,711	19,732	6,343	32.1	1,276	5,067	25.7
2012	24,400	1,494	0	595	26,489	21,491	1,802	19,689	6,799	34.5	2,942	3,857	19.6
2013	23,959	1,314	0	650	25,923	21,683	1,909	19,774	6,148	31.1	1,372	4,778	24.2
2014	25,423	1,314	0	650	27,387	22,584	2,065	20,519	6,868	33.5	1,382	5,486	28.7
2015	26,767	1,314	0	650	28,731	23,048	2,182	20,868	7,864	37.7	550	7,314	35.1
2016	26,767	383	0	740	27,690	23,302	2,288	21,014	6,876	32.7	550	6,326	30.1
2017	28,118	0	0	740	28,858	23,543	2,382	21,161	7,696	36.4	550	7,146	33.8
2018	28,118	0	0	740	28,858	23,794	2,464	21,330	7,527	35.3	550	8,977	32.7
2019	28,118	0	0	740	28,858	24,044	2,536	21,508	7,350	34.2	550	6,800	31.6
2020	28,118	0	0	740	28,858	24,305	2,596	21,709	7,148	32.9	550	6,598	30.4

Col. (2) represents capacity additions and changes projected to be in-service by January 1st. These MWs are generally considered to be available to meet winter peak loads which are forecasted to occur during January of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects tha 2011 load forecast without incremental DSM or cumulative load management.
Col. (8) represents cumulative load management capability, plus incremental conservation, from 1/2011-on intended for use with the 2011 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Winter peak period. This value is comprised of: (i) an assumed value of 550 MW on average of capacity that will be out-of-service for planned maintenance during the Winter months for all years; (ii) an additional 726 MW(at St. Lucie 2) of nuclear capacity that will be out-of-service in Winter of 2011 due to an extended planned outage as part of the capacity uprates project; (iii) an additional 1,570 MW (853 MW at St. Lucie 1 and 717 MW at Turkey Point 3) of nuclear capacity that will be out-of-service during part of the Winter of 2012 due to extended planned outeges as part of the capacity uprates project; (iv) an additional 822 MW that will be out-of-service in the Winter of 2012 (at Manatee 2) and in the Winter of 2013 (at Manatee 1) due to the installation of electrostetic precipitators; and (v) an additional 832 MW (at Martin 1) that will be out-of-service during the Winter of 2014 due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Schedule 7.3
Projection of Generation - Only Reserves
At Time Of Summer Peak (Assuming No 2016 or 2020 Generation Additions)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
					Total			Firm					
	Firm	Firm	Firm		Firm	Total		Summer	Reserve			Reserve	
	Installed	Capacity	Capacity	Firm	Capacity	Peak		Peak	Margin Before		Scheduled	Margin After	
August of	Capacity	Import	Export	QF	Available	Demand	DSM	Demand	Maintenance		Maintenance	Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2011	22,462	1,461	0	595	24,518	21,679	**0**	21,879	2,839	13.1	350	2,489	**11.5**
2012	23,437	1,306	0	650	25,393	21,853	**0**	21,853	3,540	16.2	1,064	2,476	**11.3**
2013	24,105	1,306	0	650	26,061	22,155	**0**	22,155	3,906	17.6	1,176	2,730	**12.3**
2014	25,317	1,306	0	650	27,273	23,452	**0**	23,452	3,821	16.3	1,176	2,645	**11.3**
2015	25,317	1,306	0	740	27,363	24,172	**0**	24,172	3,191	13.2	350	2,641	**11.6**
2016	25,317	0	0	740	26,057	24,605	**0**	24,605	1,452	5.9	350	1,102	**4.5**
2017	25,317	0	0	740	26,057	25,025	**0**	25,025	1,032	4.1	350	682	**2.7**
2018	25,317	0	0	740	26,057	25,266	**0**	25,266	791	3.1	350	441	**1.7**
2019	25,317	0	0	740	26,057	25,690	**0**	25,690	367	1.4	350	17	**0.1**
2020	25,317	0	0	740	28,057	26,193	**0**	26,193	(137)	(0.5)	350	(487)	**(1.9)**

Col. (2) represents capacity additions and changes, **assuming no generation additions in 2016 or 2020.**
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2011 load forecast without incremental DSM or cumulative load management.
Col. (8) shows zero contribution from DSM in order to calculate FPL's reserves that are supplied only by generation resources.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of: (i) an assumed value of 350 MW on average of capacity that will be out-of-service for planned maintenance during the Summer months for all years; (ii) an additional 714 MW (at St. Lucie 2) of nuclear capacity that will be out-of-service during part of Summer in 2012 due to an extended planned outage as part of the capacity uprates project; and (iii) an additional 826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin 1) and in the Summer of 2014 (at Martin 2) due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Schedule 7.4
Projection of Generation - Only Reserves
At Time Of Summer Peak (Assuming 2016 and 2020 CC Generation Additions)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2011	22,462	1,461	0	595	24,518	21,679	**0**	21,679	2,839	13.1	350	2,489	**11.5**
2012	23,437	1,306	0	650	25,393	21,853	**0**	21,853	3,540	16.2	1,064	2,476	**11.3**
2013	24,105	1,306	0	650	26,061	22,155	**0**	22,155	3,906	17.6	1,176	2,730	**12.3**
2014	25,317	1,306	0	650	27,273	23,452	**0**	23,452	3,821	16.3	1,176	2,645	**11.3**
2015	25,317	1,306	0	740	27,363	24,172	**0**	24,172	3,191	13.2	350	2,841	**11.8**
2016	26,508	0	0	740	27,248	24,805	**0**	24,605	2,643	10.7	350	2,293	**9.3**
2017	26,508	0	0	740	27,248	25,025	**0**	25,025	2,223	8.9	350	1,873	**7.5**
2018	26,508	0	0	740	27,248	25,266	**0**	25,266	1,982	7.8	350	1,632	**8.5**
2019	26,508	0	0	740	27,248	25,690	**0**	25,690	1,558	6.1	350	1,208	**4.7**
2020	27,899	0	0	740	28,439	26,193	**0**	26,193	2,246	8.6	350	1,896	**7.2**

Col. (2) represents capacity additions and changes, assuming one CC unit is added in 2016 and one CC unit is added in 2020.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2011 load forecast without incremental DSM or cumulative load management.
Col. (8) shows zero contribution from DSM in order to calculate FPL's reserves that are supplied only by generation resources.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peek period. This value is comprised of: (i) an assumed value of 350 MW on average of capacity that will be out-of-service for planned maintenance during the Summer months for all years; (ii) an additional 714 MW (at St. Lucie 2) of nuclear capacity that will be out-of-service during part of Summer in 2012 due to an extended planned outage as part of the capacity uprates project; end (iii) an additional 826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin 1) and in the Summer of 2014 (at Martin 2) due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability [1]		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2011														
St. Lucie (Uprates)	2	St. Lucie County	NP	UR	No	TK	No	—	Apr-11	Unknown	723,775	—	17	OT
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Feb-11	310,420	—	(277)	OT
Riviera	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Feb-11	310,420	—	(288)	OT
Scherer	4	Monroe, GA	BIT	SUB	No	RR	No	—	Jul-11	Unknown	680,368	—	28	OT
West County Energy Center	3	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	1,368,800	—	1219	V
											2011 Changes/Additions w/o Inactive Reserve Total:	9	697	
Cutler	5	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	75,000	(69)	(68)	OT
Cutler	6	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	161,500	(138)	(137)	OT
Sanford	1	Volusia County	ST	FO6	NG	WA	PL	—	—	—	156,250	(140)	(138)	OT
Port Everglades	1	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	225,250	(214)	(213)	OT
Port Everglades	2	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	225,250	(214)	(213)	OT
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	—	(387)	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	—	(374)	OT
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	402,050	—	(392)	OT
											2011 Changes/Additions with Inactive Reserve Total:	(775)	(1,225)	
2012														
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Unknown	310,420	(280)	—	OT
Riviera	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Unknown	310,420	(291)	—	OT
Scherer	4	Monroe, GA	BIT	SUB	No	RR	No	—	Jul-11	Unknown	680,368	26	—	OT
St. Lucie (Uprates) [2]	2	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	723,775	17	(17)	T
St. Lucie (Uprates) [2]	1	St. Lucie County	NP	UR	No	TK	No	—	Dec-11	Unknown	850,000	—	122	T
Turkey Point (Uprates) [2]	3	Miami Dade County	NP	UR	No	TK	No	—	May-12	Unknown	759,000	—	109	T
West County Energy Center	3	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	1,366,800	1,335	—	V
											2012 Changes/Additions w/o Inactive Reserve Total:	697	214	
Turkey Point	2	Miami Dade County	ST	FO6	NO	WA	PL	—	—	—	402,050	(394)	—	
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	—	387	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	—	374	OT
											2012 Changes/Additions with Inactive Reserve Total:	413	975	
2013														
St. Lucie (Uprates) [2]	2	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	723,775	(17)	—	T
St. Lucie (Uprates) [2]	1	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	850,000	122	—	T
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	PL	Jun-11	Jun-13	Unknown	1,288,750	—	1,210	T
St. Lucie (Uprates) [2]	2	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	723,775	93	93	T
Turkey Point (Uprates) [2]	3	Miami Dade County	NP	UR	No	TK	No	—	See Note 2	Unknown	769,900	109	—	T
Turkey Point (Uprates) [2]	4	Miami Dade County	NP	UR	No	TK	No	—	See Note 2	Unknown	759,900	—	109	T
											2013 Changes/Additions w/o Inactive Reserve Total:	307	1,412	
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(389)	(387)	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(376)	(374)	OT
											2013 Changes/Additions with Inactive Reserve Total:	(488)	851	

(1): The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June.
All MW additions/changes occuring later in the year will be picked up for reporting/planning purposes in the following year.

(2) The nuclear uprates will be performed during the extended outages for each unit.

Schedule 6
Planned And Prospective Generating Facility Additions And Changes

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm	Expected	Gen. Max.	Firm Net Capability [1]		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2014														
Turkey Point (Uprates) [2]	4	Miami Dade County	NP	UR	No	TK	No	—	See Note 2	Unknown	769,900	109	—	T
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	PL	Jun-11	Jun-13	Unknown	1,296,750	1,355	—	T
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	PL	PL	Jun-12	Jun-14	Unknown	1,296,750	—	1,212	T
											2014 Changes/Additions w/o Inactive Reserve Total:	1,464	1,212	
												—	—	
											2014 Changes/Additions with Inactive Reserve Total:	1,464	1,212	
2015														
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	PL	PL	Jun-12	Jun-14	Unknown	1,296,750	1,344	—	T
											2015 Changes/Additions w/o Inactive Reserve Total:	1,344	0	
												—	—	
											2015 Changes/Additions with Inactive Reserve Total:	1,344	0	
2016														
Unsited 3x1 H Combined Cycle	1	—	CC	NG	FO2	PL	PL	Jun-14	Jun-16	Unknown	Unknown	—	1,191	P
											2016 Changes/Additions w/o Inactive Reserve Total:	0	1,191	
												—	—	
											2016 Changes/Additions with Inactive Reserve Total:	0	1,191	
2017														
Unsited 3x1 H Combined Cycle	1	—	CC	NG	FO2	PL	PL	Jun-14	Jun-16	Unknown	Unknown	1,351	—	P
											2017 Changes/Additions w/o Inactive Reserve Total:	1,351	0	
												—	—	
											2017 Changes/Additions w/o Inactive Reserve Total:	1,351	0	
2018														
												—	—	
											2018 Changes/Additions w/o Inactive Reserve Total:	0	0	
												—	—	
											2018 Changes/Additions with Inactive Reserve Total:	0	0	
2019														
												—	—	
											2019 Changes/Additions w/o Inactive Reserve Total:	0	0	
												—	—	
											2019 Changes/Additions with Inactive Reserve Total:	0	0	
2020														
Unsited 3x1 H Combined Cycle	2	—	CC	NG	FO2	PL	PL	Jun-18	Jun-20	Unknown	Unknown	—	1,191	P
											2018 Changes/Additions w/o Inactive Reserve Total:	0	1,191	
												—	—	
											2016 Changes/Additions with Inactive Reserve Total:	0	1,191	

(1) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June.
All MW additions/changes occuring later in the year will be picked up for reporting/planning purposes in the following year.
(2) The nuclear uprates will be performed during the extended outages for each unit.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit 3

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2009
b. Commercial In-service date: 2011

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** V (Under construction, more than 50% Complete)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 93%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582 Btu/kWh	(Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2011 $/kW):	709
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	71
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2011 $kW-Yr)	11.63
Variable O&M ($/MWH): (2011 $/MWH)	0.480
K Factor:	1.4697

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** St. Lucie 1 Nuclear (Uprate)

(2) **Capacity**
a. Summer 122 MW (Incremental)
b. Winter 122 MW (Incremental)

(3) **Technology Type:** Nucleer

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel —

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data** *

Book Life (Years):	25	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost:	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2011 Nuclear Cost Recovery filing.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point 3 Nuclear (Uprate)

(2) **Capacity**
a. Summer 109 MW (Incremental)
b. Winter 109 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data** *

Book Life (Years):	21	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2011 Nuclear Cost Recovery filing.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** St. Lucie 2 Nuclear (Uprate)

(2) **Capacity**
a. Summer — 17 MW (Interim Incremental FPL's ownership share), 110 MW (final incremental FPL's ownership share)
b. Winter — 17 MW (Intarim Incremental FPL's ownership share), 110 MW (final incremental FPL's ownarship share)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2011 (Interim increase), 2012 (final increase)

(5) **Fuel**
a. Primary Fuel — Uranium
b. Altarnata Fuel — ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencias:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Basa Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data *,****

Book Life (Years):	32	years (Matches the current opereting license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2011 Nuclear Cost Recovery filing.
nuclear units.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point 4 Nuclear (Uprate)

(2) **Capacity**
a. Summer 109 MW (Incremental)
b. Winter 109 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2013

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel —

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data *,****

Book Life (Years):	21	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2011 Nuclear Cost Recovery filing.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Cape Canaveral Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,210 MW
b. Winter 1,355 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2011
b. Commercial In-service date: 2013

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 43 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Statue:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%
Forced Outage Factor (FOF):	1.1%
Equivalent Availability Factor (EAF):	96.5%
Resulting Capacity Factor (%):	Approx. 90 % (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,484 Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2013 $/kW):	921
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	98
Escalation ($/kW):	
Fixed O&M ($/kW-Yr): (2013 $)	13.29
Variable O&M ($/MWH): (2013 $)	0.16
K Factor:	1.484

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Riviera Beach Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,212 MW
b. Winter 1,344 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2012
b. Commercial In-service date: 2014

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 33 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.5%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Averaga Net Operating Heat Rate (ANOHR):	8,480	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2014 $/kW):	1,053
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	121
Escalation ($/kW):	
Fixed O&M ($/kW-Yr): (2014 $)	13.67
Variable O&M ($/MWH): (2014 $)	0.13
K Factor:	1.509

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Greenfield 3x1 Combined Cycle

(2). **Capacity**
a. Summer 1,191 MW
b. Winter 1,351 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2014
b. Commercial In-service date: 2016

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** — Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** —

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%
Forced Outage Factor (FOF):	1.1%
Equivalent Availability Factor (EAF):	96.5%
Resulting Capacity Factor (%):	Approx. 90% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,607 Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2016 $/kW):	956
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	98
Escalation ($/kW):	
Fixed O&M ($/kW-Yr): (2016 $)	17.65
Variable O&M ($/MWH): (2016 $)	0.50
K Factor:	1.5136

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Greenfield 3x1 Combined Cycle

(2) **Capacity**
a. Summer 1,191 MW
b. Winter 1,351 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2018
b. Commercial In-service date: 2020

(5) **Fuel**
a. Primary Fuel — Natural Gas
b. Alternate Fuel — Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** --- Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.5%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,607	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2020 $/kW):	1,076	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	111	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2020 $)	19.79	
Variable O&M ($/MWH): (2020 $)	0.55	
K Factor:	1.5136	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

West County Energy Center Unit 3

(1)	Point of Origin and Termination:	New Sugar Substation – Corbett Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL - Owned
(4)	Line Length:	1 mile
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: May 2009 End date: November 2010 (Completed)
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$11,300,000
(8)	Substations:	New Sugar Substation and Corbett Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

St. Lucie 1 Nuclear (Uprate)

The St. Lucie 1 Nuclear (Uprate) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point 3 Nuclear (Uprate)

The Turkey Point 3 Nuclear (Uprate) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

St. Lucie 2 Nuclear (Uprate)

The St. Lucie 2 Nuclear (Uprate) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point 4 Nuclear (Uprate)

The Turkey Point 4 Nuclear (Uprate) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Cape Canaveral Next Generation Clean Energy Center (Modernization)

The Cape Canaveral Next Generation Clean Energy Center which will result from the modernization of the Cape Canaveral power plant site does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Riviera Beach Next Generation Clean Energy Center (Modernization)

The Riviera Beach Energy Center which will result from the modernization of the Riviera Beach power plant site will require one new line and existing lines to be extended and reconfigured to accommodate the increased capacity.

(1)	Point of Origin and Termination:	Riviera – Cedar Substation
(2)	Number of Lines:	1
(3)	Right-of-way	Existing, FPL - Owned
(4)	Line Length:	15 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 2012 End date: 2014
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$12,100,000
(8)	Substations:	Riviera Substation and Cedar Substation
(9)	Participation with Other Utilities:	None

Schedule 11.1

Existing FIRM and NON-FIRM Capacity and Energy by Primary Fuel Type
Actuals for the Year 2010

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	Summer (MW)	Summer (%)	Winter (MW)	Winter (%)	GWh (2)	%
(1)	Coal	900	3.5%	902	3.3%	5,721	5.0%
(2)	Nuclear	2,939	11.4%	3,013	11.2%	22,850	20.0%
(3)	Residual	5,954	23.1%	6,004	22.3%	4,081	3.6%
(4)	Distillate	1,908	7.4%	2,087	7.7%	279	0.2%
(5)	Natural Gas	11,986	46.4%	12,756	47.3%	66,771	58.4%
(6)	Solar	35	0.1%	35	0.1%	69	0.1%
(7)	***FPL Existing Units Total (1) :***	***23,722***	***91.9%***	***24,797***	***91.9%***	***99,771***	***87.2%***
(8)	Renewables (Purchases)- Firm	61.0	0.2%	112.0	0.4%	1,004	0.9%
(9)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	800	0.7%
(10)	***Renewable Total:***	***61.0***	***0.2%***	***112.0***	***0.4%***	***1,804***	***1.58%***
(11)	***Purchases Other :***	***2,041.0***	***7.9%***	***2,074.0***	***7.7%***	***12,798***	***11.2%***
(12)	***Total :***	***25,824.0***	***100.0%***	***26,983.0***	***100.0%***	***114,373***	***100.0%***

Note:
(1) FPL Existing Units Total values on row (7), columns (2) and (4), match the System Firm Generating Capacity values found on Schedule 1 for Summer and Winter.
(2) Net Energy for Load GWh values on row (12), column (6), matches Schedule 6.1 value for 2010.

Schedule 11.2

Existing NON-FIRM Self-Service Renewable Generation Facilities
Actuals for the Year 2010

(1)	(2)	(3)	(4)	(5)	(6) = 3+4-5
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh)	Annual Energy Purchased from FPL (MWh)	Annual Energy Sold to FPL (MWh)	Projected Annual Energy Used by Customers (GWh)
Customer-Owned PV (0 kW to 10 kW)	4.6	5,214.7	53,476.4	146.5	**58.5**
Customer-Owned PV (> 10 kW to 100 kW)	1.6	1,775.4	17,858.8	158.2	**19.5**
Customer-Owned PV (> 100 kW to 2 MW)	2.9	3,708.4	118,662.7	177.6	**118,666.2**
Total:	**9.2**	**10,698.5**	**189,998.0**	**482.2**	**118,744.2**

Notes:

(1) There were approximately 1,074 customer-owned renewable generation facilities interconnected with FPL on December 31, 2010.
(2) The Installed Capacity value is the sum of the nameplate ratings (DC MW) for all of the customer-owned renewable generation facilities connected as of Dec. 31,2010.
(3) The Projected Annual Output value is based on NREL's PV Watts 1 program and the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.
(4) The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2010.
(5) The Annual Energy Sold to FPL is an actual value from FPL's metered data for 2010.
(6) The Projected Annual Energy Used by Customers is a projected value that equals:
(Renewable Projected Annual output + Annual Energy Purchased from FPL) minus the Annual Energy Sold to FPL.

CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered or threatened plant and animal species. FPL competes for air, land, and water resources that are necessary to meet the demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

FPL has been recognized for many years as one of the leaders among electric utilities for its commitment to the environment. For example, FPL has one of the lowest carbon dioxide (CO_2) emission rates in the nation. The environmental leadership of FPL and its parent company, NextEra Energy, Inc., has been heralded by many outside organizations as demonstrated by a few recent examples. In 2010, NextEra Energy, Inc. (formerly FPL Group) ranked in the top 10 among companies worldwide for innovation and, for a record fourth consecutive year, No. 1 in its industry, according to the 2010 "World's Most Admired Companies" report released by Fortune magazine. In addition to being named the most admired company in its industry, NextEra Energy, Inc. received the No. 1 ranking among its peers in the following specific areas evaluated: innovation, people management, use of corporate assets, social responsibility, quality of management, long-term investment, and quality of products and services. According to *Fortune*, America's Most Admired Companies is "the definitive report card on corporate reputations".

NextEra Energy, Inc.'s commitment to acknowledging the risks of climate change and effectively reducing its greenhouse gas emissions was again recognized when the company was named to the Carbon Disclosure Leadership Index for 2010. The Carbon Disclosure Leadership Index is produced annually by the Carbon Disclosure Project (CDP), a not-for-profit organization that reports on the business risks and opportunities of climate change for investors. CDP represents 534 institutional investors with $64 trillion in assets under management. Compiled by PricewaterhouseCoopers on behalf of CDP, the Carbon Disclosure Leadership Index highlights companies within the S&P 500 Index that excel in the area of climate change awareness and action.

NextEra Energy, Inc. was named to the 2010 Dow Jones Sustainability Index (DJSI) of the leading companies in North America for corporate sustainability. The DJSI North America selects the top 20 percent of companies in sustainability performance from the 600 largest companies in North America. According to Dow Jones, corporate sustainability leaders achieve long-term shareholder value by "gearing their strategies and management to harness the market's potential for sustainability products and services while successfully reducing and avoiding sustainability costs and risks."

FPL was recognized in 2010 by the Southeastern Electric Exchange (SEE) for outstanding performance in constructing the largest solar photovoltaic (PV) power plant at the time in the United States: the 25 MW DeSoto Next Generation Solar Energy Center. SEE gives its Chairman's Award annually to the project it deems "best of the best" among all entrants in its 11 award categories. Capable of powering approximately 3,000 homes with renewable energy, the DeSoto PV facility was completed months ahead of schedule and more than $22 million under budget.

FPL's responsible tree care practices across its 35-county service area have been recognized for almost a decade. FPL has been the recipient of the Tree Line USA award annually from 2003 - 2010. This award is sponsored by the Arbor Day Foundation in cooperation with the National Association of State Foresters. The recognition is given to utilities that demonstrate quality tree care practices, annual worker training, and public education programs.

In October 2010, FPL won the 2010 Loggerhead Marinelife Center's "Blue Business of the Year" award. The awards were given to those who are leading the way in raising awareness and have made significant contributions to improve and protect South Florida's oceans, beaches, and wildlife. The award recognized FPL's protection and conservation of the endangered Florida manatee and fostering public and employee education and support.

The 12th Annual Sustainable Florida Best Practice Awards were announced on June 4, 2010 in Orlando, Florida. FPL was named a finalist in the large business category for the previously mentioned 25 MW DeSoto PV facility. The awards were presented by the Council for Sustainable Florida, the premier statewide organization committed to balancing the economic interests of the state with the need to be socially and environmentally responsible. The Sustainable Florida Award recognizes organizations for protecting and preserving Florida's environment for the future while building markets for Florida's business.

In December 2009, Next Era Energy was named Power Company of the Year at the Platts 2009 Global Energy Awards. Platts, the leading global provider of information on the energy industry, received more than 200 nominations for its annual awards program. Nominations came from more than 30 countries. FPL Group was selected as Power Company of the Year from among six finalists. The specific judging criteria were financial results, operational excellence, innovation, and strategic vision.

As mentioned above, NextEra Energy, Inc. has taken a leadership role to address climate change and the call for action for a national climate change policy. The decision to step into the forefront of this issue goes hand-in-hand with NextEra Energy, Inc.'s longtime commitment to managing operations with sensitivity to the environment.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Statement in 1992 to clearly define its position, which it continues to stand by today. This statement reflects how FPL incorporates environmental values into all aspects of its activities and serves as a framework for new environmental initiatives throughout the company. FPL's Environmental Statement is:

> It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:
>
> - Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
> - Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
> - Encourage the wise use of energy to minimize the impact on the environment.
> - Communicate effectively on environmental issues.
> - Conduct periodic self-evaluations, report performance, and take appropriate actions.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an environmental management system to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program that is discussed below. Other components include: executive management support and commitment, a dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to evaluate environmental performance, verify compliance with corporate policy as well as legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and FPL policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2010 environmental outreach activities are noted below in Table IV.E.1. In 2009 and 2010, FPL launched web cams at four facilities in order to increase public awareness of ongoing solar projects, FPL's commitment to sea turtle rehabilitiation, and the warm water refuge for manatees provided by power plants. The "solar cams" provide the public with a glimpse of the PV installation at the Space Coast Next Generation Solar Energy Center and the solar thermal installation at the Martin Next Generation Solar Energy Center. The "turtle cam" installed at the Loggerhead Marinelife Center in Juno Beach provides interested onlookers the opportunity to view rescued sea turtles as they are nursed back to health in the sea turtle hospital. Additionally, the "manatee cam" provides the public a glimpse of hundreds of manatees that gather in the warm waters near the FPL Riviera Plant each Winter during the cold weather. These web cam addresses, respectively, are:

http://www.fpl.com/environment/solar/spacecoast_cam.shtml,
http://www.fpl.com/environment/solar/martin_cam.shtml,
http://www.fpl.com/environment/plant/turtle_cam.shtml, and,
http://www.fpl.com/environment/plant/riviera_cam.shtml.

In 2010, FPL, in partnership with the Treasured Lands Foundation, officially re-opened the Barley Barber Swamp at the Martin Power Plant for public tours. The tours began in November of 2010.

Table IV.E.1: 2010 FPL Environmental Outreach Activities

Activity	# of Participants (Approx.)
Visitors to FPL's Energy Encounter at St. Lucie	17,000
Visitors to Manatee Park	272,243
Number of visits to FPL's Environmental Website	400,000
Number of pieces of Environmental literature distributed	>60,000
Solar Schools Program (# of schools participating)	8 (6 new in 2010)
Visitors to Barley Barber Swamp	943
Number of visits to Manatee Cam Website	45,000
Number of visits to Turtle Cam Website	36,000
Number of visits to Space Coast WebCam Website	500
Number of visits to Martin WebCam Website	1,500

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified five (5) Preferred Sites and thirteen (13) Potential Sites for future generation additions. Preferred Sites are those locations where FPL has conducted significant reviews and has either taken action, or is currently committed to take action, to site new generation capacity. Potential Sites are those sites that have attributes that support the siting of generation and are under consideration as a location for future generation. Some of these sites are currently in use as existing generation sites and some are not. The identification of a Potential Site does not indicate that FPL has made a definitive decision to pursue generation (or generation expansion in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of a generator has been determined. The Preferred Sites and Potential Sites are discussed in separate sections below.

As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include all of the remainder of FPL's existing generation sites and other Greenfield sites. FPL is also analyzing the potential for modernizing existing power plant sites such as is now being done at the Cape Canaveral and Riviera sites. For example, the existing Port Everglades site is a potential site for modernization. Other existing sites may also emerge in the ongoing analyses as potential candidates for modernization. Analyses of any modernization candidates would include evaluation of numerous factors including: fuel delivery, transmission, permitting, etc.

IV.F.1 Preferred Sites

FPL identifies five Preferred Sites in this Site Plan: the existing West County Energy Center (WCEC) site, the existing St. Lucie plant site, the existing Turkey Point plant site, the existing Cape Canaveral plant site, and the existing Riviera plant site.

The West County Energy Center site is the location for one combined cycle (CC) capacity addition FPL will make in 2011. The St. Lucie site is the location for nuclear capacity uprates that FPL will make in 2011 and 2012. The Turkey Point site is the location for nuclear capacity uprates that FPL will make in 2012 and 2013. (Turkey Point is also the site for two new nuclear units, Turkey Point Units 6 & 7, for which FPL is pursuing licensing and permit approvals. Current projections for in-service dates these new nuclear units are beyond the 2011-2020 reporting time frame of this document). The Cape Canaveral and Riviera sites are the locations for modernizations of existing power plant sites for capacity additions in 2013 and 2014, respectively.

The five Preferred Sites are discussed below in general chronological order in regard to when the capacity additions are projected to occur.

Preferred Site # 1: West County Energy Center, Palm Beach County

FPL has identified the property adjacent to the existing Corbett Substation property in unincorporated western Palm Beach County as a Preferred Site for the further addition of new generating capacity. The site was selected for the addition of another CC natural gas unit (Unit 3) with ultra-low sulfur light fuel oil (distillate) as a backup fuel. WCEC Units 1 & 2 were constructed on this site and went into commercial operations on August 27, 2009, and November 3, 2009, respectively. WCEC Unit 3, which began construction in March 2009, was approved by both the FPSC and the Secretary of the Florida Department of Environmental Protection (FDEP) and is anticipated to go into commercial operation in June of 2011. Unit 3 will be identical to Units 1 & 2 in regard to technology and capacity.

The existing site is accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections. The facility will use natural gas as the primary fuel and state-of-the-art combustion controls.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the West County Energy Center (WCEC) plant site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the general layout of the WCEC generating facilities at the site is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

The site was undeveloped until February 2007 when construction of WCEC Units 1 & 2 was initiated. The site was previously dedicated to industrial (mining) and agricultural use. The site had been excavated, back-filled, and totally re-graded to an elevation of approximately 10 feet above the surrounding land surface. Prior to the initiation of power plant construction, no structures were present on the site and vegetation was virtually non-existent. Units 1 & 2 are completed and are now in commercial operation.

e. **General Environment Features On and In the Site Vicinity**

1. **Natural Environment**

The plant site had been significantly altered by the construction and operation of a limestone mine where vegetation had been cleared and removed. The surrounding land use is predominantly sugar cane, agriculture, and limestone mining. FPL's existing Corbett substation is located north of the site. The Arthur R. Marshall Loxahatchee National Wildlife Refuge is located to the south of the site.

2. **Listed Species**

Construction and operation of Unit 3 at the site will not affect any rare, endangered, or threatened species. Wildlife utilization of the property is minimal as a result of the prior mining activities. Common wading birds can be observed on areas adjacent to, and occasionally within, the property. The property is adjacent to areas that have been identified as potential habitats for wood stork.

3. **Natural Resources of Regional Significance Status**

The construction and operation of another gas-fired CC generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands including the Arthur R. Marshall Loxahatchee National Wildlife Refuge. Construction will not result in any onsite wetland impacts under federal, state, or local agency permitting criteria.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design of Unit 3 comprises the following: one 1,219 MW (Summer capacity) unit consisting of: three combustion turbines (CT), three heat recovery steam generators (HRSG), and a new steam turbine. Natural gas delivered via pipeline is the primary fuel type for this facility with ultra-low sulfur light fuel oil (distillate) serving as a backup fuel.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the project site is "Rural Residential" according to the Palm Beach County Future Land Use Map.

Designations for the area under the Palm Beach County Unified Land Development Code classified the project site and surrounding area as Special Agricultural District. The site has been granted conditional use for electrical power facilities under a General Industrial zoning district.

h. Site Selection Criteria Process

The site has been selected as a Preferred Site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues.

i. Water Resources

The primary water source for the entire site is reclaimed (reuse) water from Palm Beach County Water Utilities Department. Reclaimed water is being used for cooling, service, and process water for Units 1 and 2 and as start-up water for Unit 3. Backup water sources include utilizing the Floridan Aquifer allocation permitted for WCEC Units 1, 2, & 3. Potable water is purchased from the Palm Beach County water municipality.

j. Geological Features of Site and Adjacent Areas

The site is underlain by approximately 13,000 feet of sedimentary rock strata. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks. Little information is known about these rocks due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine in origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, clay, and phosphate grains. The deepest formation in Palm Beach County on which significant published data are available is the Eocene Age Avon Park.

Testing during construction of Exploratory Well 2 (EW-2) demonstrated the presence of a highly permeable zone (Boulder Zone) in the Oldsmar Formation below a depth of 2,790 feet below pad level (bpl) overlain by a thick confining interval (Avon Park Formation) from approximately 2,000 to 2,790 feet bpl. The base of the Underground Source of Drinking Water (USDW) was identified between the depths of 1,932 and 1,959 feet bpl through interpretation of packer tests, water quality data, and geophysical logs. Injection testing confirmed that the hydrogeology of the EW-2 site is favorable for disposal of fluids via a deep injection well system. FPL converted EW-2 to an injection well and installed a second injection well (IW-1 and IW-2, respectively). FPL conducted operational testing on the wells and applied for an operational permit. FDEP has issued a Notice of Intent to issue a Class I operational permit for the two injections wells and the associated dual-zone monitoring well.

k. Projected Water Quantities for Various Uses

The estimated annual average quantity of water required for industrial processing and cooling for all 3 units is up to 29 million gallons per day (mgd). Cooling water for the three generating units would be cycled through cooling towers.

l. Water Supply Sources by Type

WCEC Units 1 & 2, and eventually Unit 3, will use reclaimed water as the primary source of cooling water for the cooling tower with the Floridan Aquifer as backup. The cooling tower will also act as a heat sink for the facility auxiliary cooling system. Such needs for cooling and process water will comply with the existing South Florida Water Management District (SFWMD) regulations for consumptive water use. In addition, reclaimed water used at WCEC must meet all relevant requirements of Chapter 62-610, F.A.C., Part III, for use in cooling towers.

m. Water Conservation Strategies Under Consideration

The use of reclaimed water is a water conservation strategy because it is a beneficial use of wastewater. Impacts on the surficial aquifer would be minimized and used only for potable water, if necessary. Water from the Floridan Aquifer will be used for cooling purposes as a backup water source and cooling towers will be utilized. In addition, captured storm water may be reused in the cooling tower whenever feasible. Storm water captured in the storm water ponds will also recharge the surficial aquifer.

n. Water Discharges and Pollution Control

Heat will be dissipated in the cooling towers. Blowdown water from the cooling towers, along with other waste streams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Storm water runoff will be collected and used to recharge the surficial aquifer via a storm water management system. Design elements will be included to capture suspended sediments. In addition, captured storm water may be reused in the cooling towers, whenever feasible. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is serviced by a new natural gas transmission pipeline that is capable of providing a sufficient quantity of gas to the entire site. Ultra-low sulfur light fuel oil (distillate) will be received by truck and stored in above-ground storage tanks to serve as backup fuel for the WCEC generating units.

p. Air Emissions and Control Systems

The use of natural gas and ultra-low sulfur light fuel oil (distillate) and combustion controls will minimize air emissions from these units and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminants. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil (distillate) as backup fuel. These design alternatives constitute the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. In total, the designs of the WCEC generating units incorporate features that will make the units among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by construction at the site is expected to be below current noise levels for the residents nearest the site. Noise from the operation of the new unit will be within allowable levels.

r. Status of Applications

In regard to WCEC Unit 3, a Site Certification Application (SCA) was filed in December 2007 and the unit received Site Certification by the Secretary of the FDEP, in lieu of the Governor and Cabinet, in November 2008. A Prevention of Significant Deterioration (PSD) air permit was filed in December 2007. The permit was issued by FDEP in July 2008. FPL initiated construction in March 2009 and anticipates an in-service date of June 2011. WCEC Unit 3 will utilize the underground injection control (UIC) system permitted for the entire site.

Preferred Site # 2: St. Lucie Plant, St. Lucie County

FPL's St. Lucie Plant is located in St. Lucie County on Hutchinson Island on an FPL-owned 1,130-acre site. The plant site is bordered by the Atlantic Ocean to the east and the Indian River Lagoon to the west. Located on the site are two nuclear-powered generating units, St. Lucie Units 1 & 2, which have been in operation since 1976 and 1983, respectively.

The generating capacity addition is an increase in the capacity of the two existing nuclear generating units that is used to serve FPL's customers of approximately 122 MW for St. Lucie Unit 1 and 110 MW for St. Lucie Unit 2. The difference between the two values is due to FPL's 100% ownership share of St. Lucie 1 and its 85% ownership share of St. Lucie Unit 2. This work will involve changes to several existing main components within the existing facilities to increase their capability to produce steam for the generation of electricity. No new facilities are required as part of this capacity "uprate." This capacity uprate, along with a similar capacity uprate of FPL's existing Turkey Point nuclear units, was approved by the FPSC in January 2008. The capacity uprates at St. Lucie for the two nuclear units sited there are projected to be in-service partially beginning in 2011 and in their entirety in 2012.[4]

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the FPL St. Lucie Nuclear site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the general layout of the proposed generating facilities at the site is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

[4] FPL has also been pursuing the addition of six wind turbines at the St. Lucie plant site for a number of years. However, to-date FPL has been unable to obtain the necessary local land use approvals that would first be needed before state and federal approvals could be sought.

d. Existing Land Uses of Site and Adjacent Areas

St. Lucie Units 1 & 2 are pressurized water reactors, each having two steam generators. The prominent structures, enclosed facilities, and equipment associated with St. Lucie Units 1 & 2 include the containment building, the turbine generator building, the auxiliary building, and the fuel handling building.

Prominent features beyond the power block area include the intake and discharge canals, switchyard, spent-fuel storage facilities, technical and administrative support facilities, and public education facilities (the Energy Encounter and the College of Turtle Knowledge). Significant features surrounding the St. Lucie Units 1 & 2 are predominately undeveloped land and water bodies including; Big Mud Creek, the Atlantic Ocean, Herman's Bay, and Indian River Lagoon.

In regard to the nuclear capacity uprates, the only changes will be modifications to the existing power generation facilities within the power block area, modifications to the switchyard facilities, and modifications to the transmission lines from St. Lucie to Midway substation. None of the other existing facilities at the plant will change as a result of the uprates.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

FPL's St. Lucie Plant is located in St. Lucie County on Hutchinson Island on an FPL-owned 1,130-acre site. The St. Lucie Plant includes the reactor buildings, turbine buildings, access/security building, auxiliary building, maintenance facilities, and miscellaneous warehouses and other buildings associated with the operation of Units 1 & 2. The site includes adjacent undeveloped mangrove areas. As a result of the approved capacity uprates, the site characteristics will not change.

2. Listed Species

Some listed species known to occur in the area of the plant location are Atlantic sturgeon, smalltooth sawfish, loggerhead sea turtle (*Caretta caretta*), green sea turtle (*Chelonia mydas)*, leatherback sea turtle (*Dermochelys coriacea*), hawksbill sea turtle (*Eretmochelys imbriccata*), gopher tortoise (*Gopherus polyphemus*), kemp's ridley sea turtle (*Lepidochelys kempi*), wood stork (*Mycteria americana*), black skimmer (*Rynchops niger*), and least tern (*Sterna antillarum*).

In regard to the nuclear capacity uprates, neither the development work, nor the continued operation of the two nuclear units after the uprate work has been completed, are expected to adversely affect any rare, endangered, or threatened species. No changes in wildlife populations at the adjacent undeveloped areas are anticipated, including listed species. Noise and lighting impacts will not change and it is expected that wildlife will continue to use the undeveloped areas within the St. Lucie Plant boundary.

3. **Natural Resources of Regional Significance Status**

Significant features surrounding the St. Lucie Units 1 & 2 are predominately undeveloped land and water bodies including; Big Mud Creek, the Atlantic Ocean, Herman's Bay, and Indian River Lagoon.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. The cooling system for the two generating units is a once-through system. The effects of the discharge of cooling water via these discharge structures were evaluated and mixing zones were established to allow compliance with thermal water quality standards as a part of the Plant's NPDES (Permit No. FL0002208). These mixing zones include the volume of water beyond the discharge structures, at the edge of which the water temperature is no greater than 17F abov e the ambient temperature of the intake water.

In regard to the nuclear capacity uprates, the once-through cooling system will continue to be used for the nuclear units.

g. **Local Government Future Land Use Designations**

St. Lucie Units 1 & 2 are located in unincorporated St. Lucie County, Florida. The County has adopted a comprehensive plan, which is updated on a periodic basis. The County Comprehensive Plan incorporates a map that depicts the future land use categories of all property falling within the unincorporated portions of the County. The St. Lucie Plant has a Future Land Use category of Transportation/Utilities (T/U) according to the St. Lucie County Future Land Use Map. The T/U category is described in the St. Lucie County Comprehensive Plan Future Land Use Element Future Land Use.

h. Site Selection Criteria Process

The site has been selected as a Preferred Site for the nuclear capacity uprates because it is an existing nuclear plant site and, therefore, offers the opportunity for increased nuclear capacity.

i. Water Resources

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. The once-through cooling system flow will not change as a result of the nuclear uprates. Due to the existing nature of the St. Lucie Plant, surrounding surface waters will not be adversely affected by the generation capacity addition. Stormwater will be handled by the existing facilities and no new areas will be impacted. Wetlands, groundwater, and nearby surface waters will not be impacted.

j. Geological Features of Site and Adjacent Areas

Beneath the land surface, there is a peat layer 4 to 6 feet thick. Below this layer is the Anastasia Formation, a sedimentary rock formation composed of clay lenses, sandy limestone, and silty fine to medium sand with fragmented shells. This highly permeable stratum extends 35 to 90 feet below mean sea level (msl). Underlying this stratum there is a semi-permeable zone, The Hawthorn Formation, consisting of slightly clayey and very fine silt which extends 600 feet below msl.

The original surficial deposits at the St. Lucie Plant were excavated to a depth of 60 feet and backfilled with Category I or II fill. The fill is underlain by the Anastasia formation, a sequence of partially cemented sand and sandy limestone, which extends to an average depth of about 145 feet. The Anastasia is underlain to a depth of about 600 to 700 feet by the partially cemented and indurated sands, clays, and sandy limestones of The Hawthorn Formation. Underlying these surface strata are about 13,000 feet of Jurassic through Tertiary Formations, primarily carbonate rocks. These formations have a relatively gentle slope to the southeast.

k. Projected Water Quantities for Various Uses

No change is expected in the quantity or characteristics of industrial wastewaters generated by the facility. Therefore, no change in that compliance achievement status is expected. The capacity uprates will not cause any changes in hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow. The St. Lucie Plant does not directly withdraw groundwater under its current operations and it will not withdraw groundwater after the capacity uprates work is completed. The use of water supplied by the City of Fort Pierce, which does withdraw groundwater, will remain unchanged and there will be no changes to the groundwater discharges. There will be no quality, quantity, or hydrological changes, either by withdrawal or discharge to a drinking water source. Therefore, there will be no impacts on drinking water.

l. **Water Supply Sources by Type**

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. General plant service water, fire protection water, process water, and potable water are obtained from City of Fort Pierce. Process water uses include demineralizer regeneration, steam cycle makeup, and general service water use for washdowns. The existing St. Lucie Plant water use is projected to be unchanged as a result of the nuclear capacity uprates.

m. **Water Conservation Strategies Under Consideration**

The existing water resources will not change as a result of the nuclear capacity uprates.

n. **Water Discharges and Pollution Control**

St. Lucie Units 1 & 2 use once-through cooling water from the Atlantic Ocean to remove heat from the main (turbine) condensers via the Circulating Water System (CWS), and to remove heat from other auxiliary equipment via the Auxiliary Equipment Cooling Water System (AECWS). The great majority of this cooling water is used for the CWS.

Under emergency conditions, water can be withdrawn from Big Mud Creek via the Emergency Intake Canal through two 54-inch pipe assemblies in the barrier wall that separates the Creek from the Canal. FPL does not use this intake during normal operations, but does test this system quarterly.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

St. Lucie Units 1 & 2 are licensed for uranium-dioxide fuel that is slightly enriched uranium-235. The uranium-dioxide fuel is in the form of pellets contained in Zircaloy tubes with welded end plugs to confine radionuclides. The tubes are fabricated into assemblies designed for loading into the reactor core. Each reactor core includes 217 fuel assemblies.

FPL currently replaces approximately one-third of the fuel assemblies in each reactor at intervals of approximately 18 months. FPL operates the reactors such that the average fuel usage by the reactors is approximately 47,000 megawatt-days per metric ton uranium. In regard to the nuclear capacity uprates, more nuclear fuel will be used due to the increased capacity of each generating unit. No changes in the fuel-handling facilities are required. Used fuel assemblies are stored in the onsite Nuclear Regulatory Commission (NRC) approved spent fuel storage facilities. Following completion of the uprates, approximately 11 percent more nuclear fuel will be used to increase the capacity of each generating unit. No changes in the fuel-handling facilities are required.

Diesel fuel is used in a number of emergency generators that include four main plant generators, two building generators, and various general purpose diesel engines. The main plant emergency generators will not be changed as a result of the generation capacity additions. These emergency generators are for standby use only and are tested to assure reliability and for maintenance. Diesel fuel is delivered to the St. Lucie Plant by truck as needed, and stored in tanks with secondary containment.

p. Air Emissions and Control Systems

The St. Lucie Plant is classified as a minor source of air pollution, since FDEP has issued a Federally Enforceable State Operating Permit (FESOP) to keep emissions less than 100 tons per year for any air pollutant regulated under the Clean Air Act. The applicable units at the St. Lucie Plant consist of eight large main plant diesel engines, two smaller diesel engines, and various general-purpose diesel engines. The air emissions from these engines are limited by the use of 0.05-percent sulfur diesel fuel and good combustion practices. Best Available Control Technology (BACT) is not applicable to these existing emission units.

Nitrogen oxide (NO_x) emissions from the operation of the diesel engines comprise the limiting pollutant for these diesel units at the St Lucie Plant. The FDEP FESOP limits

NO_x emissions to 99.4 tons, which includes fuel use limits on the large main plant emergency diesel engines of 97,000 gallons in any 12-month consecutive period and the smaller building and general purpose diesel engines of 190,000 gallons in any 12-month consecutive period. Also, the Plant may choose to combine the diesel units' fuel-tracking, which then limits the NO_x totals for a 12-month consecutive period to a maximum of 80 tons. There will be no change in the operation or emissions of the diesel engines resulting from the nuclear capacity uprates.

In addition, the generation capacity additions will not result in an increase of CO_2 or other greenhouse gas emissions. In fact, the increases in generation capacity are projected to result in decreased FPL system-wide emissions of CO_2.

q. **Noise Emissions and Control Systems**

A field survey and impact assessment of noise expected to be caused by construction activities at the site was conducted. Predicted noise levels are not expected to result in adverse noise impacts in the vicinity of the site during construction or operation.

r. **Status of Applications**

A Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act was filed in December 2007 and a final order issued in September 2008. The FPSC voted to approve the need for the St. Lucie (and Turkey Point) nuclear capacity uprates and the final order approving the need for these capacity additions was issued in January 2008.

Preferred Site # 3: Turkey Point Plant, Miami-Dade County

The Turkey Point Plant site is located on the west side of Biscayne Bay, 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. Public access to the plant site is limited due to the nuclear units located there. The land surrounding the site is owned by FPL and acts as a buffer zone. The site is comprised of two nuclear units (Units 3 & 4), two natural gas/oil conventional steam units (Units 1 & 2), one CC natural gas unit (Unit 5), nine small diesel generators, the cooling canals, an FPL-maintained natural wildlife area, and wetlands that have been set aside as the Everglades Mitigation Bank (EMB).

Turkey Point Units 3 & 4 have been in operation since 1972 and 1973, respectively. The Turkey Point site has been selected as a Preferred Site for the increase in the capacity of its two existing nuclear generating units by approximately 109 MW each. This work will involve changes to several existing main components within the existing facilities to increase their capability to produce steam for the generation of electricity. No new or expanded facilities are required as part of this capacity "uprate." This capacity uprate, along with a similar capacity uprate of FPL's existing St. Lucie nuclear units, was approved by the FPSC in January 2008. The capacity uprates at Turkey Point are projected to be in-service in 2012 and early 2013.

As previously mentioned, FPL is pursuing licensing for two new nuclear units at the Turkey Point site. Each of these two units would provide 1,100 MW of capacity. Current projections for the in-service dates of these two units, Turkey Point Units 6 & 7, are beyond the 2011 - 2020 reporting time frame of this document.

a. <u>U.S. Geological Survey (USGS) Map</u>

A USGS map of the Turkey Point plant site is found at the end of this chapter.

b. <u>Proposed Facilities Layout</u>

A map of the general layout of the Turkey Point Units 3 and 4 generating facility at the site is found at the end of this chapter.

c. <u>*Map of Site and Adjacent Areas*</u>

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. <u>Existing Land Uses of Site and Adjacent Areas</u>

The five existing power generation units and support facilities occupy approximately 150 acres of the 11,000-acre Turkey Point Plant site. Support facilities include service buildings, an administration building, fuel oil tanks, water treatment facilities, circulating water intake and outfall structures, wastewater treatment basins, and a system substation. The cooling canal system occupies approximately 5,900 acres. The two 400-megawatt (MW) (nominal) fossil fuel-fired steam electric generation units at the Turkey Point Plant have been in service since 1967 (Unit 1) and 1968 (Unit 2). These units currently burn residual fuel oil and/or natural gas with a maximum equivalent sulfur content of 1 percent. The two 700-MW (nominal) nuclear units have been in service since 1972 (Unit 3) and 1973 (Unit 4). Turkey Point Units 3 and 4 are pressurized water reactor (PWR) units. Turkey Point Unit 5 is a nominal 1,150-MW natural gas-fired combined cycle (CC) unit that began operation in 2007. Significant features in the vicinity of the site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The prominent structures and enclosed facilities and equipment associated with Units 3 & 4 include: the containment building, which contains the nuclear steam supply system including the reactor, steam generators, reactor coolant pumps, and related equipment; the turbine generator building, where the turbine generator and associated main condensers are located; the auxiliary building, which contains waste management facilities, engineered safety components, and other facilities; and the fuel handling building, where the spent fuel storage pool and storage facilities for new fuel are located. Prominent features beyond the power block area include the intake system, cooling canal system, switchyard, spent fuel storage facilities, and technical and administrative support facilities.

2. Listed Species

The construction during the uprating of the units, and operation of the units after the capacity uprating is completed, are not expected to adversely affect any rare, endangered, or threatened species. Listed species known to occur at the site and in the nearby Biscayne National Park that could potentially utilize the site include the peregrine falcon *(Falco peregrinus)*, wood stork *(Mycteria americana)*, American crocodile *(Crocodylus acutus)*, mangrove rivulus *(Rivulus marmoratus)*, roseate spoonbill *(Ajaja ajaja)*, limpkin *(Aramus guarauna)*, little blue heron *(Egretta caerulea)*, snowy egret *(Egretta thula)*, American oystercatcher *(Haematopus palliates)*, least tern *(Sterna antillarum)*, the white ibis *(Eudocimus albus)*, and bald eagle *(Haliaeetus leucocephalus)*. No bald eagle nests are known to exist in the vicinity of the site. The federally listed, threatened American Crocodile thrives at the Turkey Point site, primarily in and around the southern end of the cooling canals which lie south of the project area. The entire site is considered crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American crocodile and is attributed with survival improvement and the downlisting of the American Crocodile from endangered to threatened.

3. Natural Resources of Regional Significance Status

Significant features in the vicinity on the site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park. Biscayne National Park contains 180,000 acres, approximately 95 percent of which is open water interspersed with more than 40 keys. The Biscayne National Park headquarters is located approximately 2 miles north of the Turkey Point plant and is adjacent to the Miami-Dade County Homestead Bayfront Park which contains a marina and day-use recreational facilities.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

Turkey Point Units 3 & 4 uses cooling water from a closed-cycle cooling canal system to remove heat from the main (turbine) condensers, and to remove heat from other auxiliary equipment. The existing cooling canals will accommodate the increase in heat load that is associated with the increased capacity from the uprates. The maximum projected increase in water temperature entering the cooling canal system from the units resulting from the uprates is predicted to be about 2.5F, from 106.1F to 108.6F. The associated projected ma ximum increase in water temperature returning to the units is about 0.9F, from 91.9F to 92.8F.

g. Local Government future Land Use Designations

Local government future land use plan designates most of the site as IU-3 "Industrial, Unlimited Manufacturing District." There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. Site Selection Criteria Process

The site has been selected as a Preferred Site for the nuclear capacity uprates because it is an existing nuclear plant site and, therefore, offers the opportunity for increased nuclear capacity.

i. **Water Resources**

Unique to the Turkey Point plant site is the self-contained cooling canal system that supplies water to condense steam used by the plant's turbine generators. The canal system consists of 36 interconnected canals. The cooling canals occupy an area approximately two miles wide by five miles long (5,900 acres), approximately four feet deep. The system performs the same function as a giant radiator. The water is circulated through the canals in a two-day journey, ending at the plant's intake pumps.

j. **Geological Features of Site and Adjacent Areas**

The Turkey Point Plant lies upon the Floridian Plateau, a partly-submerged peninsula of the continental shelf. The peninsula is underlain by approximately 4,000 to 15,000 feet of sedimentary rocks consisting of limestone and associated formations that range in age from Paleozoic to Recent. Little is known about the basement complex of Paleozoic igneous and metamorphic rocks due to their great depth.

Generally in Miami-Dade County, the surficial aquifer (Biscayne Aquifer) consists of a wedge-shaped system of porous clastic and carbonate sedimentary materials, primarily limestone and sand deposits of the Miocene to late Quaternary age. The Biscayne Aquifer is thickest along the eastern coast and varies in thickness from 80 to 200 feet thick. The surficial aquifer is typically composed of Pamlico Sand, Miami Limestone (Oolite), the Fort Thompson and Anastasia Formations (lateral equivalents), Caloosahatchee Marl, and the Tamiami formation. The lower confining layers below the surficial aquifer range in thickness from 350 to 600 feet and are composed of the Hawthorn Group. Beneath the Hawthorn Group, the Floridan Aquifer System ranges from 2,800 to 3,400 feet thick and consists of Suwannee Limestone, Avon Park Limestone, and the Oldsmar Formations.

k. **Projected Water Quantities for Various Uses**

The addition of nuclear generating capacity as a result of the uprates will not cause any changes in the quantity or characteristics of industrial wastewaters generated by the facility; therefore, no change in that compliance achievement status is expected. The uprates will not cause any changes in hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow. The Turkey Point Plant does not directly withdraw groundwater under its current operations and it will not do so after the capacity uprates. Locally, groundwater is present beneath the site in the surficial or Biscayne Aquifer and in deeper aquifer zones that are part of the Floridan

Aquifer System. There will be no effects on those deeper aquifer zones from the capacity uprates.

l. Water Supply Sources and Type

The source of cooling water for Turkey Point Units 3 & 4 is the cooling canal system. There will be no increase in the amount of water withdrawn as a result of the capacity uprates. General plant service water, fire protection water, process water, and potable water are obtained from Miami-Dade County. Process water uses include demineralizer regeneration, steam cycle makeup, and general service water use for washdowns. The water use for the facility will not change as a result of the capacity uprates.

m. Water Conservation Strategies

The existing water resources will not change as a result of the uprates.

n. Water Discharges and Pollution Control

Heated water discharges are dissipated using the existing closed cooling canal system.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Turkey Point Units 3 & 4 utilize uranium-dioxide fuel that is slightly enriched uranium-235. The uranium-dioxide fuel is in the form of pellets contained in Zircaloy tubes with welded end plugs to confine radionuclides. The tubes are fabricated into assemblies designed for loading into the reactor core. Used fuel assemblies are stored in the onsite NRC-approved spent fuel storage facilities.

FPL currently replaces approximately one-third of the fuel assemblies in each reactor at refueling intervals of approximately 18 months. FPL operates the reactors such that the average fuel usage by the reactors is approximately 45,000 megawatt-days per metric ton of uranium. Following completion of the uprates, more nuclear fuel will be used to increase the capacity of each unit. No changes in the fuel handling facilities are required. Following completion of the uprates, approximately 11 percent more nuclear fuel will be used to increase the capacity of each unit. No changes in the fuel-handling facilities are required.

Diesel fuel is used in a number of emergency generators that include four main emergency generators, five smaller emergency generators, and various general purpose diesel engines. The emergency generators will not be changed as a result of the capacity uprates. These emergency generators are for stand-by use only and only operated for testing purposes to assure reliability and for maintenance. Diesel fuel for the emergency generators is delivered to the Turkey Point Plant by truck as needed, and stored in tanks with secondary containment.

p. Air Emissions and Control Systems

The normal operation of Turkey Point Units 3 & 4 does not create fossil fuel-related air emissions. However, there are nine emergency generators associated with Units 3 & 4. Four of these nine emergency generators are main plant emergency generators which are rated at 2.5 MW each. The remaining five generators are smaller emergency generators which are associated with the security system. In addition, various general purpose diesels are used as needed for Units 3 & 4.

Turkey Point Plant Units 3 & 4's associated emergency generators and diesel engines, together with Units 1, 2, & 5, are classified as a major source of air pollution. FDEP has issued a separate Title V Air Operating Permit for the Turkey Point Nuclear Plant (Permit Number 0250003-004-AV). There are no operating limits for the emergency generators or diesel engines. Emergency diesel generators are limited to ultra-low sulfur distillate (0.0015% sulfur). NOx emissions are regulated under Reasonably Available Control Technology (RACT) requirements in Rule 62-296.570(4)(b)7 F.A.C., which limit NO_x emissions to 4.75 lb/MMBtu. The use of 0.05 percent sulfur diesel fuel and good combustion practices serve to keep NO_x emissions under this limit.

q. Noise Emissions and Control Systems

A field survey and impact assessment of noise expected to be caused by activities associated with the uprates was conducted. Predicted noise levels are not expected to result in adverse noise impacts in the vicinity of the site.

r. **Status of Applications**

A Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act was filed in January 2008 and a final order was issued in October 2008. The FPSC voted to approve the need for the Turkey Point (and St. Lucie) uprates and the final order approving the need for this additional nuclear capacity was issued in January 2008.

Preferred Site # 4: Cape Canaveral Plant, Brevard County

This site is located on the existing FPL Cape Canaveral Plant property in unincorporated Brevard County. The site is bound to the east by the Indian River Lagoon and on the west by a four lane highway (US. 1). The city of Port St. Johns is located less than a mile away. A rail line is located near the plant.

The site previously housed two steam units (Units 1 & 2) with 788 MW (summer) of generating capacity. The units formerly occupied a portion of the 43 acres that are wholly owned by FPL. The units have been taken out of service and dismantlement of the Cape Canaveral Plant began in mid-2010 and is expected to be complete by the end of first quarter 2011.

The Cape Canaveral Plant site has been listed as a Potential Site in previous FPL Site Plans for both CC and simple cycle combustion turbine (CT) generation options. FPL is in the process of modernizing the existing Cape Canaveral Plant, to be renamed the Cape Canaveral Next Generation Clean Energy Center (CCEC), by replacing the previous two steam generating units with a single modern, highly efficient, lower-emission next-generation clean energy center using the latest CC technology.

a. **Geological Survey (USGS) Map**

A USGS map of the CCEC site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the general layout of the CCEC generating facilities at the site is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing and future land uses on the site are primarily dedicated to electrical generation; i.e., FPL's former Cape Canaveral Units 1 & 2 and the future CCEC unit. The existing land uses that are adjacent to the site consist of single- and multi-family residences to the south and southwest, commercial property to the northwest, utility systems to the west, and a private medical/office facility to the north.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The natural environment surrounding the site includes the Indian River Lagoon to the east and upland scrub, pine and hardwoods to the north and south. Vegetation with the approximately 45-acre offsite construction laydown and parking area (located west of U.S. Highway 1) consists of open land, upland scrub, pine, hardwoods along with exotic plant species.

2. Listed Species

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species. Federal- or state-listed terrestrial plants and animals inhabiting the offsite construction laydown and parking area are limited to the state-listed gopher tortoise and the state- and federally-listed scrub jay. The warm water discharges from the plant attract manatees, an endangered species. FPL continues to work closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process and upon operation of the new plant. In 2010, FPL installed a temporary heating system to warm the water for the manatees as required during manatee season. FPL will also be complying with several other manatee-related conditions of certification to ensure the protection of the manatees during the modernization work.

3. Natural Resources of Regional Significance Status

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option is to replace the existing steam generating units (Units 1 & 2) with one new 1,210 MW (approximate) CC unit consisting of three new combustion turbines (CT), three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit is projected to be in-service in mid-2013. Natural gas delivered via pipeline is the primary fuel type for this unit with ultra-low sulfur light oil serving as a backup fuel.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is "Public Utilities" and the area has been rezoned to GML-U. Designations for the surrounding area are primarily "Community Commercial" and "Residential".

h. Site Selection Criteria Process

The Cape Canaveral Plant has been selected for a site modernization due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of replacing the previous steam units with a new CC unit including a significant reduction in system fuel use, a significant reduction in system air emissions, improved aesthetics at the site, and continued warm water discharge for the manatees as required during manatee season. Further, modernizing this existing facility reduces the impact on natural resources by not requiring new land, new water sources, or additional off-site transmission siting.

i. Water Resources

Condenser cooling for the steam cycle portion of the new plant and auxiliary cooling will come from the existing cooling water intake system. Process, potable, and irrigation water for the new plant will come from the existing City of Cocoa's potable water supply.

j. Geological Features of Site and Adjacent Areas

FPL's Cape Canaveral Plant is located on the Atlantic Coastal Ridge and is at an approximate elevation of 12 feet above mean sea level (msl). The land consists primarily of fine to medium sand that parallels the coast. There is a lack of shell as it was deposited during a time of transgression. The base of the sedimentary rocks is made up of a thick, primarily carbonate sequence deposited during the Jurassic age through the Pleistocene age. Starting in the Miocene age and continuing through the Holocene age, siliciclastic sedimentation became more predominant. The basement rocks in this area consist of low-grade metamorphic and igneous intrusives, which occur several thousand feet below land surface and are Precambrian, Paleozoic, and Mesozoic in age.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing is approximately 0.232 million gallons per day (mgd) for uses such as process water and service water. Approximately 619 mgd of cooling water would be cycled through the once-through cooling water system. Potable water demand is expected to average .001 mgd.

l. Water Supply Sources by Type

The modernized plant will continue to use the Indian River Lagoon water as the source of once-through cooling water. Such needs for cooling water will comply with the St. John's River Water Management District (SJRWMD) conditions of certification. Process and potable water for the new plant will come from the existing City of Cocoa's potable water supply. Reclaimed water will be used for irrigation.

m. Water Conservation Strategies Under Consideration

No additional water sources will be required as a result of the modernization project.

n. Water Discharges and Pollution Control

The modernized site will utilize portions of the existing once-through cooling water systems for heat dissipation. The heat recovery steam generator blowdown will be mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit will be transported to the site via a pipeline. New off-site or on-site gas compressors will be installed to raise the gas pressure of the existing pipeline for the new unit. Ultra-low sulfur light fuel oil will be received by truck or barge from Port Canaveral and stored in an existing above-ground storage tank.

p. Air Emissions and Control Systems

The emission rates of CCEC would decrease by over 90% from the existing Cape Canaveral Plant, resulting in substantial annual emissions reductions and increased air quality benefits. The use of natural gas and ultra-low sulfur light fuel oil and combustion controls would minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. In total, the design of the new CCEC plant will incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise from the operation of the new unit will be within allowable levels.

r. Status of Applications

The FPSC voted to approve the need for the modernization project and the need order was issued in September 2008. The project received final state certification on October 9, 2009, through the issuance of a final order signed by the Secretary of the DEP.

Preferred Site # 5: Riviera Plant, Palm Beach County

This site is located on the existing FPL Riviera Plant property primarily within Riviera Beach, Palm Beach County (with a small portion of the Site in West Palm Beach). The site is bound to the east by the Lake Worth Lagoon (Intracoastal Waterway) and on the west by a four lane highway (US. 1). The site has barge access via the Port of Palm Beach. A rail line is located near the plant.

The previous site generating capacity was made up of two 300 MW (approximate) steam generating units (Units 3 & 4) that have been taken out of service and will be dismantled in 2011. Units 1 & 2 were previously retired and dismantled and are no longer on the plant site.

The Riviera Plant site has been listed as a Potential Site in previous FPL Site Plans for both CC and simple cycle combustion turbine (CT) generation options. FPL is in the process of modernizing the existing Riviera Plant, to be renamed the Riviera Beach Next Generation Clean Energy Center (RBEC), by replacing the existing generating units with a modern, highly efficient, lower-emission next-generation clean energy center using the latest CC technology. The existing two steam units will first be removed from the site and will be replaced by a single new CC unit.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the RBEC site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A general layout of the RBEC generating facilities is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

The previous Riviera Plant consisted of two 300 MW (approximate) units with conventional dual-fuel fired steam boilers and steam turbine units. The plant site includes minimal vegetation and a landscape buffer area south of the power plant. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of facilities related to electric power generation for the existing Riviera Plant generating units. The site is located adjacent to the Intracoastal waterway. The site provides warm water as required for manatees during manatee season.

2. Listed Species

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species. The warm water discharges from the plant attract manatees, an endangered species. FPL continues to work closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process and upon operation of the new plant. In 2009, FPL installed a temporary heating system to warm the water for the manatees as required during manatee season. FPL will also be complying with several other manatee-related conditions of certification to ensure the protection of the manatees during the modernization work.

3. Natural Resources of Regional Significance Status

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option is to replace the existing units (Units 3 & 4) with one new 1,212 MW (approximate) unit consisting of three new combustion turbines (CT), three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit is projected to be in service in mid-2014. Natural gas delivered via pipeline is the primary fuel type for the unit with ultra-low sulfur light oil serving as a backup fuel.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the site is "Utility". The Port of Palm Beach is to the north of the site. Designation to the west of the site is "Commercial". To the south of the site is "Residential" and is in the City of West Palm Beach.

h. **Site Selection Criteria Process**

The Riviera plant has been selected for site modernization due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of replacing the existing steam units with a new CC unit including a significant reduction in system air emissions, improved aesthetics at the site and continued warm water discharge for the manatees as required during manatee season. Further, modernizing this existing facility reduces the impact on natural resources by not requiring new land or new water sources.

i. **Water Resources**

Water from the Lake Worth Lagoon (Intracoastal waterway) is currently used for once-through cooling water. The new plant will utilize portions of the existing once-through cooling water intake and discharge structures. Water for cooling pump seals and irrigation will come from three onsite surficial aquifer wells. Process and potable water for the converted plant will come from the existing City of Riviera Beach potable water supply.

j. **Geological Features of Site and Adjacent Areas**

FPL's Riviera Plant site is underlain by the surficial aquifer system. The Surficial aquifer system in eastern Palm Beach County is primarily composed of sand, sandstone, shell, silt, calcareous clay (marl), and limestone deposited during the Pleistocene and Pliocene Epochs. The sediments forming the aquifer system are the Pamlico Sand, Fort Thompson Formation (Pleistocene) and the Caloosahatchee Marl (Pleistocene and Pliocene). Permeable sediments in the upper part of the Tamiami Formation (Pliocene) are also part of the aquifer system. The sediments in the eastern portion of the county are appreciably more permeable than in the west due to better sorting and less silt and clay content.

The surficial aquifer is underlain by at least 600 feet the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing is approximately 0.232 million gallons per day (mgd) for uses such as process water and service water. Approximately 600 mgd of cooling water would be cycled through the once-through cooling water system. Potable water demand is expected to average .001 mgd.

l. Water Supply Sources by Type

The modernized plant will continue to use the Lake Worth Lagoon water as the source of once-through cooling water. Water for cooling pump seals and irrigation will come from on-site surficial aquifer wells currently authorized under SFWMD conditions of certification. Process and potable water for the new plant will come from the existing City of Riviera Beach's potable water supply.

m. Water Conservation Strategies Under Consideration

No additional water sources will be required as a result of the modernization project.

n. Water Discharges and Pollution Control

The modernized plant will utilize portions of the existing once-through cooling water system for heat dissipation. The heat recovery steam generator blowdown will be mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system prior to discharge. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit would be transported to the site via an approximately 6 mile FPL-owned pipeline, the RBEC Lateral. New gas compressors will be installed at the existing FPL 45th Street Terminal facility in Riviera Beach to raise the gas pressure of the pipeline to the appropriate level for the new unit. Ultra-low sulfur light fuel oil would be received by truck, pipeline, or barge and stored in a new above-ground storage tank.

p. **Air Emissions and Control Systems**

The regulated air emissions at the new plant would be more than 90 percent lower than the previous Riviera Plant's emissions are, resulting in significant annual emissions reductions and air quality benefits. The use of natural gas and ultra-low sulfur light fuel oil and combustion controls would minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of RBEC would incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q. **Noise Emissions and Control Systems**

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. **Status of Applications**

The FPSC voted to approve the need for the modernization project and the need order was issued in September 2008. The project received final state certification on November 24, 2009, through the issuance of a final order signed by the Secretary of the DEP. Final approval for the RBEC 6 mile pipeline lateral and compressor station is expected by end of March 2011.

IV.F.2 Potential Sites for Generating Options

Thirteen (13) sites are currently identified as Potential Sites for near-term future generation additions to meet FPL's projected capacity and energy needs.[5] These sites have been identified as Potential Sites due to considerations of location to FPL load

[5] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other Greenfield sites. Greenfield sites that FPL currently does not own, or for which FPL has not currently secured the necessary rights to, are not specifically identified as Potential Sites in order to protect the economic interests of FPL and its customers.

centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies, including both renewable energy and non-renewable energy technologies for various sites.

Each of these Potential Sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that will require further definition and attention. Solely for the purpose of estimating water requirements for sites more suited for non-renewable energy technologies, it was assumed that either one dual-fuel (natural gas and light oil) simple cycle CT or a natural gas-fired CC unit would be constructed at these Potential Sites unless otherwise noted.

A simple cycle CT would require approximately 50 gallons per minute (gpm) for both process and cooling water (assuming a cooling tower was utilized). A CC unit would require approximately up to 150 gpm for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized). If an existing power plant site is ultimately selected for modernization (as is the case with FPL's Cape Canaveral and Riviera sites), the water requirements discussed above for a CC unit would be approximately correct for the modernized site. If a renewable energy generating technology is ultimately selected for one of these sites, the water requirements would be significantly less than those for CT or CC facilities.

Permits are presently considered to be obtainable for each of these sites. No significant environmental constraints are currently known for any of these sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time, FPL considers each site to be equally viable. As noted previously, FPL also considers a number of other sites as possible sites for future generation additions. These include all of the remainder of FPL's existing generation sites and other Greenfield sites.

Potential Site # 1: Babcock Ranch , Charlotte County

This site is located within the proposed Babcock Ranch Community on the north side of Tuckers Grade, approximately 10.5 miles north of the intersection of SR-80 and SR-31 and 1.1 miles east of SR-31. The project is bordered on the north by the Babcock Ranch Preserve owned by the State of Florida. The site is within the SFWMD and, therefore, the drainage would be in accordance with the SFWMD Basis of Review. Permitting of the surface water management system would be through the Florida Department of

Environmental Protection (FDEP) - South District. This site is a possibility for an FPL photovoltaic (PV) facility.

a. **U.S. Geological Survey (USGS) Map**

A map of this site is found at the end of this chapter.

b. **Land Uses**

Existing land use on the site is the Babcock Ranch Overlay District, and it is zoned as the Babcock Ranch Overlay Zoning District. This land use and zoning allows for solar facilities.

c. **Environmental Features**

FPL would anticipate mitigating for any panther and/or wetland impacts as a result of a PV project at this site.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall Any such water would be brought to the site by truck.

Potential Site # 2: DeSoto Solar Expansion, DeSoto County

The DeSoto site is located at 4051 Northeast Karson Street approximately 0.3 miles east of US 17 and immediately north of Bobay Road in Arcadia, Florida. The site is located in Sections 26, 27, & 35, Township 36 South, and Range 25 East. FPL owns an approximate 13,000 acre parcel in DeSoto County. FPL has designated approximately 5,177 acres for development of a photovoltaic (PV) facility.

The DeSoto site was previously selected as the site for the addition of a 25 MW PV facility, which is operational. There is also a potential to create an additional 275 MW PV generating facility which could be implemented in phases on the additional land.

a. **U.S. Geological Survey (USGS) Map**

A map of this site is found at the end of this chapter.

b. **Land Uses**

Existing land use on the site is agricultural. The future land use is Electric Generating Facility.

c. **Environmental Features**

There are no significant environmental features on the site.

d. **Water Quantities**

Minimal amounts of water would be required for a future expansion of the existing PV facility.

e. **Supply Sources**

Minimal water would be required at for an expanded PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall and potable water will be required in the administration building and maintenance building. FPL would propose to utilize existing wells onsite to accommodate water needs.

Potential Site # 3: Florida Heartland, Glades County

This site is located within Glades County off of SR 78. This site is a possibility for an FPL PV facility.

a. **U.S. Geological Survey (USGS) Map**

A map of this site is found at the end of this chapter.

b. **Land Uses**

The existing land use on the site is agriculture.

c. **Environmental Features**

FPL would anticipate mitigating for any wildlife and/or wetland impacts as a result of a PV project at this site.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water would be brought to the site by truck.

Potential Site # 4: Hendry County

FPL is currently evaluating potential sites in Hendry County for a future PV facility or fossil generation. Sites currently under investigation are approximately 1,500 acres. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

Hendry County has predominantly agricultural land use.

c. **Environmental Features**

This information is not available because a specific site has not been selected at this time.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility. Fossil generation would require approximately up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized).

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. The supply of water for fossil generation would be dependent upon the selection of a specific site.

Potential Site # 5: Manatee Plant Site, Manatee County

The existing FPL Manatee Plant 9,500-acre site is located in unincorporated north-central Manatee County. The existing power generating facilities are located in all or portions of Sections 18 and 19 of Township 33S, Range 20-E. The plant site lies approximately 5 miles east of Parrish, Florida. It is approximately 5 miles east of U.S. 301 and 9.5 miles east of Interstate Highway 75 (I-75). The existing plant is approximately 2.5 miles south of the Hillsborough-Manatee County line; a portion of the north property boundary of the plant site abuts the county line. State Road 62 (SR 62) is about 0.7 mile south of the plant, with the plant entrance road going north from that highway. This site is a possible location for an FPL PV.facility.

a. **U.S. Geological Survey (USGS) Map**

A map of the site is found at the end of this chapter.

b. **Land Uses**

Existing land use on the site is agricultural. The property is zoned Planned Development / Public Interest (PD-PI), which will allow for electrical generation.

c. **Environmental Features**

FPL would anticipate mitigating for any wildlife and/or wetland impacts as a result of a PV project at this site.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall.

Potential Site # 6: Martin County

FPL is currently evaluating potential sites in Martin County for a future PV facility. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

This information is not available because a specific site has not been selected at this time.

c. **Environmental Features**

This information is not available because a specific site has not been selected at this time.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall.

Potential Site # 7: Northeast Okeechobee County

FPL is currently evaluating potential sites in Northeast Okeechobee County for a future PV facility or fossil generation. Sites currently under investigation are approximately 1,500 acres. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

Northeast Okeechobee County has predominantly agricultural land use.

c. **Environmental Features**

This information is not available because a specific site has not been selected at this time.

d. **Water Quantities**

As previously discussed, needed water quantities for fossil generation would be up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower would be utilized). Needed water quantities would be significantly less for a PV facility.

e. **Supply Sources**

Existing groundwater and/or regional water supply initiatives are potential water sources.

Potential Site # 8: Palatka Site, Putnam County

FPL is currently evaluating a site adjacent to the FPL Putnam Plant in Putnam County for future fossil generation. The approximately 170 acre site was the location of the former FPL Palatka Plant which was dismantled in the 1990s.

a. **U.S. Geological Survey (USGS) Map**

A map of the site is found at the end of this chapter.

b. **Land Uses**

The site has a land use designation of Industrial.

c. **Environmental Features**

The majority of site has been previously impacted by past power plant operations. No significant environmental features have been identified at this time.

d. **Water Quantities**

As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming cooling tower).

e. **Supply Sources**

The St John's River, existing groundwater, and/or regional water supply initiatives are potential water sources.

Potential Site # 9: Port Everglades Plant, Broward County

The 94-acre FPL Port Everglades plant site is located at Port Everglades in Broward County. The site has convenient access to State Road (S.R.) 84 and I-595. Rail line is located near the plant. The existing plant consists of four steam boiler generating units: two 200 MW (approximate) and two 400 MW (approximate) sized units. The four steam boilers are capable of firing residual fuel oil, natural gas, or a combination of both. The site is also home to 12 simple cycle gas turbine (GT) peaking units of 35 MW (approximate) each. The GTs are capable of firing either natural gas or liquid fuel. This site is being considered for a potential modernization.

a. **U.S. Geological Survey (USGS) Map**

A map of the site is found at the end of this chapter.

b. **Land Uses**

The land on this site is primarily industrial. The adjacent land uses are port facilities and associated industrial activities, oil storage, cruise ships, and light commercial.

c. **Environmental Features**

The shoreline of the intake and discharge canal banks are vegetated with fringing mangrove, with some open, maintained grass areas on the side.

d. **Water Quantities**

Water quantities would be up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming cooling tower).

e. **Supply Sources**

Existing groundwater or the municipal water supply could be used for industrial process and makeup water. Industrial cooling water needs could be met using the existing once-through cooling water system.

Potential Site # 10: Putnam County

FPL is currently evaluating potential sites in Putnam County for a future PV facility or fossil generation. Sites currently under investigation are approximately 2,800 acres. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

Not available because a specific site has not been selected at this time.

c. **Environmental Features**

This information is not available because a specific site has not been selected at this time.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility. Fossil generation would require approximately up to 150 gallons per minute (gpm) for process water and up to

7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized).

e. **Supply Sources**

Existing groundwater is a potential water source.

Potential Site # 11: Southwest Indian River County

FPL is currently evaluating potential sites in Southwest Indian River County for a future PV facility or fossil generation. Sites currently under investigation are approximately 1,500 acres. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

Southwestern Indian River County has predominantly agricultural land use.

c. **Environmental Features**

Not available because a specific site has not been selected at this time.

d. **Water Quantities**

As previously discussed, needed water quantities for fossil generation would be up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized). Needed water quantities would be significantly less for a PV facility.

e. **Supply Sources**

Existing groundwater is a potential water source.

Potential Site # 12: Space Coast Solar Expansion, Brevard County

The Space Coast site is located at NASA's Kennedy Space Center property in Brevard County. This site currently consists of a 10 MW PV facility with the potential to expand by another 10 MW. Also, FPL is evaluating the potential for further expansion beyond the existing site, within the Space Center property.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site has been included at the end of this chapter.

b. **Land Uses**

NASA, a federal agency, has approved use of the land at the site for PV generation.

c. **Environmental Features**

There are no significant environmental features on this site.

d. **Water Quantities**

Minimal amounts of water would be required for an expansion of the PV facility.

e. **Supply Sources**

No water would be required for an expansion of the PV facility except the small amount that may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water would be brought to the site by truck or would come from existing onsite wells.

Potential Site # 13: West Broward, Broward County

FPL has identified its Andytown Substation property in western unincorporated Broward County as a potential site for the addition of new fossil generating capacity and FPL refers to this potential site as the West Broward site. Current facilities on-site include an electric substation. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

The land uses for the site are designated as agricultural use.

c. **Environmental Features**

Extensive low-quality wetlands are present on the site. Known presence of listed species nearby, e.g. wood storks, will require further investigation.

d. **Water Quantities**

As previously discussed, needed water quantities for fossil generation would be up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized).

e. **Supply Sources**

Groundwater from the shallow aquifer or a local source of reclaimed (reuse) water has been identified as potential water sources. The Floridan Aquifer has also been identified as a potential cooling water source. FPL will also consider the potential for alternative water development options at this site.

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Environmental and Land Use Information: Supplemental Information

Preferred Site#1: West County Energy Center

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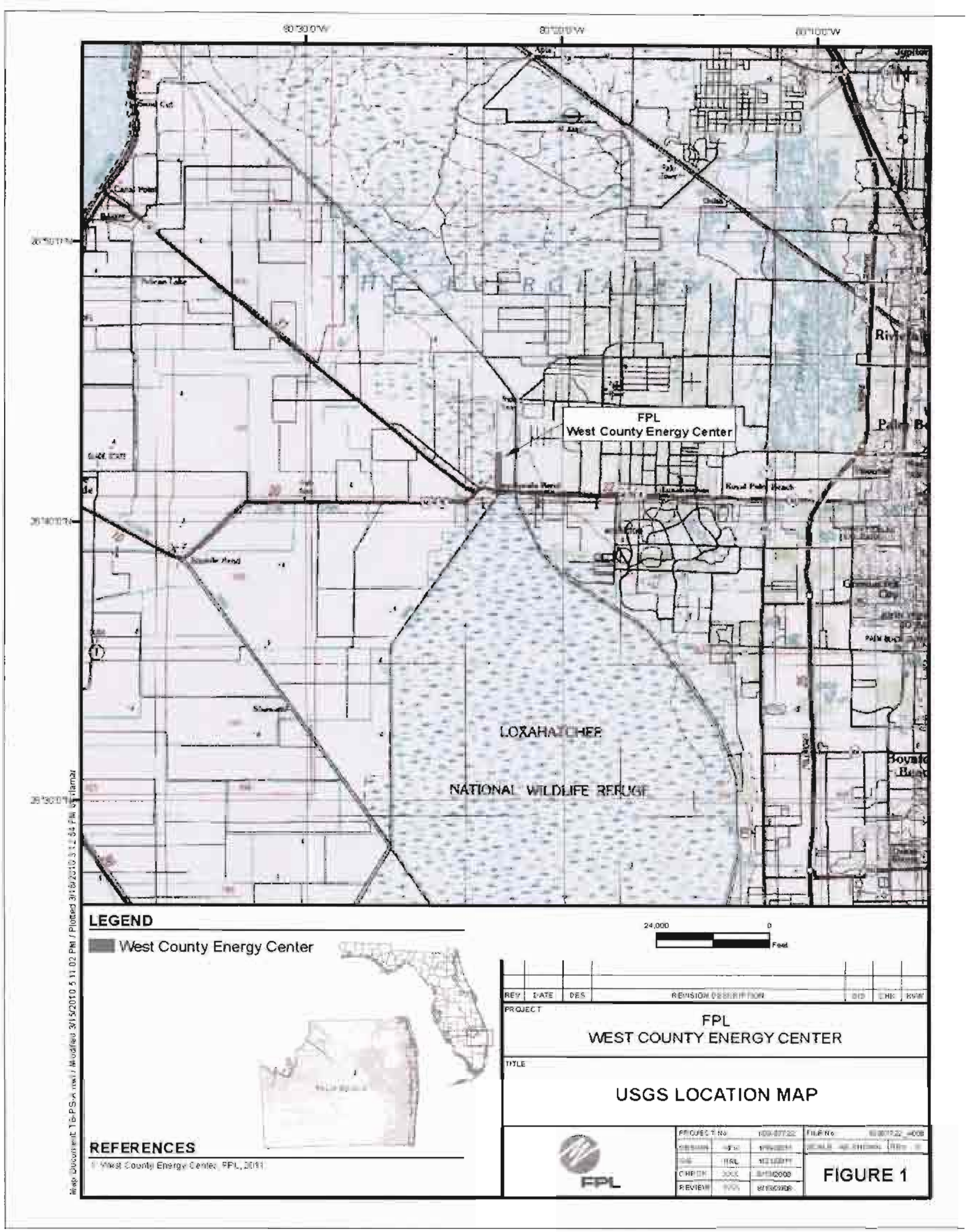
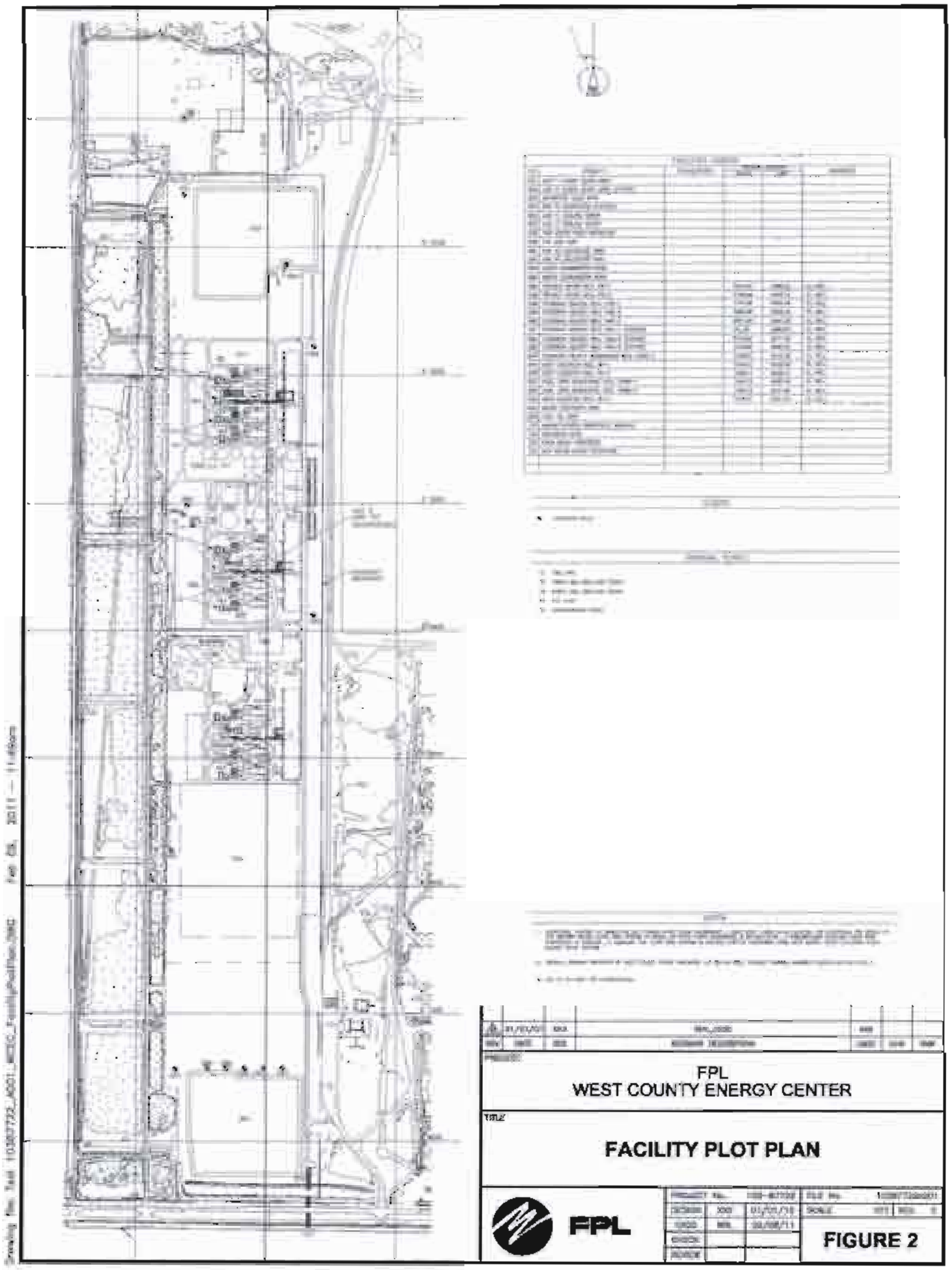
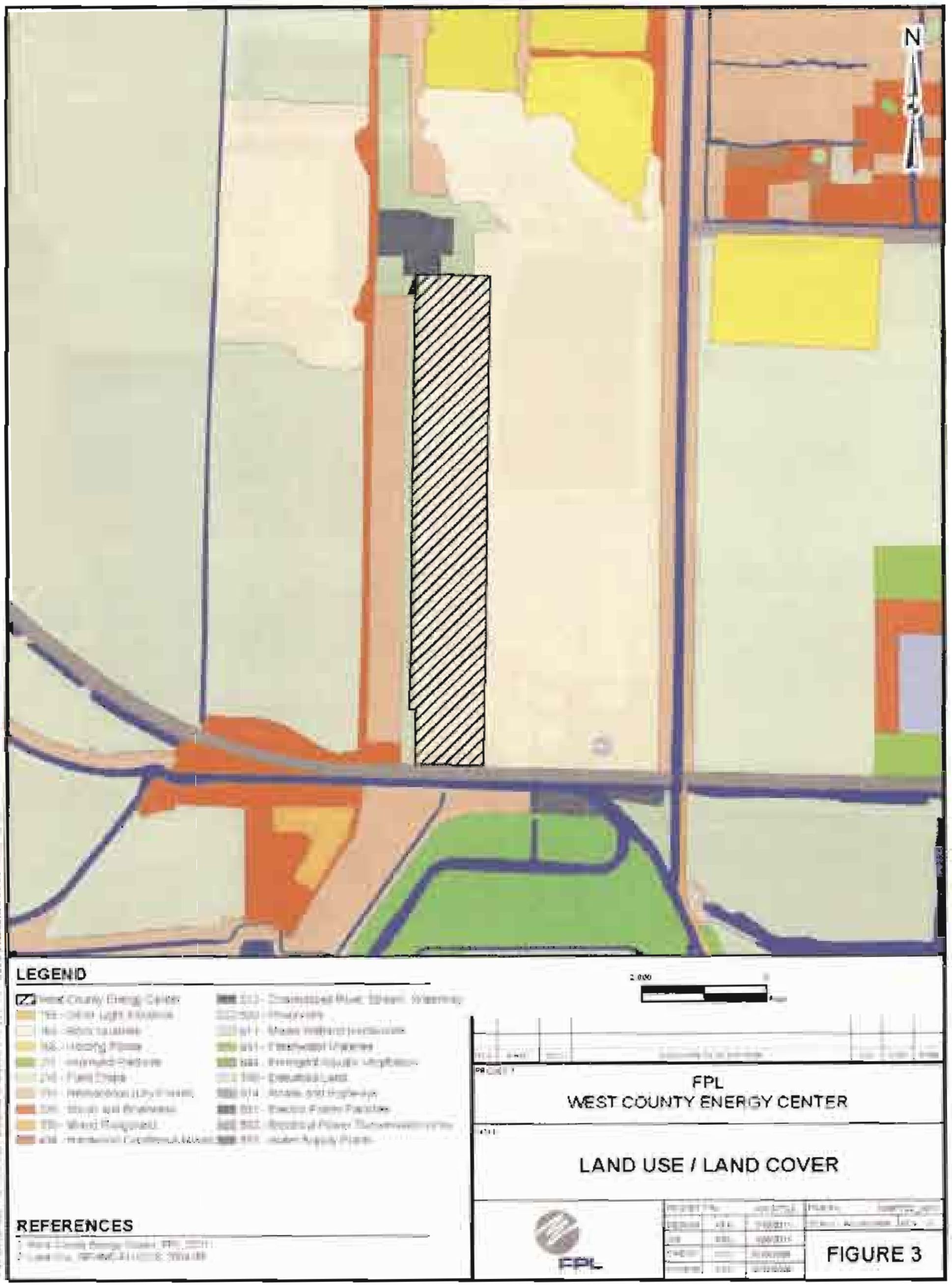

FPL
West County Energy Center
LOXAHATCHEE
NATIONAL WILDLIFE REFUGE
LEGEND
West County Energy Center
REFERENCES
24,000
0
Feet
PROJECT
FPL
WEST COUNTY ENERGY CENTER
TITLE
USGS LOCATION MAP
FPL
FIGURE 1


FPL
WEST COUNTY ENERGY CENTER
FACILITY PLOT PLAN
FPL
FIGURE 2


N
LEGEND
REFERENCES
FPL
WEST COUNTY ENERGY CENTER
LAND USE / LAND COVER
FPL
FIGURE 3

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Environmental and Land Use Information: Supplemental Information

Preferred Site #2: St. Lucie Plant

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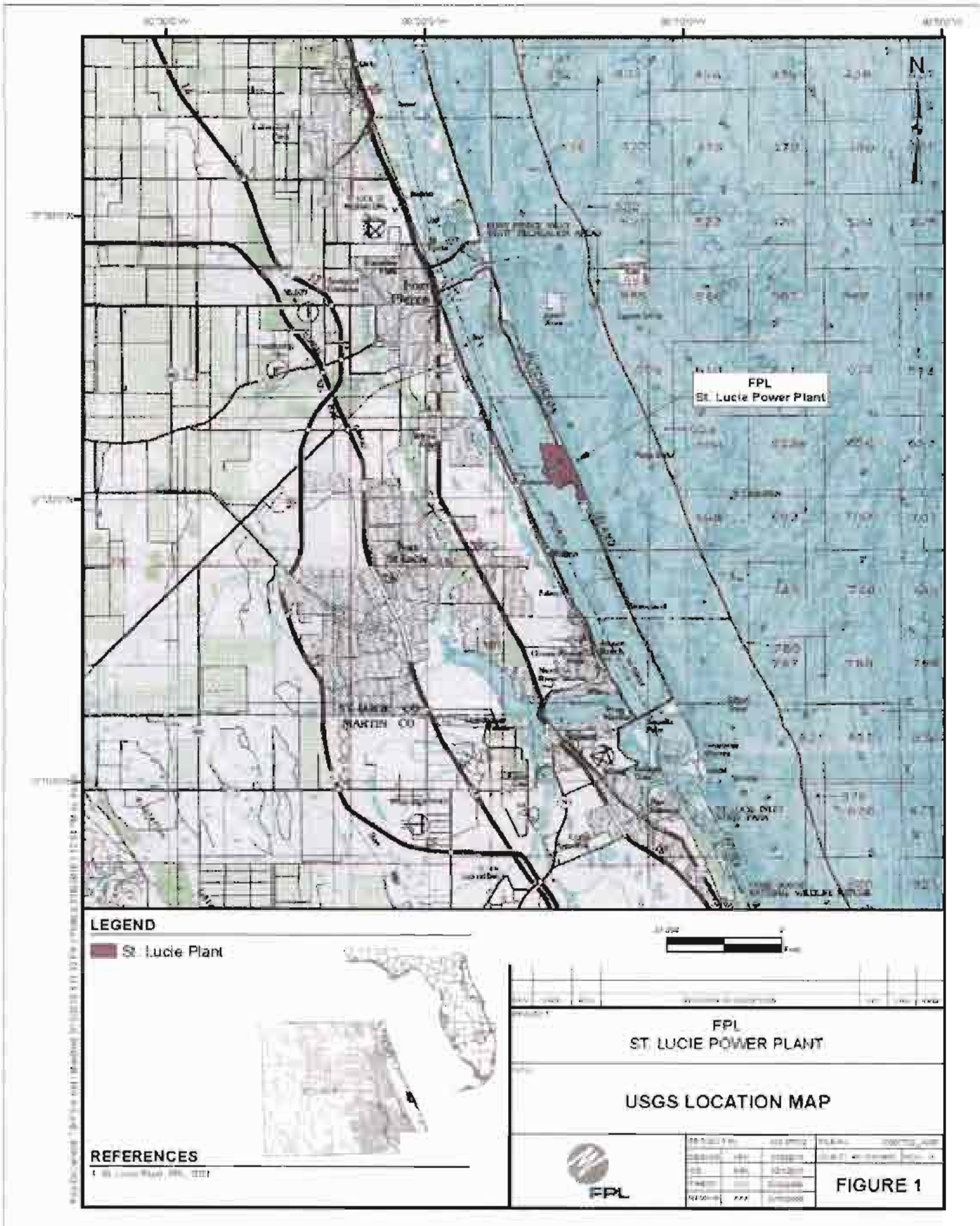
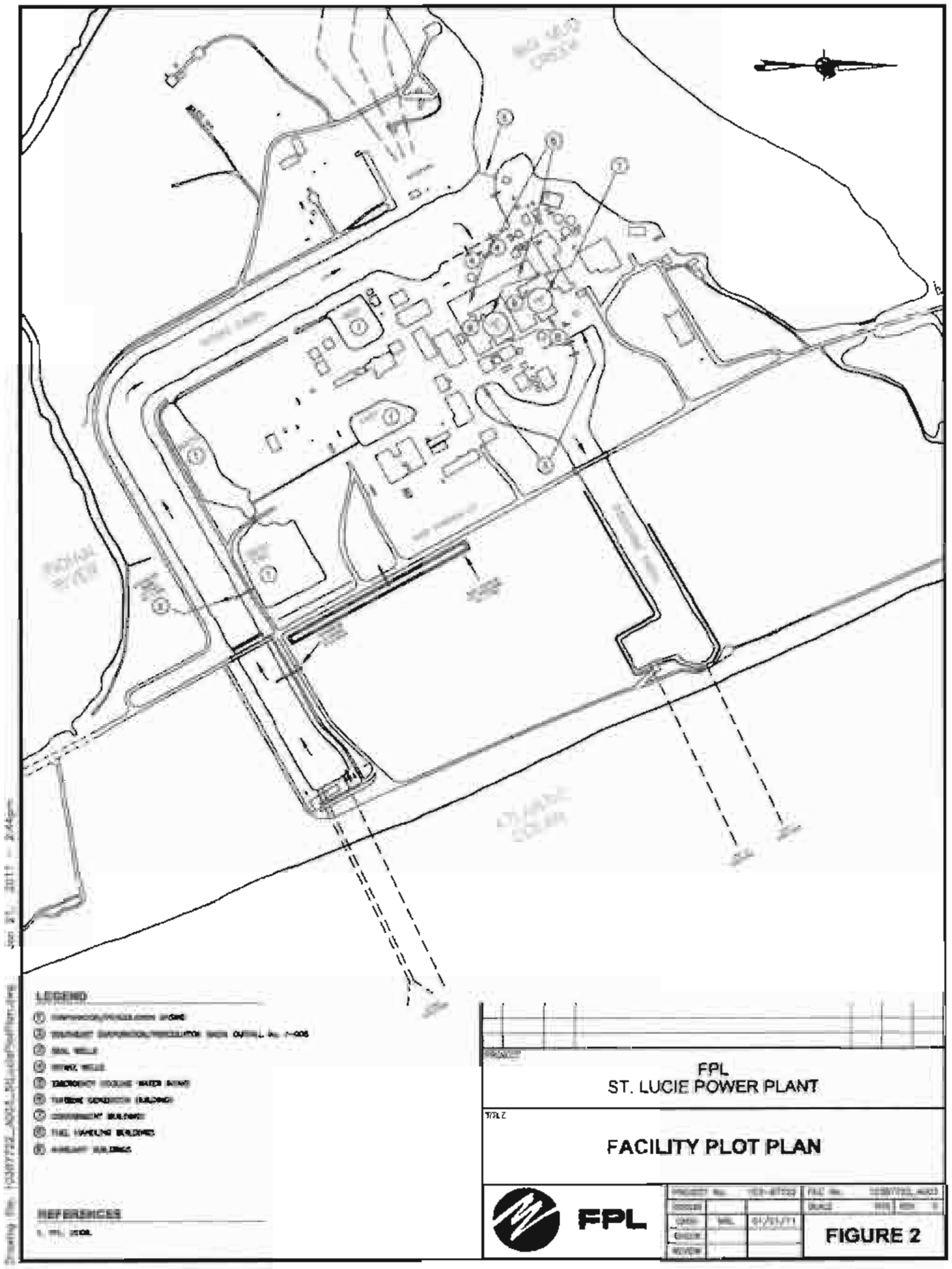

N
FPL
St. Lucie Power Plant
LEGEND
St. Lucie Plant
REFERENCES
FPL
ST. LUCIE POWER PLANT
USGS LOCATION MAP
FPL
FIGURE 1


LEGEND
REFERENCES
FPL
ST. LUCIE POWER PLANT
FACILITY PLOT PLAN
FPL
FIGURE 2


N
LEGEND
REFERENCES
FPL
ST LUCIE POWER PLANT
LAND USE / LAND COVER
FPL
FIGURE 3

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Environmental and Land Use Information: Supplemental Information

Preferred Site #3: Turkey Point Plant

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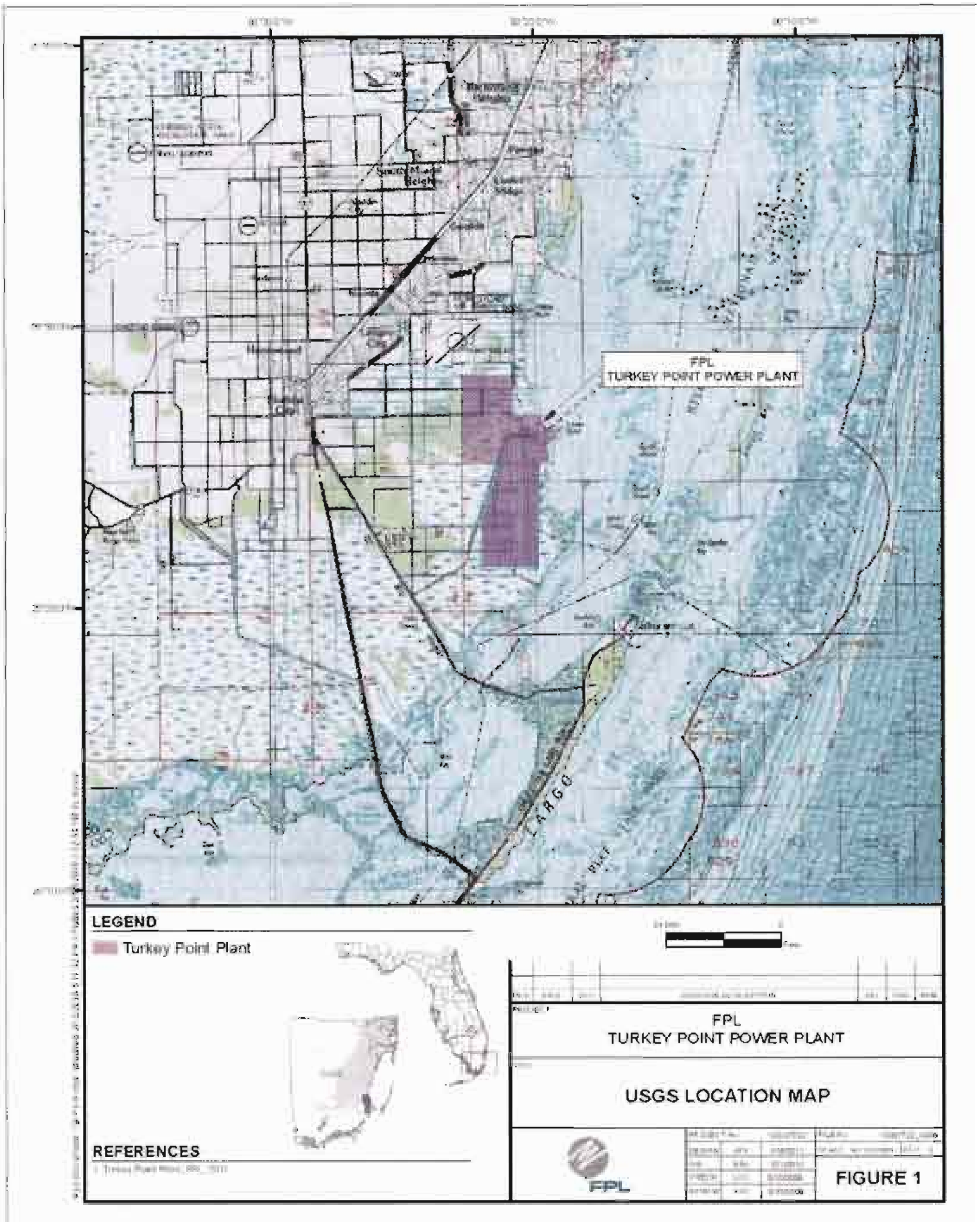
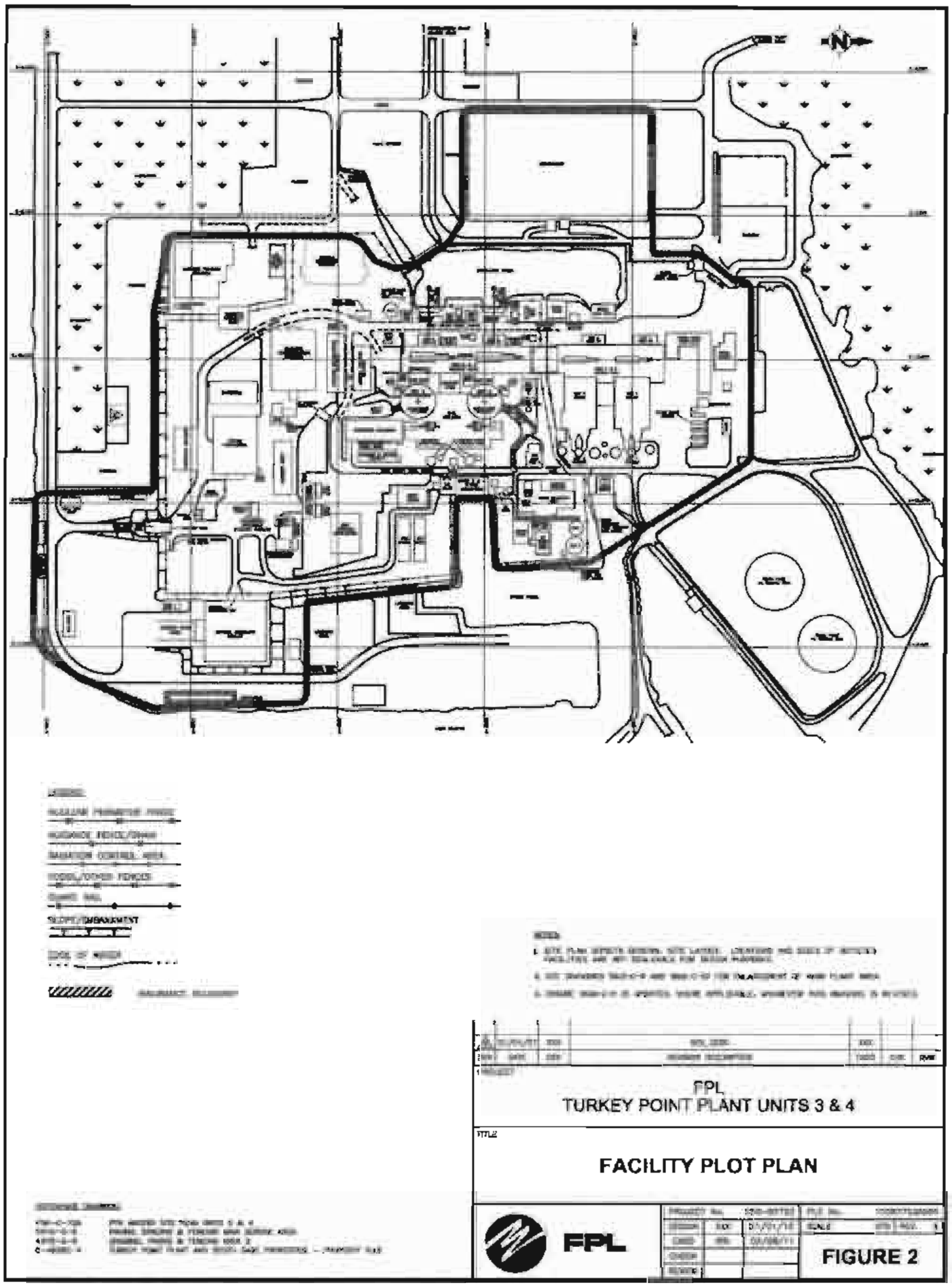
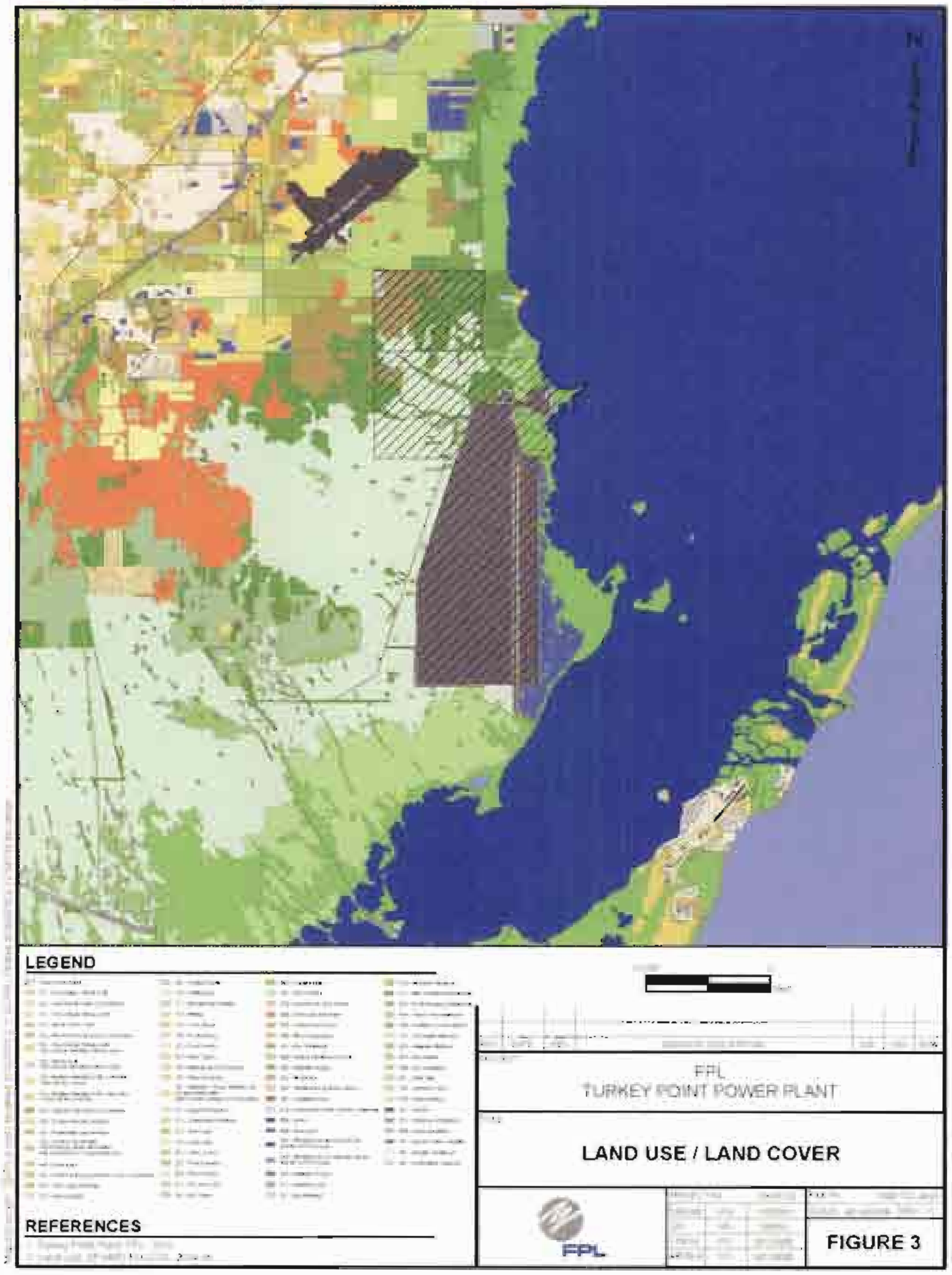

FPL
TURKEY POINT POWER PLANT
LARGO
LEGEND
Turkey Point Plant
REFERENCES
FPL
TURKEY POINT POWER PLANT
USGS LOCATION MAP
FPL
FIGURE 1


FPL
TURKEY POINT PLANT UNITS 3 & 4
FACILITY PLOT PLAN
FPL
FIGURE 2


LEGEND
REFERENCES
FPL
TURKEY POINT POWER PLANT
LAND USE / LAND COVER
FPL
FIGURE 3

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Environmental and Land Use Information: Supplemental Information

Preferred Site #4: Cape Canaveral Plant

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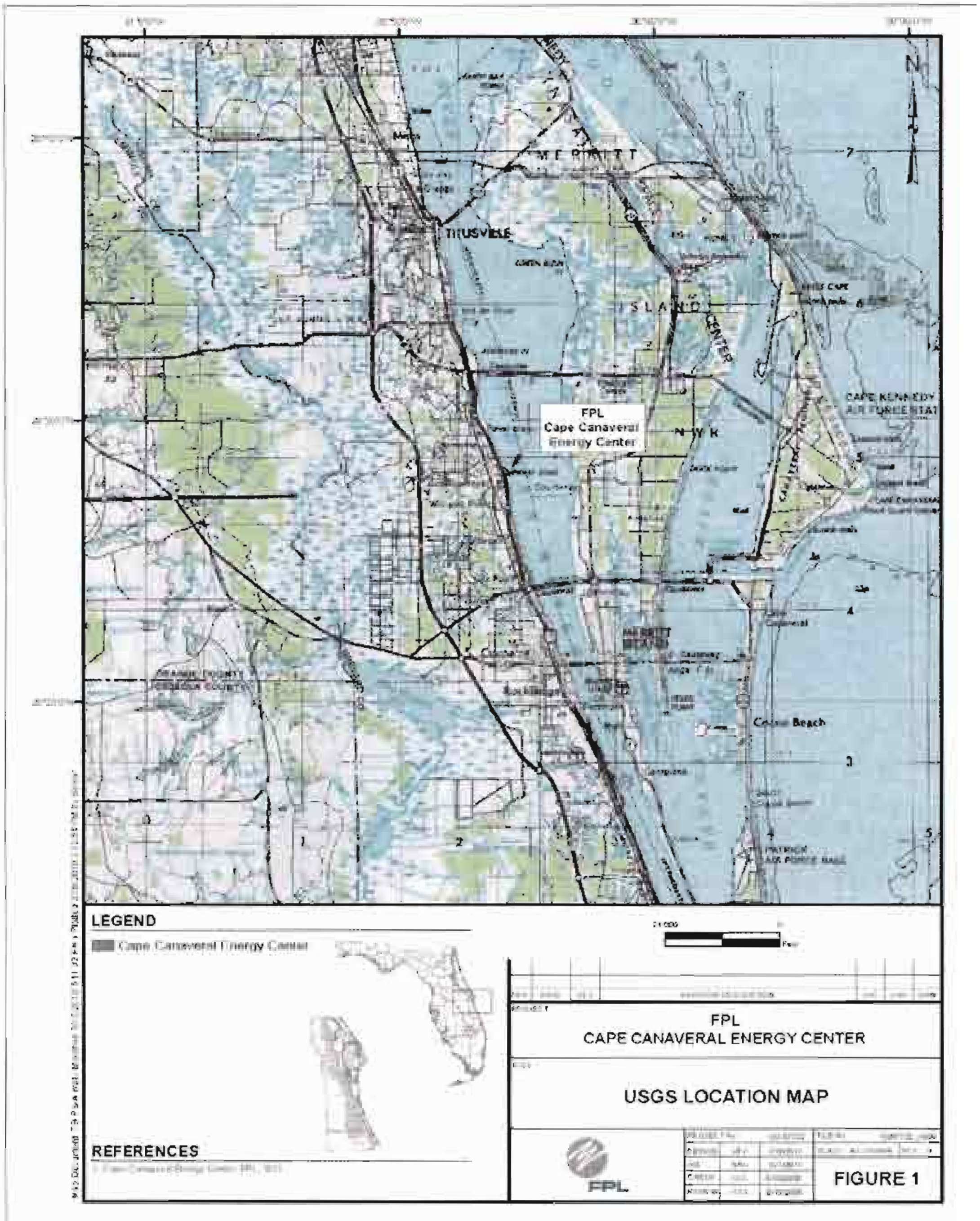
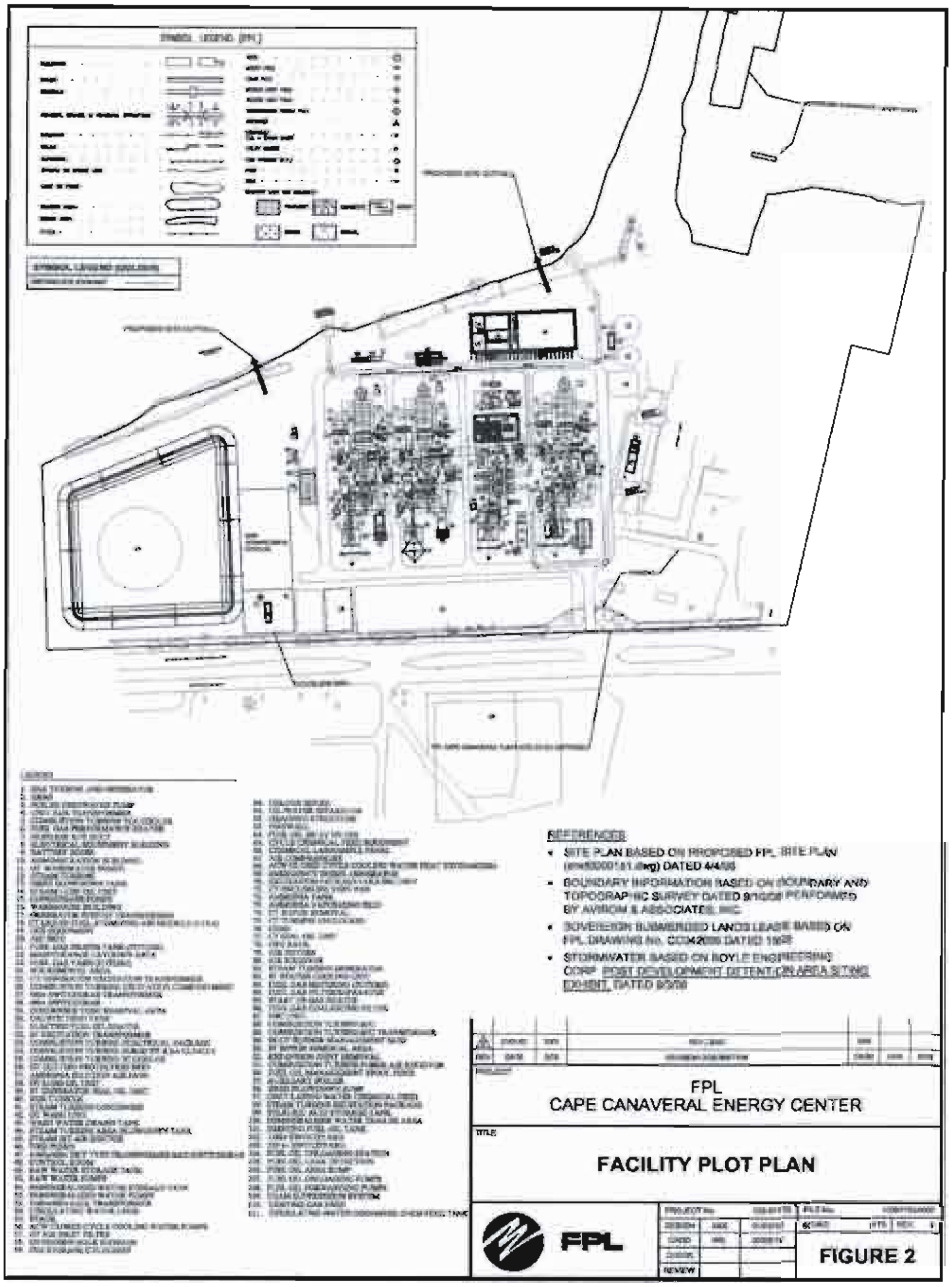

TITUSVILLE
MERRITT
ISLAND
CENTER
FPL
Cape Canaveral
Energy Center
CAPE KENNEDY
AIR FORCE STAT
Cocoa Beach
PATRICK
AIR FORCE BASE
LEGEND
Cape Canaveral Energy Center
REFERENCES
FPL
CAPE CANAVERAL ENERGY CENTER
USGS LOCATION MAP
FPL
FIGURE 1


REFERENCES
SITE PLAN BASED ON PROPOSED FPL SITE PLAN
DATED
BOUNDARY INFORMATION BASED ON BOUNDARY AND TOPOGRAPHIC SURVEY DATED
BY AVIROM & ASSOCIATES, INC.
SOVEREIGN SUBMERGED LANDS LEASE BASED ON FPL DRAWING No.
STORMWATER BASED ON BOYLE ENGINEERING CORP. POST DEVELOPMENT DETENTION AREA SITING EXHIBIT
FPL
CAPE CANAVERAL ENERGY CENTER
TITLE
FACILITY PLOT PLAN
FPL
REVIEW
FIGURE 2


N
LEGEND
REFERENCES
FPL
CAPE CANAVERAL ENERGY CENTER
LAND USE / LAND COVER
FPL
FIGURE 3

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Environmental and Land Use Information: Supplemental Information Preferred Site #5: Riviera Plant

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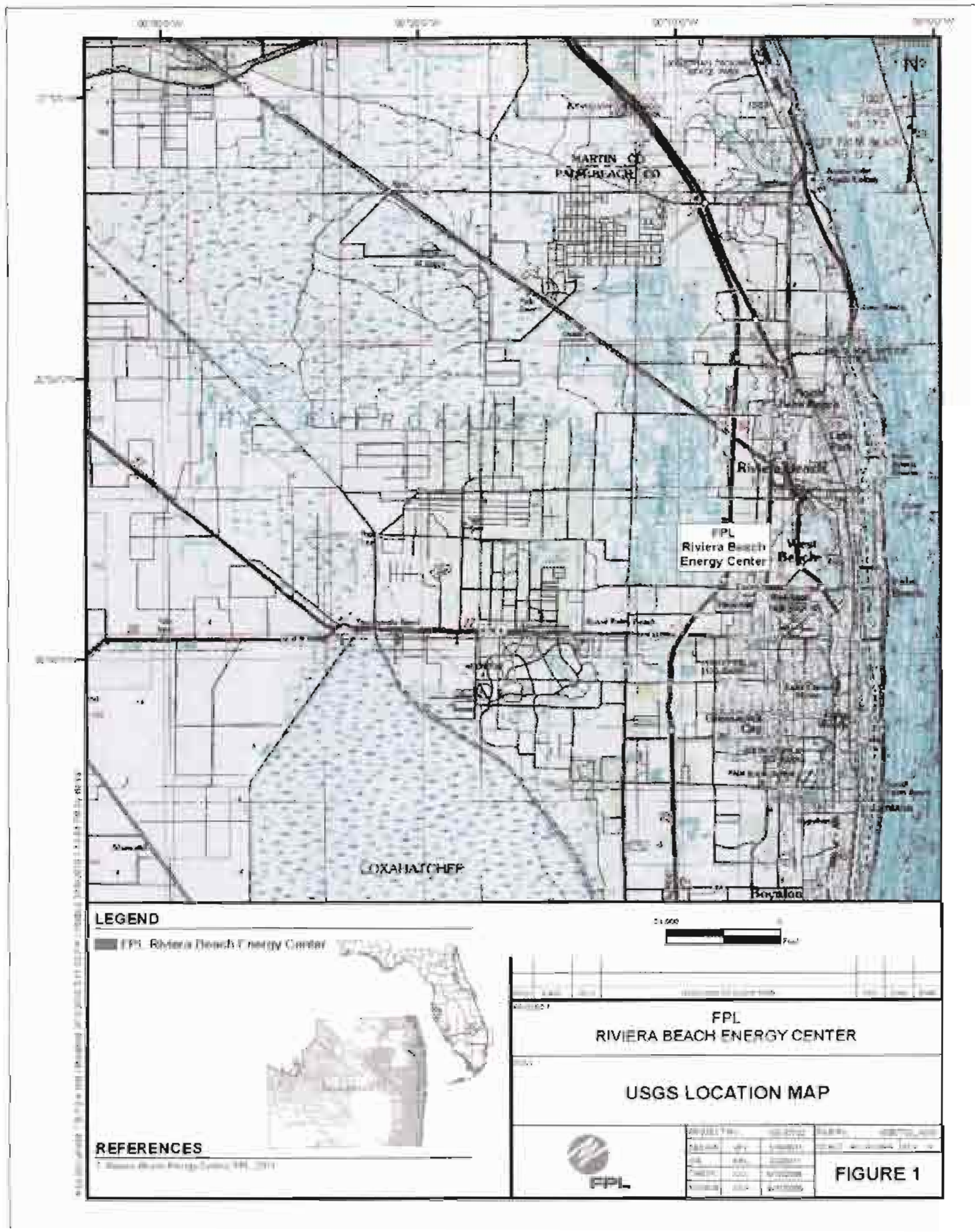
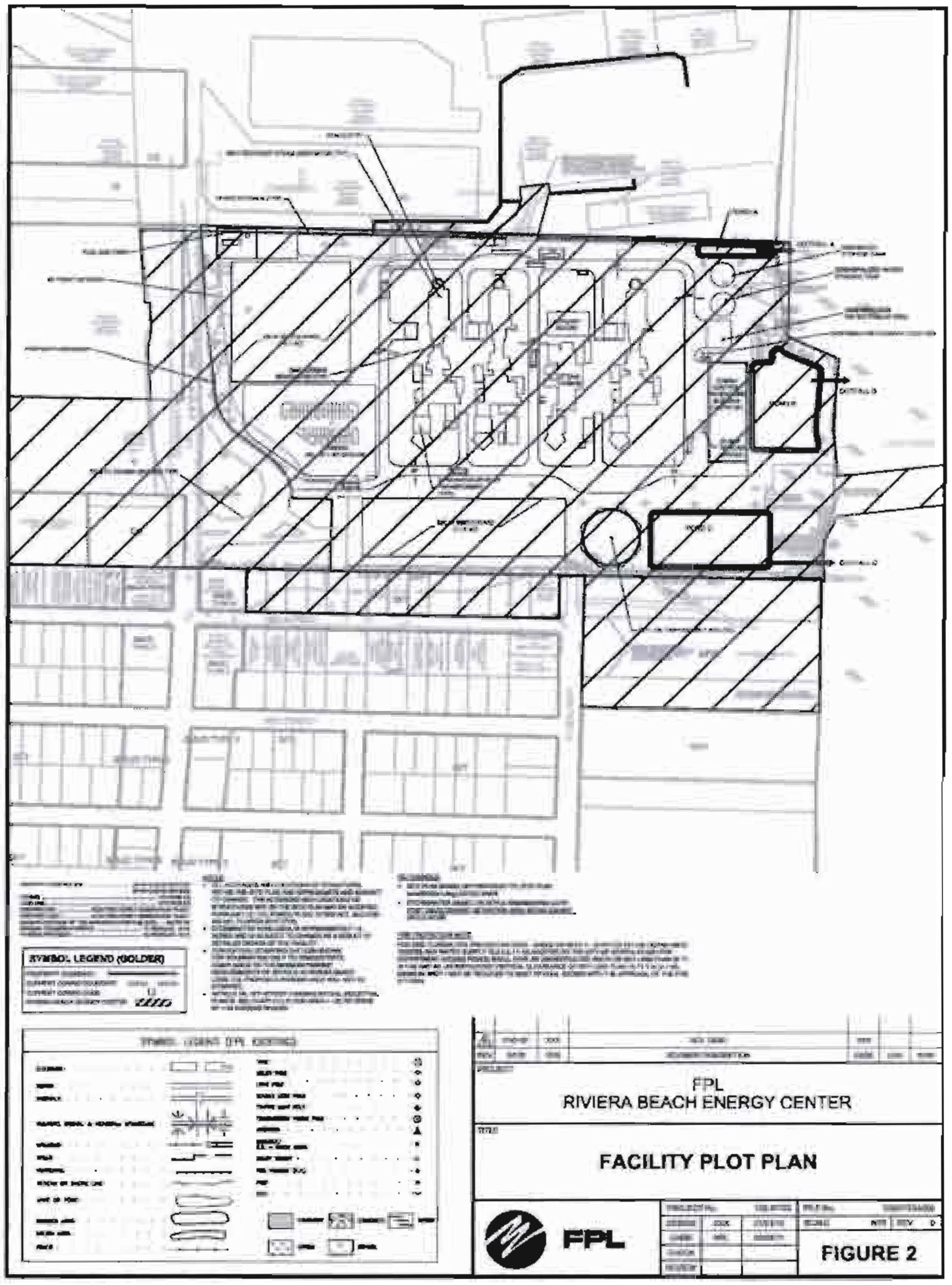
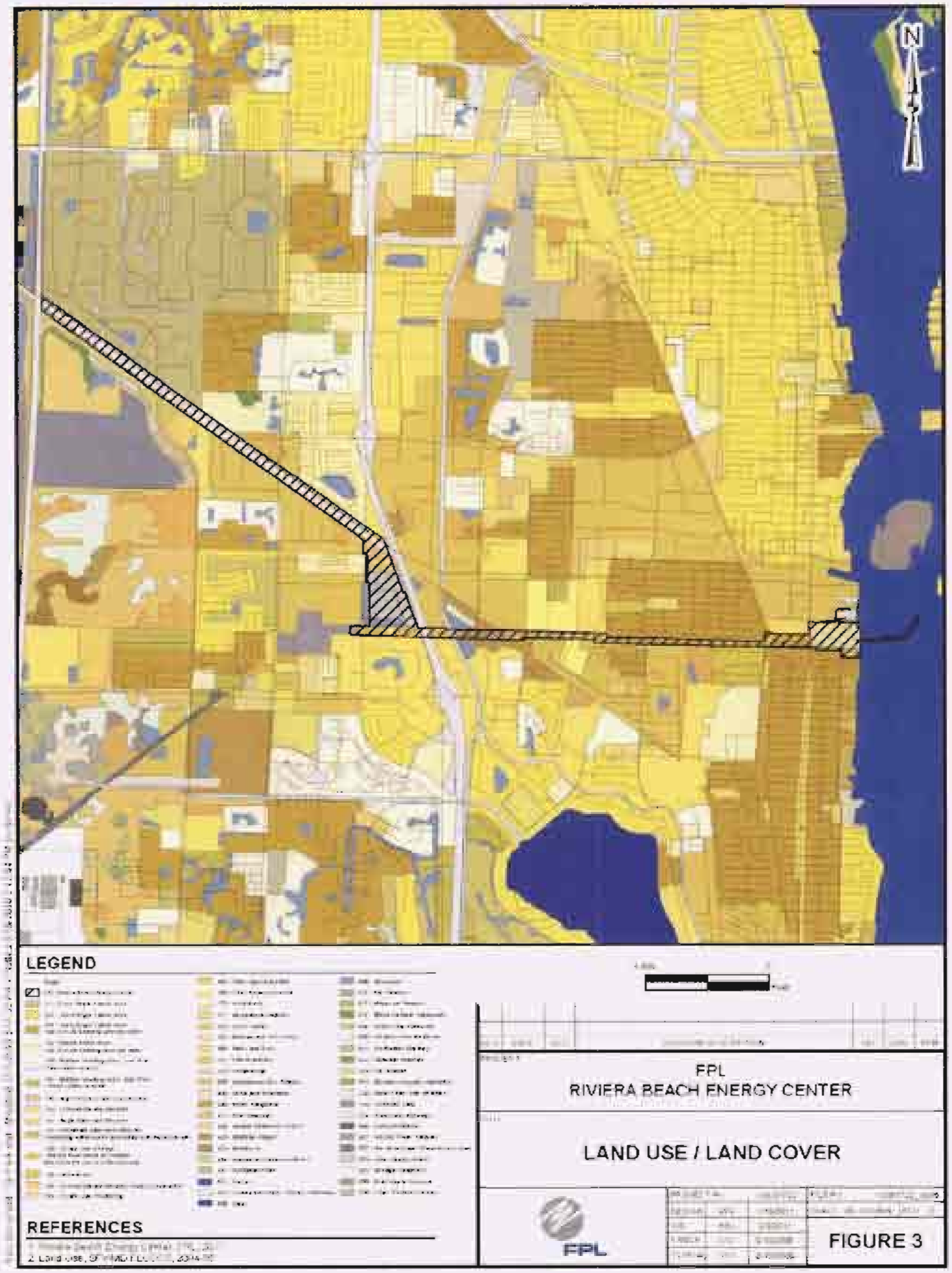

MARTIN CO
PALM BEACH CO
Riviera Beach
FPL
Riviera Beach
Energy Center
West
Beach
LOXAHATCHEE
Boynton
LEGEND
FPL Riviera Beach Energy Center
REFERENCES
FPL
RIVIERA BEACH ENERGY CENTER
USGS LOCATION MAP
FPL
FIGURE 1


SYMBOL LEGEND (GOLDER)
FPL
RIVIERA BEACH ENERGY CENTER
FACILITY PLOT PLAN
FPL
FIGURE 2


N
LEGEND
REFERENCES
FPL
RIVIERA BEACH ENERGY CENTER
LAND USE / LAND COVER
FPL
FIGURE 3

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Environmental and Land Use Information: Supplemental Information

Potential Site #1: Babcock Ranch

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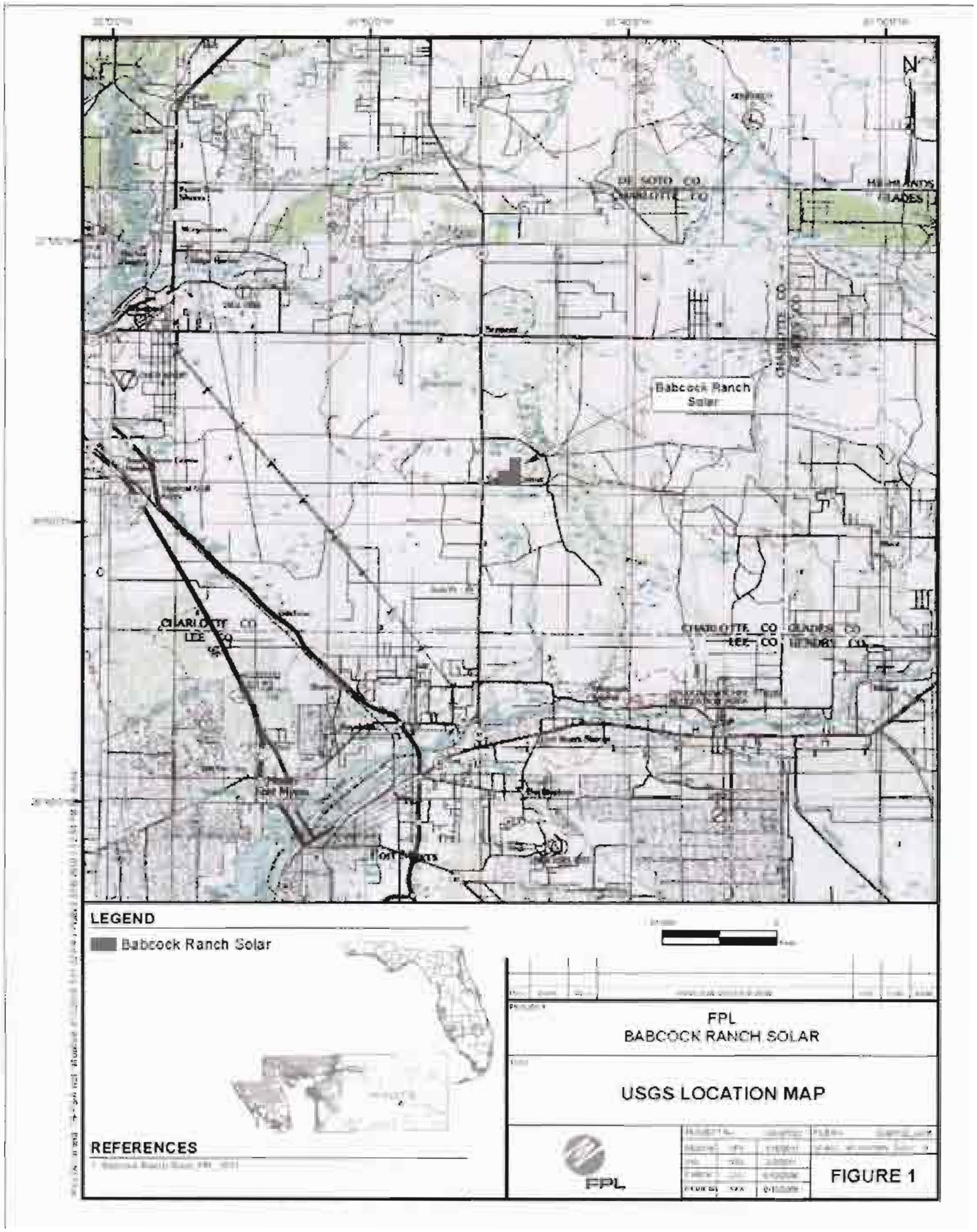
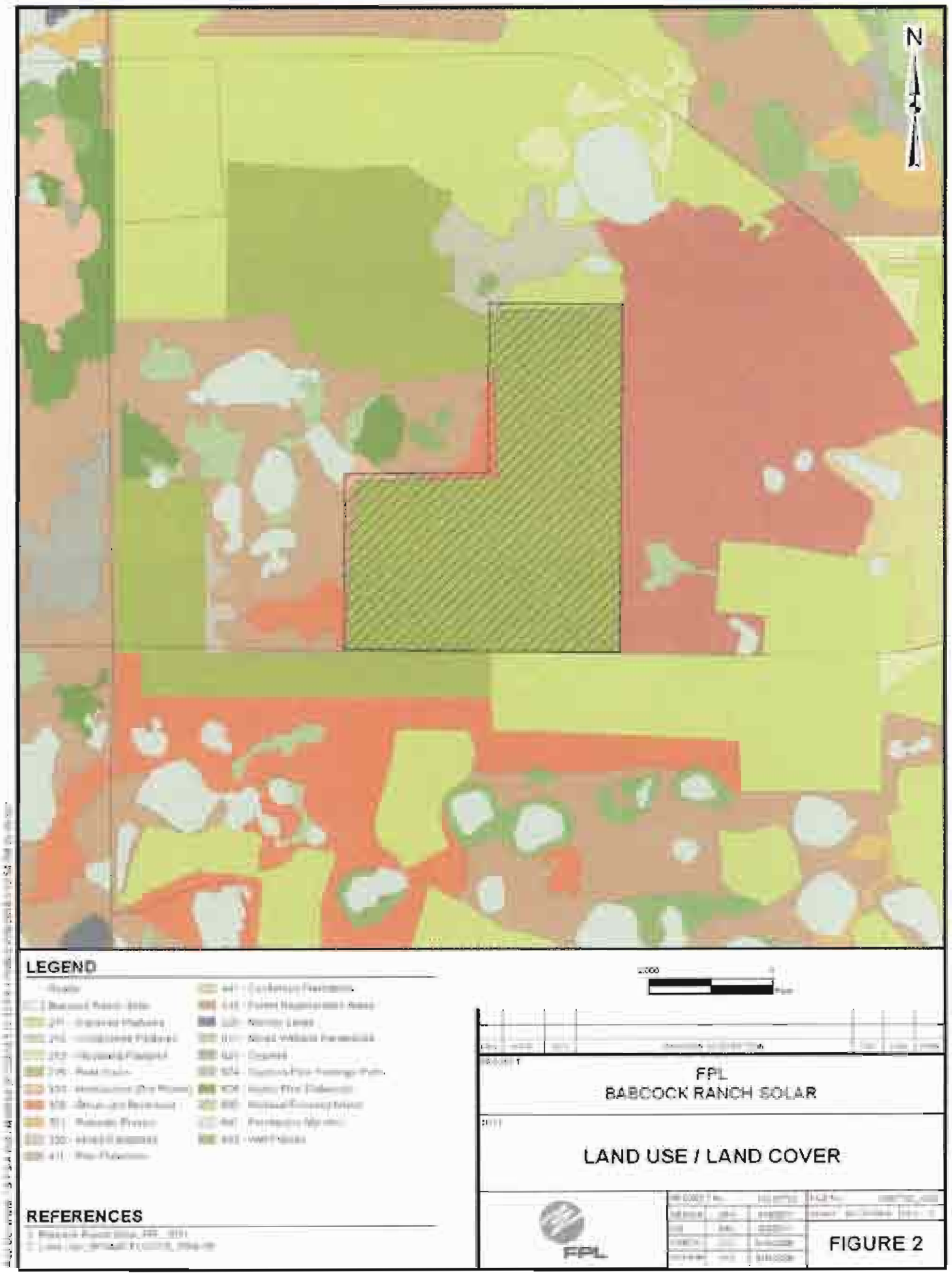

N
DE SOTO CO
CHARLOTTE CO
HIGHLANDS
GLADES
Babcock Ranch Solar
CHARLOTTE CO
LEE CO
CHARLOTTE CO
LEE CO
GLADES CO
HENDRY CO
Fort Myers
FORT MYERS
LEGEND
Babcock Ranch Solar
REFERENCES
FPL
BABCOCK RANCH SOLAR
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
REFERENCES
FPL
BABCOCK RANCH SOLAR
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #2: Desoto Solar Expansion

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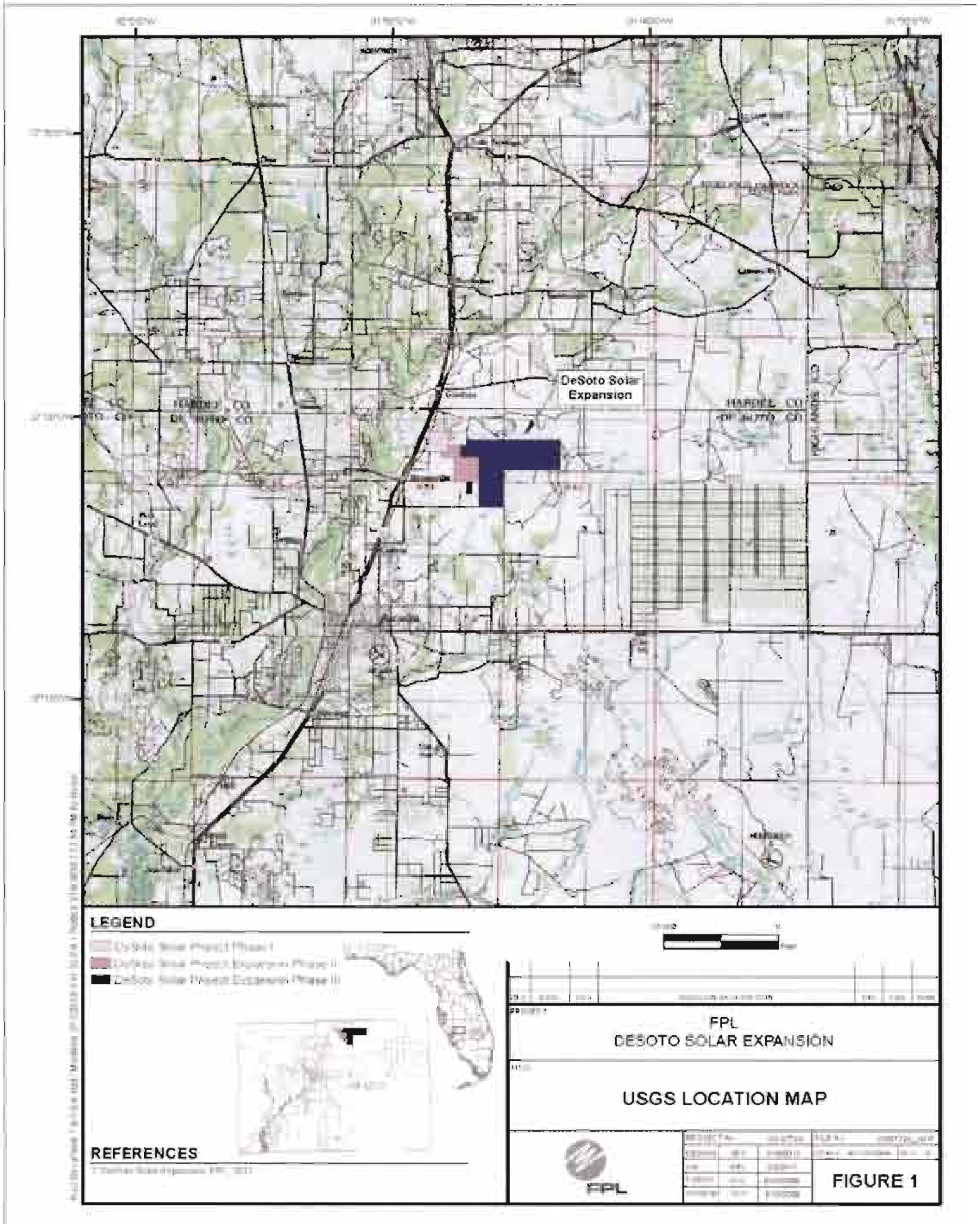
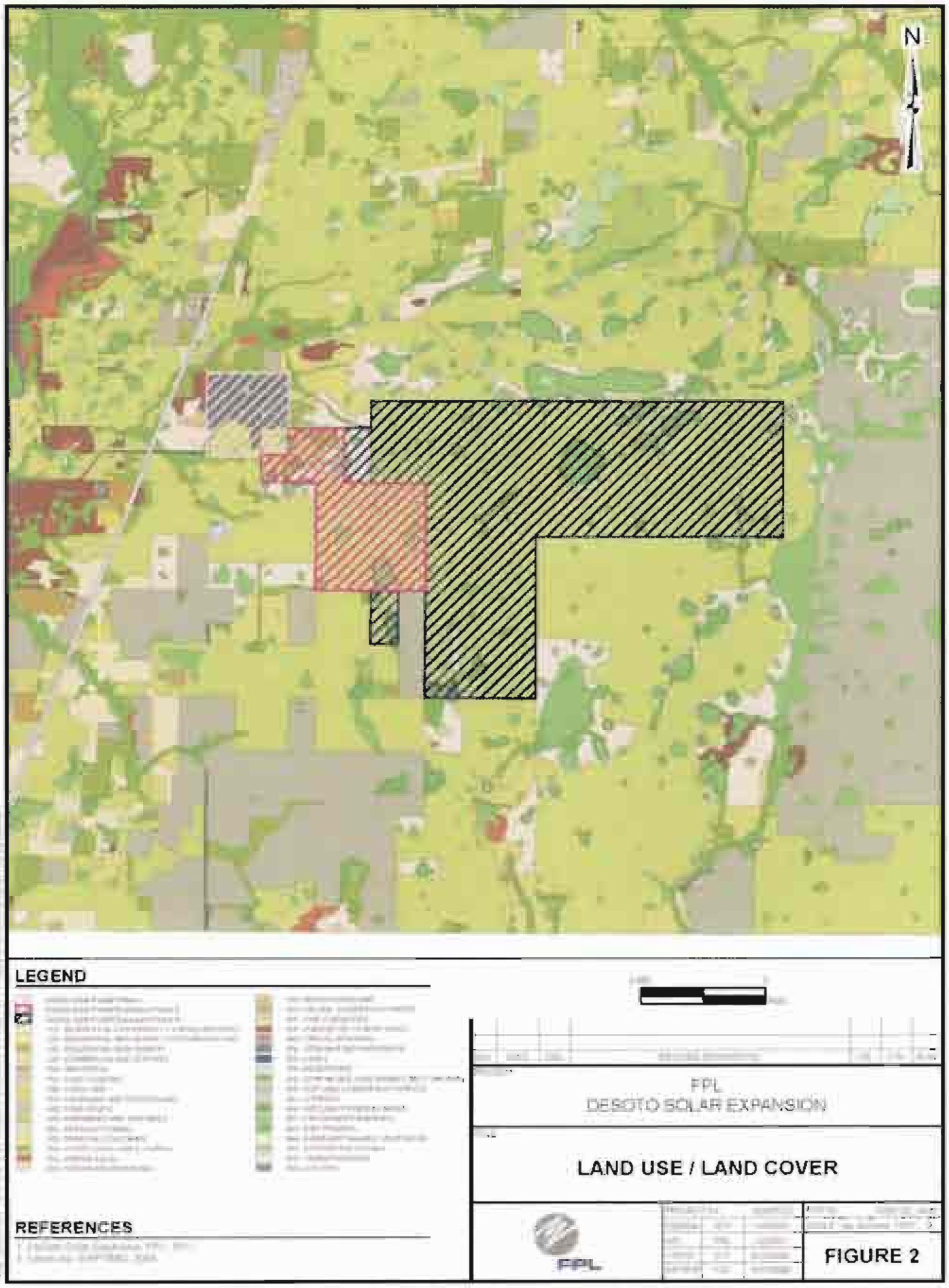

DeSoto Solar
Expansion
HARDEE CO
DE SOTO CO
LEGEND
REFERENCES
FPL
DESOTO SOLAR EXPANSION
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
REFERENCES
FPL
DESOTO SOLAR EXPANSION
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #3: Florida Heartland Solar

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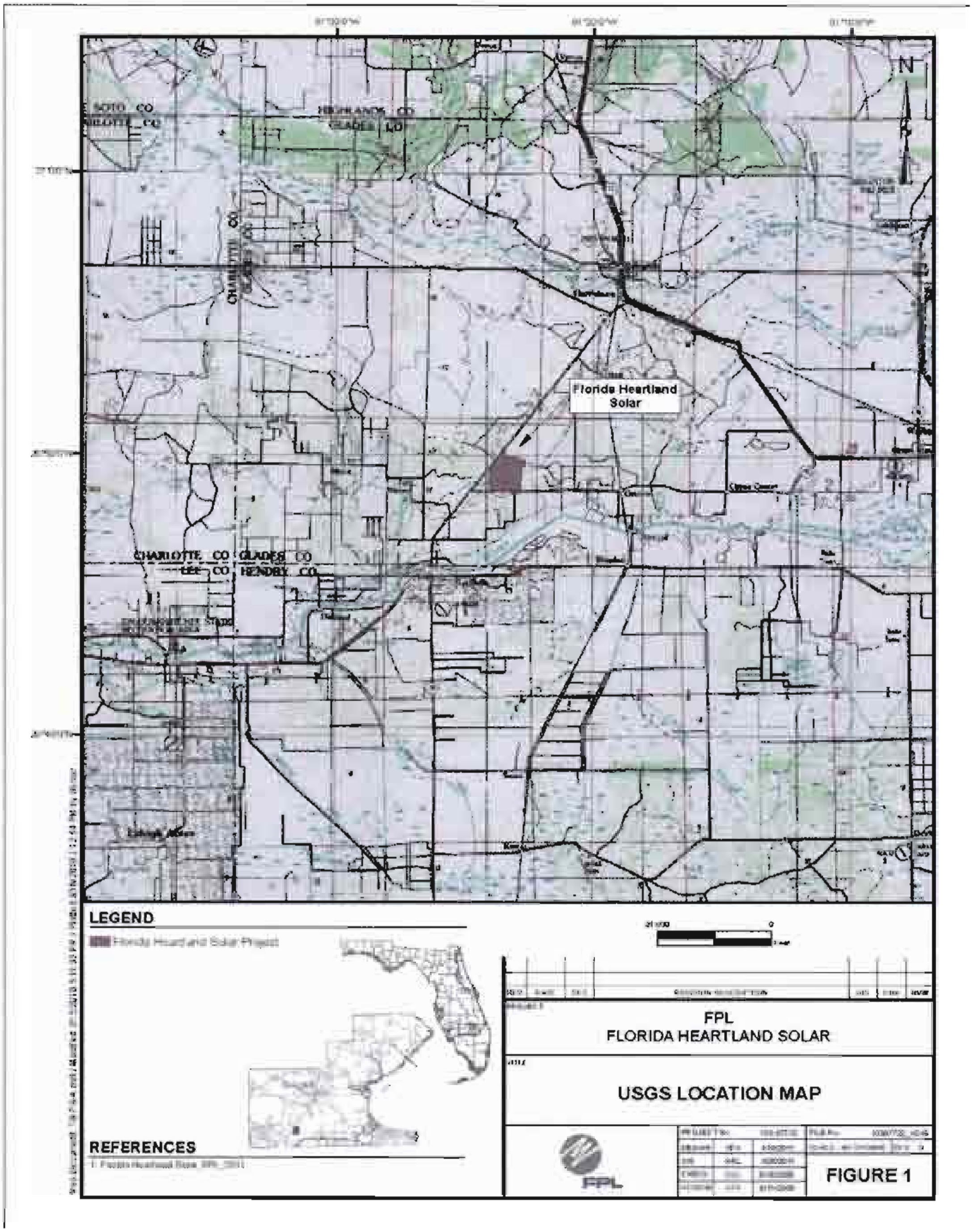
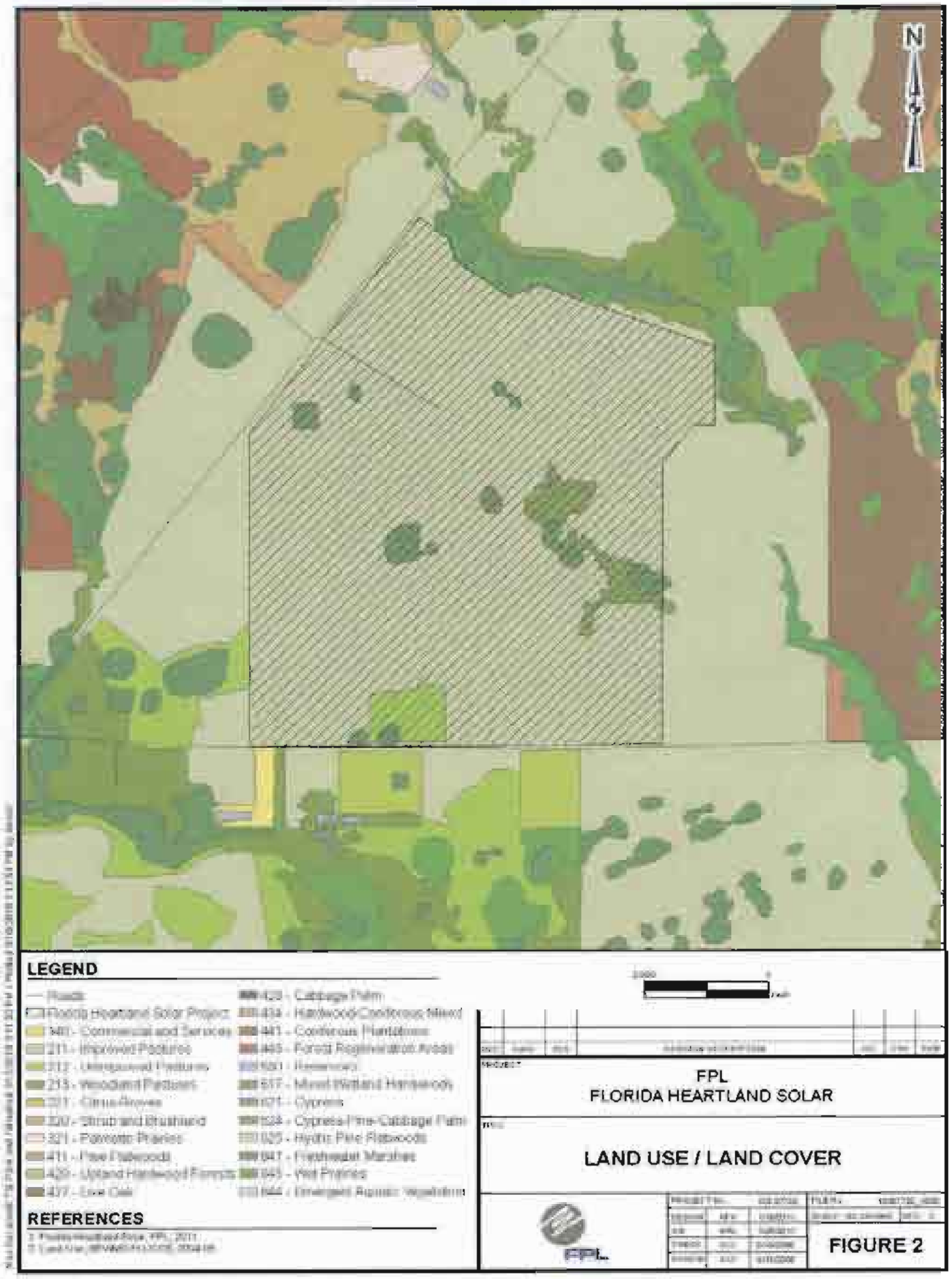

N
Florida Heartland Solar
CHARLOTTE CO
GLADES CO
LEE CO
HENDRY CO
LEGEND
REFERENCES
FPL
FLORIDA HEARTLAND SOLAR
USGS LOCATION MAP
FIGURE 1


N
LEGEND
Roads
Florida Heartland Solar Project
140 - Commercial and Services
211 - Improved Pastures
212 - Unimproved Pastures
213 - Woodland Pastures
221 - Citrus Groves
320 - Shrub and Brushland
321 - Palmetto Prairies
411 - Pine Flatwoods
420 - Upland Hardwood Forests
427 - Live Oak
428 - Cabbage Palm
434 - Hardwood/Coniferous Mixed
441 - Coniferous Plantations
443 - Forest Regeneration Areas
530 - Reservoirs
617 - Mixed Wetland Hardwoods
621 - Cypress
624 - Cypress-Pine-Cabbage Palm
625 - Hydric Pine Flatwoods
641 - Freshwater Marshes
643 - Wet Prairies
644 - Emergent Aquatic Vegetation
REFERENCES
FPL
FLORIDA HEARTLAND SOLAR
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site # 4: Hendry County

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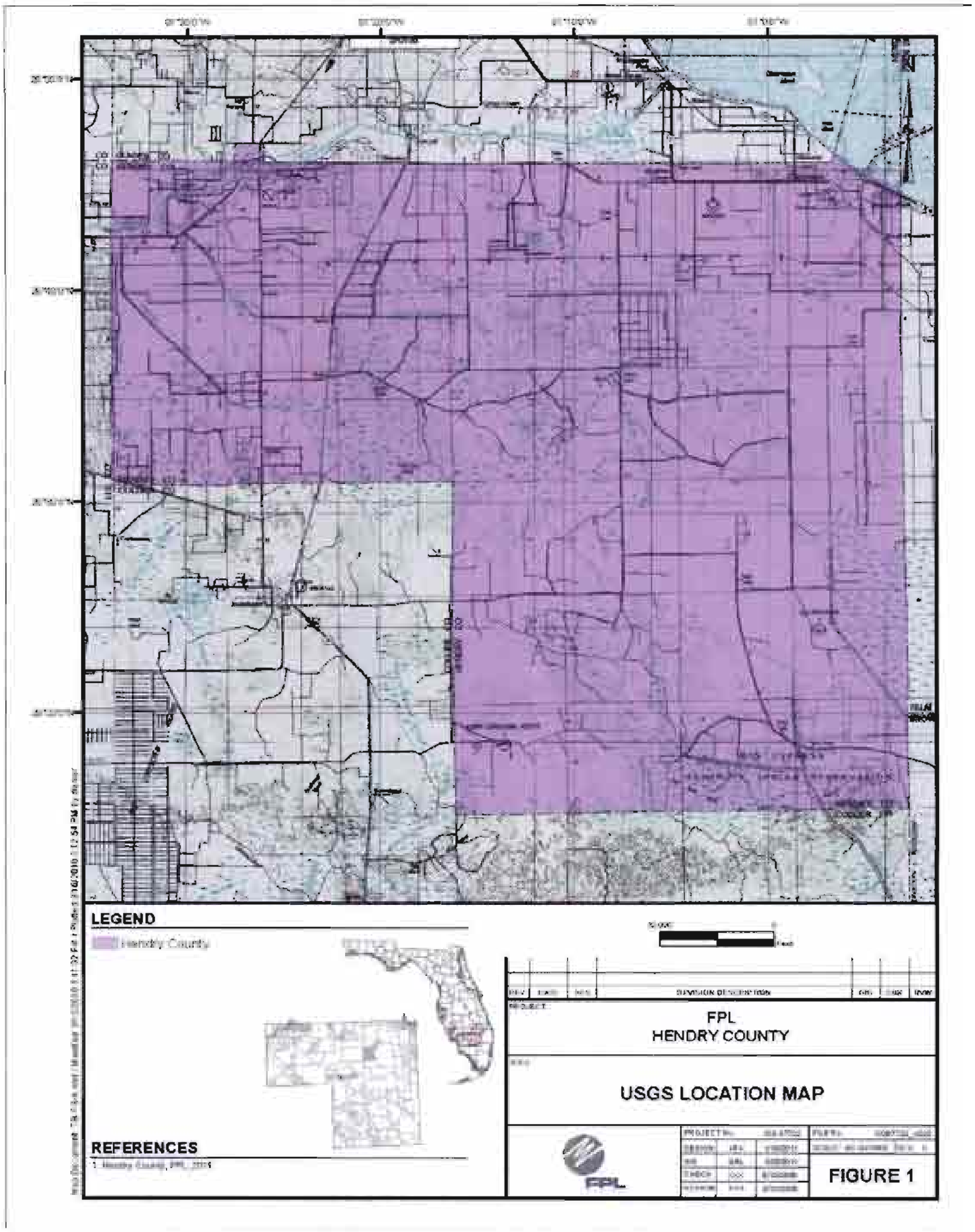
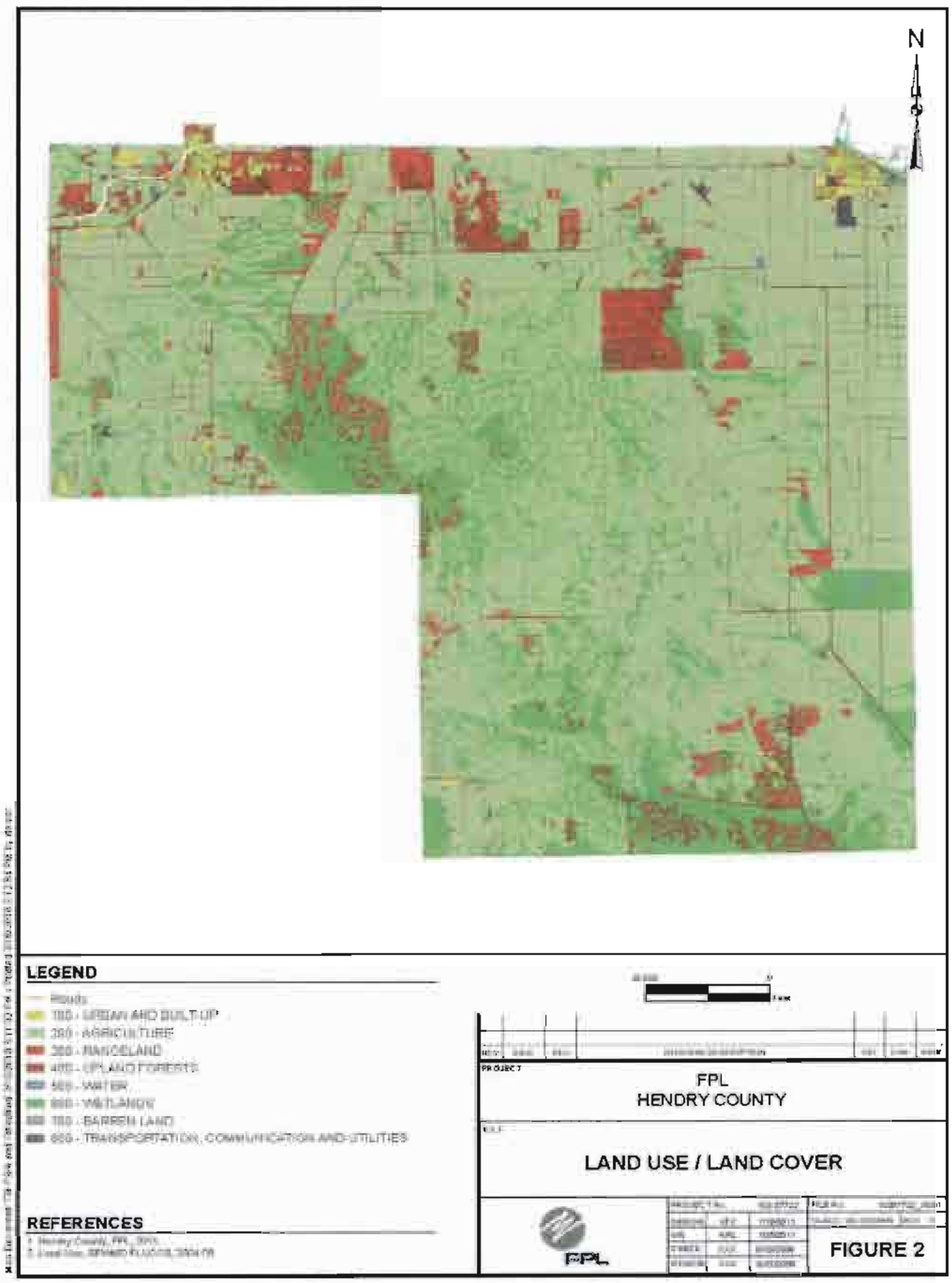

LEGEND
Hendry County
REFERENCES
FPL
HENDRY COUNTY
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
Roads
100 - URBAN AND BUILT-UP
200 - AGRICULTURE
300 - RANGELAND
400 - UPLAND FORESTS
500 - WATER
600 - WETLANDS
700 - BARREN LAND
800 - TRANSPORTATION, COMMUNICATION AND UTILITIES
REFERENCES
FPL
HENDRY COUNTY
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #5: Manatee Plant Site

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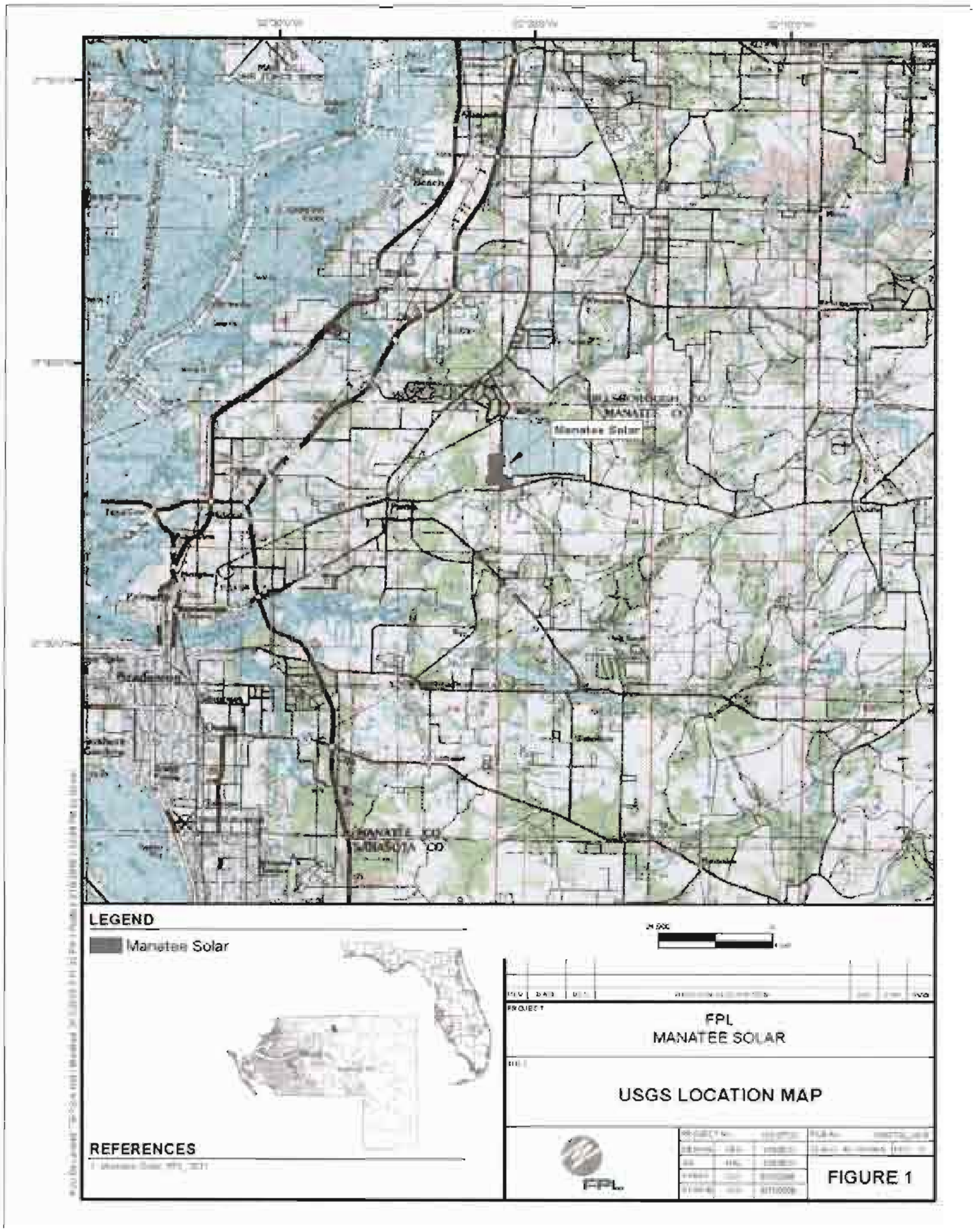
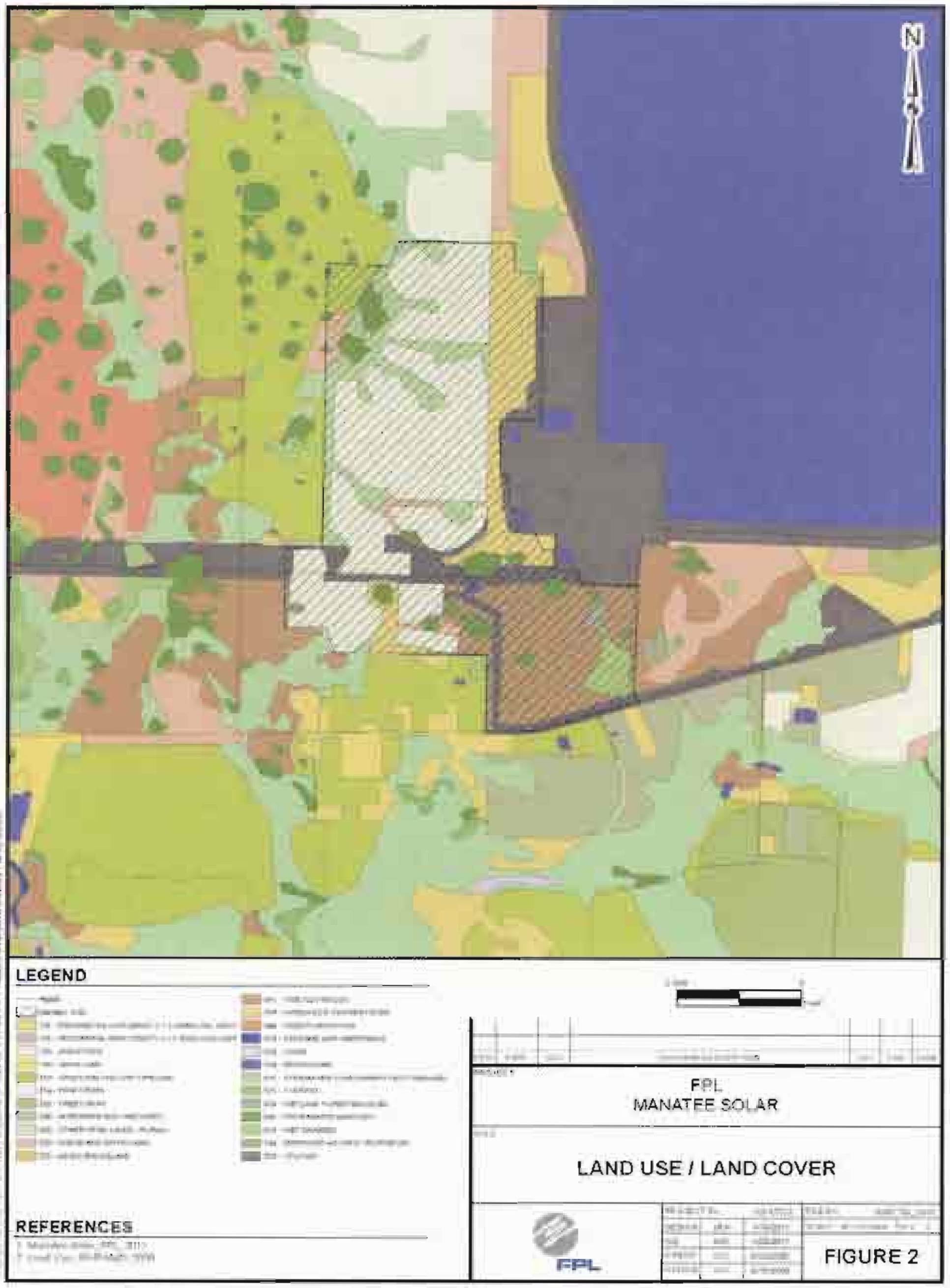

Manatee Solar
MANATEE CO
SARASOTA CO
LEGEND
Manatee Solar
REFERENCES
PROJECT
FPL
MANATEE SOLAR
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
FPL
MANATEE SOLAR
LAND USE / LAND COVER
REFERENCES
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #6: Martin County

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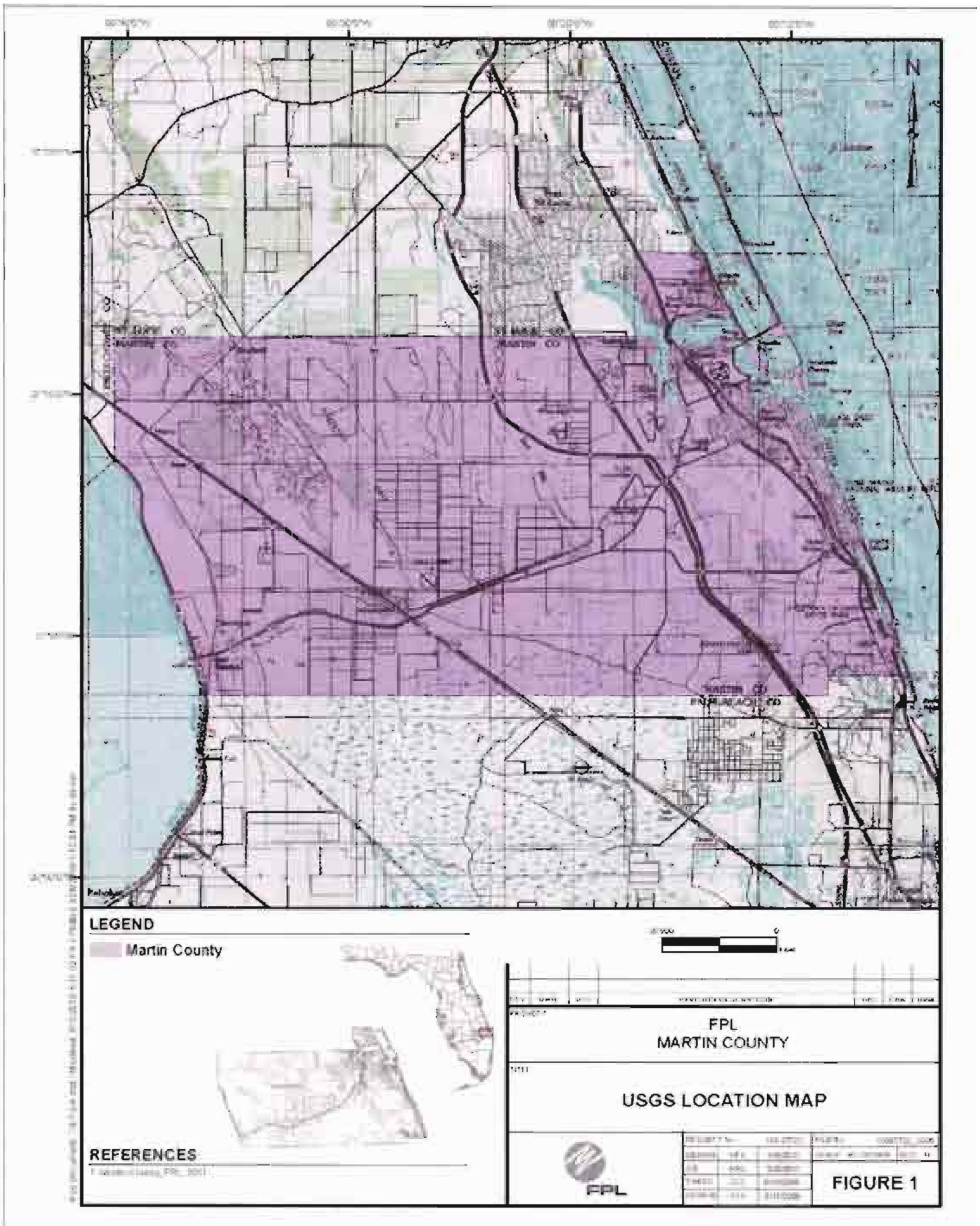
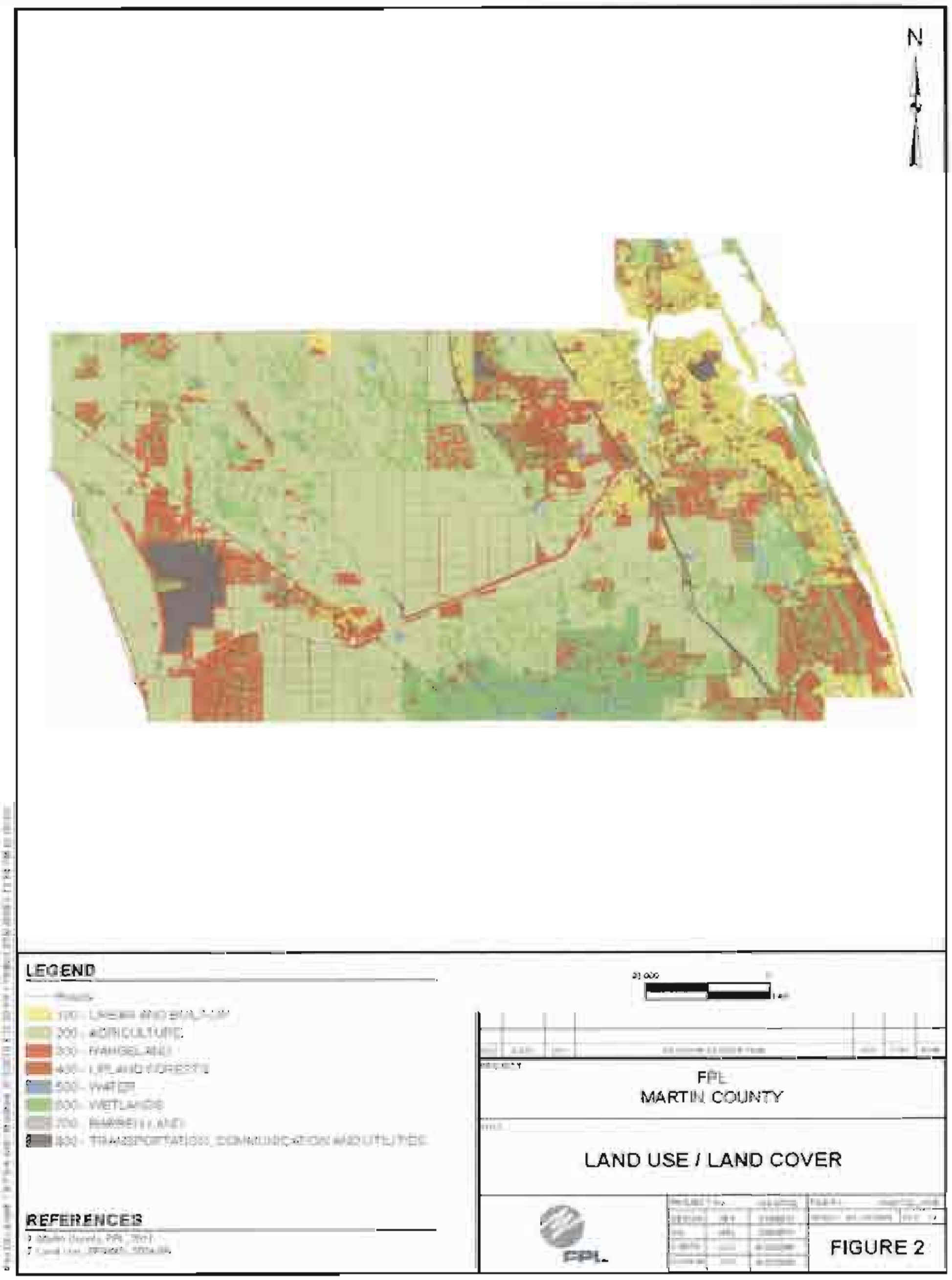

N
LEGEND
Martin County
REFERENCES
FPL
MARTIN COUNTY
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
200 - AGRICULTURE
500 - WATER
600 - WETLANDS
REFERENCES
FPL
MARTIN COUNTY
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #7: Northeast Okeechobee County

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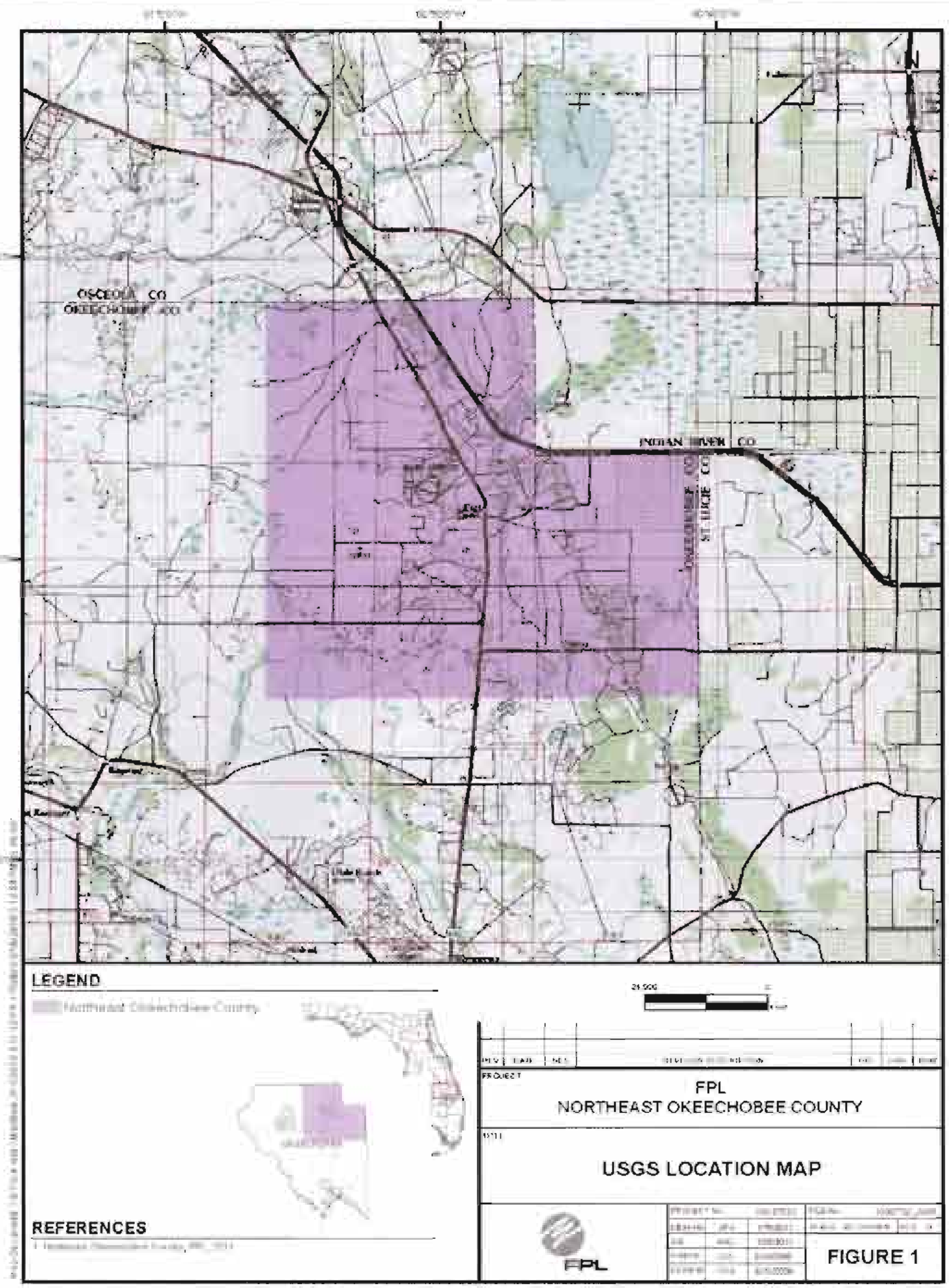
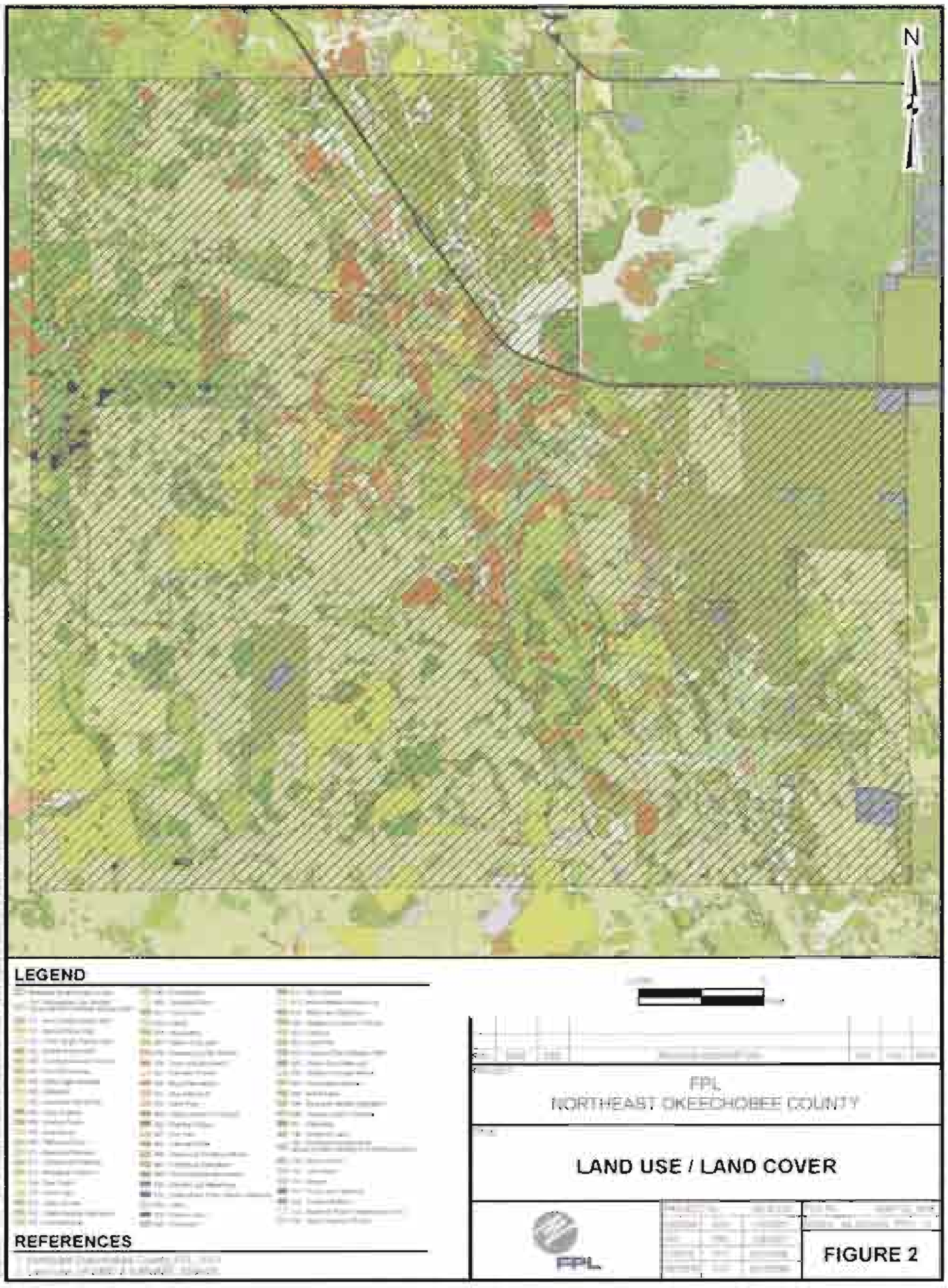

OSCEOLA CO
OKEECHOBEE CO
INDIAN RIVER CO
OKEECHOBEE CO
ST. LUCIE CO
LEGEND
Northeast Okeechobee County
REFERENCES
PROJECT
FPL
NORTHEAST OKEECHOBEE COUNTY
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
REFERENCES
FPL
NORTHEAST OKEECHOBEE COUNTY
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information:
Supplemental Information

Potential Site #8: Palatka Site

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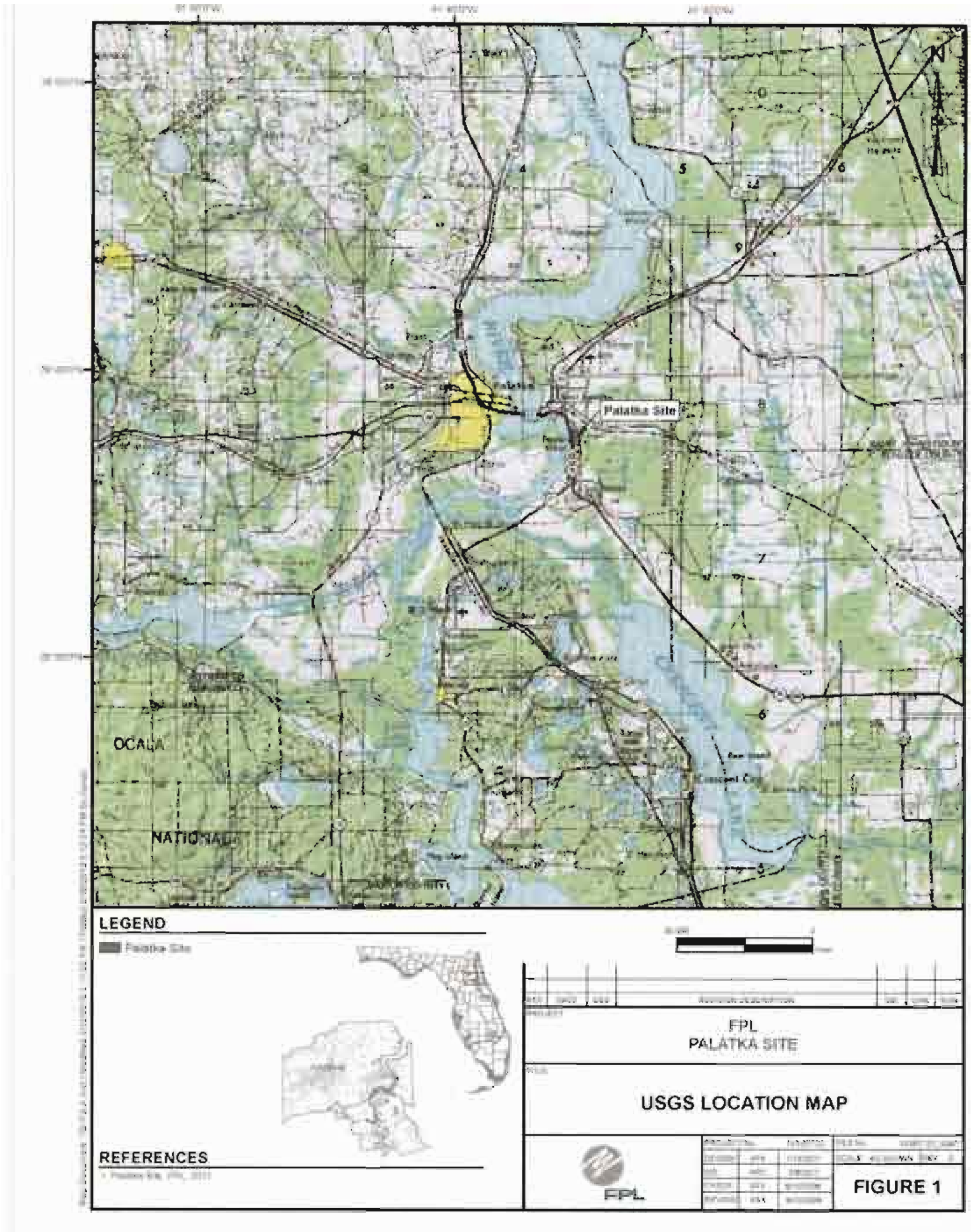
Palatka Site
OCALA
NATIONAL
LEGEND
Palatka Site
REFERENCES
FPL
PALATKA SITE
USGS LOCATION MAP
FPL
FIGURE 1

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Environmental and Land Use Information: Supplemental Information

Potential Site #9: Port Everglades Plant

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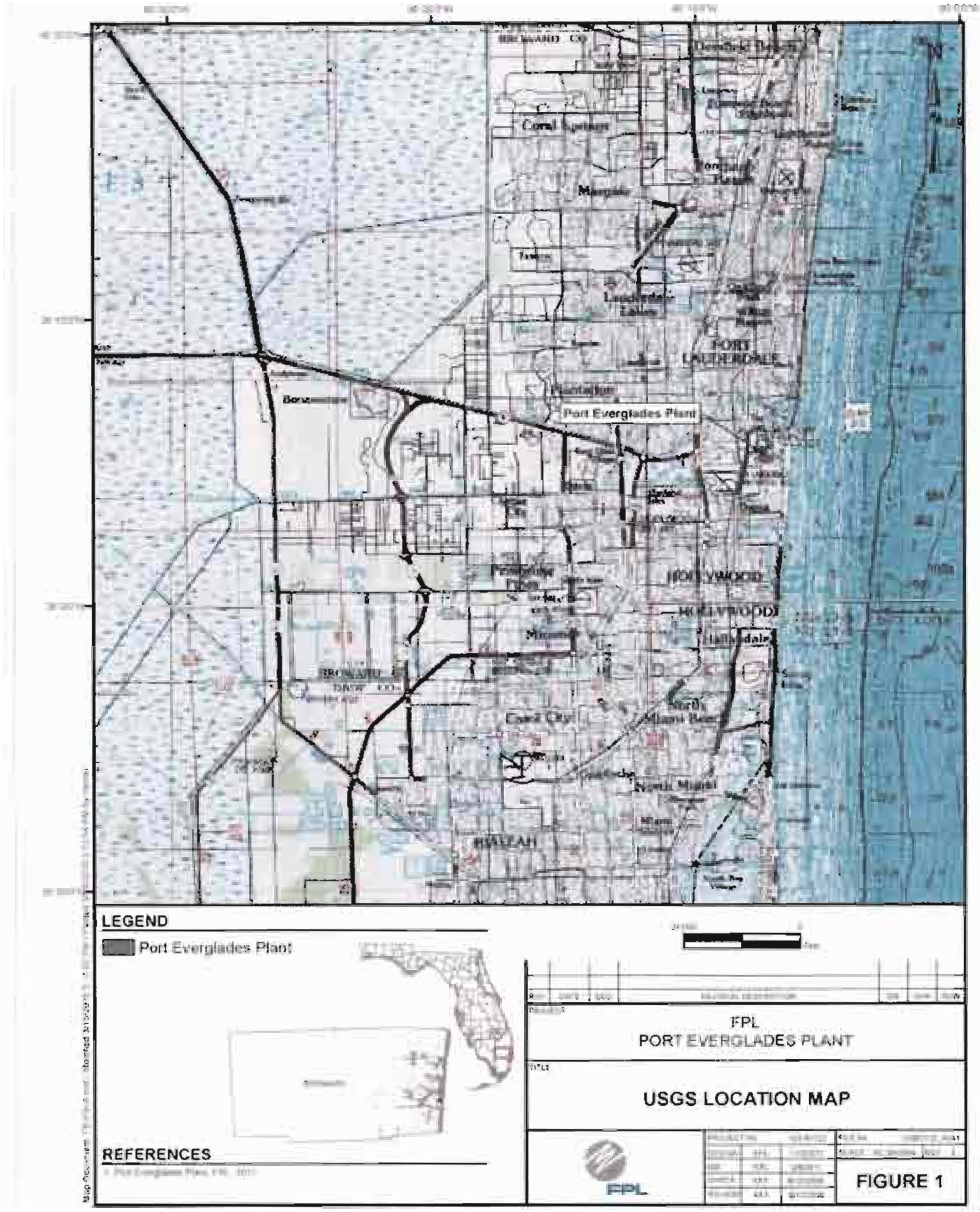
Coral Springs
Margate
Lauderdale Lakes
FORT LAUDERDALE
Plantation
Port Everglades Plant
HOLLYWOOD
Hallandale
Coral City
North Miami Beach
North Miami
HIALEAH
LEGEND
Port Everglades Plant
REFERENCES
FPL
PORT EVERGLADES PLANT
USGS LOCATION MAP
FPL
FIGURE 1

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Environmental and Land Use Information: Supplemental Information

Potential Site #10: Putnam County

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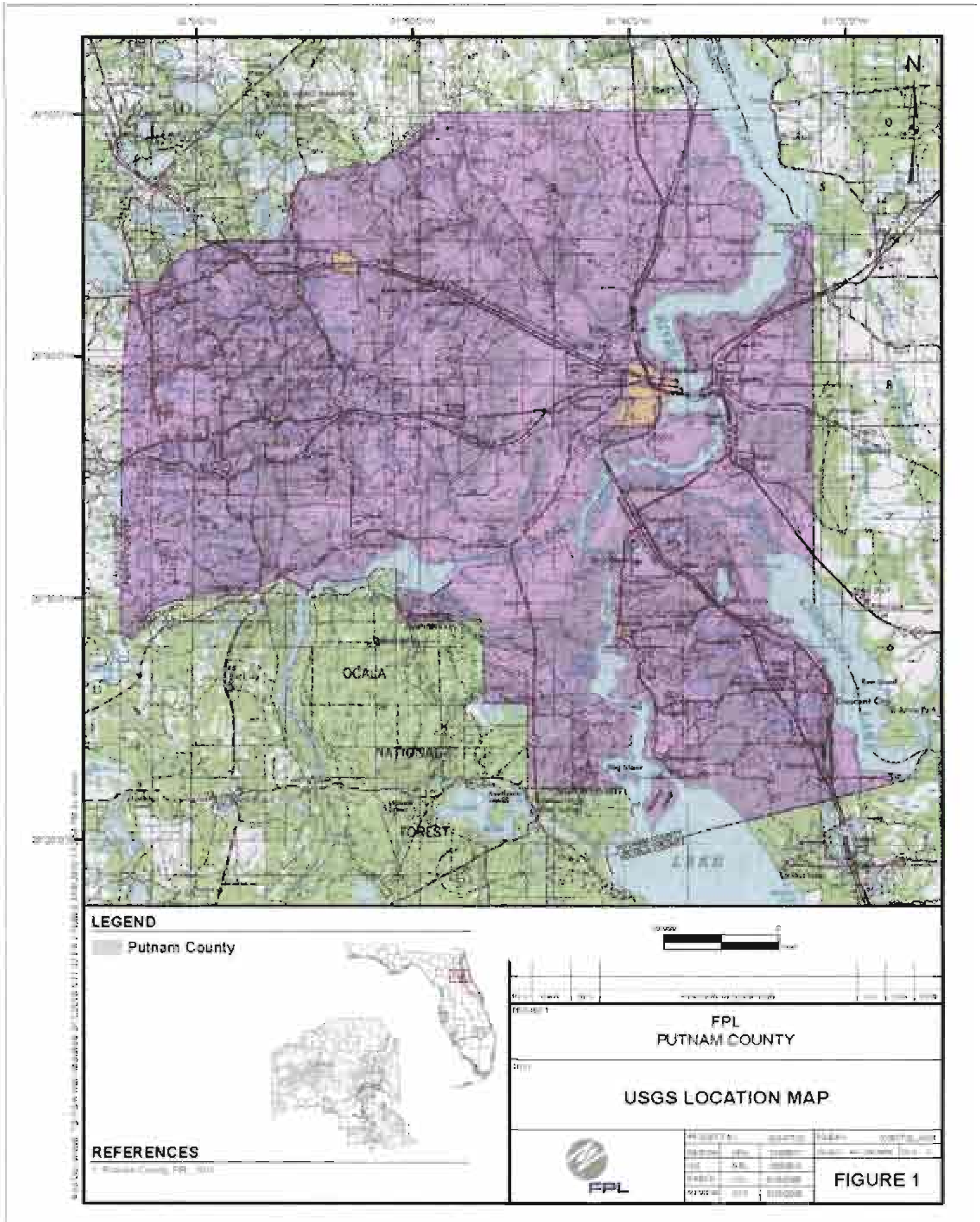
N
OCALA
NATIONAL
FOREST
LEGEND
Putnam County
REFERENCES
FPL
PUTNAM COUNTY
USGS LOCATION MAP
FPL
FIGURE 1

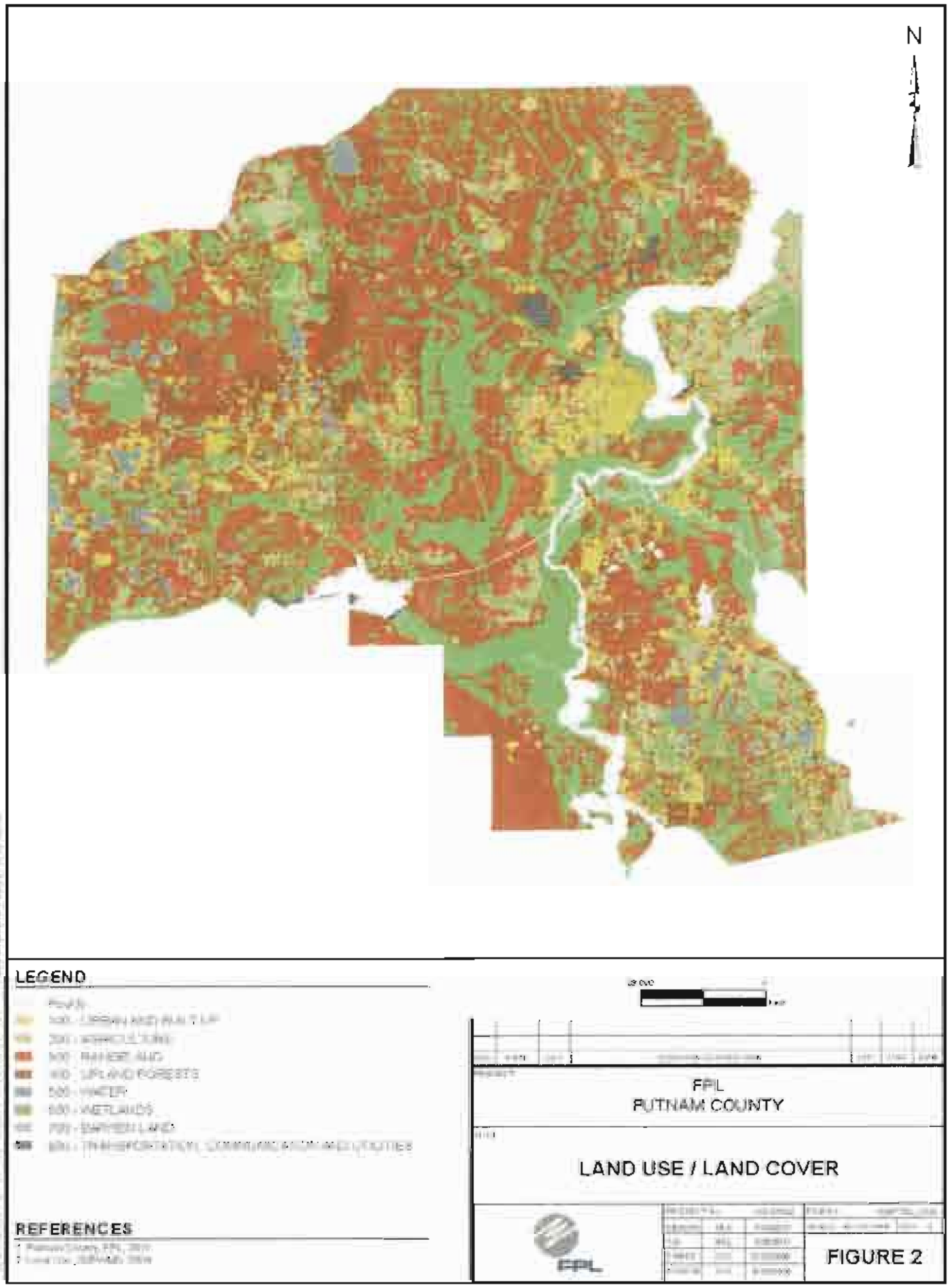
N
LEGEND
100 - URBAN AND BUILT UP
200 - AGRICULTURE
300 - RANGELAND
400 - UPLAND FORESTS
500 - WATER
600 - WETLANDS
700 - BARREN LAND
800 - TRANSPORTATION, COMMUNICATION AND UTILITIES
REFERENCES
FPL
PUTNAM COUNTY
LAND USE / LAND COVER
FPL

FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #11: Southwest Indian River County

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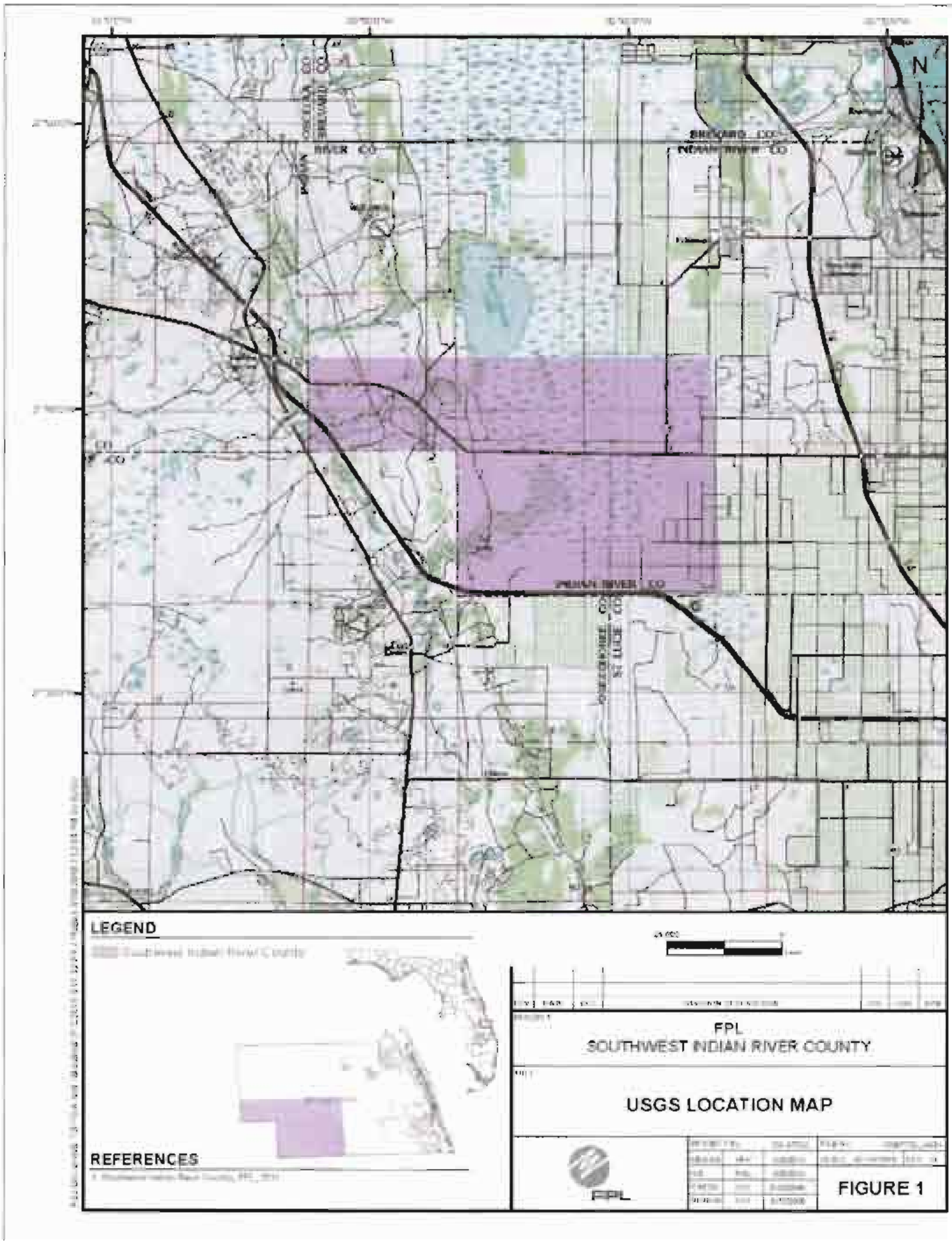
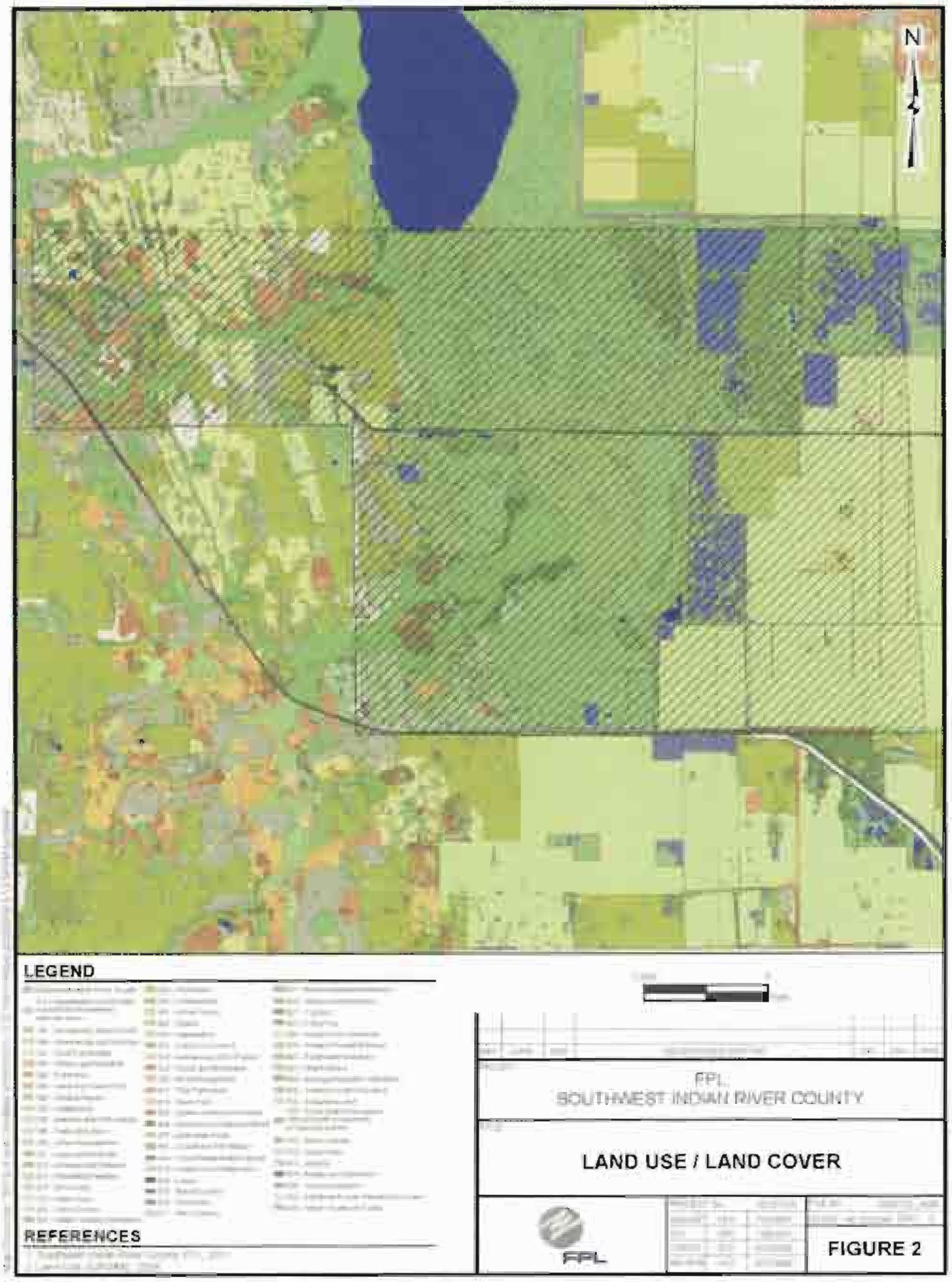

N
BREVARD CO
INDIAN RIVER CO
INDIAN RIVER CO
OKEECHOBEE CO
ST LUCIE CO
LEGEND
REFERENCES
FPL
SOUTHWEST INDIAN RIVER COUNTY
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
REFERENCES
FPL
SOUTHWEST INDIAN RIVER COUNTY
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #12: Space Coast Solar Expansion

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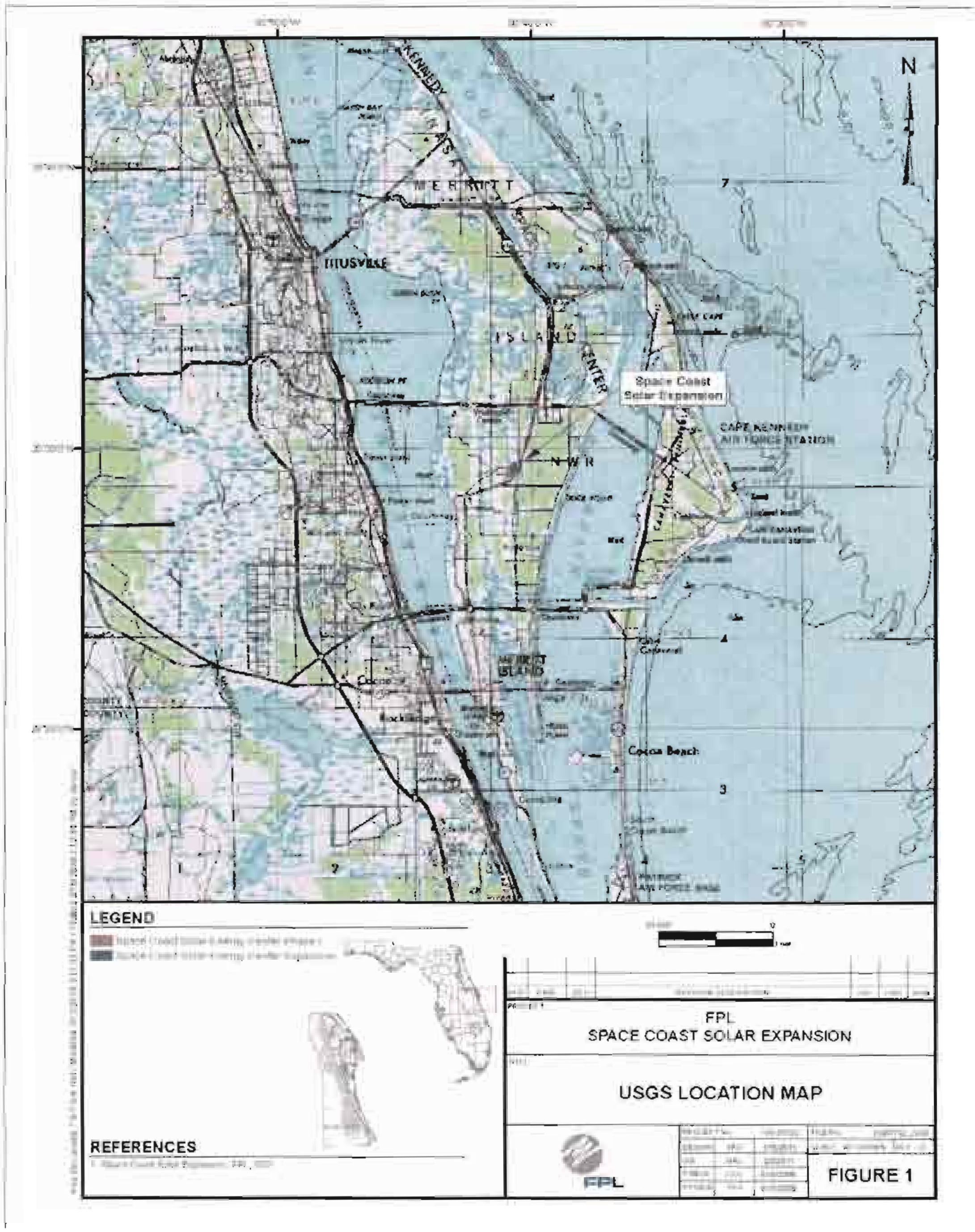
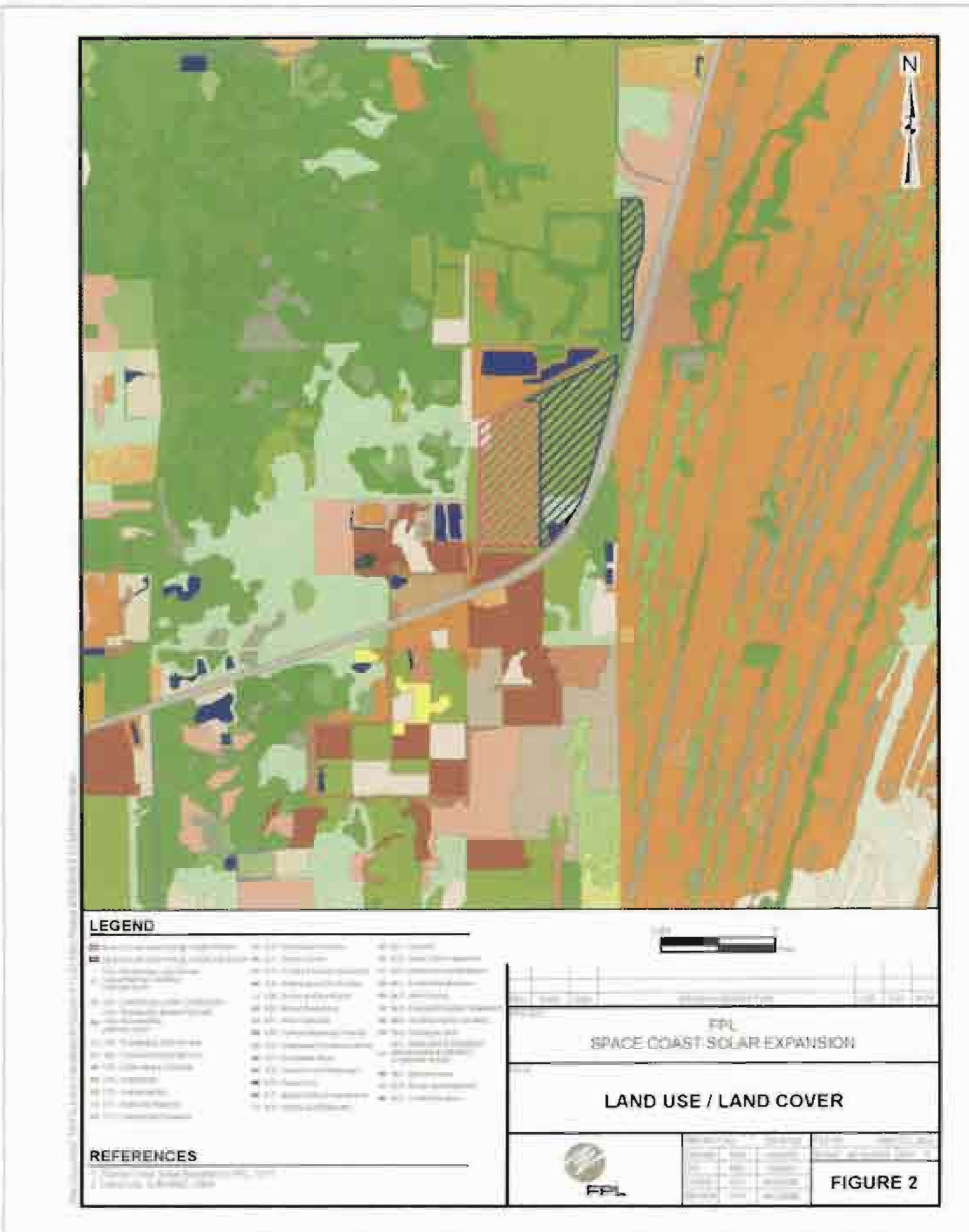

N
TITUSVILLE
MERRITT
ISLAND
KENNEDY
SPACE
CENTER
Space Coast
Solar Expansion
CAPE KENNEDY
AIR FORCE STATION
N W R
MERRITT
ISLAND
Cocoa Beach
LEGEND
REFERENCES
FPL
SPACE COAST SOLAR EXPANSION
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
REFERENCES
FPL
SPACE COAST SOLAR EXPANSION
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #13: West Broward

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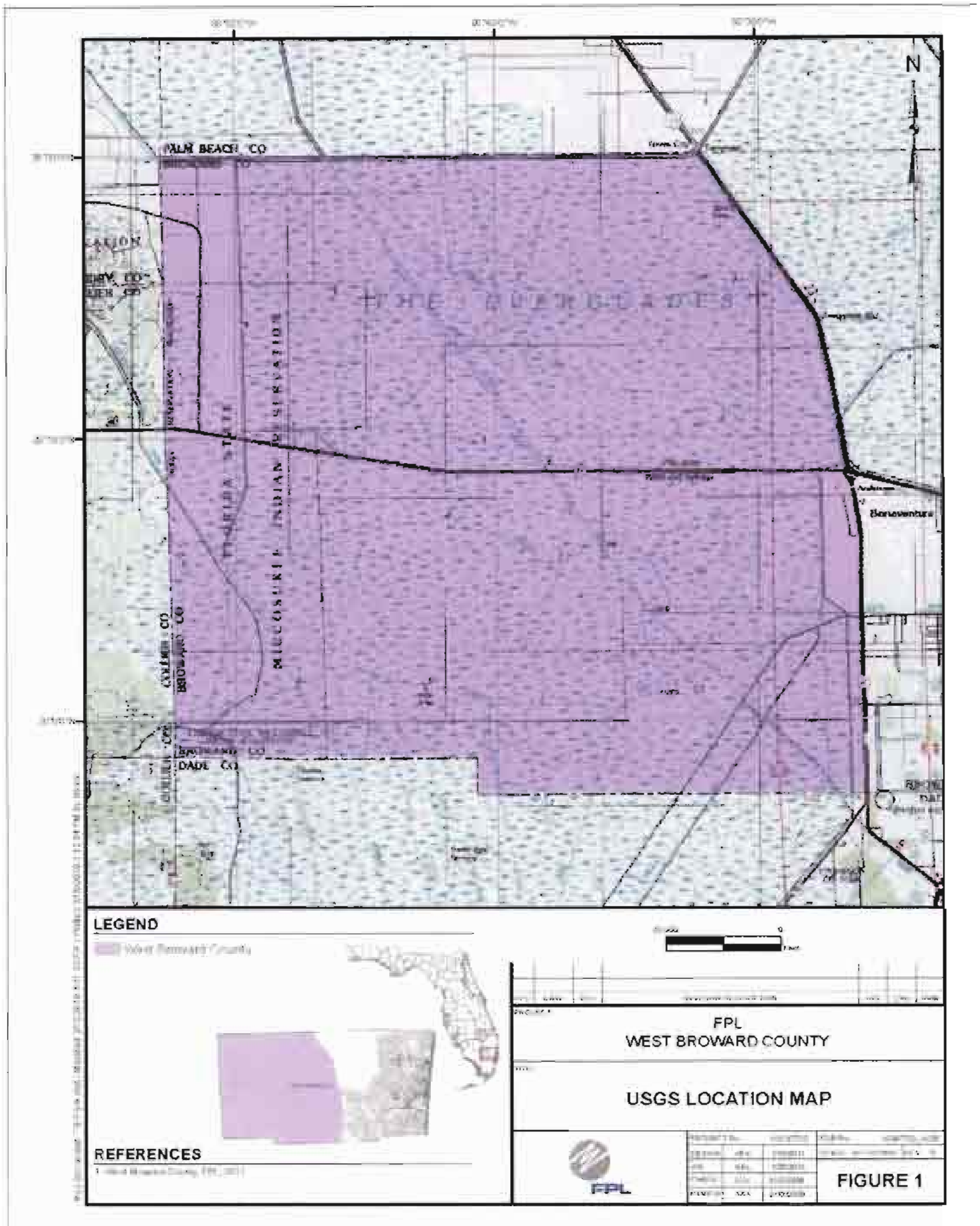
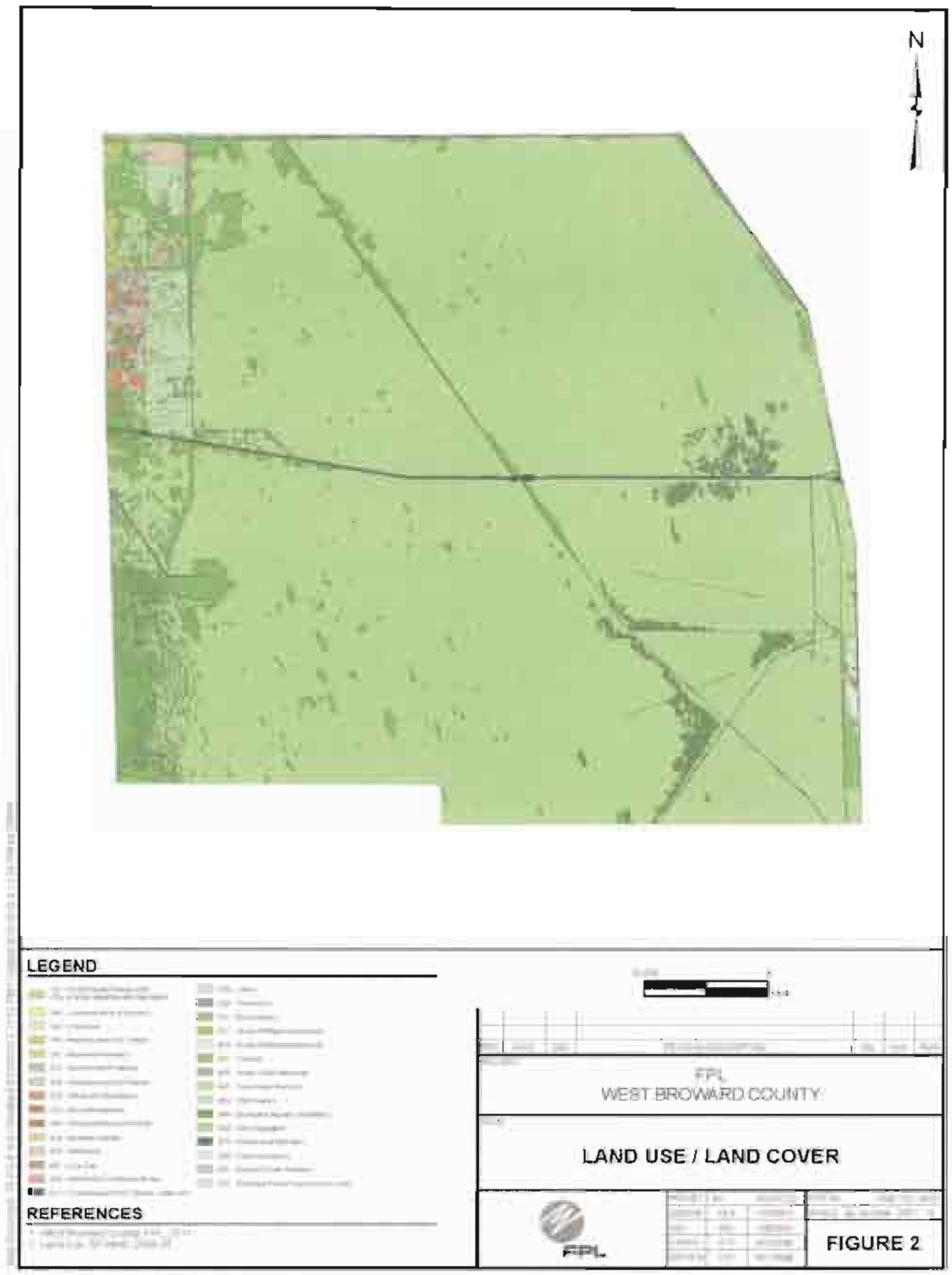

N
PALM BEACH CO
THE EVERGLADES
FLORIDA STATE
MICCOSUKEE INDIAN RESERVATION
COLLIER CO
BROWARD CO
DADE CO
Bonaventure
LEGEND
REFERENCES
FPL
WEST BROWARD COUNTY
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
REFERENCES
FPL
WEST BROWARD COUNTY
LAND USE / LAND COVER
FPL
FIGURE 2

CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information". These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints: external limitations and internal limitations. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important since they affect the development of assumptions for the amount of external assistance that is available to the FPL system as well as the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In the loss of load probability (LOLP) portion of its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new units that minimize adverse impacts to the flow of electricity within FPL's system. The internal transmission limitations are also addressed by developing the direct costs for siting new units at different locations and by evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system. Both of these site- and system-related transmission costs are developed for each different unit/unit location option or groups of options. In addition, transfer limits for capacity and energy that can be imported into the

Southeastern (Miami-Dade and Broward counties) region of FPL's system are also developed for use in FPL's production costing analyses. (A further discussion of the Southeastern Florida region, and the need to maintain a regional balance between generation and transmission contributions, is found in Chapter III.)

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's planned transmission facilities to interconnect and integrate FPL's resource plans and those that must be certified under the Transmission Line Siting Act are presented in Chapter III.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements for the FPL system.[6]

The load forecast that is presented in FPL's 2011 Site Plan was developed in February 2011. FPL has not performed sensitivity analyses on forecasts that differ from this recently developed load forecast.

[6] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis (i.e., when only new generating options are considered), the lowest electric rate basis approach and the lowest system revenue requirements basis approach, yield identical results in terms of which resource options are more economic. In such cases FPL evaluates options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its fuel price forecasts are discussed in Chapter III of this document. FPL used three fuel cost, and three environmental compliance cost, forecasts in its 2010 nuclear cost recovery filings. FPL utilized one fuel cost forecast, and one environmental compliance cost forecast in its DSM Plan analysis work in 2010 and early 2011.

The high and low fuel cost forecasts are derived from a calculation of the historical volatility of the 12-month forward price for one year ahead. From this range of volatility, a reasonable value from the high end of the range is applied to the medium cost fuel cost forecast to develop a high cost fuel cost forecast. Similarly, a reasonable value from the low end of the range is applied to the medium cost fuel cost forecast to develop a low cost fuel cost forecast.

The use of varying high and low fuel cost forecasts did not affect the generation expansion plan used in any of FPL's 2010 planning efforts.

The resource plan presented in this Site Plan is based, in part, on those prior analyses. For that reason, this resource plan, with the recently developed February 2011 load forecast, has not been further tested for different fuel cost forecasts.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item # 3, FPL used up to three fuel cost forecasts in its 2010 resource planning analyses. While these forecasts did not represent a constant cost differential between oil/gas and coal, a variety of fuel cost differentials were represented in these forecasts.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 in Chapter I and Schedule 8 in Chapter III present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years. However, as discussed briefly in the Executive Summary, and again in more detail in Chapter III, FPL is now projecting that it will begin to perform planned maintenance of its fossil-fueled generating units during the peak months of January and August. Please refer to Chapter III for this discussion.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options in its resource planning work. A summary of this information for the new capacity options FPL currently projects to add over the planning horizon is presented on the Schedule 9 forms in Chapter III.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

In its 2010 resource planning work, FPL used several sets of financial assumptions. Two sets of these assumptions were initially used in FPL's 2010 resource planning work. The first set consisted of: (i) a capital structure of 44.8% debt and 55.2% equity; (ii) a 6.48% cost of debt; (iii) a 10.0% return on equity; and (iv) an after-tax discount rate of 7.30%. A second set of data with the same debt-to-equity ratio and cost of debt, but with an 11.75% return on equity and an after-tax discount rate of 8.27%, was also used.

Later in 2010, FPL adjusted its financial assumptions and used new two sets of financial assumptions. The first set consisted of: i) a capital structure of 40.88% debt and 59.12% equity; (ii) a 6.51% cost of debt; (iii) a 10.0% return on equity; and (iv) an after-tax discount rate of 7.55%. Again, a second set of data with the same debt-to-equity ratio and cost of debt, but with an 11.75% return on equity and an after-tax discount rate of 8.58%, was used.

Going forward in 2011, FPL has again adjusted its financial assumptions. The base case financial assumptions are currently projected to be: i) a capital structure of 40.88% debt and 59.12% equity; (ii) a 5.50% cost of debt; (iii) a 10.0% return on equity; and (iv) an after-tax discount rate of 7.29%. For certain analyses, such as sensitivity analyses for FPL's two nuclear projects, a second set of financial assumptions may be used. This second set of data is currently projected to consist of the same debt-to-equity ratio and cost of debt as just described, but with an 11.75% return on equity and an after-tax discount rate of 8.33%.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item # 2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective are identical when DSM levels are unchanged between competing resource plans. Therefore, in planning work in which DSM levels were unchanged, the equivalent cumulative present value of revenue requirements perspective was utilized.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL currently uses two system reliability criteria in its resource planning work that addresses generation, purchase, and DSM options. One of these is a minimum 20% Summer and Winter reserve margin. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These reliability criteria are discussed in Chapter III of this document. As discussed briefly in the Executive Summary, and in more detail in Chapter III, FPL will be examining the extent to which its system reserves are projected to be dependent upon DSM resources and generation resources in its 2011 resource planning work. The results of this examination could require in a change to FPL's reliability criteria.

In regard to transmission reliability analysis work, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the Reliability Standards established by the North American Electric Reliability Council (NERC). The *NERC Reliability Standards* are available on the internet site (http://www.nerc.com/).

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Facility Rating Methodology* document that are also available on the internet under the FPL OATT Documents directory at https://www.oatioasis.com/FPL/index.html.

Generally, FPL limits its transmission facilities to 100% of the applicable thermal rating. The normal and contingency voltage criteria for FPL stations are provided below:

Normal/Contingency

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09
Turkey Point (*)	1.01/1.01	1.06/1.06
St. Lucie (*)	1.00/1.00	1.06/1.06

(*) Voltage range criteria for FPL's Nuclear Power Plants

There may be isolated cases for which FPL may have determined that it is acceptable to deviate from the general criteria stated above. There are several factors that could influence these criteria, such as the overall number of potential customers that may be impacted, the probability of an outage actually occurring, or transmission system performance, as well as others.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The impact of FPL's DSM programs on demand and energy consumption is revised periodically. Engineering models, calibrated with current field-metered data, are updated at regular intervals. Participation trends are tracked for all of the FPL DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants.

Survey data is collected from non-participants in order to establish the baseline efficiency. Participant data is compared against non-participant data to establish the demand and energy saving benefits of the utility program versus what would be installed in the absence of the program. For these DSM measures which involve the utilization of load management, FPL conducts periodic tests of the load control equipment to ensure that it is functioning correctly.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The Executive Summary and Chapter III provide a discussion of a variety of system concerns/issues that influence FPL's resource planning process. Please see those chapters for a discussion of those concerns/issues.

In addition to these system concerns/issues, there are other strategic factors FPL typically considers when choosing between resource options. These include the following: (1) technology risk; (2) environmental risk, and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology, which has not achieved general commercial acceptance, has a higher risk than a technology in wide use and, therefore, assuming all else equal, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the FPL system, including environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for a plan are those which minimize environmental impacts for the FPL system as a whole through highly efficient fuel use and/or state of the art controls.

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decisions, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As has been previously discussed in prior FPL Site Plans, elements of FPL's recent and future capacity additions include the construction of new generating capacity at the West County Energy Center (WCEC) site, WCEC Unit 3. This generation construction project was selected after evaluating competing bids received in response to Requests for Proposals (RFP) issued by FPL. The FPSC subsequently approved FPL's decision to construct this new combined cycle (CC) unit in a Determination of Need docket.

In regard to the Modernization projects at FPL's existing Cape Canaveral and Riviera plants, these projects were also evaluated using the competing bids received in response to the RFP issued for WCEC Unit 3. In addition, bids from competing vendors were also evaluated for FPL's recent solar thermal and PV projects.

The nuclear capacity additions, both the nuclear uprates and the new nuclear units, do not lend themselves to an RFP approach involving bids from third parties who would build new nuclear generation capacity. In addition, nuclear capacity additions are exempted from the Commission's Bid Rule by section 403.519 (4) (c). For these nuclear projects, FPL's procurement activities were conducted to ensure the best combination of quality and cost for the delivered products.

Construction capacity addition decisions for non-nuclear generation for the years 2016 through 2020 presented in this document are expected to be conducted in a manner consistent with the Commission's Bid Rule.

Identification of self-build options, beyond those units already approved by the FPSC and Governor and Siting Board or units for which FPL may be then seeking approval, in future FPL Site Plans will not be an indication that FPL has pre-judged any capacity solicitation it may conduct. The identification of future generating units is required of FPL in its Site Plan filings and represents those alternatives that appear to be FPL's best, most cost-effective self-build options at the time. FPL reserves the right to refine its planning analyses and to identify other self-build options. Such refined analyses have the potential to yield a variety of self-build options, some of which might not require an RFP. If an RFP is issued for Supply options, FPL reserves the right to choose the best alternative for its customers, even if that option is not an FPL self-build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

(1) FPL has identified the need for a new 230kV transmission line that required certification under the Transmission Line Siting Act which was issued in April 2006. The new line is to be completed in two phases connecting FPL's St. Johns Substation to FPL's Pringle Substation (also shown on Table III.E.1 in Chapter III). Phase 1 was completed in May 2009 and consisted of a new line connecting Pringle to a new Pellicer Substation. Phase 2 is planned to connect St. Johns to Pellicer and is scheduled to be completed by December 2016. The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

(2) FPL has identified the need for a new 230kV transmission line (by December 2015) that required certification under the Transmission Line Siting Act which was issued on November 2008. The new line will connect FPL's Manatee Substation to FPL's proposed Bob White Substation (also shown on Table III.E.1 in Chapter III). The construction of this line, scheduled to be completed in 2015, is necessary to serve existing and future customers in the Manatee and Sarasota areas in a reliable and effective manner.

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FPL

Florida Power & Light Company, 215 S. Monroe Street, Suite 810, Tallahassee, FL 32301

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COMMISSION
CLERK

Jessica Cano
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5226
(561) 691-7135 (Facsimile)

June 10, 2011

VIA HAND DELIVERY
Ms. Ann Cole
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

Re: Docket No. 110000; Corrections to FPL's 2011 Ten Year Power Plant Site Plan

Dear Ms. Cole:

Please find enclosed an original and 25 copies of four replacement pages for FPL's 2011 Ten Year Power Plant Site Plan, originally filed on April 1, 2011, reflecting corrected information.

Specifically, pages 45, 46, 98, and 116 are being replaced. Corrections are included in red, bold font.

Please contact me if you have any questions regarding this filing.

Sincerely,

for Lynne A. Adams
Jessica Cano

Enclosures

cc: Charles Murphy

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APA ___
ECR ___
GCL ___
RAD 25 - Phillip Ellis
SSC ___
ADM ___
OPC ___
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04032 JUN 10 ≡
FPSC-COMMISSION CLERK

Schedule 3.1
History and Forecast of Summer Peak Demand (MW)
(Historical)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2001	18,754	169	18,585	0	842	697	489	481	17,423
2002	19,219	261	18,958	0	879	754	489	517	17,851
2003	19,668	253	19,415	0	892	798	577	554	18,200
2004	20,545	258	20,287	0	894	846	588	577	19,063
2005	22,361	264	22,097	0	902	895	600	611	20,858
2006	21,819	256	21,563	0	928	948	635	640	20,256
2007	21,962	261	21,701	0	952	982	716	683	20,295
2008	21,060	181	20,879	0	966	1042	760	706	19,334
2009	22,351	249	22,102	0	981	1097	811	732	20,558
2010	22,256	419	21,837	0	990	1147	815	749	18,555

Historical Values (2001 - 2010):

Col. (2) - Col. (4) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) represent actual DSM capabilities starting from January 1988 and are annual (12-month) values except for 2010 values which are August values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC), CILC, and Commercial /Industrial Demand Reduction (CDR). Historical Residential Load Management MWs reflect the effect of new Measurement and Verification kw/participant factors.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.1
History and Forecast of Summer Peak Demand (MW)
(Projected)

(1) August of Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2011	21,679	383	21,295	0	1,005	79	858	39	19,697
2012	21,853	385	21,468	0	1,017	154	878	93	19,712
2013	22,155	343	21,812	0	1,023	244	896	154	19,837
2014	23,452	1,129	22,322	0	1,041	343	934	216	20,917
2015	24,172	1,136	23,037	0	1,044	442	952	272	21,462
2016	24,605	1,143	23,463	0	1,047	536	971	318	21,734
2017	25,025	1,150	23,875	0	1,050	625	989	353	22,008
2018	25,266	1,157	24,109	0	1,053	711	1,007	378	22,117
2019	25,690	1,165	24,526	0	1,056	792	1,026	397	22,419
2020	26,193	1,172	25,022	0	1,060	837	1,042	412	22,823

Projected Values (2011 - 2020):

Col. (2) - Col. (4) represent FPL's forecasted peak w/o incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected August values. The 2011 values are based on IRP projections after the 2010 Summer peak and FPL's new DSM Goals for 2011. The projections for 2012 through 2020 are based on FPL's DSM Goals. Res. Load Management and C/I Load Management include MW values of load management capability from Lee County that can be initiated at FPL's request.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand' which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case
(Historical)

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2001	18,199	150	18,049	0	749	459	448	183	17,002
2002	17,597	145	17,452	0	768	500	457	196	16,373
2003	20,190	246	19,944	0	802	546	453	206	18,935
2004	14,752	211	14,541	0	813	567	534	227	13,405
2005	18,108	225	17,883	0	816	583	542	233	16,751
2006	19,683	225	19,458	0	823	600	550	240	18,311
2007	16,815	223	16,592	0	846	620	577	249	15,392
2008	18,055	163	17,892	0	868	644	636	279	16,551
2009	20,081	207	19,874	0	881	666	676	285	18,524
2010	24,346	500	23,846	0	895	687	721	291	21,752

Historical Values (2001 - 2010):

Col. (2) - Col. (4) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) for 2001 through 2010 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values for December 31st of the prior year.

Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC), CILC, and Commercial /Industrial Demand Reduction (CDR). Historical Residential Load Management MWs reflect the effect of new Measurement and Vertification kw/participant factors.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case
(Projected)

(1) January of Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2011	21,443	376	21,067	0	911	31	754	15	19,732
2012	21,491	378	21,113	0	922	63	769	47	19,689
2013	21,683	380	21,303	0	932	104	784	89	19,774
2014	22,584	1,015	21,569	0	956	158	817	134	20,518
2015	23,048	1,222	21,826	0	959	214	832	177	20,866
2016	23,302	1,229	22,073	0	961	267	846	215	21,014
2017	23,543	1,237	22,306	0	963	314	860	244	21,161
2018	23,794	1,245	22,550	0	966	358	874	266	21,331
2019	24,044	1,252	22,792	0	968	398	889	282	21,506
2020	24,305	1,260	23,045	0	970	431	902	293	21,709

Projected Values (2011 - 2020):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected January values. The 2011 values are based on IRP projections after the 2010 Winter peak and FPL's new DSM Goals for 2011. The projections for 2012 through 2020 are based on FPL's DSM Goals.Res. Load Management and C/I Load Management include MW values of load management capability from Lee County that can be initiated at FPL's request.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand' which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

Plant Name	(2) Unit No	(3) Location	(4) Unit Type	(5) Fuel Pri	(5) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Const Start Mo/Yr	(10) Comm In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen Max Nameplate KW	(13) Firm Net Capability [1] Winter MW	(14) Firm Net Capability [1] Summer MW	(15) Status
ADDITIONS/ CHANGES														
2011														
St. Lucie (Uprates)	2	St. Lucie County	NP	UR	No	TK	No	—	Apr-11	Unknown	723,775	—	17	OT
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Feb-11	310,420	—	(277)	OT
Riviera	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Feb-11	310,420	—	(288)	OT
Scherer	4	Monroe, GA	BIT	SUB	No	RR	No	—	Jul-11	Unknown	680,368	—	26	OT
West County Energy Center	3	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	1,366,800	—	1219	V
								2011 Changes/Additions w/o Inactive Reserve Total:				0	697	
Cutler	5	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	75,000	(69)	(68)	OT
Cutler	6	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	161,500	(138)	(137)	OT
Sanford	3	Volusia County	ST	FO6	NG	WA	PL	—	—	—	156,250	(140)	(138)	OT
Port Everglades	1	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	225,250	(214)	(213)	OT
Port Everglades	2	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	225,250	(214)	(213)	OT
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	—	(387)	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	—	(374)	OT
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	402,050	—	(392)	OT
								2011 Changes/Additions with Inactive Reserve Total:				(775)	(1,225)	
2012														
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Unknown	310,420	(280)	—	OT
Riviera	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Unknown	310,420	(291)	—	OT
Scherer	4	Monroe, GA	BIT	SUB	No	RR	No	—	Jul-11	Unknown	680,368	26	—	OT
St. Lucie (Uprates) [2]	2	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	723,775	17	(17)	T
St. Lucie (Uprates) [2]	1	St. Lucie County	NP	UR	No	TK	No	—	Dec-11	Unknown	850,000	—	122	T
Turkey Point (Uprates) [2]	3	Miami Dade County	NP	UR	No	TK	No	—	May-12	Unknown	759,900	—	109	T
West County Energy Center	3	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	1,366,800	1,335	—	V
								2012 Changes/Additions w/o Inactive Reserve Total:				807	214	
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	402,050	(394)	—	
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	—	387	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	—	374	OT
								2012 Changes/Additions with Inactive Reserve Total:				413	975	
2013														
St. Lucie (Uprates) [2]	2	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	723,775	(17)	—	T
St. Lucie (Uprates) [2]	1	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	650,000	122	—	T
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	PL	Jun-11	Jun-13	Unknown	1,296,750	—	1,210	T
St. Lucie (Uprates) [2]	2	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	723,775	110	110	T
Turkey Point (Uprates) [2]	3	Miami Dade County	NP	UR	No	TK	No	—	See Note 2	Unknown	759,900	109	—	T
Turkey Point (Uprates) [2]	4	Miami Dade County	NP	UR	No	TK	No	—	See Note 2	Unknown	759,900	—	109	T
								2013 Changes/Additions w/o Inactive Reserve Total:				324	1,429	
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(389)	(387)	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(376)	(374)	OT
								2013 Changes/Additions with Inactive Reserve Total:				(441)	668	

(1) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring later in the year will be picked up for reporting/planning purposes in the following year.

(2) The nuclear uprates will be performed during the extended outages for each unit.

Schedule 11.1

Existing FIRM and NON-FIRM Capacity and Energy by Primary Fuel Type
Actuals for the Year 2010

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	Summer (MW)	Summer (%)	Winter (MW)	Winter (%)	GWh (2)	%
(1)	Coal	900	3.5%	902	3.3%	5,721	5.0%
(2)	Nuclear	2,939	11.4%	3,013	11.2%	22,850	20.0%
(3)	Residual	5,954	23.1%	6,004	22.3%	4,081	3.6%
(4)	Distillate	1,908	7.4%	2,087	7.7%	279	0.2%
(5)	Natural Gas	11,986	46.4%	12,756	47.3%	66,771	58.4%
(6)	Solar	35	0.1%	35	0.1%	69	0.1%
(7)	*FPL Existing Units Total (1):*	*23,722*	*91.9%*	*24,797*	*91.9%*	*99,771*	*87.2%*
(8)	Renewables (Purchases)- Firm	61.0	0.2%	112.0	0.4%	1,004	0.9%
(9)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	800	0.7%
(10)	*Renewable Total:*	*61.0*	*0.2%*	*112.0*	*0.4%*	*1,804*	*1.58%*
(11)	*Purchases Other :*	*2,041.0*	*7.9%*	*2,074.0*	*7.7%*	*12,798*	*11.2%*
(12)	*Total:*	*25,824.0*	*100.0%*	*26,983.0*	*100.0%*	*114,373*	*100.0%*

Note:
(1) FPL Existing Units Total values on row (7), columns (2) and (4), match the System Firm Generating Capacity values found on Schedule 1 for Summer and Winter.
(2) Net Energy for Load GWh values on row (12), column (6), matches Schedule 6.1 value for 2010.

Schedule 11.2

Existing NON-FIRM Self-Service Renewable Generation Facilities
Actuals for the Year 2010

(1)	(2)	(3)	(4)	(5)	(6) = 3+4-5
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh)	Annual Energy Purchased from FPL (MWh)	Annual Energy Sold to FPL (MWh)	Projected Annual Energy Used by Customers (GWh)
Customer-Owned PV (0 kW to 10 kW)	4.6	5,214.7	53,476.4	146.5	58.5
Customer-Owned PV (> 10 kW to 100 kW)	1.6	1,775.4	17,858.8	158.2	19.5
Customer-Owned PV (> 100 kW to 2 MW)	2.9	3,708.4	118,662.7	177.6	118,666.2
Total:	9.2	10,698.5	189,998.0	482.2	118,744.2

Notes:

(1) There were approximately 1,064 customer-owned renewable generation facilities interconnected with FPL on December 31, 2010.
(2) The Installed Capacity value is the sum of the nameplate ratings (DC MW) for all of the customer-owned renewable generation facilities connected as of Dec. 31,2010.
(3) The Projected Annual Output value is based on NREL's PV Watts 1 program and the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.
(4) The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2010.
(5) The Annual Energy Sold to FPL is an actual value from FPL's metered data for 2010.
(6) The Projected Annual Energy Used by Customers is a projected value that equals:
(Renewable Projected Annual output + Annual Energy Purchased from FPL) minus the Annual Energy Sold to FPL.

FPL

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April 2, 2012

VIA HAND DELIVERY

Ms. Ann Cole
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

120000-OT

RECEIVED-FPSC
12 APR -2 PM 3:5
COMMISSION CLERK

RE: Florida Power & Light Company's 2012 Ten Year Power Plant Site Plan

Dear Ms. Cole:

In accordance with Rule 25-22.071, F.A.C., please find enclosed for filing the original and twenty-five (25) copies of Florida Power & Light Company's 2012-2021 Ten Year Power Plant Site Plan.

Sincerely,

Jessica Cano

Jessica A. Cano

Enclosure

COM ____
APA ____
ECR ____
GCL 2
RAD 22
SRC ____
ADM ____
OPC ____
CLK 1-original

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 47
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-L

DOCUMENT NUMBER-DATE
01983 APR -2 ≌
FPSC-COMMISSION CLERK

Ten Year Power Plant Site Plan
2012 – 2021

FPL

FPL

Ten Year Power Plant Site Plan

2012-2021

Submitted To:

Florida Public
Service Commission

Miami, Florida
April 2012

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Table of Contents

List of Figures and Tables

List of Schedules

Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan. This plan should include an estimate of the utility's future electric power generating needs, a projection of how these estimated generating needs might be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The information contained in this Site Plan is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

This Ten Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) integrated resource planning (IRP) analyses that were carried out in 2011 and that were on-going in the first Quarter of 2012. The forecasted information presented in this plan addresses the years 2012 through 2021.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information and all of this information is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, based on FPL's IRP work in 2011 and

early 2012.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as Preferred and Potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional information that is included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	***Abbreviation***	***Definition***
Unit Type	BIT	Bituminous Coal
	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	IC	Internal Combustion
	NP	Nuclear Power
	PV	Photovoltaic
	ST	Steam Unit
Fuel Type	UR	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	Solar	Solar Energy
	SUB	Sub Bituminous Coal
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	P	Planned Unit
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	ESP	Electrostatic Precipitators

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Executive Summary

Florida Power & Light Company's (FPL) 2012 Ten Year Power Plant Site Plan (Site Plan) presents FPL's current plans to augment and enhance its electric generation capability (owned or purchased) as part of its efforts to meet its projected incremental resource needs for the 2012 - 2021 time period. By design, the primary focus of this document is on supply side additions; i.e., electric generation capability and the sites for these additions. The supply side additions discussed in this document are resources projected to be needed after accounting for FPL's demand side management (DSM) efforts and the significant energy efficiency contributions from the current federal appliance and lighting efficiency standards. The projected impacts of the federal appliance and lighting efficiency standards are accounted for in FPL's load forecast which is discussed in Chapter II. The projected impacts of FPL's DSM efforts are addressed as projected reductions to the forecasted load. FPL's DSM programs are presented in Chapter III.

The resource plan that is presented in FPL's 2012 Site Plan contains a number of key similarities to the resource plan presented in FPL's 2011 Site Plan. On the other hand, there are specific factors that result in changes in FPL's current resource plan compared to the resource plan presented in FPL's 2011 Site Plan. There are also other factors that will continue to influence FPL's on-going resource planning work. A brief discussion of these similarities, changes, and factors is provided below. Additional information regarding many of these topics is presented in Chapter III.

I. Similarities to the Resource Plan Previously Presented in FPL's 2011 Site Plan:

There are four key similarities in the current resource plan presented in this document compared to the resource plan presented in the 2011 Site Plan.

Similarity # 1: Generating capacity at FPL's four existing nuclear generation units will continue to increase in the 2012 – 2013 time frame.

FPL will be adding approximately 490 MW of increased generating capacity from "uprates" at its existing Turkey Point and St. Lucie nuclear power plants. 31 MW of this increased capacity has already come in-service at St. Lucie Unit 2 and is already benefiting FPL's customers. The capacity uprates at 3 of the 4 nuclear units are currently projected to be completed by the end of 2012 and the uprate at the 4th unit is projected to be completed by March 2013. The need for these nuclear capacity uprates was approved by the FPSC in January 2008 in Order No. PSC-08-0021-FOF-EI. The Final Order for the Site Certification was issued in September 2008 for the

St. Lucie uprates in Order No. DEP 08-0942 and in October 2008 for the Turkey Point uprates in Order No. DEP 08-1141. [1]

Similarity # 2: FPL continues to pursue licenses, permits, and approvals that would be necessary for future construction and operation of two new nuclear generating units at its Turkey Point site.

FPL is continuing its work to obtain all of the licenses, permits, and approvals that would be necessary to construct and operate two new nuclear units at its Turkey Point site in the future. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. The earliest practical deployment dates for the two new units continue to be beyond the 10-year reporting period for this Site Plan. Therefore, these additions are not shown in this document.

Similarity # 3: A number of existing generating units have been placed on Inactive Reserve.

In 2009, FPL began to take a number of its existing generating units out of active service and has placed them on Inactive Reserve status. The specific generating units that have been placed on Inactive Reserve status are discussed in Chapter III of this document. However, there are changes in regard to FPL's current plans for these units that are discussed later in this Executive Summary and in more detail in Chapter III.

Similarity # 4: The modernizations of FPL's existing Cape Canaveral and Riviera plant sites are underway and are projected to be completed on time in 2013 and 2014, respectively.

FPL's 2011 Site Plan projected that the modernizations of these two existing sites would be completed in 2013 (Cape Canaveral) and 2014 (Riviera). FPL received need determination approval from the FPSC for both of these modernizations in September 2008 in Order No. PSC-08-0591-FOF-EI. Site Certification was received for Cape Canaveral in October 2009 in Order No. DEP 09-1015. Site Certification was received for Riviera in November 2009 in Order No. DEP O9-1245. The work to complete these modernizations is underway, on budget and these modernizations are again reflected in this Site Plan with no changes to the projected completion dates.

[1] The nuclear uprate project outage schedules for 2012 and 2013 are still being developed at the time the 2012 Site Plan is being finalized. The project schedule dates presented in this Site Plan document are the best available information available at this time. However, this schedule information is subject to change.

II. Factors That Are Driving Changes in FPL's Resource Plan:

There are two primary factors that are driving changes in FPL's 2012 resource plan compared to the resource plan presented in FPL's 2011 Site Plan. These changes are summarized below.

Factor # 1: It will not be necessary to schedule planned maintenance outages for FPL's fleet of fossil-fueled generating units during all Summer and Winter peak load months.

In FPL's 2011 Site Plan, it was projected that scheduled maintenance for FPL's generating units would need to be extended into all Summer and Winter peak load months. After further analysis, FPL concluded that it would not be necessary to schedule maintenance during all peak load months. (However, FPL will maintain the practice of using available capacity year-round for scheduling maintenance of its fossil-fueled units as opportunities arise.)

Factor # 2: Changes in the load forecast, generating unit capabilities, and power purchase capabilities have combined to result in a net lowering of FPL's projected resource needs through 2021.

The combined effect of several factors has led to a lowering of FPL's projected resource needs. In addition to the aforementioned removal of scheduled maintenance during peak load months, FPL is also projecting a load forecast that is slightly lower than the forecast used in the 2011 Site Plan. Also, several FPL units are now projected to increase their capabilities during the 2012-2021 time frame. These increases include additional incremental generation from the modernization at the Port Everglades site, greater than previously projected output from the nuclear capacity uprates project, and upgrades to the combustion turbines at several of FPL's combined cycle plant sites. The effect of these projects is only slightly offset by a decrease in the amount of a purchased power agreement (PPA) with Palm Beach SWA. However, the combined net effects result in an overall decrease in FPL's projected resource needs.

III. Resulting Changes in FPL's Resource Plan Compared to the Resource Plan Previously Presented in FPL's 2011 Site Plan:

The combined effect of the factors discussed above contributed to three significant changes in FPL's resource plan presented in this document compared to the resource plan previously presented in FPL's 2011 Site Plan. These changes are presented below and are discussed in more detail in Chapter III.

Change # 1: FPL's next resource need will be met by the modernization of FPL's Port Everglades site.

In its 2011 Site Plan, FPL projected, for planning purposes, to meet its next resource need with a Greenfield combined cycle (CC) unit that would come in-service in 2016. However, FPL discussed in its 2011 Site Plan that FPL was examining a variety of options with which to meet this need including a modernization of the Port Everglades site. Subsequent analyses determined that a modernization of this site was the most economic and best option for FPL's customers. FPL filed for a need determination for the modernization on November 21, 2011. The FPSC voted on March 27, 2012, to approve the modernization of Port Everglades with a 2016 in-service date. (As a result, Port Everglades' existing generating units 1 – 4, currently on Inactive Reserve status, will eventually be removed as part of the modernization process.)

Change # 2: Three generating units are being retired and two other generating units have been/will be switched to operate as synchronous condensers.

Sanford Unit 3, Cutler Unit 5, and Cutler Unit 6 are currently on Inactive Reserve status and will be retired in the fourth quarter of 2012. In addition, Turkey Point Unit 2 has been converted to operate in synchronous condenser mode to provide voltage support for the transmission system in Southeastern Florida. FPL also projects that Turkey Point Unit 1 will be similarly converted to run in synchronous condenser mode starting in 2016.

Change # 3: FPL's next resource need is now projected to be in 2021.

FPL's 2011 Site Plan showed a resource need in 2020 that was originally projected to be met with a Greenfield CC unit. This resource need has moved back one year from 2020 to 2021. FPL has made no decision regarding how this need will be met. For planning purposes, FPL is currently assuming that this 2021 resource need will be met by a PPA in 2021.

IV. Additional Factors Influencing FPL's Resource Planning Work:

In addition to the two factors previously mentioned (no necessity to schedule or execute planned maintenance in all peak load months and a projection of lower resource needs through the end of the 10-year reporting time frame of this document) that are driving changes in FPL's resource plans, there are additional factors that also influence FPL's resource planning work. Among these other additional factors are two that FPL typically refers to as on-going system concerns that FPL has considered in its resource planning work for a number of years. These two on-going system concerns are: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward Counties.

A third factor that could affect FPL's resource planning is the possibility of the establishment of a Florida standard for renewable energy or clean energy. A Renewable Portfolio Standard (RPS) proposal was prepared by the FPSC, and then sent to the Florida Legislature for consideration, with a possible change to a Clean Portfolio Standard (CPS), during the 2009 legislative session. However, no RPS or CPS legislation has been enacted in subsequent legislative sessions. Furthermore, during the 2012 legislative session the legislature deleted a now obsolete directive to the FPSC that had instructed them to adopt RPS rules. RPS or CPS legislation, or other legislative initiatives regarding renewable or clean energy contributions, may still occur in the future. If such legislation is enacted in later years, FPL would then determine what steps need to be taken to address the legislation. Such steps would then be discussed in FPL's Site Plan in the year following the enactment of such legislation.

A fourth factor that will affect FPL's resource planning is the issue of how best to reliably obtain additional natural gas for FPL's system which is needed due to growing electrical load. This need for additional natural gas is minimized, but only in part, by the addition of highly fuel-efficient natural gas-fired generating units with the modernizations of the Cape Canaveral, Riviera, and Port Everglades plant sites.

A fifth factor or issue that will affect FPL's resource planning is the extent to which FPL's reserves are projected to become increasingly dependent upon DSM resources as opposed to generation resources. This projected imbalance in future reserves is becoming more pronounced, in part, because of the high level of DSM currently required to be implemented while FPL's projected resource needs have decreased (as previously mentioned).

Each of these factors will continue to be examined in FPL's on-going resource planning work during the rest of 2012 and in future years.

Table ES-1 presents a current projection of major changes to specific generating units and firm capacity purchases for 2012 – 2021 in terms of Summer MW. Table ES-2 then expands upon the information presented in Table ES-1 by adding projections of Winter MW impacts, Summer reserve margins, Winter reserve margins, etc. (Although neither table specifically identifies the impacts of projected DSM additions on FPL's resource needs and resource plan, FPL's projected DSM additions have been fully accounted for in the resource plan presented in this Site Plan.)

Table ES-1: Projected Capacity & Firm Purchase Power Changes

*Year **	*Projected Capacity & Firm Purchase Power Changes*	*Summer MW*	*Date*
2012	Inactive Reserve Unit (PE Units 3 & 4) - active service	761	January-12
	DeSoto 1 Short Term Purchase	150	January-12
	DeSoto 2 Short Term Purchase	155	January-12
	Sanford 5 CT Upgrade	19	March-12
	Palm Beach SWA - PPA extension	40	April-12
	TECO System Gen Short Term Purchase	125	April-12
	Oleander PPA - contract ends	(155)	May-12
	St. Lucie Unit 2 outage	(745)	August-12
	St. Lucie Unit 1 Uprates - completed	129	July-12
	Turkey Point Unit 3 Uprates - completed	123	August-12
	Total of MW changes to Summer firm capacity:	**602**	
2013	TECO System Gen Short Term Purchase	(125)	October-12
	St. Lucie Unit 2 Uprates - completed	84	November-12
	Martin 8 CT Upgrade	10	December-12
	DeSoto 1 Short Term Purchase	(150)	December-12
	DeSoto 2 Short Term Purchase	(155)	December-12
	Inactive Reserve Unit (PE Units 3 & 4) - inactive status	(761)	January-13
	Sanford 5 CT Upgrade	9	February-13
	Turkey Point Unit 4 Uprates - completed	123	March-13
	Sanford 4 CT Upgrade	31	April-12
	Cape Canaveral Next Generation Clean Energy Center	1,210	June-13
	Martin 1 ESP - outage	(826)	June-13
	Total of MW changes to Summer firm capacity:	**(550)**	
2014	Sanford 5 CT Upgrade	10	September-13
	Martin 2 ESP - outage	(826)	March-14
	Manatee 3 CT Upgrade	19	May-14
	Turkey Point 5 CT Upgrade	33	June-14
	Riviera Beach Next Generation Clean Energy Center	1,212	June-14
	Total of MW changes to Summer firm capacity:	**448**	
2015	Manatee 3 CT Upgrade	20	September-14
	Fort Myers 2 CT Upgrades	51	May-15
	Total of MW changes to Summer firm capacity:	**71**	
2016	UPS Replacement	(928)	December-15
	Palm Beach SWA - additional	70	April-16
	Port Everglades Modernization	1,277	June-16
	Turkey Point 1 synchronous condenser	(396)	June-16
	Total of MW changes to Summer firm capacity:	**23**	
2017	SJRPP suspension of energy	(375)	April-17
	Total of MW changes to Summer firm capacity:	**(375)**	
2018			
	Total of MW changes to Summer firm capacity:	**0**	
2019			
	Total of MW changes to Summer firm capacity:	**0**	
2020			
	Total of MW changes to Summer firm capacity:	**0**	
2021	Short Term Purchase	250	May-21
	Total of MW changes to Summer firm capacity:	**250**	

* Year shown reflects when the MW change begins to be accounted for in Summer reserve margin calculations. (Note that addition of MW values for each year will not yield a current cumulative value.)

Table ES-2: Projected Capacity Changes and Reserve Margins for FPL

Projected Capacity Changes and Reserve Margins for FPL (1)					
		Net Capacity Changes (MW)		Reserve Margin (%) After Maintenance	
Year	Projected Capacity Changes	Winter (2)	Summer (3)	Winter	Summer
2012	Sanford Unit 5 CT Upgrade	---	19		
	Manatee Unit 2	---	(3)		
	St. Lucie Unit 1 Uprate - Outage (6)	(853)	---		
	St. Lucie Unit 1 Uprates - Completed	---	129		
	Turkey Point Unit 3 Uprates - Completed	---	123		
	St. Lucie Unit 2 Uprate - Outage (6)	---	(745)		
	Changes to Existing Purchases (4)	375	470		
	Scherer Unit 4	---	(30)		
	Inactive Reserve Units (PE Units 3 & 4) -return to active status (8)	765	761		
	Manatee Unit 2 ESP - Outage (7)	(822)	---	31.9%	28.0%
2013	Cape Canaveral Next Generation Clean Energy Center (5)	---	1,210		
	Manatee Unit 2	(3)	---		
	Changes to Existing Purchases (4)	(555)	(430)		
	Sanford Unit 5 CT Upgrade	19	9		
	Martin Unit 8 CT Upgrade	10	10		
	Sanford Unit 4 CT Upgrade	22	31		
	Scherer Unit 4	(28)	---		
	St. Lucie Unit 1 Uprates - Completed	129	---		
	St. Lucie Unit 2 Uprates - Completed	84	84		
	Turkey Point Unit 3 Uprates - Completed	123	---		
	Turkey Point Unit 4 Uprates - Completed	---	123		
	Turkey Point Unit 4 Uprates - Outage (6)	(717)	---		
	Inactive Reserve Unit (PE Units 3 & 4) - return to inactive status (8)	(765)	(761)		
	Manatee Unit 1 ESP - Outage (7)	(822)	---		
	Martin Unit 1 ESP - Outage (7)	--	(826)	26.9%	27.8%
2014	Cape Canaveral Next Generation Clean Energy Center (5)	1,355	---		
	Sanford Unit 4 CT Upgrade	16	---		
	Sanford Unit 5 CT Upgrade	19	10		
	Manatee Unit 3 CT Upgrade	---	19		
	Turkey Point Unit 5 CT Upgrade	---	33		
	Turkey Point Unit 4 Uprates - Completed	123	---		
	Martin Unit 1 ESP - Outage (7)	(832)	---		
	Martin Unit 2 ESP - Outage (7)	---	(826)		
	Riviera Beach Next Generation Clean Energy Center (5)	---	1,212	33.6%	26.8%
2015	Manatee Unit 3 CT Upgrade	39	20		
	Turkey Point Unit 5 CT Upgrade	33	---		
	Ft. Myers Unit 2 CT Upgrade	---	51		
	Riviera Beach Next Generation Clean Energy Center (5)	1,344	---	42.5%	28.6%
2016	Changes to Existing Purchases (4)	(858)	(858)		
	Ft. Myers Unit 2 CT Upgrade	51	---		
	Turkey Point Unit 1 operation changed to synchronous condenser	---	(396)		
	Port Everglades Next Generation Clean Energy Center (5)	---	1,277	37.6%	26.4%
2017	Changes to Existing Purchases (4)	---	(375)		
	Turkey Point Unit 1 operation changed to synchronous condenser	(398)	---		
	Port Everglades Next Generation Clean Energy Center (5)	1,429	---	41.9%	24.2%
2018	Changes to Existing Purchases (4)	(383)	---	39.2%	24.1%
2019	---	---	---	38.3%	22.8%
2020	---	---	---	37.2%	20.9%
2021	Short Term Purchase	---	250	36.0%	20.0%

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are forecasted values for January of the year shown.
(3) Summer values are forecasted values for August of the year shown.
(4) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(5) All new unit additions are scheduled to be in-service in June of the year shown. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.
(6) Outages for uprate work.
(7) Outages for ESP work.
(8) A number of existing FPL power plants have been removed from service and placed on Inactive Reserve status. See Chapter III for a discussion of the units on Inactive Reserves.

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 8.8 million people. FPL served an average of 4,547,051 customer accounts in thirty-five counties during 2011. These customers were served by a variety of resources including: FPL-owned fossil-fueled, renewable, and nuclear generating units, non-utility owned generation, demand side management (DSM), and interchange/purchased power.

I.A. FPL-Owned Resources

The existing FPL generating resources are located at seventeen generating sites distributed geographically around its service territory including one site in Georgia (partial FPL ownership of one unit) and one site in Jacksonville, Florida (partial FPL ownership of two units). The current electrical generating facilities consist of four nuclear units, three coal units, fifteen combined cycle (CC) units, twelve fossil steam units, forty-eight combustion gas turbines, one simple cycle combustion turbine, and two photovoltaic facilities[2]. The locations of these eighty-five generating units are shown on Figure I.A.1 and in Table I.A.1. Table I.A.2 provides a "break down" of the capacity provided by the combustion turbine (CT) and steam turbine (ST) components of FPL's existing CC units.

FPL's bulk transmission system is comprised of 6,721 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 587 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3 shows FPL's interconnection ties with other utilities.

[2] FPL also has one 75 MW solar thermal facility at its Martin plant site. This facility does not generate electricity as the other units mentioned above do. Instead, it produces steam that reduces the use of fossil fuel to produce steam for electricity generation.

FPL Generating Resources by Location

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point [1/]	4	2,930
B	St. Lucie [2/]	2	1,584
C	Manatee	3	2,735
D	Fort Myers	2	1,747
E	Cutler [3/]	2	205
F	Lauderdale	2	884
G	Port Everglades [3/,4/]	4	1,187
H	Riviere [4/]	0	0
I	Martin	5	3,722
J	Cape Canaveral [4/]	0	0
K	Sanford [3/]	3	2,050
L	Putnam	2	498
M	St. John's River Power Park [2/]	2	254
N	West County	3	3,657
O	DeSoto [5/]	1	25
P	Space Coast [5/]	1	10
	Scherer [6/]	1	672
	Gas Turbines	48	1,908
	Total System Generation =	**85**	**24,068**
	Total System Generation without Inactive Reserves =	**78**	**22,538**
	System Firm Generation =	**78**	**22,503**

1/ Turkey Point Unit 2 is now a synchronous condenser
2/ Represents FPL's ownership share: St Lucie nuclear: 100% Unit 1, 85% Unit 2: St. Johns River: 20% of two units
3/ Cutler Units 5 &6, Port Everglades Units 1- 4 and Sanford Unit 3 are on Inactive Reserve status
Their capacity values are presented on the MW-by-unit line only to assist in comparisons back to previous Site Plans. However, the capacity from the Inactive Reserve units has been removed from the "Total System Generation without Inactive Reserves row at the end of the table.
4/ Will be site of new Modernization Plants
5/ The 25 MW of PV at DeSoto and the 10 MW of PV at Space Coast are considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generation" row at the end of the table
6/ The Scherer unit is located in Georgia and is not shown on this map

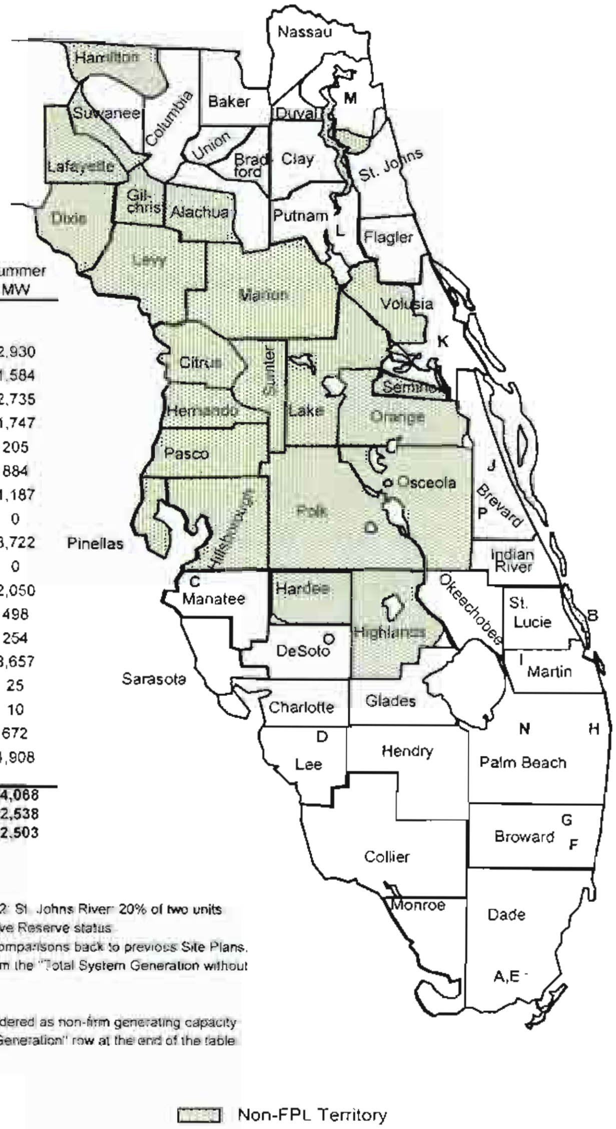


Figure I.A.1: Capacity Resources by Location (as of December 31, 2011)

Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2011)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Nuclear				
Turkey Point	Florida City, FL	2	Nuclear	1,386
St. Lucie 1/	Hutchinson Island, FL	2	Nuclear	1,584
Total Nuclear:		4		2,970
Coal Steam				
SJRPP 2/	Jacksonville, FL	2	Coal	254
Scherer	Monroe County, Ga	1	Coal	672
Total Coal Steam:		3		926
Combined-Cycle 3/				
Sanford	Lake Monroe, FL	2	Gas	1,912
Fort Myers	Fort Myers, FL	1	Gas	1,432
Manatee	Parrish, FL	1	Gas	1,111
Martin	Indiantown, FL	3	Gas	2,070
Turkey Point	Florida City, FL	1	Gas/Oil	1,148
Lauderdale	Dania, FL	2	Gas/Oil	884
Putnam	Palatka, FL	2	Gas/Oil	498
West County	Palm Beach County, FL	3	Gas/Oil	3,657
Total Combined Cycle:		15		12,712
Oil/Gas Steam				
Cutler 4/	Miami, FL	2	Gas	205
Manatee	Parrish, FL	2	Oil/Gas	1,624
Martin	Indiantown,FL	2	Oil/Gas	1,652
Port Everglades 4/	Port Everglades, FL	4	Oil/Gas	1,187
Sanford 4/	Lake Monroe, FL	1	Oil/Gas	138
Turkey Point 5/	Florida City, FL	1	Oil/Gas	396
Total Oil/Gas Steam:		12		5,202
Gas Turbines(GT)/Diesels(IC)				
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Total Gas Turbines/Diesels:		48		1,908
Combustion Turbines 3/				
Fort Myers 6/	Fort Myers, FL	1	Gas/Oil	315
Total Combustion Turbines:		1		315
PV				
DeSoto 7/	DeSoto, FL	1	Solar Energy	25
Space Coast 7/	Brevard County, FL	1	Solar Energy	10
Total PV:		2		35
Total System Generation as of December 31, 2011 =		85		24,068
Total System Generation without Inactive Reserves as of December 31, 2011 =		78		22,538
System Firm Generation as of December 31, 2011 =		76		22,503

1/ Total capability of each unit is 853/839 MW. FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively.
2/ Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit Represents FPL's ownership share: SJRPP coal. 20% of two units).
3/ The Combined Cycles and Combustion Turbines are broken down by components on Table 1.A.2.
4/ Cutler Units 5 & 6, Port Everglades Units 1-4 and Sanford Unit 3 are on Inactive Reserve status. Their capacity values are presented on the MW-by-unit line only to assist in comparisons back to previous Site Plans. However, the capacity from the Inactive Reserve units has been removed from the "Total System Generation without Inactive Reserves as of December 31, 2011" row at the end of the table.
5/ Turkey Point Unit 2 is now a synchronous condenser.
6/ This unit consists of two combustion turbines.
7/ The 25 MW of PV at DeSoto and the 10 MW of PV at Space Coast are considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generation" row at the end of the table.

Table I.A.2: Combined Cycle and Combustion Turbine Components

Combined-Cycle

	Summer MW *									
Plant Name/ Unit No.	CT A	CT B	CT C	CT D	CT E	CT F	Steam 1	Steam 2	BOP Aux	Total Unit MW
Ft Myers 2	159	159	159	159	159	159	59	437	(20)	1,433
Lauderdale 4	158	158	---	---	---	---	131	---	(5)	442
Lauderdale 5	158	158	---	---	---	---	131	---	(5)	442
Manatee 3	167	167	167	167	---	---	457	---	(17)	1,109
Martin 3	166	166	---	---	---	---	144	---	(6)	469
Martin 4	166	166	---	---	---	---	144	---	(6)	469
Martin 8	170	170	170	170	---	---	476	---	(23)	1,135
Putnam 1	71	71	---	---	---	---	112	---	(5)	249
Putnam 2	71	71	---	---	---	---	112	---	(5)	249
Sanford 4	160	160	160	160	---	---	328	---	(12)	958
Sanford 5	159	159	159	159	---	---	330	---	(13)	954
Turkey Point 5	174	174	174	174	---	---	478	---	(26)	1,149
West County 1	248	248	248	---	---	---	499	---	(25)	1,219
West County 2	248	248	248	---	---	---	499	---	(25)	1,219
West County 3	248	248	248	---	---	---	499	---	(25)	1,219

Combustion Turbines

Ft. Myers 3	158	158	---	---	---	---	---	---	(1)	315

This table shows the breakdown of total MW for each unit by CT and steam component.

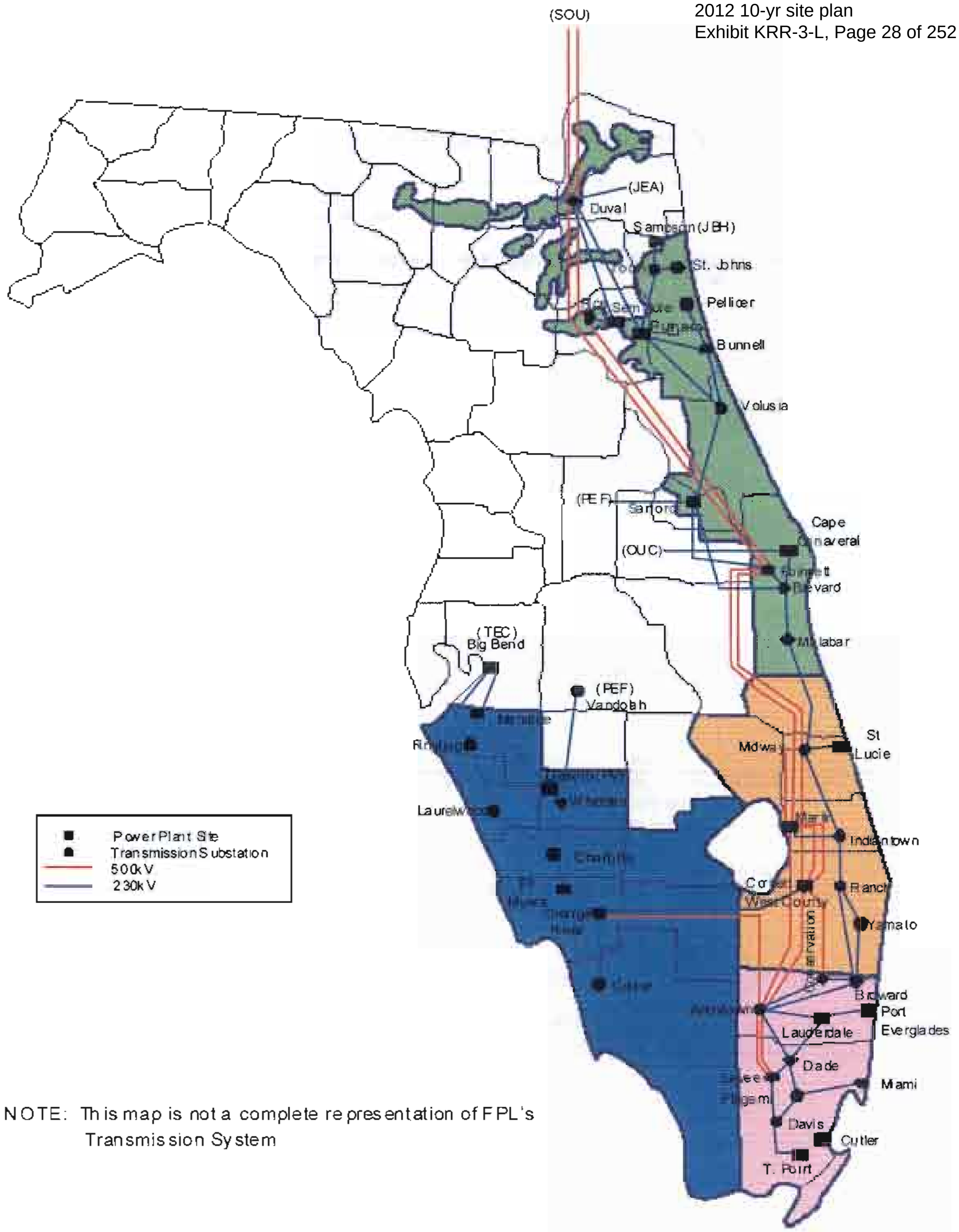
* The total MW values shown in this table may differ slightly from values shown in other tables due to rounding of per-component values.

Table 1.A.3: Purchase Power Resources by Contract (as of December 31, 2011)

	Location (City or County)	Fuel	Summer MW
I. Purchases from QF's: Cogeneration/Small Power Production Facilities			
Cedar Bay Generating Co.	Duval	Coal (Cogen)	250
Indiantown Cogen., LP	Martin	Coal (Cogen)	330
Broward South	Broward	Solid Waste	4
Broward North	Broward	Solid Waste	11
		Total:	**595**
II. Purchases from Utilities:			
UPS from Southern Company	Various in Georgia	Coal	928
SJRPP	Jacksonville, FL	Coal	375
		Total:	**1,303**
III. Other Purchases:			
Oleander (Extension)	Brevard	Gas	155
			155
	Total Net Firm Generating Capability:		**2,053**

Non-Firm Energy Purchases (MWH)

Project	County	Fuel	Energy (MWH) Delivered to FPL in 2011
Okeelanta (known as Florida Crystals and New Hope Power Partners)	Palm Beach	Bagasse/Wood	172,050
Broward South	Broward	Garbage	289,953
Tomoka Farms	Volusia	Landfill Gas	0
Waste Management - Renewable Energy	Broward	Landfill Gas	59,719
Waste Management - Collier County Landfill	Broward	Landfill Gas	18,046
Tropicana	Manatee	Natural Gas	30,532
Calnetix	Palm Beach	Natural Gas	0
Georgia Pacific	Putnam	Paper by-product	2,013
Rothenbach Park (known as MMA Bee Ridge)	Sarasota	PV	321
First Solar	Miami	PV	10
Customer - Owned PV & Wind	Various	PV/Wind	415
Palm Beach SWA	Palm Beach	Solid Waste	346,035



NOTE: This map is not a complete representation of FPL's Transmission System

Figure I.A.2: FPL Substation and Transmission System Configuration

FPL Interconnection Diagram

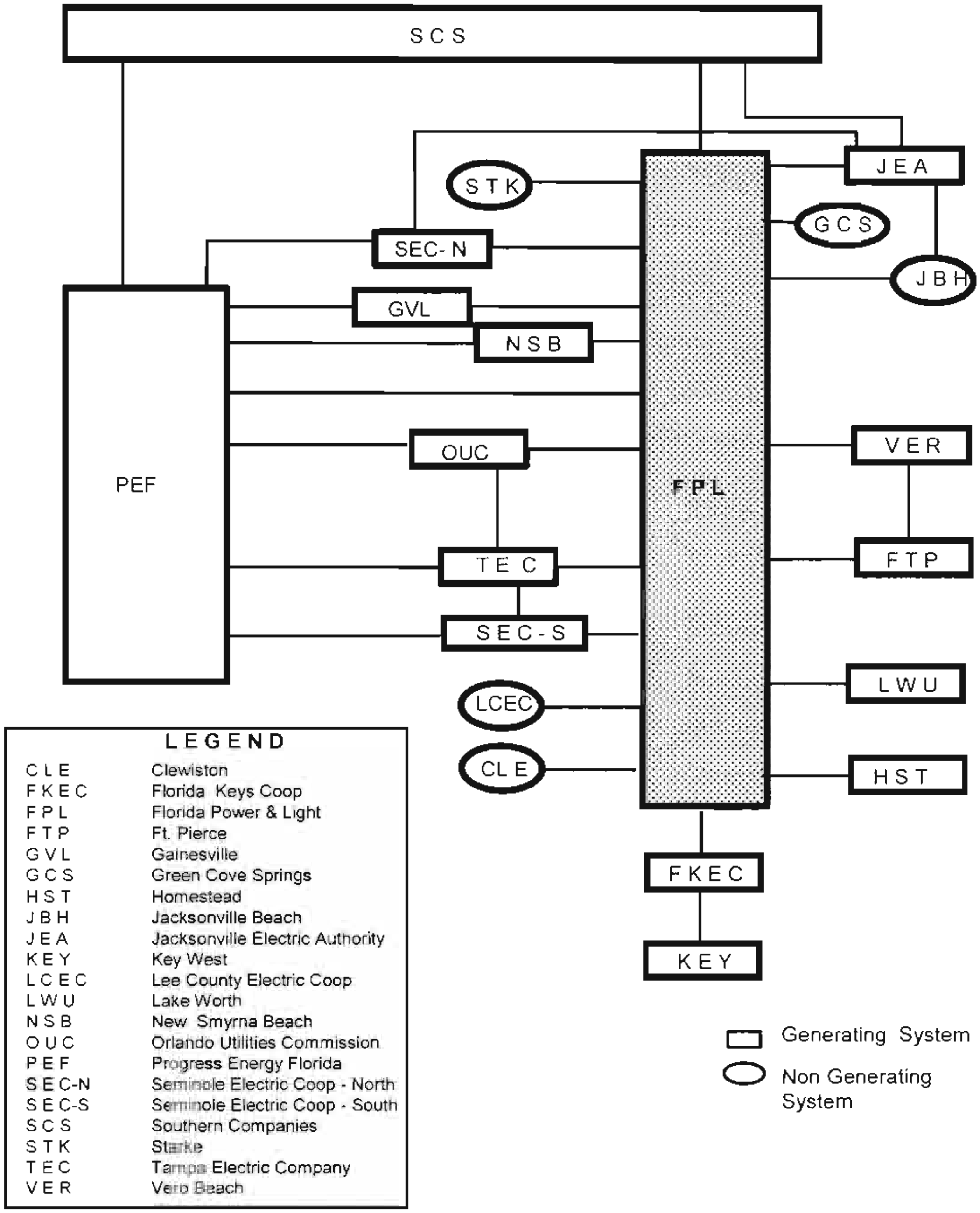


Figure I.A.3: FPL Interconnection Diagram

I.B Firm Capacity Power Purchases

Purchases from Qualifying Facilities (QF):

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has contracts with five qualifying facilities; i.e., cogeneration/small power production facilities, to purchase firm capacity and energy as shown in Table I.A.3, Table I.B.1, and Table I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

Purchases from Utilities:

FPL has a Unit Power Sales (UPS) contract to purchase 928 MW from the Southern Company (Southern) through the end of December 2015. This capacity will be supplied by Southern from a mix of gas-fired and coal-fired units.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 375 MW (Summer) and 383 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. However, due to Internal Revenue Service (IRS) regulations, the total amount of energy that FPL may receive from this purchase is limited. FPL currently assumes, for planning purposes, that this limit will be reached in the Spring of 2017. Once this limit is reached, FPL will be unable to receive firm capacity and energy from these purchases. (However, FPL will continue to receive firm capacity and energy from its ownership portion of the SJRPP units.)

FPL has an additional one-year contract with TECO for 125 MW of firm capacity through December 2012.

These purchases are shown in Table I.A.3, Table I.B.1, and Table I.B.2. FPL also has ownership interest in the SJRPP units. The ownership amount is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.

Other Purchases:

FPL has three other short-term firm capacity purchase contracts with non-QF, non-utility suppliers. One of these purchase contracts runs through May 2012 and the other two run through December 2012. Table I.B.1 and I.B.2 present the Summer and Winter MW, respectively, resulting from these contracts under the category heading of Other Purchases.

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA - extension	01/01/12	04/01/32	40	40	40	40	40	40	40	40	40	40
Palm Beach SWA - additional	04/01/16	04/01/32	0	0	0	0	70	70	70	70	70	70
		QF Purchases Sub Total:	**635**	**635**	**635**	**635**	**705**	**705**	**705**	**705**	**705**	**705**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
UPS Replacement	06/01/10	12/31/15	928	928	928	928	0	0	0	0	0	0
SJRPP	04/02/82	04/01/17 *	375	375	375	375	375	0	0	0	0	0
TECO	01/01/12	12/31/12	125	0	0	0	0	0	0	0	0	0
		Utility Purchases Sub Total:	**1,428**	**1,303**	**1,303**	**1,303**	**375**	**0**	**0**	**0**	**0**	**0**
		Total of QF and Utility Purchases =	**2,063**	**1,938**	**1,938**	**1,938**	**1,080**	**705**	**705**	**705**	**705**	**705**

III. Other Purchases:

	Contract Start Date	Contract End Date	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Oleander (Extension)	06/01/07	05/31/12	0	0	0	0	0	0	0	0	0	0
DeSoto Unit 1	01/01/12	12/31/12	150	0	0	0	0	0	0	0	0	0
DeSoto Unit 2	01/01/12	12/31/12	155	0	0	0	0	0	0	0	0	0
		Other Purchases Sub Total:	**305**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total "Non-QF" Purchase =	**1,733**	**1,303**	**1,303**	**1,303**	**375**	**0**	**0**	**0**	**0**	**0**

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Summer Firm Capacity Purchases Total MW:	2,368	1,938	1,938	1,938	1,080	705	705	705	705	705

* Contract End Date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.

Table I.B.2: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA - extension	01/01/12	04/01/32	40	40	40	40	40	40	40	40	40	40
Palm Beach SWA - additional	04/01/16	04/01/32	0	0	0	0	70	70	70	70	70	70
		QF Purchases Sub Total:	**635**	**635**	**635**	**635**	**705**	**705**	**705**	**705**	**705**	**705**

II. Purchases from Utilities:	Contract Start Date	Contract End Date	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
UPS Replacement	06/01/10	12/31/15	928	928	928	928	0	0	0	0	0	0
SJRPP	04/02/82	04/01/17 *	383	383	383	383	383	383	0	0	0	0
TECO	01/01/12	12/31/12	75	0	0	0	0	0	0	0	0	0
		Utility Purchases Sub Total:	**1,386**	**1,311**	**1,311**	**1,311**	**383**	**383**	**0**	**0**	**0**	**0**

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total of QF and Utility Purchases =	**2,021**	**1,946**	**1,946**	**1,946**	**1,088**	**1,088**	**705**	**705**	**705**	**705**

III. Other Purchases:	Contract Start Date	Contract End Date	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Oleander (Extension)	06/01/07	05/31/12	180	0	0	0	0	0	0	0	0	0
DeSoto Unit 1	01/01/12	12/31/12	150	0	0	0	0	0	0	0	0	0
DeSoto Unit 2	01/01/12	12/31/12	155	0	0	0	0	0	0	0	0	0
		Other Purchases Sub Total:	**485**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
"Non-QF" Purchase =	**1,871**	**1,311**	**1,311**	**1,311**	**383**	**383**	**0**	**0**	**0**	**0**

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Winter Firm Capacity Purchases Total MW:	**2,506**	**1,946**	**1,946**	**1,946**	**1,088**	**1,088**	**705**	**705**	**705**	**705**

* Contract End Date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.

I.C Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. Table I.C.1 shows the amount of energy purchased in 2011 from these facilities.

Table I.C.1: As-Available Energy Purchases From Non-Utility Generators in 2011

Project	County	Fuel	In-Service Date	Energy (MWH) Delivered to FPL in 2011
Okeelanta (known as Florida Crystals and New Hope Power Partners)	Palm Beach	Bagasse/Wood	11/95	172,050
Broward South	Broward	Garbage	9/09	289,953
Tomoka Farms	Volusia	Landfill Gas	7/98	0
Waste Management - Renewable Energy	Broward	Landfill Gas	1/10	59,719
Waste Management - Collier County Landfill	Broward	Landfill Gas	5/1/2011	18,046
Tropicana	Manatee	Natural Gas	2/90	30,532
Calnetix	Palm Beach	Natural Gas	7/05	0
Georgia Pacific	Putnam	Paper by-product	2/94	2,013
Rothenbach Park (known as MMA Bee Ridge)	Sarasota	PV	10/07	321
First Solar	Miami	PV	4/1/2011	10
Customer - Owned PV & Wind	Various	PV/Wind	Various	415
Palm Beach SWA	Palm Beach	Solid Waste	4/10	346,035

I.D. Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include a number of conservation/energy efficiency and load management initiatives. FPL's DSM efforts through 2011 have resulted in a cumulative Summer peak reduction of approximately 4,513 MW at the generator and an estimated cumulative energy saving of approximately 59,890 Gigawatt-hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2011 have eliminated the need to construct the equivalent of more than 13 new 400 MW generating units. DSM is discussed further in Chapter III.

Schedule 1

Existing Generating Facilities
As of December 31, 2011

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability [1] Winter MW	(14) Net Capability [1] Summer MW
Cape Canaveral [2]		Brevard County											
		19/24S/36E									0	0	0
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Jun-10	0	0	0
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Jun-10	0	0	0
Cutler [3]		Miami Dade County											
		27/55S/40E									236,500	207	205
	5		ST	NG	No	PL	No	Unknown	Nov-54	Nov-12	75,000	69	68
	6		ST	NG	No	PL	No	Unknown	Jul-55	Nov-12	181,500	138	137
DeSoto [4]		DeSoto County											
		27/36S/25E									27,000	25	25
	1		PV	N/A	N/A	N/A	N/A	Unknown	Oct-09	Unknown	27,000	25	25
Fort Myers		Lee County											
		35/43S/25E									2,895,890	2,552	2,395
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,775,390	1,490	1,432
	3A & B		CT	NG	FO2	PL	PL	Unknown	Jun-03	Unknown	376,380	352	315
	1-12		GT	FO2	No	PL	No	Unknown	May-74	Unknown	744,120	710	646
Lauderdale		Broward County											
		30/50S/42E									1,873,968	1,884	1,724
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	483	442
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	483	442
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
Manatee		Manatee County											
		18/33S/20E									2,951,110	2,812	2,735
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	822	812
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	822	812
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,168	1,111

1/ These ratings are peak capability.

2/ The Cape Canaveral modernization project has resulted in the removal of the two steam units previously at the Canaveral site to clear the site for the introduction of a new combined cycle generating unit. This new unit is projected to go into service in June 2013.

3/ Cutler Units 5 & 6 are on Inactive Reserve status. Their capacity values are presented on the MW-by-unit line only to assist in comparisons back to previous Site Plans. However, the capacity from the Inactive Reserve units has been removed from the "Total System Generation without Inactive Reserves as of December 31, 2011" row at the end of the table. Cutler Units 5 & 6 will be retired by the end of 2012.

4/ The capacity shown for the PV facility at DeSoto is considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generating Capacity as of December 31, 2011" row at the end of the table.

Schedule 1

Existing Generating Facilities
As of December 31, 2011

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel	Commercial	Actual/ Expected	Gen Max	Net Capability 1/	
Plant Name	Unit No.	Location	Unit Type	Fuel Pri.	Fuel Alt.	Transport Pri.	Transport Alt.	Days Use	In-Service Month/Year	Retirement Month/Year	Nameplate KW	Winter MW	Summer MW
Martin		Martin County											
		29/29S/38E									4,317,510	3,861	3,722
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	832	826
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	832	826
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	469	469
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	469	469
	8 2/		CC	NG	FO2	PL	PL	Unknown	Jun-05	Unknown	1,224,510	1,219	1,132
Port Everglades		City of Hollywood											
		23/50S/42E									1,655,354	1,652	1,607
	1 3/		ST	FO6	NG	WA	PL	Unknown	Jun-60	Jan-13	225,250	214	213
	2 3/		ST	FO6	NG	WA	PL	Unknown	Apr-61	Jan-13	225,250	214	213
	3 3/		ST	FO6	NG	WA	PL	Unknown	Jul-64	Jan-13	402,050	389	387
	4 3/		ST	FO6	NG	WA	PL	Unknown	Apr-65	Jan-13	402,050	376	374
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	459	420
Putnam		Putnam County											
		16/10S/27E									580,008	530	498
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,004	265	249
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,004	265	249
Riviera		City of Riviera Beach											
		33/42S/43E									0	0	0
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Feb-11	0	0	0
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Feb-11	0	0	0
Sanford		Volusia County											
		16/19S/30E									2,533,970	2,227	2,050
	3 3/		ST	FO6	NG	WA	PL	Unknown	May-59	Nov-12	156,250	140	138
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,186,860	1,040	958
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	1,047	954
Scherer 4/		Monroe, GA											
											680,368	678	672
	4		BIT	SUB	No	RR	No	Unknown	Jul-89	Unknown	680,368	678	672

1/ These ratings are peak capability.

2/ Martin Unit 8 is also partially fueled by a 75 MW solar thermal facility that supplies steam when adequate sunlight is available, thus reducing fossil fuel use.

3/ Port Everglades Units 1- 4 and Sanford Unit 3 are on Inactive Reserves status. Their capacity values are presented on the MW-by-unit line only to assist in comparisons back to previous Site Plans. However, the capacity from the Inactive Reserve units have been removed from the "Total System Generation without Inactive Reserves as of December 31, 2011" row at the end of the table. Sanford Unit 3 will be retired by the end of 2012

4/ These ratings represent Florida Power & Light Company's share of Scherer Unit 4, adjusted for transmission losses

Schedule 1

Existing Generating Facilities
As of December 31, 2011

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen Max. Nameplate KW	(13) Net Capability [1/] Winter MW	(14) Net Capability [1/] Summer MW
Space Coast [2/]		Brevard County											
		13/23S/36E									10,000	10	10
	1		PV	N/A	N/A	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10
St. Johns River Power Park [3/]		Duval County 12/15/28E											
		(RPC4)									271,836	260	254
	1		BIT	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	130	127
	2		BIT	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	130	127
St. Lucie [4/]		St. Lucie County											
		16/36S/41E									1,573,775	1,610	1,584
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	850,000	853	839
	2		NP	UR	No	TK	No	Unknown	Jun-83	Unknown	723,775	757	745
Turkey Point		Miami Dade County											
		27/57S/40E									3,548,550	3,010	2,930
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	398	396
	2 [5/]		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	0	0
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	759,970	717	693
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	759,970	717	693
	5		CC	NG	FO2	PL	PL	Unknown	May-07	Unknown	1,224,510	1,178	1,148
West County		Palm Beach County											
		29&32/43S/40E									2,733,600	4,005	3,657
	1		CC	NG	FO2	PL	PL	Unknown	Aug-09	Unknown	1,366,800	1,335	1,219
	2		CC	NG	FO2	PL	PL	Unknown	Nov-09	Unknown	1,366,800	1,335	1,219
	3		CC	NG	FO2	PL	PL	Unknown	May-11	Unknown	1,366,800	1,335	1,219
Total System Generating Capacity as of December 31, 2011 [6/] =												25,323	24,068
Total System Generation without Inactive Reserves as of December 31, 2011 [7/] =												23,783	22,538
System Firm Generating Capacity as of December 31, 2011 [8/] =												23,748	22,503

1/ These ratings are peak capability.

2 The capacity shown for the PV facility at Space Coast is considered as non-firm generating capacity due to the intermittent nature of the solar resource.

3/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Units 1 and 2, excluding the Jacksonville Electric Authority (JEA) share of 80%.

4/ Total capability of each unit is 853/839 MW. FPL's ownership share of St. Lucie Units 1 and 2 is 100%(853/839) and 85% (714/726), respectively, as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.

5/ This generating unit is currently serving as a synchronous condenser.

6/ The Total System Generating Cpacity value shown includes FPL-owned firm and non-firm generating capacity

7/ The Total System Generation without the Inactive Reserves Units (Cutler Units 5 & 6, Port Everglades Units 1- 4, Sanford Unit 3).

8/ The System Firm Generating Capacity value shown includes only firm generating capacity

CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

II. A. Overview of the Load Forecasting Process

Long-term forecasts of sales, net energy for load (NEL), and peak loads are typically developed on an annual basis for resource planning work at FPL. New long-term forecasts were developed by FPL in late 2011 that replaced the previous long-term load forecasts that were used by FPL during 2011 in much of its resource planning work and which were presented in FPL's 2011 Site Plan. These new load forecasts are utilized throughout FPL's 2012 Site Plan. These forecasts are a key input to the models used to develop FPL's integrated resource plan.

The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads. Consistent with past forecasts, the primary drivers to develop these forecasts include economic conditions and weather.

The projections for the national and Florida economies are obtained from the consulting firm IHS Global Insight. Population projections are obtained from the Florida Legislature's Office of Economic and Demographic Research (EDR). These projections are developed, in conjunction with the Bureau of Economic and Business Research (BEBR) of the University of Florida. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects FPL's energy sales and peak demand. Three sets of weather variables are developed and used in FPL's forecasting models:

1. Cooling and heating degree-hours based on 72° F, winter heating degree-days based on 66° F, and heating degree-days based on 45° F are used to forecast energy sales.
2. The maximum temperature on the peak day, along with the build-up of cooling degree-hours prior to the peak, are used to forecast Summer peaks.
3. The minimum temperature on the peak day, along with the build-up of heating degree-hours based on 66° F on the day prior to the peak, are used to forecast Winter peaks.

The cooling degree-hours and winter heating degree-days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. Heating degree-days based on 45° F are used to capture heating load resulting from sustained periods of unusually cold weather not fully captured by heating degree-days based on 66° F. A composite hourly temperature profile is derived using hourly temperatures across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained. In developing the composite hourly profile, these regional temperatures are weighted by regional energy sales. The resulting composite temperature is used to derive projected cooling degree-hours and heating degree-days. Similarly, composite temperature and hourly profiles of temperatures are used for the Summer and Winter peak models.

II. B. Comparison of FPL's Current and Previous Load Forecasts

FPL's current load forecast is somewhat lower than the load forecast presented in its 2011 Site Plan. There are three primary factors that are driving the current load forecast: projected population growth, a projection of gradual recovery following the economic recession in Florida, and energy efficiency standards. The net impact of these three factors is that the current load forecast is lower than the 2011 Site Plan forecast.

The customer forecast is based on recent population projections. Population projections are derived from the EDR's August 2011 Demographic Estimating Conference. This forecast indicates generally lower population levels than previously forecasted although long-term rates of population growth are comparable. Net migration into Florida fell to a record low in 2009 during the height of the recession. Florida has since experienced a small rebound in net migration, but population growth rates have remained well below their historical averages. The population growth rate projected for 2012 reflects a continuation of the low rates of population growth Florida has experienced since the start of the recession. Progressively higher rates of population growth are projected until 2016 when population growth approaches the level historically experienced in Florida. Consistent with prior population projection from EDR, the rate of population growth is expected to gradually stabilize after 2016.

FPL's customer base is expected to mirror the state's projected rates of population growth. As population growth recovers, modestly higher customer growth is projected thru 2016, followed by relatively stable growth thereafter. By 2019, the total number of customer accounts (customers) is expected to exceed five million. Between 2012 and 2021, the total number of customers projected in the current load forecast is about 1%

below the levels projected in FPL's 2011 Site Plan, however the longer-term percentage growth rates are comparable.

After suffering for years under the lingering effects of the recent recession, the outlook on the Florida economy is now one of cautious optimism. By year-end 2011, Florida was adding jobs at an annual rate of more than 100,000; more than in any year since 2006. Although significant problems persist in the housing market, the outlook for Florida is for positive, if somewhat modest economic growth. Accordingly, IHS Global Insight is projecting a steady increase in employment and income growth through 2015 after which growth moderates.

Estimates of savings from energy efficiency standards are developed by ITRON, a leading expert in this area. Included in these estimates are savings from federal and state energy efficiency standards, including the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the savings occurring from the use of compact fluorescent bulbs.[3]

Consistent with the forecast presented in FPL's 2011 Site Plan, the total growth projected for the ten-year reporting period of this document is significant. The Summer peak is projected to increase to 25,960 MW by 2021, an increase of 4,341 MW over the 2011 actual Summer peak. Likewise, NEL is projected to reach 133,646 GWH in 2021, an increase of 21,192 GWH from the actual 2011 value.

II.C. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for each revenue class and are adjusted to match the NEL forecast. The results of these sales forecasts for the years 2012 - 2021 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and NEL forecast are outlined below.

1. Residential Sales

Residential electric usage per customer is estimated by using an econometric model. Residential sales are a function of: cooling degree-hours, heating degree-hours,

[3] Note that in addition to the fact that these energy efficiency standards lower the forecasted load (as described in more detail later in this chapter), these standards also lower the efficiency potential that would otherwise be available through utility DSM programs.

lagged cooling degree-hours, lagged heating degree-hours, a proxy for energy prices, and Florida real per capita income weighted by the percent of the population employed. The impact of weather is captured by the cooling degree-hours, heating degree-hours, and the one month lag of these variables. The proxy for energy prices incorporates the impact of energy prices on electric consumption. As energy prices rise, less disposable income is available for all goods and services, electricity included. To capture economic conditions, the model includes a composite variable based on Florida real per capita income and the percent of the state's population that is employed. Because of the relatively large percentage of Florida's population that has been unemployed during the recession, real per capita income alone does not capture the full magnitude of the downturn. The composite variable more accurately reflects economic conditions. Residential energy sales are forecasted by multiplying the residential use per customer forecast by the number of residential customers forecasted.

2. Commercial Sales

The commercial sales forecast is also developed using an econometric model. Commercial sales are a function of the following variables: Florida real per capita income weighted by the percent of the population employed, cooling degree-hours, heating degree-hours, lagged cooling degree-hours, a variable designed to reflect the impact of empty homes, a dummy variable for the month of December and for the specific month of January 2007, and an autoregressive term. Cooling degree-hours, heating degree-hours, and the one month lag of cooling degree-hours are used to capture weather-sensitive load in the commercial sector.

3. Industrial Sales

The industrial class is comprised of three distinct groups: very small accounts (those with less than 20 kW of demand), medium accounts (those with 21 kW to 499 kW of demand), and large accounts (those with demands of 500 kW or higher). As such, the forecast is developed using a separate econometric model for each group of industrial customers. The small industrial sales model utilizes the following variables: Florida real disposable income, cooling degree-hours, heating degree-hours, a dummy variable for the specific month of February 2009, and an autoregressive term. The medium industrial sales model utilizes the following variables: cooling degree-hours, Florida real disposable income, a dummy variable for the specific month of February 2006, and two autoregressive terms. The large industrial sales model utilizes the following variables: Florida real per capita income, the Consumer Price

Index, the industrial real price of electricity (a 24-month moving average), and a dummy variable for the specific month of October 2004.

4. Railroad and Railways Sales and Street and Highway Sales

This class consists solely of Miami-Dade County's Metrorail system. The projections for railroad and railways sales are based on historical average use per customer which is multiplied by the forecasted number of customers. The number of customers is based on the planned addition of new Metrorail stations.

The forecast for street and highway sales is developed by using a trended use per customer, which is multiplied by the number of forecasted customers.

5. Other Public Authority Sales

This revenue class is closed to new customers. This class consists of sports fields and one government account. The forecast for this class is based on historical knowledge of its usage characteristics.

6. Total Sales to Ultimate Customer

Sales forecasts by revenue class are summed to produce a total sales forecast.

7. Sales for Resale

Sales for resale (wholesale) customers are composed of municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers. Currently there are five customers in this class: the Florida Keys Electric Cooperative; City of Key West; Metro-Dade County; Lee County Electric Cooperative; and Wauchula. In addition, FPL will begin making sales to Seminole Electric Cooperative in June 2014 under a long term agreement[4].

Beginning in May 2011, FPL began providing service to the Florida Keys Electric Cooperative under a long-term full requirements contract. Previously FPL was serving the Florida Keys under a partial requirements contract. The sales to Florida Keys Electric Cooperative are based on customer-supplied information and historical load factors.

[4] FPL is currently evaluating the possibility of serving the electrical loads of several entities (including Vero Beach and Lake Worth) at the time the 2012 Site Plan is being prepared. Because these possibilities are still being evaluated, the load forecast presented in this Site Plan does not include these potential loads.

FPL's sales to the City of Key West are expected to terminate in 2013. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor.

Metro-Dade County sells 60 MW to Progress Energy Florida. Line losses are billed to Metro-Dade under a wholesale contract. This contract expires in 2013.

Lee County has contracted with FPL for FPL to supply a portion of their load through 2013, then to begin serving their entire load beginning in 2014. This contract began in January 2010. Lee County provides a forecast of their sales by delivery point which is used to derive their sales forecast.

A new contract with Seminole Electric Cooperative is included in the forecast which includes delivery of 200 MW beginning in June 2014.

II.D. Net Energy for Load (NEL)

An econometric model is developed to produce a NEL per customer forecast. The inputs to the model include Florida real per capita income weighted by the percent of the population employed, and a proxy for energy prices. The model also includes three weather variables: Cooling degree-hours, winter heating degree-days, and heating degree-days based on 45° F. In addition, the model also includes variables for weather-sensitive energy efficiency standards and a variable designed to capture the impact of empty homes. Seasonal dummy variables are included for the months of February, April, June, September, and November and the specific months of March 2003, May 2004, and November 2005. There is also an autoregressive term in the model.

The weather-sensitive energy efficiency variable is included to capture the weather sensitive impacts of the 2005 National Energy Policy Act and the 2007 Energy Independence and Security Act. The estimated impact of this factor for the 2012 - 2021 time period is a reduction, on average, of 7,837 GWh per year. This reduction is inclusive of engineering estimates and any resulting behavioral changes. The increase in the number of empty homes resulting from the current housing slump has affected use per customer and is captured in a separate variable. The forecast was also adjusted for additional load estimated from hybrid vehicles, beginning in 2011, which resulted in an increase of approximately 1,010 GWh by the end of the ten-year reporting period. The forecast is also adjusted for projected incremental load resulting from FPL's economic development riders which will impact the forecast beginning in 2013, and result in an increase, on average, of 311 GWh per year between 2013 and 2021.

The NEL forecast is developed by multiplying the NEL per customer forecast by the total number of customers forecasted. Once the NEL forecast is obtained, total billed sales are computed using a historical ratio of sales to NEL. The sales by class forecasts previously discussed are then adjusted to match the total billed sales. The forecasted NEL values for 2012 - 2021 are presented in Schedule 3.3 that appears at the end of this chapter.

II.E. System Peak Forecasts

The rate of absolute growth in FPL system peak load has been a function of the size of the customer base, varying weather conditions, projected economic conditions, changing patterns of customer behavior (including an increased stock of electricity-consuming appliances), and more efficient appliances and lighting. FPL developed the peak forecast models to capture these behavioral relationships. Impacts of the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the impact of compact fluorescent light bulbs are taken into account in developing the peak forecast. The estimated impact of these energy efficiency standards for the 2012 - 2021 time frame is a reduction of approximately 692 MW (Summer) and 521 MW (Winter) in 2012, and approximately 1,484 MW (Summer) and 1,360 MW (Winter) by 2021. The forecast was also adjusted for additional load estimated from hybrid vehicles which resulted in an increase of approximately 163 MW in the Summer and 58 MW in the Winter by the end of the ten-year reporting period.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2012 – 2021 are presented at the end of this chapter in Schedules 3.1 and 3.2, and in Chapter III in Schedules 7.1 through 7.4.

1. System Summer Peak

The Summer peak forecast is developed using an econometric model. The variables included in the model are the real price of electricity lagged one month, Florida real per capita income weighted by the percent of the population employed, cooling degree-hours in the day prior to the peak, the maximum temperature on the day of the peak, dummy variables for the years 1982, 1989, and 1990, and a variable for energy efficiency standards. The model is based on the Summer peak contribution per customer and is, therefore, multiplied by total customers, and adjusted to account for incremental loads resulting from hybrid vehicles, new wholesale contracts, and incremental load from FPL's economic development riders to derive FPL's system Summer peak.

2. System Winter Peak

Like the system Summer peak model, this model is also an econometric model. The model consists of two weather-related variables: the minimum temperature on the peak day and heating degree-hours for the prior day squared. The model also includes a dummy variable for winter peaks occurring on weekends and an autoregressive term. The forecasted results are adjusted for the impact of energy efficiency standards. The model is based on the Winter peak contribution per customer and is, therefore, multiplied by total customers, and adjusted to account for incremental loads resulting from hybrid vehicles, new wholesale contracts, and FPL's economic development riders, to derive FPL's system Winter peak.

3. Monthly Peak Forecasts

The forecasting process for monthly peaks consists of the following actions:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to the appropriate seasonal peak.

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.F. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2012 - 2021 are produced using a System Load Forecasting "shaper" program. This model uses years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

II.G. Uncertainty

In order to address uncertainty in the forecasts of aggregate peak demand and NEL, FPL first evaluates the assumptions underlying the forecasts. FPL takes a series of steps in evaluating the input variables, including comparing projections from different sources, identifying outliers in the series, and assessing the series' consistency with past forecasts. As needed, FPL reviews additional factors which may affect the input variables.

Uncertainty is also addressed in the modeling process. Generally, econometric models are used to forecast the aggregate peak demand and NEL. During the modeling process, the relevant statistics (goodness of fit, F-statistic, P-values, mean absolute deviation (MAD), mean absolute percentage error (MAPE), etc.) are scrutinized to ensure that the models adequately explain historical variation. Once a forecast is developed, it is compared with past forecasts. Deviations from past forecasts are examined in light of changes in input assumptions to ensure that the drivers underlying the forecast are well understood. Finally, forecasts of aggregate peak demand and NEL are compared with their actual values as they become available. An ongoing process of variance analyses is performed. To the extent that the variance analysis identifies large unexplained deviations between the forecast and actual values, revisions to the econometric model may be considered.

The inherent uncertainty in load forecasting is addressed in different ways in regard to FPL's overall resource planning and operational planning work. In regard to FPL's resource planning work, FPL's utilization of a 20% reserve margin criterion (approved by the FPSC) is designed, in part, to maintain reliable electric service to FPL's customers in light of forecasting uncertainty. In regard to operational planning, an extreme weather load forecast for the projected Summer peak day is developed based on the historical distribution of temperatures on the day of the Summer peak. This produces a probability distribution of Summer peak outcomes with associated probabilities. Likewise, an extreme weather Winter peak forecast is developed based on the historical distribution of temperatures on the day of the Winter peak. Statistical analysis on the distribution of historical weather data is performed to evaluate and understand the impact of extreme weather on the peaks and on NEL, and the likelihood of experiencing extreme weather.

II.H. DSM

The effects of FPL's DSM energy efficiency programs implementation through August 2011 are assumed to be imbedded in the actual usage data for forecasting purposes. Any change in usage pattern, be it the impact of FPL's DSM energy efficiency efforts, price impact, or weather impact, is reflected in the actual observed load data. Therefore, energy efficiency impacts, whether market-driven or as a result of FPL's DSM programs, are assumed to be included in the historical usage data for peaks and NEL.

The impacts of incremental energy efficiency that FPL plans to implement in the future, plus the cumulative and projected incremental impacts of FPL's load management programs, are accounted for as "line item reductions" to the forecasts as part of the IRP process as shown in Schedules 7.1 through 7.4. After making these adjustments to the load forecasts, the resulting "firm" load forecast is then used in FPL's IRP work.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class
(Historical)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
		Members per		Average No. of	Average kWh Consumption		Average No. of	Average kWh Consumption
Year	Population	Household	GWh	Customers	Per Customer	GWh	Customers	Per Customer
2002	7,898,628	2.21	50,865	3,566,167	14,263	40,029	435,313	91,955
2003	8,079,316	2.21	53,485	3,652,663	14,643	41,425	444,650	93,163
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,620,855	2.21	54,570	3,906,267	13,970	44,487	478,867	92,901
2007	8,729,806	2.19	55,138	3,981,451	13,849	45,921	493,130	93,121
2008	8,771,694	2.20	53,229	3,992,257	13,333	45,561	500,748	90,987
2009	8,732,591	2.19	53,950	3,984,490	13,540	45,025	501,055	89,860
2010	8,762,399	2.19	56,343	4,004,366	14,070	44,544	503,529	88,464
2011	8,810,688	2.19	54,642	4,026,760	13,570	45,052	508,005	88,685

Historical Values (2002 - 2011):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve month values.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class
(Projected)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
		Members per		Average No. of	Average kWh Consumption		Average No. of	Average kWh Consumption
Year	Population	Household	GWh	Customers	Per Customer	GWh	Customers	Per Customer
2012	8,907,339	2.20	52,523	4,048,790	12,972	45,624	517,894	88,095
2013	8,986,956	2.20	53,197	4,084,980	13,023	46,666	527,238	88,511
2014	9,101,294	2.20	54,385	4,136,952	13,146	47,882	536,943	89,176
2015	9,239,272	2.20	55,785	4,199,669	13,283	49,215	547,026	89,968
2016	9,384,988	2.20	56,832	4,265,904	13,322	49,965	556,937	89,714
2017	9,522,465	2.20	57,741	4,328,393	13,340	50,568	566,462	89,269
2018	9,654,385	2.20	58,595	4,388,357	13,352	51,166	575,771	88,864
2019	9,785,765	2.20	59,565	4,448,075	13,391	51,761	585,184	88,452
2020	9,916,132	2.20	61,093	4,507,333	13,554	52,760	594,671	88,721
2021	10,044,320	2.20	62,713	4,565,600	13,736	53,970	604,150	89,333

Projected Values (2012 - 2021):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption
And Number of Customers by Customer Class
(Historical)

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads	Street &	Sales to	Sales to
		Average	Average kWh	&	Highway	Public	Ultimate
		No. of	Consumption	Railways	Lighting	Authorities	Consumers
Year	GWh	Customers	Per Customer	GWh	GWh	GWh	GWh
2002	4,057	15,533	261,199	89	420	63	95,523
2003	4,004	17,029	235,135	93	425	64	99,496
2004	3,964	18,512	214,139	93	413	58	99,095
2005	3,913	20,392	191,873	95	424	49	102,296
2006	4,036	21,211	190,277	94	422	49	103,659
2007	3,774	18,732	201,499	91	437	53	105,415
2008	3,587	13,377	268,168	81	423	37	102,919
2009	3,245	10,084	321,796	80	422	34	102,755
2010	3,130	8,910	351,318	81	431	28	104,557
2011	3,086	8,691	355,104	82	437	27	103,327

Historical Values (2002 - 2011):

Col. (10) and Col.(15) represent actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve month values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.2
History and Forecast of Energy Consumption
And Number of Customers by Customer Class
(Projected)

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads	Street &	Sales to	Sales to
		Average	Average kWh	&	Highway	Public	Ultimate
		No. of	Consumption	Railways	Lighting	Authorities	Consumers
Year	GWh	Customers	Per Customer	GWh	GWh	GWh	GWh
2012	3,092	8,813	350,834	92	450	28	101,808
2013	3,021	9,174	329,265	93	461	28	103,465
2014	3,045	9,634	316,036	93	471	28	105,903
2015	3,090	10,257	301,272	93	482	27	108,691
2016	3,095	10,787	286,896	93	492	27	110,504
2017	3,042	11,064	274,927	93	503	27	111,972
2018	2,940	11,167	263,278	93	513	27	113,333
2019	2,873	11,316	253,860	93	523	27	114,841
2020	2,831	11,496	246,272	93	533	27	117,336
2021	2,782	11,637	239,091	93	543	27	120,127

Projected Values (2012 - 2021):

Col. (10) and Col.(15) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve month values.

Col. (16) = Col (4) + Col. (7) + Col (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class
(Historical)

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2002	1,233	7,443	104,199	2,792	4,019,805
2003	1,511	7,386	108,393	2,879	4,117,221
2004	1,531	7,467	108,093	3,029	4,224,509
2005	1,506	7,498	111,301	3,156	4,321,895
2006	1,569	7,909	113,137	3,218	4,409,563
2007	1,499	7,401	114,315	3,276	4,496,589
2008	993	7,092	111,004	3,348	4,509,730
2009	1,155	7,394	111,303	3,439	4,499,067
2010	2,049	7,870	114,475	3,523	4,520,328
2011	2,176	6,950	112,454	3,596	4,547,051

Historical Values (2002 - 2011):

Col. (19) represents actual energy sales including the impacts of existing conservation.

Col. (19) = Col. (16) + Col. (17) + Col. (18). Historical NEL includes the impacts of existing conservation and agrees to Col. (5) on schedule 3.3. Historical GWH are based on fiscal calendar. The 2011 value is based on 12/29/10 to 12/31/11.

Col. (20) represents the annual average of the twelve month values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class
(Projected)

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2012	2,314	7,034	111,156	3,678	4,579,174
2013	2,210	6,812	112,487	3,757	4,625,149
2014	5,013	7,065	117,982	3,836	4,687,365
2015	5,667	7,049	121,407	3,915	4,760,867
2016	5,699	7,107	123,310	3,993	4,837,621
2017	5,657	7,177	124,806	4,069	4,909,988
2018	5,677	7,260	126,270	4,145	4,979,439
2019	5,717	7,360	127,918	4,220	5,048,794
2020	5,768	7,527	130,631	4,294	5,117,793
2021	5,812	7,706	133,646	4,369	5,185,756

Projected Values (2012 - 2021):

Col. (19) represents forecasted energy sales that do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

Col. (19) = Col. (16) + Col. (17) + Col. (18). These values are based on calendar year.

Col. (20) represents the annual average of the twelve month values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 3.1
History and Forecast of Summer Peak Demand (MW)
(Historical)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2002	19,219	261	18,958	0	879	754	489	517	17,851
2003	19,668	253	19,415	0	892	798	577	554	18,200
2004	20,545	258	20,287	0	894	846	588	577	19,063
2005	22,361	264	22,097	0	902	895	600	611	20,858
2006	21,819	256	21,563	0	928	946	635	640	20,256
2007	21,962	261	21,701	0	952	982	716	683	20,295
2008	21,060	181	20,879	0	966	1,042	760	706	19,334
2009	22,351	249	22,102	0	981	1,097	811	732	20,558
2010	22,256	419	21,837	0	990	1,181	815	756	18,512
2011	21,618	427	21,191	0	1,002	1,252	821	776	17,767

Historical Values (2002 - 2011):

Col. (2) - Col. (4) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) represent actual DSM capabilities starting from January 1988 and are annual (12-month) values except for 2011 values which are through August. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC), CILC, and Commercial /Industrial Demand Reduction (CDR).

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.1
History and Forecast of Summer Peak Demand (MW)
(Projected)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
August of Year	Total	Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2012	21,623	432	21,191	0	1,036	64	865	26	19,632
2013	21,931	389	21,542	0	1,048	125	884	56	19,817
2014	23,243	1,187	22,056	0	1,075	190	922	90	20,966
2015	23,786	1,194	22,592	0	1,088	257	940	123	21,378
2016	24,315	1,201	23,114	0	1,101	324	959	155	21,775
2017	24,529	1,195	23,334	0	1,114	391	978	188	21,858
2018	24,674	1,202	23,472	0	1,127	458	996	221	21,871
2019	25,041	1,210	23,832	0	1,140	526	1,015	253	22,107
2020	25,499	1,217	24,282	0	1,156	579	1,028	280	22,456
2021	25,960	1,225	24,735	0	1,172	626	1,042	303	22,816

Projected Values (2012 - 2021):

Col. (2) - Col. (4) represent FPL's forecasted peak w/o incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected August values. The projections for 2012 through 2019 are based on the FPSC's 2011 order in the DSM Plan docket. Projected DSM values for 2020 and 2021 assume 100 MW/year of incremental DSM.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County.

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case
(Historical)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2002	17,597	145	17,452	0	768	500	457	196	16,373
2003	20,190	246	19,944	0	802	546	453	206	18,935
2004	14,752	211	14,541	0	813	567	534	227	13,405
2005	18,108	225	17,883	0	816	583	542	233	16,751
2006	19,683	225	19,458	0	823	600	550	240	18,311
2007	16,815	223	16,592	0	846	620	577	249	15,392
2008	18,055	163	17,892	0	868	644	636	279	16,551
2009	20,081	207	19,874	0	881	666	676	285	18,524
2010	24,346	500	23,846	0	895	687	721	291	22,730
2011	21,126	383	20,743	0	903	717	722	303	19,501

Historical Values (2002 - 2011):

Col. (2) - Col. (4) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand. For year 2011, the actual peaked occurred in December of 2010.

Col. (5) - Col. (9) for 2002 through 2011 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC), CILC, and Commercial /Industrial Demand Reduction (CDR).

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case
(Projected)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
January of Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2012	20,889	411	20,478	0	1,003	15	652	3	19,216
2013	21,101	413	20,688	0	1,015	74	664	34	19,314
2014	21,959	1,038	20,921	0	1,048	136	695	66	20,014
2015	22,412	1,245	21,167	0	1,060	203	708	99	20,342
2016	22,675	1,252	21,423	0	1,073	271	720	131	20,481
2017	22,902	1,246	21,656	0	1,085	338	732	164	20,584
2018	23,151	1,254	21,897	0	1,097	405	745	197	20,708
2019	23,403	1,261	22,142	0	1,110	472	757	229	20,835
2020	23,667	1,269	22,398	0	1,124	522	767	254	21,000
2021	23,952	1,276	22,675	0	1,139	565	778	275	21,195

Projected Values (2012 - 2021):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation, cumulative load management, or incremental load management

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected January values. The projections for 2012 through 2019 are based on the FPSC's 2011 order in the DSM Plan docket. Projected DSM values for 2020 and 2021 assume 100 MW/year of incremental DSM.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9)

* Res. Load Management and C/I Load Management include MW values of load management from Lee County.

Schedule 3.3
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))
(Historical)

(1) Year	(2) Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Actual Net Energy For Load GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Total Billed Retail Energy Sales (GWh)	(9) Load Factor(%)
2002	107,380	1,682	1,499	104,199	1,233	7,443	95,523	61.9%
2003	111,784	1,773	1,619	106,393	1,511	7,386	99,496	62.9%
2004	111,659	1,872	1,693	108,093	1,531	7,467	99,095	59.9%
2005	115,065	1,970	1,793	111,301	1,506	7,498	102,296	56.8%
2006	117,116	2,078	1,901	113,137	1,569	7,909	103,659	59.2%
2007	118,518	2,138	2,066	114,315	1,499	7,401	105,415	59.4%
2008	115,379	2,249	2,126	111,004	993	7,092	102,919	60.0%
2009	115,844	2,345	2,196	111,303	1,155	7,394	102,755	56.8%
2010	119,220	2,487	2,259	114,475	2,049	7,870	104,557	58.7%
2011	117,460	2,683	2,324	112,454	2,176	6,950	103,327	59.4%

Historical Values (2002 - 2011):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula Col. (2) = Col. (3) + Col. (4) + Col. (5)

Col. (3) & Col. (4) are DSM values starting in January 1988 and are annual (12-month) values. Col. (3) and Col. (4) for 2011 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWh reductions experienced each year.

Col. (5) is the actual Net Energy for Load (NEL) for years 2002 - 2011.

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760) Adjustments are made for leap years.

Schedule 3.3
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))
(Projected)

(1) Year	(2) Forecasted Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Net Energy For Load Adjusted for DSM GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Forecasted Total Billed Retail Energy Sales w/o DSM GWh	(9) Load Factor(%)
2012	111,156	87	48	111,021	2,314	7,034	101,808	58.5%
2013	112,487	183	104	112,201	2,210	6,812	103,465	58.6%
2014	117,982	282	162	117,538	5,013	7,065	105,903	57.9%
2015	121,407	383	222	120,802	5,667	7,049	108,691	58.3%
2016	123,310	483	282	122,545	5,699	7,107	110,504	57.7%
2017	124,806	584	342	123,880	5,657	7,177	111,972	58.1%
2018	126,270	685	401	125,183	5,677	7,260	113,333	58.4%
2019	127,918	786	461	126,671	5,717	7,360	114,841	58.3%
2020	130,631	857	503	129,271	5,768	7,527	117,336	58.3%
2021	133,646	927	545	132,174	5,812	7,706	120,127	58.8%

Projected Values (2012 - 2021):

Col. (2) represents Forecasted Net Energy for Load w/o incremental DSM from 2012 - on. The Col. (2) values are extracted from Schedule 2.3, Col. (19). The effects of conservation implemented prior to September 2011 are incorporated into the load forecast values in Col. (2).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation from Jan 2012 - on and are mid-year (6-month) values reflecting DSM signups occurring evenly thoughout each year.

Col. (5) is the forecasted Net Energy for Load (NEL) after adjusting for impacts of incremental DSM for years 2012 - 2021 using the formula: Col. (6) = Col. (2) - Col. (3) - Col. (4)

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760) Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of
Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2011 ACTUAL		2012 FORECAST		2013 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	18,552	8,061	20,889	8,291	21,101	8,429
FEB	14,483	7,228	16,965	7,420	17,137	7,547
MAR	16,088	8,082	16,965	8,318	17,137	8,440
APR	19,615	9,730	17,278	8,495	17,524	8,598
MAY	19,747	9,721	19,296	9,804	19,570	9,902
JUN	21,222	10,924	19,572	10,217	19,851	10,279
JUL	21,377	11,848	20,184	11,124	20,471	11,195
AUG	21,619	11,326	21,623	11,103	21,931	11,174
SEP	20,035	10,531	20,061	10,295	20,347	10,380
OCT	18,757	9,051	18,808	9,674	19,076	9,792
NOV	16,831	8,021	17,601	8,089	18,317	8,240
DEC	14,575	7,931	17,616	8,328	18,332	8,511
TOTALS		112,454		111,156		112,487

Col. (3) annual value shown is consistent with value shown in Col.(5) of Schedule 3.3.

Cols. (4) - (7) do not include the impacts of cumulative load management, incremental conservation, and incremental load management and are consistent with values shown in Col. (19) of Schedule 2.3 and Col. (2) of Schedule 3.3.

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CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL utilizes its well established integrated resource planning (IRP) process in whole or in part as analysis needs warranted, to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of new power plants, the primary subjects of this document, are determined as part of the IRP process work.

This section describes FPL's basic IRP process. Some of the key assumptions, in addition to a new load forecast, that were used in developing the resource plan presented in this Site Plan are also discussed.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental steps to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Evaluate the competing options and resource plans in regard to system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process

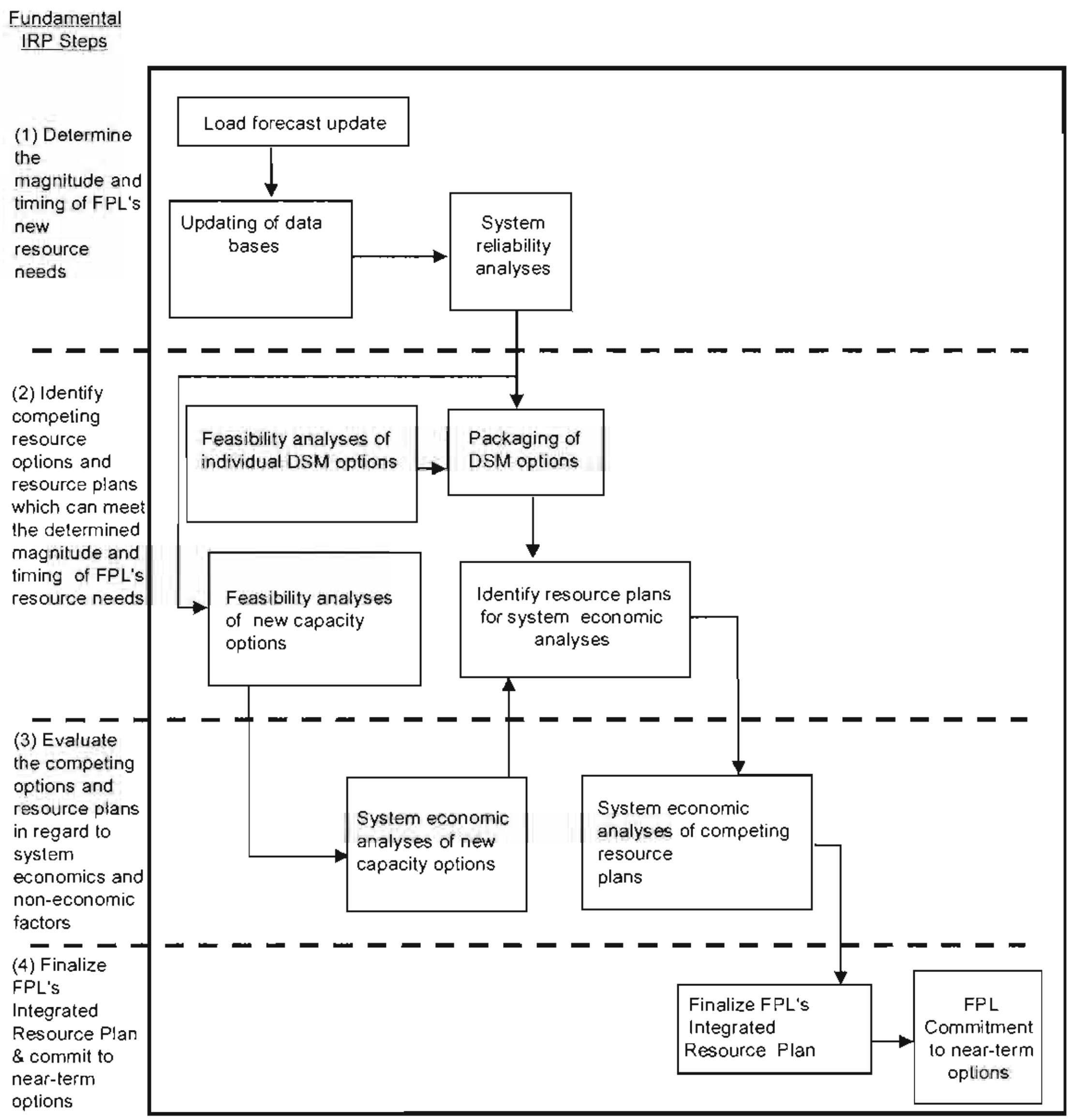

Figure III.A.1: Overview of FPL's IRP Process

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of the four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed to maintain system reliability. Also determined in this step is when the MW additions are needed to meet FPL's reliability criteria. This step is often referred to as a reliability assessment, or resource adequacy, analysis for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include, but are not limited to: delivered fuel price projections, current financial and economic assumptions, and power plant capability and operating assumptions. FPL also includes key assumptions regarding three specific resource areas: (1) near-term construction capacity additions, (2) firm capacity power purchases, and (3) DSM implementation.

The first of these assumptions is based on new generating capacity additions that have been approved by the Florida Public Service Commission (FPSC) through Determination of Need proceedings that evaluated both the need for, and the cost-effectiveness of, each of the new capacity additions. These generating capacity additions have also either received the necessary Site Certification approvals from either the Secretary of the Florida Department of Environmental Protection (FDEP) or the Governor and Cabinet (acting as the Siting Board), or these approvals have been applied for. (There is also work in progress to obtain the necessary federal and state licenses, permits, and approvals for construction and operation of two new nuclear units whose earliest practical deployment dates continue to be outside of the 2012 – 2021 reporting period of this Site Plan.)

Several new generating unit additions will occur in the 2012 – 2021 reporting time frame of this document. These generating unit additions include:

- Two existing generating plant sites, each featuring two older fossil fuel-fired steam generating units, are currently in the process of being modernized by removing the existing generating units and replacing them with one new, highly efficient combined cycle (CC) unit. The new CC plant at FPL's Cape Canaveral site is projected to be placed in-service in mid-2013. This new CC unit is projected to have a peak Summer output of 1,210 MW and will be called the Cape Canaveral Next Generation Clean Energy Center (CCEC). The new CC unit at FPL's Riviera site is projected to be placed in-service in mid-2014 and it is expected to have a peak Summer output of 1,212 MW. This new plant will be called the Riviera Beach Next Generation Clean Energy Center (RBEC). These modernizations were approved by the FPSC in September 2008. The site certification application for Cape Canaveral was granted in October 2009. The site certification application for Riviera Beach was granted in November 2009.

- Similar to the two modernization projects mentioned above, the four existing steam units at the Port Everglades site will be removed and replaced with a new highly efficient CC unit. This unit, called the Port Everglades Next Generation Clean Energy Center (PEEC), is projected to be in-service in mid-2016 and is projected to have a peak Summer output of 1,277 MW. The FPSC voted to approve this modernization project on March 27, 2012. The site certification process is underway.
- FPL will be adding approximately 490 MW of generating capacity at its existing nuclear power plants at the Turkey Point and St. Lucie sites. 31 MW of this increased capacity has already been added at St. Lucie Unit 2 and this additional nuclear capacity is already benefiting FPL's customers. The remaining increased capacity is scheduled to come in-service in the 2012 – 2013 time period. These capacity uprates were approved by the FPSC in January 2008. The Final Order for the Site Certification was issued in September 2008 for the St. Lucie uprates and in October 2008 for the Turkey Point uprates.
- In the fourth quarter of 2011, FPL started upgrading the 7FA combustion turbines (CT) that are components of several of its CC units. These upgrades will economically benefit FPL's customers by increasing the MW output of these CC units by approximately 228 MW (Summer peak value) in total. As reflected in Schedule 1, 26 MW of the increased capacity from these CT upgrades is already in service at Martin 8. The remaining upgrades are projected to be completed during the 2012 through 2015 time period.

These new generating units and generating capacity additions were selected for a variety of reasons including cost-effectiveness, significant system fuel savings, fuel diversity, mitigation of regional generation/load imbalances, and significant system emission reductions, including greenhouse gas emission reductions.

The second of these assumptions involves firm capacity power purchases. FPL's current projection of firm capacity purchases has changed from the projection in the 2011 Site Plan. FPL has three additional short-term purchases for the year 2012 only. These purchases consist of a 125 MW agreement with TECO and two purchases totaling 305 MW from CT facilities in DeSoto County. FPL's current projection also includes an additional 70 MW from the Palm Beach Solid Waste Authority (SWA) starting in year 2016. However, the total projected incremental capacity from Palm Beach SWA has decreased by 35 MW compared to the 2011 Site Plan projection. Also, FPL now projects that its purchase agreement with Jacksonville Electric Authority (JEA) for St. Johns Regional Power Park (SJRPP)-based capacity and energy will allow FPL to continue to receive purchased capacity and energy until the Spring of 2017. At that time, FPL projects that Internal Revenue Service (IRS) regulations regarding the amount of energy that FPL can receive will result in the suspension of any further capacity and energy by FPL.[5]

In total, the projected firm capacity purchases are from a combination of utility and independent power producers. Details, including the annual total capacity values for these purchases, are presented in Chapter I in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's resource planning work.

The third of these assumptions involves a projection of the amount of additional DSM that is anticipated to be implemented annually over the ten-year period. Since 1994, FPL's resource planning work has assumed that, at a minimum, the DSM MW called for in FPL's approved DSM Plan will be achieved. The resource plan presented in FPL's 2012 Site Plan fully accounts for the DSM Plan direction provided by the FPSC in 2011.

These key assumptions, plus the other updated information described above, are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's future resource needs. This determination is accomplished by system reliability analyses which for FPL are currently based on dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry.

[5] FPL's projected suspension date for the SJRPP purchase is based on a system reliability perspective; i.e., the earliest projected date at which the suspension of capacity and energy could occur.

Historically, two types of methodologies, deterministic and probabilistic, have been utilized in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Among the most widely used is loss-of-load probability (LOLP) which FPL utilizes. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of the "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

The result of the first fundamental step of resource planning is a projection of how many new MW of resources are needed to meet both reserve margin and LOLP criteria, and thus maintain system reliability, and when the MW are needed. Information regarding the timing and magnitude of these resource needs is then used in the second fundamental step: identifying resource options and resource plans that can meet the determined magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, preliminary economic screening analyses of new capacity options that are very similar in regard to certain key characteristics may be conducted to determine which new capacity options appear to be the most competitive on FPL's system. This preliminary analysis work can also help identify capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. Similarly, preliminary economic screening analyses of new DSM options and/or continued growth in existing DSM options are often conducted.

FPL typically utilizes the P-MArea production cost model and a Fixed Cost Spreadsheet, and/or the Strategist model, as well as spreadsheet analyses, to perform the preliminary economic screening of generation resource options. For the preliminary economic screening analyses of DSM resource options, FPL typically uses its DSM cost-effectiveness model which is an FPL spreadsheet model utilizing the FPSC's approved methodology for performing preliminary cost-effectiveness screening of individual DSM measures and programs. FPL also utilizes its non-linear programming model for analyzing the potential for lowering system peak loads through additional load management/demand response capability. Then FPL typically utilizes its linear programming model to develop DSM portfolios that are subsequently used in developing resource plans for final system analyses of DSM-based resource plans.

The individual new resource options emerging from these preliminary economic screening analyses are then typically "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's projected new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet and/or dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans in Regard to System Economics and Non-Economic Factors:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for evaluating these resource options and resource plans in final, or system, economic analyses that attempt to account for all of the impacts to the FPL system from the competing resource options/resource plans. (These system impacts are typically not accounted for in preliminary economic screening analyses.) In FPL's 2011 and early 2012 resource planning work, once the resource plans were developed, FPL utilized the P-MArea production cost model and a Fixed Cost Spreadsheet, and/or the Strategist model, to perform the system economic analyses.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM methodology). In cases in which the DSM contribution was assumed as a given and the only competing options were new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and plans in such cases were evaluated on a cumulative present value revenue requirement (CPVRR) basis.

Other factors are also included in FPL's evaluation of resource options and resource plans. While these factors may have an economic component or impact, they are often discussed in quantitative, but non-economic terms, such as percentages, tons, etc. rather than in terms of dollars. These factors are often referred to by FPL as "system concerns" that include (but are not necessarily limited to) maintaining/enhancing fuel diversity in the FPL system, system emission levels, and maintaining a regional balance between load and generating capacity, particularly in the Southeastern Florida counties of Miami-Dade and Broward. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL's system, the non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps are typically used to develop the current resource plan. This plan is presented in the following section.

III.B Projected Incremental Resource Additions/Changes

FPL's projected incremental generation capacity additions/changes for 2012 through 2021 are depicted in Table III.B.1. These capacity additions/changes result from a variety of actions that primarily consist of: (i) changes to existing units (which are frequently achieved as a result of plant component replacements during major overhauls), (ii) increases in generating capacity at FPL's four existing nuclear units, (iii) the temporary return of certain generating units from Inactive Reserve status to active service, then returning these units to Inactive Reserve status, (iv) changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, (v) the modernizations of FPL's existing Cape Canaveral, Riviera, and Port Everglades sites by the removal of the steam generating units that were previously, or are currently, on the sites and the addition of one new, very fuel-efficient CC generating unit at each site, and (vi) upgrades to the CTs at a number of existing combined cycle plants.

Although the DSM additions that are consistent with the FPSC's directions regarding FPL's DSM Plan are not explicitly presented in this table, these DSM additions have been fully accounted for in all of FPL's resource planning work reflected in this document. The DSM Plan projects annual DSM additions through 2019. For planning purposes, FPL currently projects an additional 100 MW (Summer) of DSM per year for the subsequent two years (2020 and 2021) addressed in this document. In addition, the projected MW reductions from these DSM additions are reflected in the projected reserve margin values shown in the table below and in Schedules 7.1 and 7.2 presented later in this chapter. (Subsequent analyses will ultimately determine the actual levels of DSM that should be implemented in these later years.)

Table III.B.1: Projected Capacity Changes for FPL

Year	Projected Capacity Changes	Net Capacity Changes (MW) Winter [1]	Summer [2]
2012	Sanford Unit 5 CT Upgrade	---	19
	St. Lucie Unit 1 Uprate - Outage [5]	(853)	---
	St. Lucie Unit 1 Uprates - Completed	---	129
	Turkey Point Unit 3 Uprates - Completed	---	123
	St. Lucie Unit 2 Uprate - Outage [5]	---	(745)
	Changes to Existing Purchases [3]	375	470
	Scherer Unit 4	---	(30)
	Manatee Unit 2	---	(3)
	Inactive Reserve Units (PE Units 3 & 4) -return to active status [7]	765	761
	Manatee Unit 2 ESP - Outage [6]	(822)	---
2013	Cape Canaveral Next Generation Clean Energy Center [4]	---	1,210
	Changes to Existing Purchases [3]	(555)	(430)
	Manatee Unit 2	(3)	---
	Sanford Unit 5 CT Upgrade	19	9
	Martin Unit 8 CT Upgrade	10	10
	Sanford Unit 4 CT Upgrade	22	31
	Scherer Unit 4	(28)	---
	St. Lucie Unit 1 Uprates - Completed	129	---
	St. Lucie Unit 2 Uprates - Completed	84	84
	Turkey Point Unit 3 Uprates - Completed	123	---
	Turkey Point Unit 4 Uprates - Completed	---	123
	Turkey Point Unit 4 Uprates - Outage [5]	(717)	---
	Inactive Reserve Unit (PE Units 3 & 4) - return to inactive status [7]	(765)	(761)
	Manatee Unit 1 ESP - Outage [6]	(822)	---
	Martin Unit 1 ESP - Outage [6]	---	(826)
2014	Cape Canaveral Next Generation Clean Energy Center [4]	1,355	---
	Sanford Unit 4 CT Upgrade	16	---
	Sanford Unit 5 CT Upgrade	19	10
	Manatee Unit 3 CT Upgrade	---	19
	Turkey Point Unit 5 CT Upgrade	---	33
	Turkey Point Unit 4 Uprates - Completed	123	---
	Martin Unit 1 ESP - Outage [6]	(832)	---
	Martin Unit 2 ESP - Outage [6]	---	(826)
	Riviera Beach Next Generation Clean Energy Center [4]	---	1,212
2015	Manatee Unit 3 CT Upgrade	39	20
	Turkey Point Unit 5 CT Upgrade	33	---
	Ft. Myers Unit 2 CT Upgrade	---	51
	Riviera Beach Next Generation Clean Energy Center [4]	1,344	---
2016	Changes to Existing Purchases [3]	(858)	(858)
	Ft. Myers Unit 2 CT Upgrade	51	---
	Turkey Point Unit 1 operation changed to synchronous condenser	---	(396)
	Port Everglades Next Generation Clean Energy Center [4]	---	1,277
2017	Changes to Existing Purchases [3]	---	(375)
	Turkey Point Unit 1 operation changed to synchronous condenser	(398)	---
	Port Everglades Next Generation Clean Energy Center [4]	1,429	---
2018	Changes to Existing Purchases [3]	(383)	---
2019	---	---	---
2020	---	---	---
2021	Short Term Purchase	---	250

(1) Winter values are forecasted values for January of the year shown.
(2) Summer values are forecasted values for August of the year shown.
(3) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(4) All new unit additions are scheduled to be in-service in June of the year shown. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.
(5) Outages for uprate work.
(6) Outages for ESP work.
(7) A number of existing FPL power plants have been removed from service and placed on Inactive Reserve status. See Chapter III for a discussion of the units on Inactive Reserves.

III.C Discussion of the Projected Resource Plan and Issues Impacting FPL's Resource Planning Work

As indicated in the Executive Summary, FPL's resource planning efforts in 2011 and early 2012 were influenced by a number of factors. Furthermore, these factors are expected to continue to influence FPL's resource planning work for the foreseeable future. There are 5 such factors that are of primary importance:

1) Maintaining/enhancing fuel diversity in the FPL system;
2) Maintaining a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward Counties;
3) Growing dependence upon DSM resources to maintain FPL system reliability;
4) Securing additional natural gas (and doing so in a manner that enhances the reliability of the natural gas supply system); and,
5) Possible establishment of "Clean Energy Standards" or another mechanism to promote large scale utilization of renewable energy.

These 5 factors, and their various impacts on FPL's resource planning efforts including the current resource plan that is presented in this Site Plan, are briefly discussed below.

1. **Maintaining/Enhancing System Fuel Diversity;**

FPL is currently dependent upon using natural gas to generate more than half of the electricity it delivers to its customers. In the future, the percentage of FPL's electricity that is generated by natural gas is projected to increase. Therefore, FPL is continually seeking opportunities to maintain and enhance the fuel diversity of its system.

In 2007, following express direction by the Commission to do so, FPL sought approval from the FPSC to add two new advanced technology coal units to its system. These two new units would have been placed in-service in 2013 and 2014. However, in part due to concerns over potential greenhouse gas emission legislation/regulation, FPL was unable to obtain approval for these units. Several other factors are currently unfavorable to new coal units compared to new CC units. The first of these factors is a significant reduction in the fuel cost difference between coal and natural gas compared to the fuel cost difference projected in 2007 that favored coal; i.e., the projected cost advantage of coal versus natural gas has been significantly reduced. Second is the continuation of significantly higher capital cost for coal units compared to capital cost for CC units. Third is the increased fuel efficiency of new CC units compared to projected CC unit efficiencies in 2007. Fourth are the stricter non-greenhouse gas environmental regulations that are more unfavorable to new coal units than to new CC units. Consequently, FPL does not believe that new advanced technology coal units are currently economically, politically, or environmentally viable fuel diversity enhancement options in Florida.

Therefore, FPL has turned its attention to nuclear energy and renewable energy to enhance its fuel diversity and to using natural gas more efficiently. In regard to nuclear energy, FPL previously obtained approval to increase capacity at each of its four existing nuclear units. In total, these capacity uprates will add approximately 490 MW of nuclear capacity and energy for FPL's customers. 31 MW of increased nuclear capacity from the uprates have been achieved at St. Lucie Unit 2 and this increased nuclear capacity is already benefiting FPL's customers. The remaining increased nuclear capacity from the uprates project is scheduled to come on-line during 2012 through early 2013. In 2008, the FPSC approved the need for these uprates and authorized FPL to recover uprates-related expenditures that are approved as a result of annual nuclear cost recovery filings.

FPL is continuing its work to obtain all of the licenses, permits, and approvals that would be necessary to construct and operate two new nuclear units at its Turkey Point site in the future. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units at Turkey Point for a commercial operations date expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. The earliest practical deployment dates for the two new units continue to be beyond the 10-year reporting period for this Site Plan. Therefore, these units are not shown in this document.

FPL also has been involved in activities to investigate adding or maintaining renewable resources as a part of its generation supply. One of these activities is a variety of discussions with the owners of existing facilities aimed at maintaining or extending current agreements that are scheduled to end during the ten-year reporting period of this document. FPL also sought and received approval from the FPSC in 2008 to add 110 MW through three new FPL-owned solar facilities: one solar thermal facility and two photovoltaic (PV) facilities. One 25 MW PV facility began commercial operation in 2009. The remaining two solar facilities, a 10 MW PV facility and a 75 MW solar thermal steam generating facility, began commercial operation in 2010. The addition of these renewable energy facilities was made possible due to enabling legislation from the Florida Legislature in 2008. FPL remains strongly supportive of Federal and/or State legislation that enables electric utilities to add renewable energy resources and authorize the utilities to recover appropriate costs for these resources.

In regard to using natural gas more efficiently, FPL received approvals in 2008 from the FPSC to modernize the existing Cape Canaveral and Riviera plant sites with new, highly efficient CC units that replace the former steam generating units on each of those sites. The modernizations of Cape Canaveral and Riviera are currently underway and are projected to go in-service on time in mid-2013 and mid-2014, respectively. On March 27, 2012, FPL received FPSC approval to proceed with a similar modernization project at the Port Everglades site which is scheduled for completion in mid-2016. The modernization of Port Everglades will retain the capability of receiving water-borne delivery of oil as a backup fuel.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity. Moreover, FPL is also maintaining the ability to utilize fuel oil at existing units that have that capability. FPL is in the process of installing electrostatic precipitators (ESPs) at its four 800 MW steam generating units at the Martin and Manatee sites which will enable FPL to retain the ability to burn oil, as needed, at these sites while retaining the flexibility to use natural gas when economically attractive. Furthermore, FPL continues to evaluate the potential for greater diversity in the delivery of natural gas through a new, third natural gas pipeline. A third pipeline would result in a more reliable, and more economic and more diverse, natural gas supply for FPL's customers and the state of Florida.

2. **Maintaining a Balance Between Load and Generation in Southeastern Florida:**

   In recent years, an imbalance was projected to develop between regionally installed generation and regional peak load in Southeastern Florida. With such an imbalance, a significant amount of energy required in the Southeastern Florida region during peak periods would need to be provided either by operating less efficient generating units located in Southeastern Florida out of economic dispatch, or by importing the energy through the transmission system from plants located outside the region. FPL's prior planning work concluded that either additional installed generating capacity in this region, or additional installed transmission capacity capable of delivering more electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location, four recent capacity addition decisions (Turkey Point Unit 5 and WCEC Units 1, 2, & 3) were determined to be the most cost-effective options to meet FPL's capacity needs in the near-term. In addition, FPL will be adding increased capacity at FPL's existing two nuclear units at Turkey Point in 2012 and 2013. The recently approved Port Everglades modernization project scheduled for completion in 2016 will also significantly aid in mitigating this imbalance. Adding this additional generation capacity contributes to addressing the imbalance between generation and load in Southeastern Florida for the approximately the remainder of this decade.

The planned two new nuclear units at FPL's Turkey Point site will also address the imbalance issue for an additional period of time. Due to steadily increasing load in the Southeastern region, the Southeastern Florida imbalance issue will remain an important consideration in FPL's on-going resource planning work in future years.

3. Growing Dependence Upon DSM Resources to Maintain System Reliability:

In late 2009, the FPSC imposed significantly higher DSM Goals than had been deemed appropriate in previous DSM Goals dockets. The FPSC's 2011 DSM Plan decision lowered these required levels of DSM, but only by a relatively small amount.

As a result, FPL is projected to become increasingly dependent upon DSM resources, instead of generation resources, to maintain system reliability. Schedules 7.3 and 7.4 demonstrate this point. These schedules are presented in the back portion of this chapter. Both of these schedules use Schedule 7.1, which presents FPL's projected Summer reserve margins, as a starting point.

In Schedule 7.3, Column (14), FPL projects what a "generation-only" reserve margin would be for each year in the 10-year reporting period, after accounting for all approved generation additions through 2016, by making two changes in Schedule 7.1. First, the projected DSM values in Column (8) have been zeroed out to remove the projected contribution from DSM. Second, the projected addition of a 250 MW short-term power purchase in 2021 has been removed. These two changes result in a projection of reserve margins that are based solely on generation resources that currently exist or which have been approved by the FPSC.

The result is a projected generation-only reserve margin in the range of approximately 16% to 13% through 2016, but which decreases steadily thereafter to 4.5% by 2021.

In Schedule 7.4, the projected addition of the projected 2021 PPA has been added back in as reflected by the values in Column (1). The projected generation-only reserve margin for the year 2021 now increases, but only to 5.5%. Although marginally higher than the 4.5% value for 2021 projected in Schedule 7.3, the 5.5% value is also considerably lower than the 16% to 13% range for the years 2012 through 2016. In the years from 2017 through 2020, the projected generation-only reserve margin steadily decreases to less than 6.5% by 2020 and under 6% by 2021.

Therefore, FPL's projected system reserves, already dependent to a significant degree upon DSM resources, are becoming increasingly more dependent upon DSM. Stated another way, the FPL system's ability to continue to provide reliable electricity service to FPL's customers is becoming increasingly dependent upon DSM. FPL currently believes that generation-only reserves at these projected low levels may not be adequate, and FPL will continue to evaluate the appropriateness of a minimum generation-only requirement as part of its on-going resource planning work.

4. **Securing Additional Natural Gas:**

The recent trend of increasing reliance upon natural gas to produce electricity for FPL's customers is projected to continue due to FPL's growing load. The addition of the highly fuel-efficient Cape Canaveral, Riviera, and Port Everglades modernizations will serve to reduce the growth in natural gas use from what it otherwise might have been due to the high fuel-efficiency levels of these new CC units, but these efficiencies do not offset the effects of FPL's growing load. Therefore, FPL will need to secure more natural gas supply and more gas transportation capacity. The issue is how to secure these additional natural gas resources in a manner that is economical for FPL's customers and which maintains and/or enhances the reliability of natural gas supply and deliverability to FPL's generating units.

FPL has historically purchased the gas transportation capacity required for new natural gas supply from two existing natural gas pipeline companies. As more natural gas is delivered through two pipelines entering Florida, the impact of a supply disruption on either pipeline becomes more problematic. Therefore, FPL sought approval in 2009 from the FPSC for the construction of a new, third natural gas pipeline into Florida capable of serving future gas-fired generation needs for FPL and others in the state. Such a third pipeline was projected to have benefits for FPL and its customers by increasing the diversity of FPL's fuel supply sources, increasing the physical reliability of the pipeline delivery system, and enhancing competition among pipelines. However, the application for an FPL-owned pipeline was denied by the FPSC in 2009. FPL is continuing to evaluate alternatives to increase the diversity of natural gas deliveries in order to meet the future gas requirements of FPL and the State of Florida.

5. **Possible Establishment of "Clean Energy Standards":**

At the time this document is being prepared, neither the United States nor the State of Florida has established a "Clean Energy Standard" which would require that a certain amount of energy be supplied by "clean" energy sources. A similar "Renewable Portfolio Standard" proposal was prepared by the FPSC and sent to the Florida Legislature for their consideration, including an option to change the standard to a Clean Energy Standard, during the 2009 legislative session. However, no such legislation was enacted during the 2009 session or in subsequent legislative sessions. Such legislation, or other legislative initiatives regarding clean energy contributions, may occur in the future. If such legislation is enacted in a future year, FPL will then determine what steps need to be taken to comply with the legislation. Such steps would then be discussed in FPL's Site Plan in the year following the enactment of such legislation.

III.D Demand Side Management (DSM)

During 2011 and early 2012, FPL offered the following DSM programs to its customers:

Residential DSM Programs

1. **Residential Building Envelope:** Offers rebates to residential customers to install energy-efficient reflective roof and ceiling insulation measures.

2. **Duct System Testing and Repair:** Provides reduced cost duct system testing to identify leaks in air conditioning duct systems, and encourages the repair of those leaks by qualified contractors. Rebates are offered for duct system repair.

3. **Residential Air Conditioning:** Offers rebates to customers to purchase higher efficiency air conditioning and heating equipment. The program includes additional rebates for plenum repair measure and air handler units with electronically commutated motors.

4. **Residential Load Management (On Call Program):** Offers load control of major appliances/household equipment in exchange for monthly electric bill credits. Direct load control equipment is installed on selected customer end-use equipment allowing FPL to control these customer loads as needed. Qualifying equipment includes central electric air conditioners, central electric heaters, conventional electric water heaters, and swimming pool pumps.

5. **Residential New Construction (BuildSmart):** Encourages the design and construction of energy-efficient homes by offering education to contractors on energy efficiency measures, and providing construction design reviews and home inspections.

6. **Residential Low Income Weatherization:** Combines energy audits and incentives to encourage low income housing administrators to retrofit homes with energy efficiency measures. The housing authorities include: weatherization agency providers (WAPS), non-weatherization agency providers (non-WAPS), and other providers approved by FPL. The rebates are used by these providers to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting. FPL offers rebates for HVAC maintenance, reduced air infiltration measures, and room air conditioning replacement.

7. **Residential Conservation Service:** Offers a walk-through energy audit, a computer-generated Class A audit, and a customer-assisted energy audit. For customer-assisted energy audits, mail-in, phone, and Internet audit options are available. (Note that FPL does not count demand and energy savings from this program towards its DSM Goals.)

Business DSM Programs

1. **Business Heating, Ventilating, and Air Conditioning (HVAC):** Offers business customers financial rebates to upgrade to higher efficiency HVAC equipment that

exceed the minimum efficiencies mandated by the U.S. Department of Energy. The current FPL program includes rebates for: 1) thermal storage; 2) chillers; 3) energy recovery ventilator units; 4) direct expansion (DX) units and efficient air conditioning room units; 5) demand control ventilation systems including kitchen hood control; and 6) electrically commutated motors for air conditioning systems.

2. **Business Efficient Lighting:** Offers business customers financial rebates to install high efficiency lighting measures at the time of replacement. FPL's program addresses linear fluorescent, plus other, efficient lighting technologies.

3. **Business Building Envelope:** Offers financial rebates to customers to install high efficiency building envelope measures such as roof/ceiling insulation, reflective roof coatings, and window treatments.

4. **Business Custom Incentive:** Serves as a "catch-all" program for customer-specific cost-effective efficiency measures which are not included in other FPL programs. DSM measures must reduce or shift at least 25 kW during peak hours, have verifiable demand and energy savings, and pass FPL's preliminary cost-effectiveness screening testing.

5. **Business On Call:** Offers load control of central air conditioning units to both small non–demand-billed, and medium demand-billed, customers in exchange for monthly electric bill credits.

6. **Commercial Industrial Demand Reduction (CDR):** Reduces peak demand by allowing the direct control of customer loads of 200 kW or greater during periods of extreme demand or capacity shortages. Participants contract for a firm demand level which may not be exceeded during load control periods. In return, participants receive a monthly credit. Participants must provide a 5-year termination notice to discontinue service under this program.

7. **Business Energy Evaluation:** Offers free standard level energy evaluations on-site and on-line. More detailed evaluations are available through this audit program with costs shared between FPL and the participating customer. Participation in FPL's other business DSM programs is promoted through this program. (Note that FPL does not count demand or energy savings from this program towards its DSM Goals.)

8. **Commercial/Industrial Load Control:** Reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity

shortages in exchange for monthly electric bill credits. (This program has been closed to new participants since the year 2000).

9. **Business Water Heating:** Encourages the installation of energy-efficient heat recovery units or heat pump water heaters.

10. **Business Refrigeration:** Encourages the installation of controls and equipment to reduce the usage of electric strip heat for defrosting purposes.

11. **Cogeneration and Small Power Production:** Facilitates FPL compliance with all regulatory requirements concerning qualifying facilities and small power producers. One role of the program is to assist customers in the evaluation of potential cogeneration projects, including self-generation. (Note that FPL does not count demand or energy savings from this program towards its DSM Goals.)

DSM Research and Development:

FPL's Conservation Research and Development (CRD) Program is an umbrella research project under which new DSM technologies are analyzed. Several FPL DSM programs have emerged from the CRD program including the business Building Envelope, Business On Call, and Residential New Construction programs. The program has also resulted in the addition of cost-effective measures to existing programs, such as the proposed inclusion of Energy Recovery Ventilators to the Business HVAC Program. FPL operates the CRD program based on DSM Plan approval, or for 6 years, whichever occurs first, with a spending cap as approved in the most current DSM Plan.

In summary regarding FPL's DSM efforts, FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include both conservation initiatives and load management. FPL's DSM efforts through 2011 have resulted in a cumulative Summer peak reduction of approximately 4,513 MW (Summer) at the generator and an estimated cumulative energy saving of approximately 59,890 Gigawatt Hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2011 have eliminated the need to construct the equivalent of more than 13 new 400 MW generating units.

The FPSC in late 2009 imposed significantly higher DSM Goals for FPL for 2010 – 2019 than were deemed appropriate in prior DSM Goals dockets. The DSM Goals recently imposed by the FPSC have three components: Summer MW reductions, Winter MW reductions, and GWh reductions. The Summer MW component, and to a much lesser degree the Winter MW reduction component, impacts FPL's need for future resources such as those discussed in this document. The GWh reduction component has no impact on FPL's need for future resources.

In 2011, based on concerns over the projected higher electric rates that would occur if a new DSM Plan to meet the new DSM Goals were implemented, the FPSC determined in the DSM Plan docket that FPL should continue to implement the specific DSM programs, that FPL was implementing at that time (FPSC Order PSC-11-0590-FOF-EG). The projected demand reduction impact of these DSM programs from 2012 through 2019 (plus an assumed additional 100 MW per calendar year for 2020 and 2021) is presented below in Table III.D.1. (Subsequent analyses will ultimately determine the actual levels of DSM that should be added in these later years.)

Table III.D.1: FPL's Projected DSM Summer MW Reduction for 2012 - 2021

August MW values (at the Generator)

Year	Cumulative Summer MW DSM Goals for FPL (at Generator)
2012	136
2013	259
2014	422
2015	553
2016	685
2017	816
2018	947
2019	1079
2020	1188
2021	1288

FPL has consistently been among the leading utilities nationally in DSM achievement. For example, according to the U.S. Department of Energy's 2010 data (the last year for which the DOE data was available at the time this Site Plan is being developed), FPL ranked # 2 nationally in cumulative DSM demand reduction. And, importantly, FPL has achieved these significant DSM accomplishments while seeking to lessen the DSM-based impact on electric rates for all of its customers.

In regard to DSM, FPL's intent is to follow the FPSC's directions regarding DSM implementation and to continue its national leadership role in DSM consistent with efforts both to continue to lessen the DSM-based impact on electric rates for all of FPL's customers, and to ensure that FPL's system reliability does not become too dependent upon DSM resources.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy to FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV bulk transmission lines that must be certified under the Transmission Line Siting Act.

Table III.E.1: List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	St. Johns 1/	Pringle	25	Dec - 16	230	759
FPL	Manatee 2/	Bob White	30	Dec - 14	230	1195

1/ Final order certifying the corridor was issued on April 21, 2006. This project is to be completed in two phases. Phase I consisted of 4 miles of new 230 kV line (Pringle to Pellicer) and was completed in May-2009. Phase II consists of 21 miles of new 230 kV line (St. Johns to Pellicer) and is scheduled to be completed by Dec-2016.

2/ Final order certifying the corridor was issued on November 6, 2008. This project consists of 30 miles of new 230 kV line (Manatee to Bob White) and is scheduled to be completed by Dec-2014

In addition, there will be transmission facilities needed to connect several of FPL's projected generating capacity additions to the system transmission grid. These transmission facilities (described on the following pages) are for the capacity increases (uprates) at the existing St. Lucie and Turkey Point nuclear sites, and the generating capacity additions with the Cape Canaveral, Riviera Beach and Port Everglades modernizations.

In regard to the existing generating units that have been placed on Inactive Reserve status and/or which will be retired in late 2012, there are no projected impacts to FPL's transmission system from these units.

III.E.1 Transmission Facilities for St. Lucie Units 1 & 2 Capacity Uprates

The work required to address the St. Lucie Units 1 & 2 uprates in 2012 in regard to the FPL grid consists of the following:

I. Substation:

1. At Midway Substation, replace eleven 230 kV disconnect switches, and remove six wave traps. Also upgrade associated jumpers, bus work and equipment connections.
2. At St. Lucie Switchyard, replace eighteen 230 kV disconnect switches and remove six wave traps.
3. Uprate the Unit 1A and 1B main step-up transformers to 635 MVA. Unit 1B main step-up transformer is to be replaced by the uprated spare main step-up transformer. Existing Unit 1B main step-up transformer is to become the new station spare
4. Uprate the spare main step-up transformer to 635 MVA to replace Unit 2A main step-up transformer.
5. Replace the Unit 2A and Unit 2B main step-up transformer with a new one rated at 635 MVA.
6. Add fiber optic relays and other protective equipment.

II. Transmission:

1. Upgrade the three existing St. Lucie-Midway 230 kV lines with spacers between the conductors to achieve a normal (continuous) rating of 2790 Amperes.
2. Replace one existing overhead ground wire on each of the three existing St. Lucie Midway 230 kV line with fiber optic overhead ground wire for protective relay communication.

III.E.2 Transmission Facilities for Turkey Point Units 3 & 4 Capacity Uprates

The work required to address the Turkey Point Units 3 & 4 uprates in 2012 for Unit 3 and in 2012-2013 for Unit 4, in regard to the FPL grid consists of the following:

I. Substation:

1. At Turkey Point Switchyard, install two 5-Ohm series phase inductors combined with external shunt capacitors on the southeast and southwest 230 kV operating busses.
2. At Turkey Point Switchyard, replace twelve 230 kV disconnect switches. Also upgrade associated jumpers, bus work and equipment connections.
3. Uprate the Unit 3 and Unit 4 main step-up transformers to 970 MVA.
4. Replace spare main step-up transformer with 1028 MVA transformer.
5. Add relays and other protective equipment.
6. Replace breaker failure panels at Davis Substation.
7. Replace breaker failure panels at Flagami Substation.

II. Transmission:

1. Upgrade the existing string busses for both Units 3 & 4 between the main step-up transformers and the switchyard with spacers between the conductors.

III.E.3 Transmission Facilities for Cape Canaveral Next Generation Clean Energy Center (Modernization)

The work required to connect the Cape Canaveral Next Generation Clean Energy Center in 2013 to the FPL grid is projected to be as follows:

I. Substation:

1. Build new collector yard containing two collector busses with four breakers to connect the three combustion turbines (CT), and one steam turbine (ST).
2. Construct two string busses to connect the collector busses to Cape Canaveral 230 kV Substation.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. At Cape Canaveral Switchyard replace eight 230 kV disconnect switches. Also upgrade associated jumpers, bus work and equipment connections.
5. Expand switchyard relay vault and add relays and other protective equipment.

II. Transmission:

1. Relocate the Cape Canaveral-Grissom 115 kV line.

III.E.4 Transmission Facilities for Riviera Beach Next Generation Clean Energy Center (Modernization)

The work required to connect the Riviera Beach Next Generation Clean Energy Center in 2014 to the FPL grid is projected to be as follows:

I. Substation:

1. Expand the Riviera 230 kV Switchyard five breakers to accommodate terminals for one combustion turbine (CT), and one steam turbine (ST).
2. Construct a new 138 kV Riviera Switchyard - five bays, 14 breakers with terminals to connect two CT units and seven 138 kV lines.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. Add relays and other protective equipment.
5. At Ranch Substation, add a new 230 kV bay 5 and upgrade bay 4 to 3000 Amperes.
6. Breaker replacements:
   Ranch Substation – Replace one 230 kV breaker
   Broward Substation – Replace one 230 kV breaker

II. Transmission:

1. Break the Indiantown-Riviera 230 kV and extend each of the line segments south (approx. 4 miles) to connect to the Ranch 230 kV Substation forming Indiantown-Ranch and a Ranch-Riviera 230 kV circuits.
2. Remove Corbett-Ranch #2 230 kV line at Ranch and:
   a. extend to meet the Cedar-Lauderdale 230 kV line N/S corridor (approx. 10 miles).
3. Break Cedar-Corbett 230 kV (near Ranch Sub in Corbett-Jog section) and:
   a. Extend Cedar side to Riviera, (approx. 15 miles) creating new Cedar-Riviera 230 kV.
   b. Extend Corbett side to meet the Cedar-Lauderdale 230 kV N/S corridor (approx. 10 miles).
4. Break Cedar-Lauderdale 230 kV (near 230 corridor running N/S)
   a. Connect Cedar side to meet 3.b. to create a Cedar to Corbett 230 kV.
   b. Connect Lauderdale side to meet 2.a. to create a Corbett to Lauderdale 230 kV.
5. Upgrade the existing IBM-Yamato 138 kV line to 1200 Amperes.
6. New underground 138 kV tie line between new Riviera 138 kV Switchyard and 560 MVA, 230/138 kV autotransformer in the expanded Riviera 230 kV Substation.
7. Relocate six existing 138 kV lines from existing Riviera 138 kV Switchyard to new Riviera 138 kV Switchyard.

III.E.5 Transmission Facilities for Port Everglades Next Generation Clean Energy Center (Modernization)

The work required to connect the Port Everglades Next Generation Clean Energy Center in 2016 to the FPL grid is projected to be as follows:

I. Substation:

1. Construct two string busses to connect two combustion turbines (CT) to the Port Everglades 138 kV Substation.
2. Construct two string busses to connect one CT, and one steam turbine (ST) to the Port Everglades 230 kV Substation.
3. Add four main step-up transformers (3-450 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. Replace ten (10) 138 kV breakers
5. Replace eight (8) 230 kV breakers
6. At Port Everglades Switchyard replace twenty-two 138 kV disconnect switches. Also upgrade associated jumpers, bus work, and equipment connections.
7. Expand switchyard relay vault and add relays and other protective equipment.

II. Transmission:

1. Upgrade of existing transmission facilities:
   - An ampacity upgrade up to 1905 amps on the Port Everglades-Port Everglades Tap 138kV line section.
   - An ampacity upgrade up to 1905 amps on the Port Everglades Tap-Port Everglade Tap 2 138 kV line section.
   - An ampacity upgrade up to 1695 amps on the Port Everglades Tap 1-Dania 138 kV line section.
   - An ampacity upgrade up to 1695 amps on the Dania-Hollywood 138 kV line section.

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to effectively utilize renewable energy technologies to serve its customers. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. For purposes of discussing FPL's renewable energy efforts in this document, those efforts will be placed into five categories.

Two of these categories are Supply-Side Efforts – Power Purchases and Supply-Side Efforts – FPL Facilities. In 2011, the energy (MWh) total output from these renewable energy sources was greater than the energy produced from oil-fired generation. This information is presented in Schedule 11.1 at the end of this chapter.

1) <u>Early Research & Development Efforts:</u>

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970s in demonstrating the first residential PV system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-kilowatt (kW) system was placed into operation in 1984. (The system was removed in 1990 to make room for substation expansion once PV testing had been completed.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. This FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's "green pricing" efforts.

2) <u>Demand Side & Customer Efforts:</u>

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers who chose solar water heaters. Before the program ended (due to the fact that it was no longer cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for six passive home designs with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code was one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the FPSC to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test were deemed to be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, and various customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

FPL has since continued to analyze and promote the utilization of PV. These efforts have included PV research, development, and education, as well as development and implementation of the FPL Next Generation Solar Station Program. As part of this program in 2011, FPL contributed 30 kW of PV to schools and educational non-profit organizations within its service area. This initiative also delivers teacher training and curriculum that is tied to the Sunshine Teacher Standards in Florida. Additionally, the program provides teacher grants to promote and fund projects in the classrooms.

In addition, FPL assists customers who are interested in installing PV equipment at their facilities. Consistent with Florida Administrative Code Rule 25-6.065, Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned PV systems. Through December 2011, approximately 1,580 customer systems (predominantly residential) have been interconnected.

As part of its 2009 DSM Goals decision, the FPSC imposed a requirement for Florida's investor-owned utilities to spend up to a set, not-to-exceed amount of money annually to facilitate demand side solar water heater and photovoltaic applications. FPL's not-to-exceed amount of money for these applications is approximately $15.5 million per year through 2014. In regard to this direction, FPL received approval from the FPSC in 2011 to initiate a solar pilot portfolio that consists of three PV-based programs and three solar water heating-based programs. These programs are currently projected to be offered through 2014. FPL is now evaluating the results from the first year of implementation of these programs.

FPL has also been investigating fuel cell technologies through monitoring of industry trends, discussions with manufacturers, and direct field trials. From 2002 through the end of 2005, FPL conducted field trials and demonstration projects of Proton Exchange Membrane (PEM) fuel cells with the objectives of serving customer end-uses while evaluating the technical performance, reliability, economics, and relative readiness of the PEM technology. The demonstration projects were conducted in partnership with customers and included five locations. The research projects were useful to FPL in identifying specific issues that can occur in field applications and the current commercial viability of this technology. FPL will continue to monitor the progress of these technologies and conduct additional field evaluations as significant developments in fuel cell technologies occur.

3) **Supply Side Efforts – Power Purchases:**

FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy, and as-available energy, have been purchased by FPL from these types of facilities. (Please refer to Tables I.B.1, I.B.2, and I.C.1 in Chapter I).

Periodically, FPL invites renewable energy suppliers to provide proposals for renewable power and energy at or below avoided costs in response to FPL's Requests for Proposals (RFPs). FPL issued Renewable RFPs in 2007 and 2008 soliciting proposals to provide firm capacity and energy, and energy only, at or below avoided costs, from renewable generators. FPL also promptly responds to inquiries for information from prospective renewable energy suppliers either by e-mail or phone.

With regard to existing contracts that have recently ended, FPL and the Solid Waste Authority of Palm Beach (SWA) agreed to extend their contract that expired March 31, 2010 for a 20-year term beginning in April 1, 2012 through April 1, 2032. However, the SWA refurbished their generating unit ahead of schedule and, as of January 2012, this unit began delivering firm capacity to FPL. In 2011, the FPSC approved a contract for an additional 70 MW between FPL and SWA for a new unit to be constructed. Construction has now commenced. At the end of December 2011, the contract between FPL and Okeelanta (New Hope) expired. However, Okeelanta continues to deliver energy to FPL as an as-available, non-firm supplier of renewable energy.

4) **Supply Side Efforts – FPL Facilities:**

With regard to solar generating facilities, FPL has three such facilities: (i) a 75 MW steam generation solar thermal facility in Martin County (the Martin Next Generation Solar Energy Center); (ii) a 25 MW PV electric generation facility in DeSoto County (the DeSoto Next Generation Solar Energy Center); and (iii) a 10 MW PV electric generation facility in Brevard County at NASA's Kennedy Space Center (the Space Coast Next Generation Solar Energy Center). The DeSoto County project was completed in 2009 and the other two projects were completed in 2010. These three solar facilities were constructed in response to the Florida Legislature's House Bill 7135 which was signed into law by then-Governor Crist in June 2008. House Bill 7135 was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in the State of Florida. Specifically, the bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land, zoning, and transmission rights in place. FPL's three solar projects met the specified criteria, and were granted approval for cost recovery in 2008. Each of the three solar facilities is discussed below.

a. **The Martin Next Generation Solar Energy Center:**

This facility began commercial operation in 2010 and provides 75 MW of solar thermal capacity in an innovative way that directly displaces fossil fuel usage on the FPL system. This facility consists of solar thermal technology which generates steam that is integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired CC plant. This project is the first "hybrid" solar plant in the world, the second largest solar facility in the world, and the largest solar plant of any kind in the U.S. outside of California.

b. **The DeSoto Next Generation Solar Energy Center:**

This PV facility began commercial operation in 2009 and provides 25 MW of non-firm capacity and energy, making it one of the largest PV facilities in the U.S. The facility utilizes a tracking PV array that is designed to follow the sun as it traverses across the sky.

c. **The Space Coast Next Generation Solar Energy Center:**

Located at the Kennedy Space Center, this facility is part of an innovative public/private partnership with NASA. This non-tracking PV facility began commercial operation in 2010 and provides 10 MW of non-firm capacity and energy.

Collectively, these Next Generation Solar Energy Centers are expected to produce a total of approximately 200,000 megawatt-hours (MWh) of electricity each year, and at peak production provide enough energy to serve the requirements of more than 14,380 homes at current levels of average residential use.

For resource planning purposes, FPL currently projects that the output from these renewable facilities will be "as available," non-firm energy only. This is due to several factors. First, the Martin solar thermal facility is a "fuel-substitute" facility, not a facility that provides additional capacity and energy. The solar thermal facility displaces the use of fossil fuel to produce steam on the FPL system when the solar thermal facility is operating. Second, in regard to the two PV facilities, the intermittent nature of the solar resource makes it difficult to accurately determine what contribution the PV facilities at these specific locations can consistently make at FPL's late Summer afternoon and early Winter morning peak load hours. Once site-specific operating data has been gathered for an appropriate amount of time, FPL will then re-evaluate the actual output from each PV facility to determine what portion, if any, of its output can be projected as firm capacity at the projected peak hours in FPL's resource planning work.

In addition to these three solar facilities, FPL is currently in the process of identifying other potential solar sites in the state in the event that a future Renewable Portfolio Standard (RPS), Clean Energy Portfolio Standard (CPS), or other energy legislation is enacted by the Florida legislature that enables FPL to construct and recover costs for additional renewable energy generation. FPL is evaluating existing FPL generation sites along with potential Greenfield sites within FPL's service territory. These potential FPL and Greenfield sites are discussed further in Chapter IV.

FPL remains hopeful of developing a wind generation project on South Hutchinson Island in St. Lucie County. This project is known as the St. Lucie Wind Project and it would consist of up to six wind turbine generators capable of generating up to approximately 13.8 MW. In 2007, FPL began the St. Lucie County land use approval process, and soon after applied for the necessary federal and state permitting. However, a decision by the state and federal agencies on the St. Lucie Wind Project's permitting cannot be finalized until the local land use approval process is completed. At the time this Site Plan document is being developed, the local land use approval process has not been completed. An in-service date for the project is dependent upon a successful outcome in the local approval and permitting process.

5) **Ongoing Research & Development Efforts:**

FPL has developed alliances with several Florida universities to promote development of emerging technologies. For example, an alliance has been established with the newly formed Southeast National Marine Renewable Energy Center (SNMREC) at Florida Atlantic University (FAU), which will focus on the commercialization of ocean current, ocean thermal (i.e., energy conversion as well as cold water air conditioning), and hydrogen technologies. FPL has been taking the lead in assisting FAU with the discussions being held with the U.S. Department of the Interior's Minerals Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE). BOEMRE is working to establish the permitting process for ocean energy development on the outer continental shelf.

FPL has also developed an alliance with the University of Florida to support its biomass-related studies to determine improved vegetative management techniques for use in minimizing maintenance costs at FPL's current and future solar sites and to perform wind studies within the state. In addition, FPL has partnered with the Florida Institute of Technology on fuel cell technology and with the Florida State Universities Center for Applied Power System in regard to grid integration of ocean energy and other renewables.

FPL has also developed a "Living Lab" to demonstrate FPL's solar energy commitment to employees and visitors at its Juno Beach office facility. To-date, FPL has installed five different PV arrays (different technologies) of rooftop PV totaling 24 kW at the Living Lab. In addition, construction of two PV-covered parking structures with a total of approximately 90 kW of PV is near completion at the FPL Juno office parking lot. Through these Living Lab projects, FPL is able to evaluate multiple solar technologies and applications for the purpose of developing a renewable business model resulting in the most cost-effective and reliable uses of solar energy for FPL's customers. FPL plans to continue to expand the Living Lab as new solar products come to market.

FPL has also been in discussions with several private companies on multiple emerging technology initiatives including ocean current, ocean thermal, hydrogen, fuel cell technology, biomass, biofuels, and energy storage.

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fired generation. In the early 1980s, FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership (20%) and additional purchases (30%) from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit 4 which began serving FPL's customers in 1991. Starting in 1997, petroleum coke was added to the fuel mix as a blend stock with coal at SJRPP when economic.

The trend since the early 1990s has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective CC generating units and the ready availability of natural gas. This planning document reflects an evolution in that trend in recognition that, although efficient gas-fired generation continues to provide significant benefits to FPL's customers, adding natural gas-fired additions exclusively would, in the long term, create an unbalanced generation portfolio. In 2009, FPL placed into commercial operation two new gas-fired CC units at the West County Energy Center (WCEC) site. A third new CC unit was added to the WCEC site in 2011. In addition, FPL is currently modernizing its existing Cape Canaveral and Riviera plant sites by removing the steam generating units previously on the sites and replacing them with two highly efficient new CC units, one at each site. FPL has also recently received

FPSC approval to perform a similar modernization project at its Port Everglades site. These new CC units will provide highly efficient generation that will dramatically improve the efficiency of FPL's generation system in general, and, more specifically, the efficiency at which natural gas is utilized..

In addition, FPL is increasing its utilization of nuclear energy through capacity uprates of its four existing nuclear units. These uprates have begun and will add a total of approximately 490 MW of nuclear generation capacity by early 2013. 31 MW of the projected 490 MW total increase have already been added at FPL's St. Lucie Unit 2 and this increased nuclear capacity is already benefitting FPL's customers. (FPL is also pursuing plans to obtain licenses, permits, and approvals to construct and operate two new nuclear units at its existing Turkey Point site that, in total, would add approximately 2,200 MW of new nuclear generating capacity. The earliest dates by which those new nuclear units could practically be deployed continue to be outside of the ten-year reporting time frame of this document.)

In regard to utilizing renewable energy, FPL has added 110 MW of solar generating capacity through a 75 MW solar thermal steam generating facility at FPL's existing Martin site, a 25 MW PV facility in DeSoto County, and a 10 MW PV facility in Brevard County. The DeSoto facility was placed into commercial operation in 2009. The other two solar facilities were placed into commercial operation in 2010.

FPL's future resource planning work will continue to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance FPL's long-term fuel diversity. These fuel diverse alternatives may include: the purchase of power from renewable energy facilities, additional FPL-owned renewable energy facilities, obtaining additional access to diversified sources of natural gas such as liquefied natural gas (LNG) and natural gas from the Mid-Continent unconventional reserves, preserving FPL's ability to utilize fuel oil at its existing units, and increased utilization of nuclear energy. (As previously discussed, new advanced technology coal generating units are not currently considered as viable options in Florida in the ten-year reporting period of this document due, in part, to current projections of relatively small differences in fuel costs between coal and natural gas, significantly higher capital costs for coal units compared to CC units, greater efficiencies of CC units, and concerns over non-greenhouse gas environmental regulations that would impact coal units more negatively than CC units.) The evaluation of the feasibility and cost-effectiveness of these, and other possible fuel diversity alternatives, will be part of on-going resource planning efforts.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2021 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

2. FPL's Fossil Fuel Cost Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future resource needs. FPL's forecasts are generally consistent with other published contemporary forecasts.

Future oil and natural gas prices, and to a lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, coal, and petroleum coke. These drivers include U.S. and worldwide demand, production capacity, economic growth, environmental legislation, and politics.

The inherent uncertainty and unpredictability in these factors today and tomorrow clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal and petroleum coke) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed and utilized Low, Medium, and High price forecasts for fossil fuels in some of its 2011 and early 2012 resource planning work, particularly in regard to analyses conducted as part of the nuclear cost recovery filing work.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

a. For 2011 through 2013, the methodology used the November 14, 2011 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil, ultra low sulfur diesel fuel oil, and Henry Hub natural gas commodity prices;

b. For the next two years (2014 and 2015), FPL used a 50/50 blend of the November 14, 2011 forward curve and the most current projections at the time from The PIRA Energy Group;

c. For the 2016 through 2025 period, FPL used the annual projections from The PIRA Energy Group; and,

d. For the period beyond 2025, FPL used the real rate of escalation from the Energy Information Administration (EIA). In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach:

a. Delivered price forecasts for Central Appalachian (CAPP), Illinois Basin (IB), Powder River Basin (PRB), and South American coal and petroleum coke were provided by JD Energy; and,

b. The coal price forecast for SJRPP and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for oil, natural gas, coal, and petroleum coke prices were based on the historical volatility of the 12-month forward price, one year ahead. FPL developed these forecasts to account for the uncertainty which exists within each commodity as well as across commodities. These forecasts reflect a range of reasonable forecast outcomes.

3. Nuclear Fuel Cost Forecast

This section reviews the various steps needed to fabricate nuclear fuel for delivery to the nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

a) Steps Required for Nuclear Fuel to be delivered to FPL's Plants

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

(1) Mining: Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U3O8 (sometimes referred to as yellowcake).

(2) Conversion: During the second step, the U3O8 is chemically converted into UF6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

(3) Enrichment: The third step is called enrichment. Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 3% to as high as 5%). The output of this enrichment process is enriched uranium in the form of UF6.

(4) Fabrication: During the last step, fuel fabrication, the enriched UF6 is changed to a UO2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) Mining: There is some volatility in the current uranium market. Current demand continues to be rather stable and outputs from production facilities have been increasing steadily. The following are the current major contributors that led to some volatility in the prices for uranium:

- In March 2011, an earthquake and tsunami struck the Fukushima nuclear complex in Japan. The immediate impact was a perceived reduction in worldwide nuclear fuel demand and thus prices have generally declined, with some small periodic increases through 2011.

- Hedge funds are currently in the market. This causes more speculative demand, not tied to market fundamentals, and causes the market price to move according to news potentially affecting potential future supply/demand balance, or news regarding current suppliers.

- The large inventory from the U.S. Department of Energy (DOE) is being withheld from the market due to political pressure from suppliers. Some of this uranium finds its way into the market periodically to fund cleanup of certain Department of Energy facilities.

- The U.S. Department of Commerce (DOC) has imposed restrictions on the import of nuclear fuel from France and Russia.

- Although a limited number of new nuclear units is scheduled to start production in the U.S. during the next 5 to 10 years, other countries, more specifically China, have announced a significant increase in construction of new units which has caused a short term increase in the uranium market price.

Over a 10-year horizon, FPL expects the market to be more consistent with market fundamentals The supply picture is more stable, with laws enacted to resolve the import of Russian-enriched uranium, by allowing some imports of Russian-enriched uranium to meet about 20-25% of needs for currently operating units, but with no restriction on the first core for new units and no restrictions after 2020. New and current facilities continue to add capacity to meet demands. Actual demand tends to grow over time because of the long lead time to build nuclear units. However, FPL cannot discount the possibility of future periodic sharp increase in prices, but believes such occurrences will likely be temporary in nature.

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies.

(2) Conversion: FPL's price forecast considers the construction of new nuclear units. Just like for raw uranium, an increase in demand for conversion services would result from this need. Insufficient planned production is currently forecasted after 2013 to meet the higher demand scenario, but is sufficient to meet most reference case scenarios. As with additional raw uranium production, supply will expand beyond current level once more firm commitments are made including commitments to building new nuclear units.

(3) Enrichment: As a result of the Fukushima events in March 2011, the near-term price of enrichment services has declined. However, plans for several of the new facilities that were expected to come on-line in the next few years have been delayed. Also, some of the current high operating cost diffusion plants are indicating that they will shutdown in the next year or two. As with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand. Meanwhile, world supply and demand will continue to be balanced such that FPL expects adequate supply of enrichment services. The tight supply/demand profile will most likely cause the price of enrichment services to remain stable or decline for the next few years before starting to increase.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the Nuclear Regulatory Commission (NRC), not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand is expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast

The calculations for the nuclear fuel cost forecasts used in FPL's 2011 and early 2012 resource planning work were performed consistent with the method then used for FPL's Fuel Clause filings, including the assumption of refueling outages every 18 months and plant operation at power uprate levels. The costs for each step to fabricate the nuclear fuels were added to come up with the total costs of the fresh fuel to be loaded at each refueling (acquisition costs). The acquisition cost for each group of fresh fuel assemblies were then amortized over the energy produced by each group of fuel assemblies. FPL also added 1 mill per kilowatt hour net to reflect payment to DOE for spent fuel disposal.

Schedule 5
Fuel Requirements
(for FPL only)

	Fuel Requirements	Units	Actual 1/ 2010	2011	Forecasted 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Nuclear	Trillion BTU	250	241	208	286	303	285	307	307	294	306	306	294
(2)	Coal	1,000 TON	3,191	3,135	2,895	3,497	3,254	3,832	3,699	4,069	3,713	4,065	3,761	4,079
(3)	Residual (FO6) - Total	1,000 BBL	6,754	1,141	1,516	664	494	671	768	731	636	690	766	1,041
(4)	Steam	1,000 BBL	6,754	1,141	1,516	664	494	671	768	731	636	690	766	1,041
(5)	Distillate (FO2) - Total	1,000 BBL	522	332	2	51	0	0	15	5	9	32	63	76
(6)	Steam	1,000 BBL	4	2	0	0	0	0	0	0	0	0	0	0
(7)	CC	1,000 BBL	194	290	0	12	0	0	4	3	5	8	16	23
(8)	CT	1,000 BBL	324	40	2	40	0	0	11	2	5	24	47	53
(9)	Natural Gas - Total	1,000 MCF	504,996	555,988	565,962	514,784	535,140	545,403	546,986	563,767	588,554	586,343	602,249	624,406
(10)	Steam	1,000 MCF	56,729	61,272	29,586	10,538	7,785	10,572	12,601	11,852	10,409	11,206	12,447	16,842
(11)	CC	1,000 MCF	443,108	486,116	535,610	502,562	527,045	534,746	533,914	551,606	577,940	574,788	589,210	606,514
(12)	CT	1,000 MCF	5,159	8,600	766	1,684	310	84	471	310	205	349	591	1,050

1/ Source: A Schedules.
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual [1/] 2010	Actual [1/] 2011	Forecasted 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Annual Energy Interchange 2/	GWH	8,333	6,008	4,214	3,205	3,197	4,091	2,805	658	0	0	0	0
(2)	Nuclear	GWH	22,650	21,510	19,162	26,493	28,076	26,465	28,458	28,463	27,286	28,376	28,545	27,288
(3)	Coal	GWH	5,721	5,634	5,064	6,029	5,683	6,825	6,743	7,395	6,791	7,391	6,884	7,417
(4)	Residual(FO6) -Total	GWH	4,081	630	971	422	314	430	491	468	407	441	490	666
(5)	Steam	GWH	4,081	630	971	422	314	430	491	468	407	441	490	666
(6)	Distillate(FO2) -Total	GWH	279	123	1	21	0	0	7	3	5	14	27	36
(7)	Steam	GWH	2	1	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	143	107	0	9	0	0	4	2	4	6	13	19
(9)	CT	GWH	134	15	1	12	0	0	4	1	2	7	14	17
(10)	Natural Gas -Total	GWH	66,771	74,388	78,888	73,106	77,223	78,824	79,606	82,436	86,264	85,886	88,106	90,976
(11)	Steam	GWH	5,041	5,429	2,828	995	739	1,008	1,197	1,127	989	1,066	1,184	1,603
(12)	CC	GWH	61,304	68,328	75,999	72,005	76,457	77,609	78,376	81,285	85,258	84,795	86,879	89,293
(13)	CT	GWH	426	631	61	105	27	7	35	24	16	26	44	80
(14)	Solar [3/]	GWH	69	71	195	209	209	186	208	192	207	206	200	206
(15)	PV	GWH	69	71	73	72	72	71	71	70	70	69	69	68
(16)	Solar Thermal [4/]	GWH	0	0	122	137	137	115	138	122	137	137	131	137
(17)	Other [5/]	GWH	6,441	4,090	2,662	3,003	3,280	4,587	4,990	5,192	5,310	5,604	6,380	7,057
	Net Energy For Load 6/	GWH	114,475	112,454	111,156	112,487	117,982	121,407	123,310	124,806	126,270	127,919	130,631	133,646

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies (UPS contract).
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Estimated projected values Solar thermal does not produce GWh, but produces steam that displaces fossil fuel-derived steam.
Its 2011 contribution to the Martin 8 CC GWh output is rolled into row (12) for reporting purposes. Its projected contributions for 2012 - 2021 are provided separately on row (16).
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
6/ Net Energy For Load values for the years 2012 - 2021 are also shown in Col. (19) on Schedule 2 3

Schedule 6.2
Energy Sources % by Fuel Type

	Energy Source	Units	Actual [1] 2010	Actual [1] 2011	Forecasted 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Annual Energy Interchange [2]	%	7.3	5.3	3.8	2.8	2 7	3.4	2.3	0.5	0.0	0.0	0.0	0.0
(2)	Nuclear	%	20.0	19.1	17.2	23 6	23 8	21.8	23.1	22.8	21 6	22.2	21.9	20.4
(3)	Coal	%	5.0	5.0	4.6	5 4	4.8	5.8	5.5	5 9	5.4	5.8	5.3	5 5
(4)	Residual (FO6) -Total	%	3.6	0.6	0.9	0 4	0.3	0.4	0.4	0 4	0.3	0 3	0.4	0 5
(5)	Steam	%	3 6	0.6	0.9	0.4	0.3	0.4	0.4	0.4	0 3	0 3	0.4	0.5
(6)	Distillate (FO2) -Total	%	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0 0	0 0	0.0
(8)	CC	%	0.1	0.1	0.0	0 0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0 0
(9)	CT	%	0.1	0.0	0 0	0.0	0 0	0.0	0.0	0.0	0 0	0 0	0 0	0.0
(10)	Natural Gas -Total	%	58.3	66.1	71.0	65.0	65.5	64 9	64 6	66.1	68 3	67.1	67.4	68.1
(11)	Steam	%	4.4	4.8	2.5	0 9	0 6	0 8	1 0	0.9	0 8	0.8	0 9	1 2
(12)	CC	%	53.6	60.8	68.4	64.0	64.8	64.1	63.6	65 1	67 5	66.3	66 5	66 8
(13)	CT	%	0.4	0.6	0.1	0.1	0.0	0 0	0.0	0.0	0.0	0.0	0 0	0.1
(14)	Solar [3]	%	0.1	0.1	0 2	0.2	0.2	0.2	0.2	0 2	0 2	0 2	0.2	0.2
(15)	PV	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0 1
(16)	Solar Thermal [4]	%	0.0	0.0	0.1	0.1	0.1	0.1	0 1	0.1	0.1	0 1	0.1	0.1
(17)	Other [5]	%	5 6	3 6	2.4	2.7	2.8	3.8	4.0	4.2	4.2	4.4	4.9	5.3
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies (UPS contract).
3/ Represents output from FPL's PV and solar thermal facilities
4/ Estimated projected values Solar thermal does not produce GWh, but produces steam that displaces fossil fuel-derived steam.
Its 2011 contribution to the Martin 8 CC GWh output is rolled into row (12) for reporting purposes. Its projected contributions for 2012 - 2021 are provided separately on row (16)
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
6/ Net Energy For Load values for the years 2012 - 2021 are also shown in Col. (19) on Schedule 2.3.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2012	23,502	1,733	0	635	25,870	21,623	1,991	19,632	6,238	31.8	745	5,493	28.0
2013	24,208	1,303	0	635	26,146	21,931	2,114	19,817	6,329	31.9	826	5,503	27.8
2014	25,482	1,303	0	635	27,420	23,243	2,277	20,966	6,453	30.8	826	5,627	26.8
2015	25,553	1,303	0	635	27,491	23,786	2,408	21,378	6,113	28.6	0	6,113	28.6
2016	26,434	375	0	705	27,514	24,315	2,540	21,775	5,738	26.4	0	5,738	26.4
2017	26,434	0	0	705	27,139	24,529	2,671	21,858	5,280	24.2	0	5,280	24.2
2018	26,434	0	0	705	27,139	24,674	2,802	21,871	5,267	24.1	0	5,267	24.1
2019	26,434	0	0	705	27,139	25,041	2,934	22,107	5,031	22.8	0	5,031	22.8
2020	26,434	0	0	705	27,139	25,499	3,043	22,456	4,683	20.9	0	4,683	20.9
2021	26,684	0	0	705	27,389	25,960	3,143	22,817	4,572	20.0	0	4,572	20.0

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2011 load forecast without incremental DSM or cumulative load management.
Col. (8) represents cumulative load management capability, plus incremental conservation, from 1/2012-on intended for use with the 2011 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of:
(i) 745 MW (at St. Lucie Unit 2) of nuclear capacity that will be out-of-service during part of Summer in 2012 due to an extended planned outage as part of the capacity uprates project;
(ii) an additional 826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin Unit 1) and in the Summer of 2014 (at Martin Unit 2) due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
January of Year	Firm Installed Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2012	24,513	1,866	0	635	27.014	20,889	1,673	19,216	7,797	40.6	1,675	6,122	31.9
2013	24,104	1,311	0	635	26,050	21,101	1,787	19.314	6,735	34.9	1,539	5,196	26.9
2014	25,617	1,311	0	635	27,563	21,959	1,946	20,014	7,549	37.7	832	6,717	33.6
2015	27,034	1.311	0	635	28,980	22,412	2,070	20,342	8,638	42.5	0	8,638	42.5
2016	27,084	383	0	705	28,172	22,675	2,194	20,481	7,691	37.6	0	7,691	37.6
2017	28,115	383	0	705	29,203	22.902	2,319	20,584	8,619	41.9	0	8,619	41.9
2018	28,115	0	0	705	28,820	23,151	2,444	20,708	8,112	39.2	0	8,112	39.2
2019	28,115	0	0	705	28,820	23,403	2,568	20.835	7,985	38.3	0	7,985	38.3
2020	28.115	0	0	705	28.820	23,667	2,667	21,000	7,819	37.2	0	7,819	37.2
2021	28,115	0	0	705	28.820	23,952	2,757	21,195	7,624	36.0	0	7,624	36.0

Col. (2) represents capacity additions and changes projected to be in-service by January 1st. These MW are generally considered to be available to meet winter peak loads which are forecasted to occur during January of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2011 load forecast without incremental DSM or cumulative load management. 2011 load is an actual load value.
Col. (8) represents cumulative load management capability, plus incremental conservation, from 1/2011-on intended for use with the 2011 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Winter peak period. This value is comprised of:
(i)an additional 853 MW (at St. Lucie Unit 1) of nuclear capacity that will be out-of-service during part of the Winter of 2012 due to extended planned outages as part of the capacity uprates project; (ii) 717 MW(at Turkey Point Unit 4) that will be out-of-service in Winter of 2013 due to an extended planned outage as part of the capacity uprates project; (iii) an additional 822 MW that will be out-of-service in the Winter of 2012 (at Manatee Unit 2) and in the Winter of 2013 (at Manatee Unit 1) due to the installation of electrostatic precipitators; and (iv) an additional 832 MW (at Martin Unit 1) that will be out-of-service during the Winter of 2014 due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Schedule 7.3
Projection of Generation - Only Reserves
At Time Of Summer Peak (Assuming PEEC in 2016 but no 2021 PPA)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2012	23,502	1,733	0	635	25,870	21,623	0	21,623	4,246	19.6	745	3,501	16.2
2013	24,208	1,303	0	635	26,146	21,931	0	21,931	4,214	19.2	826	3,388	15.5
2014	25,482	1,303	0	635	27,420	23,243	0	23,243	4,176	18.0	826	3,350	14.4
2015	25,553	1,303	0	635	27,491	23,786	0	23,786	3,704	15.6	0	3,704	15.6
2016	26,434	375	0	705	27,514	24,315	0	24,315	3,199	13.2	0	3,199	13.2
2017	26,434	0	0	705	27,139	24,529	0	24,529	2,609	10.6	0	2,609	10.6
2018	26,434	0	0	705	27,139	24,674	0	24,674	2,465	10.0	0	2,465	10.0
2019	26,434	0	0	705	27,139	25,041	0	25,041	2,097	8.4	0	2,097	8.4
2020	26,434	0	0	705	27,139	25,499	0	25,499	1,640	6.4	0	1,640	6.4
2021	26,434	0	0	705	27,139	25,960	0	25,960	1,179	4.5	0	1,179	4.5

Col. (2) represents capacity additions and changes, **assuming no generation additions in 2021.**
Col. (6) = Col.(2) + Col.(3) - Col (4) + Col.(5).
Col. (7) reflects the load forecast without incremental DSM or cumulative load management.
Col. (8) shows zero contribution from DSM in order to calculate FPL's reserves that are supplied only by generation resourc
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of: (i) 745 MW (at St. Lucie Unit 2) of nuclear capacity that will be out-of-service during part of Summer in 2012 due to an extended planned outage as part of the capacity uprates project; and (ii) an additional 826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin Unit 1) and in the Summer of 2014 (at M due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Schedule 7.4
Projection of Generation - Only Reserves
At Time Of Summer Peak (Assuming PEEC in 2016 and 2021 PPA)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2012	23,502	1,733	0	635	25,870	21,623	**0**	21,623	4,246	19.6	745	3,501	**16.2**
2013	24,208	1,303	0	635	26,146	21,931	**0**	21,931	4,214	19.2	826	3,388	**15.5**
2014	25,482	1,303	0	635	27,420	23,243	**0**	23,243	4,176	18.0	826	3,350	**14.4**
2015	25,553	1,303	0	635	27,491	23,786	**0**	23,786	3,704	15.6	0	3,704	**15.6**
2016	26,434	375	0	705	27,514	24,315	0	24,315	3,199	13.2	0	3,199	**13.2**
2017	26,434	0	0	705	27,139	24,529	0	24,529	2,609	10.6	0	2,609	**10.6**
2018	26,434	0	0	705	27,139	24,674	0	24,674	2,465	10.0	0	2,465	**10.0**
2019	26,434	0	0	705	27,139	25,041	0	25,041	2,097	8.4	0	2,097	**8.4**
2020	26,434	0	0	705	27,139	25,499	**0**	25,499	1,640	6.4	0	1,640	**6.4**
2021	26,684	0	0	705	27,389	25,960	**0**	25,960	1,429	5.5	0	1,429	**5.5**

Col. (2) represents capacity additions and changes, assuming a 250 MW PPA is added in 2021.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the load forecast without incremental DSM or cumulative load management.
Col. (8) shows zero contribution from DSM in order to calculate FPL's reserves that are supplied only by generation resourc
Col. (10) = Col (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of: (i) an additional 745 MW (at St. Lucie Unit 2) of nuclear capacity that will be out-of-service during part of Summer in 2012 due to an extended planned outage as part of the capacity uprates project; and (ii) an additional 826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin Unit 1) and in the Summer of 2014 (at M due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability [1]		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2012														
Manatee	2	Manatee County	ST	FO6	NG	WA	PL	May-12	Jun-12	Unknown	863,300	—	(3)	P
Scherer	4	Monroe, GA	BIT	SUB	No	RR	No	Apr-12	May-12	Unknown	880,388	—	(30)	P
Sanford CT Upgrade	5A	Volusia County	CC	NG	No	PL	No	Feb-12	Mar-12	Unknown	1,188,860	—	10	P
Sanford CT Upgrade	5D	Volusia County	CC	NG	No	PL	No	Feb-12	Mar-12	Unknown	1,188,860	—	9	P
St. Lucie (Uprates) [2]	1	St. Lucie County	NP	UR	No	TK	No	See Note 2	Dec-11	Unknown	850,000	—	129	T
Turkey Point (Uprates) [2]	3	Miami Dade County	NP	UR	No	TK	No	See Note 2	May-12	Unknown	759,900	—	123	T
								2012 Changes/Additions w/o Inactive Reserve Total:				0	238	
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	389	387	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	376	374	OT
								2012 Changes/Additions with Inactive Reserve Total:				765	999	
2013														
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	PL	Jun-11	Jun-13	Unknown	1,295,750	—	1,210	T
Scherer	4	Monroe, GA	BIT	SUB	No	RR	No	Unknown	May-12	Unknown	880,388	(28)	—	P
Manatee	2	Manatee County	ST	FO6	NG	WA	PL	May-12	Jun-12	Unknown	863,300	(3)	—	P
Sanford CT Upgrade	5A	Volusia County	CC	NG	No	PL	No	Feb-12	Mar-12	Unknown	1,188,860	10	—	P
Sanford CT Upgrade	5D	Volusia County	CC	NG	No	PL	No	Feb-12	Mar-12	Unknown	1,188,860	9	—	P
Sanford CT Upgrade	5C	Volusia County	CC	NG	No	PL	No	Jan-13	Feb-13	Unknown	1,188,860	—	9	P
Martin CT Upgrade	8B	Martin County	CC	NG	FO2	PL	PL	Nov-12	Dec-12	Unknown	1,224,510	10	10	P
Sanford CT Upgrade	4A	Volusia County	CC	NG	No	PL	No	Oct-12	Nov-12	Unknown	1,188,860	11	8	P
Sanford CT Upgrade	4B	Volusia County	CC	NG	No	PL	No	Sep-12	Oct-12	Unknown	1,188,860	11	7	P
Sanford CT Upgrade	4C	Volusia County	CC	NG	No	PL	No	Mar-13	Apr-13	Unknown	1,188,860	—	8	P
Sanford CT Upgrade	4D	Volusia County	CC	NG	No	PL	No	Mar-13	Mar-13	Unknown	1,188,860	—	8	P
St. Lucie (Uprates) [2]	1	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	850,000	129	—	T
St. Lucie (Uprates) [2]	2	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	723,775	84	84	T
Turkey Point (Uprates) [2]	3	Miami Dade County	NP	UR	No	TK	No	—	See Note 2	Unknown	759,900	123	—	T
Turkey Point (Uprates) [2]	4	Miami Dade County	NP	UR	No	TK	No	—	See Note 2	Unknown	759,900	—	123	T
								2013 Changes/Additions w/o Inactive Reserve Total:				356	1,467	
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(389)	(387)	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(376)	(374)	OT
								2013 Changes/Additions with Inactive Reserve Total:				(409)	706	
2014														
Turkey Point (Uprates) [2]	4	Miami Dade County	NP	UR	No	TK	No	—	See Note 2	Unknown	759,900	123	—	T
Sanford CT Upgrade	4C	Volusia County	CC	NG	No	PL	No	Mar-13	Apr-13	Unknown	1,188,860	8	—	P
Sanford CT Upgrade	4D	Volusia County	CC	NG	No	PL	No	Mar-13	Mar-13	Unknown	1,188,860	8	—	P
Sanford CT Upgrade	5B	Volusia County	CC	NG	No	PL	No	Aug-13	Sep-13	Unknown	1,188,860	10	—	P
Sanford CT Upgrade	5C	Volusia County	CC	NG	No	PL	No	Jan-13	Feb-13	Unknown	1,188,860	9	10	P
Manatee CT Upgrade	3C	Manatee County	CC	NG	No	PL	No	Apr-14	May-14	Unknown	1,224,510	—	10	P
Manatee CT Upgrade	3D	Manatee County	CC	NG	No	PL	No	Apr-14	May-14	Unknown	1,224,510	—	9	P
Turkey Point CT Upgrade	5A	Miami Dade County	CC	NG	FO2	PL	PL	Jan-14	Feb-14	Unknown	1,224,510	—	8	P
Turkey Point CT Upgrade	5B	Miami Dade County	CC	NG	FO2	PL	PL	Jan-14	Feb-14	Unknown	1,224,510	—	8	P
Turkey Point CT Upgrade	5C	Miami Dade County	CC	NG	FO2	PL	PL	Feb-14	Mar-14	Unknown	1,224,510	—	8	P
Turkey Point CT Upgrade	5D	Miami Dade County	CC	NG	FO2	PL	PL	Feb-14	Mar-14	Unknown	1,224,510	—	9	P
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	PL	Jun-11	Jun-13	Unknown	1,295,750	1,355	—	T
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	PL	PL	Jun-12	Jun-14	Unknown	1,295,750	—	1,212	T
								2014 Changes/Additions w/o Inactive Reserve Total:				1,513	1,274	

(1) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring later in the year will be picked up for reporting/planning purposes in the following year.
(2) The nuclear uprates will be performed during the extended outages for each unit.

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

Plant Name (1)	Unit No (2)	Location (3)	Unit Type (4)	Fuel Pri. (5)	Fuel Alt. (6)	Fuel Transport Pri. (7)	Fuel Transport Alt. (8)	Const. Start Mo./Yr. (9)	Comm. In-Service Mo./Yr. (10)	Expected Retirement Mo./Yr. (11)	Gen. Max. Nameplate KW (12)	Firm Net Capability [1] Winter MW (13)	Firm Net Capability [1] Summer MW (14)	Status (15)
ADDITIONS/ CHANGES														
2015														
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	PL	PL	Jun-12	Jun-14	Unknown	1,296,750	1,344	—	T
Manatee CT Upgrade	3A	Manatee County	CC	NG	No	PL	No	Aug-14	Sep-14	Unknown	1,224,510	10	10	P
Manatee CT Upgrade	3B	Manatee County	CC	NG	No	PL	No	Aug-14	Sep-14	Unknown	1,224,510	10	10	P
Manatee CT Upgrade	3C	Manatee County	CC	NG	No	PL	No	Apr-14	May-14	Unknown	1,224,510	10	—	P
Manatee CT Upgrade	3D	Manatee County	CC	NG	No	PL	No	Apr-14	May-14	Unknown	1,224,510	9	—	P
Turkey Point CT Upgrade	5A	Miami Dade County	CC	NG	FO2	PL	PL	Jan-14	Feb-14	Unknown	1,224,510	8	—	P
Turkey Point CT Upgrade	5B	Miami Dade County	CC	NG	FO2	PL	PL	Jan-14	Feb-14	Unknown	1,224,510	8	—	P
Turkey Point CT Upgrade	5C	Miami Dade County	CC	NG	FO2	PL	PL	Feb-14	Mar-14	Unknown	1,224,510	8	—	P
Turkey Point CT Upgrade	5D	Miami Dade County	CC	NG	FO2	PL	PL	Feb-14	Mar-14	Unknown	1,224,510	9	—	P
Ft. Myers CT Upgrade	2A	Lee County	CC	NG	No	PL	No	Jun-15	Jul-15	Unknown	1,775,390	—	8	P
Ft. Myers CT Upgrade	2B	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	1,775,390	—	8	P
Ft. Myers CT Upgrade	2C	Lee County	CC	NG	No	PL	No	Jul-15	Aug-15	Unknown	1,775,390	—	9	P
Ft. Myers CT Upgrade	2D	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	1,775,390	—	8	P
Ft. Myers CT Upgrade	2E	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	1,775,390	—	9	P
Ft. Myers CT Upgrade	2F	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	1,775,390	—	9	P
											2015 Changes/Additions w/o Inactive Reserve Total:	1,416	71	
2016														
Port Everglades Next Generation Clean Energy Center	1	—	CC	NG	FO2	PL	PL	Jun-14	Jun-16	Unknown	Unknown	—	1,277	P
Ft. Myers CT Upgrade	2A	Lee County	CC	NG	No	PL	No	Jun-15	Jul-15	Unknown	1,775,390	8	—	P
Ft. Myers CT Upgrade	2B	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	1,775,390	8	—	P
Ft. Myers CT Upgrade	2C	Lee County	CC	NG	No	PL	No	Jul-15	Aug-15	Unknown	1,775,390	9	—	P
Ft. Myers CT Upgrade	2D	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	1,775,390	8	—	P
Ft. Myers CT Upgrade	2E	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	1,775,390	9	—	P
Ft. Myers CT Upgrade	2F	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	1,775,390	9	—	P
Turkey Point Synchronous condenser	1	Miami Dade County	ST	FO6	NG	WA	PL	—	—	Jun-16	402,050	—	(396)	P
											2016 Changes/Additions w/o Inactive Reserve Total:	51	881	
2017														
Port Everglades Next Generation Clean Energy Center	1	—	CC	NG	FO2	PL	PL	Jun-14	Jun-16	Unknown	Unknown	1,429	—	P
Turkey Point Synchronous condenser	1	Miami Dade County	ST	FO6	NG	WA	PL	—	—	Jun-16	402,050	(398)	—	P
											2017 Changes/Additions w/o Inactive Reserve Total:	1,031	0	
2018														
												—	—	
											2018 Changes/Additions w/o Inactive Reserve Total:	0	0	
2019														
												—	—	
											2019 Changes/Additions w/o Inactive Reserve Total:	0	0	
2020														
												—	—	
											2020 Changes/Additions w/o Inactive Reserve Total:	0	0	
2021														
Short Term Purchase		---						Jun-18	Jun-20	Unknown	Unknown	---	250	P
											2021 Changes/Additions w/o Inactive Reserve Total:	0	250	

(1) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring later in the year will be picked up for reporting/planning purposes in the following year

(2) The nuclear uprates will be performed during the extended outages for each unit.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** St. Lucie 1 Nuclear (Uprate)

(2) **Capacity**
a. Summer 129 MW (Incremental)
b. Winter 129 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data** *

Book Life (Years):	25	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost:	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2012 Nuclear Cost Recovery filing.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point 3 Nuclear (Uprate)

(2) **Capacity**
a. Summer 123 MW (Incremental)
b. Winter 123 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data ***

Book Life (Years):	21	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2012 Nuclear Cost Recovery filing.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** St. Lucie 2 Nuclear (Uprate)

(2) **Capacity**
a. Summer 84 MW (final incremental FPL's ownership share; 31 MW have already been achieved)
b. Winter 84 MW (final incremental FPL's ownership share; 31 MW have already been achieved)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date. 2012 (final increase)

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data *,****

Book Life (Years):	32	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2012 Nuclear Cost Recovery filing. nuclear units.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Turkey Point 4 Nuclear (Uprate)	
(2)	**Capacity**		
	a. Summer	123	MW (Incremental)
	b. Winter	123	MW (Incremental)
(3)	**Technology Type:**	Nuclear	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	During scheduled refueling outage	
	b. Commercial In-service date:	2013	
(5)	**Fuel**		
	a. Primary Fuel	Uranium	
	b. Alternate Fuel	---	
(6)	**Air Pollution and Control Strategy:**	No change from existing unit	
(7)	**Cooling Method:**	No change from existing unit	
(8)	**Total Site Area:**	No change from existing unit	
(9)	**Construction Status:**	T	(Regulatory approval received, but not under construction)
(10)	**Certification Status:**	T	(Regulatory approval received, but not under construction)
(11)	**Status with Federal Agencies:**	T	(Regulatory approval received, but not under construction)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	No change from existing unit	
	Forced Outage Factor (FOF):	No change from existing unit	
	Equivalent Availability Factor (EAF):	No change from existing unit	
	Resulting Capacity Factor (%):	No change from existing unit	
	Average Net Operating Heat Rate (ANOHR):	No change from existing unit	
	Base Operation 75F,100%	No change from existing unit	
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	21	years (Matches the current operating license period.)
	Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
	Direct Construction Cost ($/kW):	TBD	(See Note (1) for explanation.)
	AFUDC Amount ($/kW):		(See Note (2) for explanation.)
	Escalation ($/kW):		(See Note (3) for explanation.)
	Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
	Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
	K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2012 Nuclear Cost Recovery filing.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Cape Canaveral Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,210 MW
b. Winter 1,355 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2011
b. Commercial In-service date: 2013

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 43 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.5%	
Resulting Capacity Factor (%):	Approx. 90 %	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,484	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2013 $/kW):	921	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	98	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2013 $)	13.29	
Variable O&M ($/MWH): (2013 $)	0.16	
K Factor:	1.484	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing plant are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Riviera Beach Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,212 MW
b. Winter 1,344 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2012
b. Commercial In-service date: 2014

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 33 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.5%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,480	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2014 $/kW):	1,053	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	121	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2014 $)	13.67	
Variable O&M ($/MWH): (2014 $)	0.13	
K Factor:	1.509	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.Demolition costs of existing plant are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Port Everglades Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,277 MW
b. Winter 1,429 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2014
b. Commercial In-service date: 2016

(5) **Fuel**
a. Primary Fuel — Natural Gas
b. Alternate Fuel — Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** Existing Site Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.5%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	95.4%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,330	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2016 $/kW):	928	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	87	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2016 $)	30.00	
Variable O&M ($/MWH): (2016 $)	0.10	
K Factor:	1.51	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing plant are not included.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

St. Lucie 1 Nuclear (Uprate)

The St. Lucie 1 Nuclear (Uprate) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point 3 Nuclear (Uprate)

The Turkey Point 3 Nuclear (Uprate) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

St. Lucie 2 Nuclear (Uprate)

The St. Lucie 2 Nuclear (Uprate) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point 4 Nuclear (Uprate)

The Turkey Point 4 Nuclear (Uprate) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Cape Canaveral Next Generation Clean Energy Center (Modernization)

The Cape Canaveral Next Generation Clean Energy Center which will result from the modernization of the Cape Canaveral power plant site does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Riviera Beach Next Generation Clean Energy Center (Modernization)

The Riviera Beach Energy Center which will result from the modernization of the Riviera Beach power plant site will require one new line and existing lines to be extended and reconfigured to accommodate the increased capacity.

(1)	Point of Origin and Termination:	Riviera – Cedar Substation
(2)	Number of Lines:	1
(3)	Right-of-way	Existing, FPL - Owned
(4)	Line Length:	15 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 2012 End date: 2014
(7)	Anticipated Capital Investment: (Trans. and Sub.)	$12,100,000
(8)	Substations:	Riviera Substation and Cedar Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Port Everglades Next Generation Clean Energy Center

The Port Everglades Next Generation Clean Energy Center which will result from the modernization of the Port Everglades power plant site does not require any "new" transmission lines.

Schedule 11.1

Existing FIRM and NON-FIRM Capacity and Energy by Primary Fuel Type
Actuals for the Year 2011

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	Summer (MW)	Summer (%)	Winter (MW)	Winter (%)	GWh (2)	%
(1)	Coal	926	3.8%	928	3.6%	5,634	5.0%
(2)	Nuclear	2,970	12.1%	3,044	11.7%	21,510	19.1%
(3)	Residual	3,672	14.9%	3,706	14.3%	630	0.6%
(4)	Distillate	1,908	7.7%	2,087	8.0%	123	0.1%
(5)	Natural Gas	13,027	52.9%	13,941	53.8%	74,388	66.1%
(6)	Solar	35	0.1%	35	0.1%	71	0.1%
(7)	***FPL Existing Units Total (1):***	***22,538***	***91.5%***	***23,741***	***91.6%***	***102,356***	***91.0%***
(8)	Renewables (Purchases)- Firm	61.0	0.2%	112.0	0.5%	965	0.9%
(9)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	885	0.8%
(10)	***Renewable Total:***	***61.0***	***0.2%***	***112.0***	***0.5%***	***1,850***	***1.65%***
(11)	***Purchases Other :***	***2,038.0***	8.3%	***2,074.0***	8.0%	***8,248***	7.3%
(12)	***Total :***	***24,637.0***	***100.0%***	***25,927.0***	***100.0%***	***112,454***	***100.0%***

Note.
(1) FPL Existing Units Total values on row (7), columns (2) and (4), match the System Firm Generating Capacity values found on Schedule 1 for Summer and Winter.
(2) Net Energy for Load GWh values on row (12), column (6), matches Schedule 6.1 value for 2011.

Schedule 11.2

Existing NON-FIRM Self-Service Renewable Generation Facilities
Actuals for the Year 2011

(1)	(2)	(3)	(4)	(5)	(6) = 3+4-5
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh)	Annual Energy Purchased from FPL (MWh)	Annual Energy Sold to FPL (MWh)	Projected Annual Energy Used by Customers (GWh)
Customer-Owned PV (0 kW to 10 kW)	7.3	7,298.5	61,881.5	163.3	**69.0**
Customer-Owned PV (> 10 kW to 100 kW)	3.5	3,148.1	116,049.8	192.0	**119.0**
Customer-Owned PV (> 100 kW to 2 MW)	3.3	4,100.1	118,972.0	59.8	**123.0**
Total:	**14.1**	**14,546.7**	**296,903.3**	**415.1**	**311.0**

Notes:

(1) There were approximately 1,580 customer-owned renewable generation facilities interconnected with FPL on December 31, 2011.
(2) The Installed Capacity value is the sum of the nameplate ratings (DC MW) for all of the customer-owned renewable generation facilities connected as of Dec. 31,2011.
(3) The Projected Annual Output value is based on NREL's PV Watts 1 program and the installed capacity for each customer, adjusted for the days they were actively interconnected during 2011, and assuming each facility operated as planned.
(4) The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2011.
(5) The Annual Energy Sold to FPL is an actual number of kWH credited back to the customer from FPL's metered data for 2011.
(6) The Projected Annual Energy Used by Customers is a projected value that equals:
Renewable Projected Annual output + Annual Energy Purchased from FPL - Annual Energy Sold to FPL.

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered or threatened plant and animal species. FPL competes for air, land, and water resources that are necessary to meet the demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

FPL has been recognized for many years as one of the leaders among electric utilities for its commitment to the environment. For example, FPL has one of the lowest emissions profiles among U.S. utilities and its carbon dioxide (CO_2) emission rate is 36% lower (better) than the industry average. The environmental leadership of FPL and its parent company, NextEra Energy, Inc., has been heralded by many outside organizations as demonstrated by a few recent examples. In 2011, NextEra Energy, Inc. ranked in the top 10 among companies worldwide for social responsibility and, for a record sixth consecutive year, No. 1 in its industry, according to the 2011 "World's Most Admired Companies" report released by Fortune magazine. Being ranked first, for five consecutive years, is unprecedented in the industry and according to *Fortune*, America's Most Admired Companies is "the definitive report card on corporate reputations".

NextEra Energy, Inc. was named to the 2011 Dow Jones Sustainability Index (DJSI) of the leading companies in North America for corporate sustainability for the third consecutive year. The DJSI North America selects the top 20 percent of companies in sustainability performance from the 600 largest companies in North America. According to Sustainable Asset Management, the investment research firm that conducts the DJSI research, the evaluation is continuously adapted to capture the sustainability trends that are at the forefront of each industry sector and are likely to have an impact on the companies' competitive landscape.

FPL was recognized in 2010 by the Southeastern Electric Exchange (SEE) for outstanding performance in constructing the largest photovoltaic (PV) power plant at the time in the United States: the 25 MW DeSoto Next Generation Solar Energy Center. SEE gives its Chairman's Award annually to the project it deems "best of the best" among all entrants in its 11 award categories. Capable of powering approximately 3,000 homes with renewable energy, the DeSoto PV facility was completed months ahead of schedule and more than $22 million under budget.

In 2011, FPL's Martin Next Generation Solar Energy Center earned NextEra Energy recognition as a finalist in the competition for the Edison Award, presented annually by EEI. The award for "distinguished leadership, innovation and contribution to the advancement of the electric industry for the benefit of all" is EEI's most prestigious award. Also in 2011, the Martin Next Generation Solar Energy Center was named Project of the Year - Best Renewable Project by Power Engineering magazine, the leading power generation industry publication.

FPL was named a finalist in the Annual Sustainable Florida Best Practice Awards in both 2010 and 2011. In 2010, Sustainable Florida recognized the previously mentioned 25 MW DeSoto PV facility and in 2011 the organization recognized FPL's partnership with Palm Beach County to utilize reclaimed water at the West County Energy Center. The awards were presented by the Council for Sustainable Florida, the premier statewide organization committed to balancing the economic interests of the state with the need to be socially and environmentally responsible. The Sustainable Florida Award recognizes organizations for protecting and preserving Florida's environment for the future while building markets for Florida's businesses.

FPL's responsible tree care practices across its 35-county service area have been recognized for almost a decade. FPL has been the recipient of the Tree Line USA award annually from 2003 - 2011. This award is sponsored by the Arbor Day Foundation in cooperation with the National Association of State Foresters. The recognition is given to utilities that demonstrate quality tree care practices, annual worker training, and public education programs.

In October 2010, FPL won the 2010 Loggerhead Marinelife Center's "Blue Business of the Year" award. The awards were given to those who are leading the way in raising awareness about, and have made significant contributions to improve and protect South Florida's oceans, beaches, and wildlife. The award recognized FPL's protection and conservation of the endangered Florida manatee and fostering public and employee education and support.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Statement in 1992 to clearly define its position, which it continues to stand by today. This statement reflects how FPL incorporates environmental values into all aspects of its activities and serves as a framework for new environmental initiatives throughout the company. FPL's Environmental Statement is:

> It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:
>
> - Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
> - Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
> - Encourage the wise use of energy to minimize the impact on the environment.
> - Communicate effectively on environmental issues.
> - Conduct periodic self-evaluations and report performance.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an Environmental Management System to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program that is discussed below. Other components include: executive management support and commitment, a dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to evaluate environmental performance, verify compliance with corporate policy as well as legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and FPL policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2011 environmental outreach activities are summarized below in Table IV.E.1.

Table IV.E.1: 2011 FPL Environmental Outreach Activities

Activity	# of Participants (Approx.)
Visitors to FPL's Energy Encounter at St. Lucie	12,000
Visitors to Manatee Park	146,814
Number of visits to FPL's Environmental Website	>500,000
Number of pieces of Environmental literature distributed	>20,000
Solar Schools Program (# of schools participating)	1 school and 2 non-profits
Visitors to Barley Barber Swamp	2,955
Number of visits to Manatee Cam Website	66,769

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified five (5) Preferred Sites and ten (10) Potential Sites for future generation additions. Preferred Sites are those locations where FPL has conducted significant reviews and has either taken action, or is currently committed to take action, to site new generation capacity. Potential Sites are those sites that have attributes that support the siting of generation and are under consideration as a location for future generation. Some of these sites are currently in use as existing generation sites and some are not. The identification of a Potential Site does not indicate that FPL has made a definitive decision to pursue generation (or generation expansion in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of a generator has been determined. The Preferred Sites and Potential Sites are discussed in separate sections below.

As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include all of the remainder of FPL's existing generation sites and other Greenfield sites. FPL will continue to analyze the potential for modernizing existing power plant sites such as is now being done at the Cape Canaveral and Riviera sites, and which will occur by 2016 at the existing Port Everglades site. Analyses of any modernization candidates would include evaluation of numerous factors including: fuel delivery, transmission, permitting, etc.

IV.F.1 Preferred Sites

FPL identifies five Preferred Sites and all of them are existing plant sites: the St. Lucie plant site, the Turkey Point plant site, the Cape Canaveral plant site, the Riviera plant site and the Port Everglades plant site.

The St. Lucie site is the location for nuclear capacity uprates that FPL will complete work for in 2012. The Turkey Point site is the location for nuclear capacity uprates that FPL will complete work for in 2012 and 2013. (Turkey Point is also the site for two new nuclear units, Turkey Point Units 6 & 7, for which FPL is pursuing licensing and permit approvals. Current projections for in-service dates for these new nuclear units remain beyond the 2012 through 2021 reporting time frame of this document). The Cape Canaveral, Riviera, and Port Everglades sites are the locations for modernizations of existing power plant sites for capacity additions in 2013, 2014, and 2016, respectively.

The five Preferred Sites are discussed below in general chronological order in regard to when the capacity additions are projected to occur.

Preferred Site # 1: St. Lucie Plant, St. Lucie County

FPL's St. Lucie Plant is located in St. Lucie County on Hutchinson Island on an FPL-owned 1,130-acre site. The plant site is bordered by the Atlantic Ocean to the east and the Indian River Lagoon to the west. Located on the site are two nuclear-powered generating units, St. Lucie Units 1 & 2, which have been in operation since 1976 and 1983, respectively.

The generating capacity addition is an increase in the capacity of the two existing nuclear generating units that is used to serve FPL's customers of approximately 129 MW for St. Lucie Unit 1 and 115 MW for St. Lucie Unit 2. This capacity uprate is referred to as an Extended Power Uprate (EPU). The difference between the two values is due to FPL's 100% ownership share of St. Lucie Unit 1 and its 85% ownership share of St. Lucie Unit 2. This work involves changes to several existing main components within the existing facilities to increase their capability to produce steam for the generation of electricity. No new site facilities are required as part of this capacity "uprate." This capacity uprate, along with a similar capacity uprate of FPL's existing Turkey Point nuclear units, was approved by the FPSC in January 2008. A portion (31 MW) of the uprated capacity for St. Lucie Unit 2 has already been implemented and the remainder of the uprated capacity is projected to be in-service by the end of 2012.[6]

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the FPL St. Lucie Nuclear site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the general layout of the proposed generating facilities at the site is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

St. Lucie Units 1 & 2 are pressurized water reactors, each having two steam generators. The prominent structures, enclosed facilities, and equipment associated

[6] FPL has also been pursuing the addition of six wind turbines at the St. Lucie plant site for a number of years. However, to-date FPL has been unable to obtain the necessary local land use approvals that would first be needed before state and federal approvals could be sought.

with St. Lucie Units 1 & 2 include the containment building, the turbine generator building, the auxiliary building, and the fuel handling building.

Prominent features beyond the power block area include the intake and discharge canals, switchyard, spent-fuel storage facilities, technical and administrative support facilities, and public education facilities (the Energy Encounter and the College of Turtle Knowledge). Significant features surrounding the St. Lucie Units 1 & 2 are predominately undeveloped land and water bodies including; Big Mud Creek, the Atlantic Ocean, Herman's Bay, and Indian River Lagoon.

In regard to the nuclear capacity uprates, the only changes will be modifications to the existing power generation facilities within the power block area, modifications to the switchyard facilities, and modifications to the transmission lines from St. Lucie to Midway substation. None of the other existing facilities at the plant will change as a result of the uprates.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

FPL's St. Lucie Plant is located in St. Lucie County on Hutchinson Island on an FPL-owned 1,130-acre site. The St. Lucie Plant includes the reactor buildings, turbine buildings, access/security building, auxiliary building, maintenance facilities, and miscellaneous warehouses and other buildings associated with the operation of Units 1 & 2. The site includes adjacent undeveloped mangrove areas. As a result of the capacity uprates, the site characteristics will not change.

2. Listed Species

The construction during the uprating of the units, and operation of the units after the capacity uprating is completed, are not expected to adversely affect any rare, endangered, or threatened species. Some listed species known to occur in the area of the plant location are Atlantic sturgeon (*Acipenser oxyrinchus*), smalltooth sawfish (*Pristis pectinate*), loggerhead sea turtle (*Caretta caretta*), green sea turtle (*Chelonia mydas)*, leatherback sea turtle (*Dermochelys coriacea*), hawksbill sea turtle (*Eretmochelys imbriccata*), gopher tortoise (*Gopherus polyphemus*), kemp's ridley sea turtle (*Lepidochelys kempi*), wood stork (*Mycteria americana*), black skimmer (*Rynchops niger*), and least tern (*Sterna antillarum*).

No changes in wildlife populations at the adjacent undeveloped areas are anticipated, including listed species. Noise and lighting impacts will not change and it is expected that wildlife will continue to use the undeveloped areas within the St. Lucie Plant boundary.

3. **Natural Resources of Regional Significance Status**

Significant features surrounding the St. Lucie Units 1 & 2 are predominately undeveloped land and water bodies including; Big Mud Creek, the Atlantic Ocean, Herman's Bay, and Indian River Lagoon.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. The cooling system for the two generating units is a once-through system. The effects of the discharge of cooling water via these discharge structures were evaluated and mixing zones were established to allow compliance with thermal water quality standards as a part of the Plant's NPDES (Permit No. FL0002208). In regard to the nuclear capacity uprates, the once-through cooling system will continue to be used for the nuclear units.

g. **Local Government Future Land Use Designations**

St. Lucie Units 1 & 2 are located in unincorporated St. Lucie County, Florida. The County has adopted a comprehensive plan, which is updated on a periodic basis. The County Comprehensive Plan incorporates a map that depicts the future land use categories of all property falling within the unincorporated portions of the County. The St. Lucie Plant has a Future Land Use category of Transportation/Utilities (T/U) according to the St. Lucie County Future Land Use Map. The T/U category is described in the St. Lucie County Comprehensive Plan Future Land Use Element Future Land Use.

h. **Site Selection Criteria Process**

The site has been selected as a Preferred Site for the nuclear capacity uprates because it is an existing nuclear plant site and, therefore, offers the opportunity for increased nuclear capacity.

i. **Water Resources**

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. The once-through cooling system flow will not change as a result of the nuclear uprates. Due to the existing nature of the St. Lucie Plant, surrounding surface waters will not be adversely affected by the generation capacity addition. Storm water will be handled by the existing facilities and no new areas will be impacted. Wetlands, groundwater, and nearby surface waters will not be impacted.

j. **Geological Features of Site and Adjacent Areas**

Beneath the land surface, there is a peat layer 4 to 6 feet thick. Below this layer is the Anastasia Formation, a sedimentary rock formation composed of clay lenses, sandy limestone, and silty fine to medium sand with fragmented shells. This highly permeable stratum extends 35 to 90 feet below mean sea level (msl). Underlying this stratum there is a semi-permeable zone, The Hawthorn Formation, consisting of slightly clayey and very fine silt which extends 600 feet below msl.

The original surficial deposits at the St. Lucie Plant were excavated to a depth of 60 feet and backfilled with Category I or II fill. The fill is underlain by the Anastasia formation, a sequence of partially cemented sand and sandy limestone, which extends to an average depth of about 145 feet. The Anastasia is underlain to a depth of about 600 to 700 feet by the partially cemented and indurated sands, clays, and sandy limestones of The Hawthorn Formation. Underlying these surface strata are about 13,000 feet of Jurassic through Tertiary Formations, primarily carbonate rocks. These formations have a relatively gentle slope to the southeast.

k. **Projected Water Quantities for Various Uses**

No change is expected in the quantity of industrial wastewaters generated by the facility. Therefore, no change in that compliance achievement status is expected. The capacity uprates will not cause any changes in hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow. The St. Lucie Plant does not directly withdraw groundwater under its current operations and it will not withdraw groundwater after the capacity uprates work is completed. The use of water supplied by the City of Fort Pierce will remain unchanged and there will be no changes to the groundwater discharges. There will be no quality, quantity, or hydrological changes, either by withdrawal or discharge to a drinking water source. Therefore, there will be no impacts on drinking water.

l. **Water Supply Sources by Type**

The source of cooling water for the St. Lucie Plant is the Atlantic Ocean. General plant service water, fire protection water, process water, and potable water are obtained from City of Fort Pierce. Process water uses include demineralizer regeneration, steam cycle makeup, and general service water use for washdowns. The existing St. Lucie Plant water use is projected to be unchanged as a result of the nuclear capacity uprates.

m. **Water Conservation Strategies Under Consideration**

The existing water resources will not change as a result of the nuclear capacity uprates.

n. **Water Discharges and Pollution Control**

St. Lucie Units 1 & 2 use once-through cooling water from the Atlantic Ocean to remove heat from the main (turbine) condensers via the Circulating Water System (CWS), and to remove heat from other auxiliary equipment via the Auxiliary Equipment Cooling Water System (AECWS). The great majority of this cooling water is used for the CWS.

Under emergency conditions, water can be withdrawn from Big Mud Creek via the Emergency Intake Canal through two 54-inch pipe assemblies in the barrier wall that separates the Creek from the Canal. FPL does not use this intake during normal operations, but does test this system quarterly.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

St. Lucie Units 1 & 2 are licensed for uranium-dioxide fuel that is slightly enriched uranium-235. The uranium-dioxide fuel is in the form of pellets contained in Zircaloy tubes with welded end plugs to confine radionuclides. The tubes are fabricated into assemblies designed for loading into the reactor core. Each reactor core includes 217 fuel assemblies.

FPL currently replaces approximately one-third of the fuel assemblies in each reactor at intervals of approximately 18 months. FPL operates the reactors such that the average fuel usage by the reactors is approximately 47,000 megawatt-days per metric ton uranium. In regard to the nuclear capacity uprates, more nuclear fuel will be used due to the increased capacity of each generating unit. Used fuel assemblies are stored in the onsite Nuclear Regulatory Commission (NRC)-approved spent fuel storage facilities. Following completion of the uprates, approximately 11 percent more nuclear fuel will be used to increase the capacity of each generating unit. No changes in the fuel-handling facilities are required.

Diesel fuel is used in a number of emergency generators that include four main plant generators, two building generators, and various general purpose diesel engines. The main plant emergency generators will not be changed as a result of the generation capacity additions. These emergency generators are for standby use only and are tested to assure reliability and for maintenance. Diesel fuel is delivered to the St. Lucie Plant by truck as needed, and stored in tanks with secondary containment.

p. **Air Emissions and Control Systems**

The St. Lucie Plant is classified as a minor source of air pollution, since FDEP has issued a Federally Enforceable State Operating Permit (FESOP) to keep emissions less than 100 tons per year for any air pollutant regulated under the Clean Air Act. The applicable units at the St. Lucie Plant consist of eight large main plant diesel engines, two smaller diesel engines, and various general-purpose diesel engines. The air emissions from these engines are limited by the use of 0.05-percent sulfur diesel fuel and good combustion practices. Best Available Control Technology (BACT) is not applicable to these existing emission units.

Nitrogen oxide (NO_x) emissions from the operation of the diesel engines comprise the limiting pollutant for these diesel units at the St Lucie Plant. The FDEP FESOP limits NO_x emissions to 99.4 tons, which includes fuel use limits on the large main plant emergency diesel engines of 97,000 gallons in any 12-month consecutive period and the smaller building and general purpose diesel engines of 190,000 gallons in any 12-month consecutive period. Also, the Plant may choose to combine the diesel units' fuel-tracking which then limits the NO_x totals for a 12-month consecutive period to a maximum of 80 tons. There will be no change in the operation or emissions of the diesel engines resulting from the nuclear capacity uprates.

In addition, the generation capacity additions will not result in an increase of CO_2 or other greenhouse gas emissions. In fact, the increases in emission-free nuclear generation capacity are projected to result in decreased FPL system-wide emissions of CO_2.

q. **Noise Emissions and Control Systems**

A field survey and impact assessment of noise expected to be caused by construction activities at the site was conducted. Predicted noise levels are not expected to result in adverse noise impacts in the vicinity of the site during construction or operation.

r. **Status of Applications**

A Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act was filed in December 2007 and a final order issued in September 2008. The FPSC voted to approve the need for the St. Lucie (and Turkey Point) nuclear capacity uprates and the final order approving the need for these capacity additions was issued in January 2008.

A License Amendment request for the EPU was submitted to the NRC in November 2010. There are two components to that application; one is the Environmental Assessment (EA) and the other is the Safety component. The St. Lucie Plant EA was published in the Federal Register in January 2012. The Application is still in process.

Preferred Site # 2: Turkey Point Plant, Miami-Dade County

The Turkey Point Plant site is located on the west side of Biscayne Bay, 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. Public access to the plant site is limited due to the nuclear units located there. The land surrounding the site is owned by FPL and acts as a buffer zone. The site is comprised of two nuclear units (Units 3 & 4), two natural gas/oil conventional steam units (Units 1 & 2 with Unit 2 currently serving in a synchronous condenser mode to provide voltage support), one CC natural gas unit (Unit 5), nine small diesel generators, the cooling canals, an FPL-maintained natural wildlife area, and wetlands that have been set aside as the Everglades Mitigation Bank (EMB).

Turkey Point Units 3 & 4 have been in operation since 1972 and 1973, respectively. The Turkey Point site has been selected as a Preferred Site for the increase in the capacity of its two existing nuclear generating units by approximately 123 MW each. This capacity uprate is referred to as an Extended Power Uprate (EPU). This work involves changes to several existing main components within the existing facilities to increase their capability to produce steam for the generation of electricity. No new or expanded facilities are required as part of this capacity "uprate." This capacity uprate, along with a similar capacity uprate of FPL's existing St. Lucie nuclear units, was approved by the FPSC in January 2008. The capacity uprates at Turkey Point are projected to be in-service, in part, during 2012 and completely in-service in 2013.

As previously mentioned, FPL is pursuing licensing for two new nuclear units at the Turkey Point site. Each of these two units would provide 1,100 MW of capacity. Current projections for the in-service dates of these two units, Turkey Point Units 6 & 7, remain beyond the 2012 through 2021 reporting time frame of this document.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the Turkey Point plant site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the general layout of the Turkey Point Units 3 and 4 generating facilities at the site is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

The Turkey Point Plant site is located on the west side of Biscayne Bay, 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive.
The five existing generating units and support facilities occupy approximately 150 acres of the approximately 11,000-acre Turkey Point Plant site.

Prominent features beyond the power block area include the intake system, cooling canal system, switchyard, spent fuel storage facilities, and technical and administrative support facilities The cooling canal system occupies approximately 5,900 acres.

The two 400-megawatt (MW) (nominal) fossil fuel-fired steam electric generation units at the Turkey Point Plant have been in service since 1967 (Unit 1) and 1968 (Unit 2). These units have historically burned residual fuel oil and/or natural gas with a maximum equivalent sulfur content of 1 percent. Unit 2 is currently serving, not as a power generating unit, but as a synchronous condenser to provide voltage support to the southeastern end of FPL's transmission system. The two 700-MW (nominal) nuclear units have been in service since 1972 (Unit 3) and 1973 (Unit 4). Turkey Point Units 3 and 4 are pressurized water reactor (PWR) units. Turkey Point Unit 5 is a nominal 1,150-MW natural gas-fired combined cycle (CC) unit that began operation in 2007. Significant features in the vicinity of the site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park.

e. **General Environment Features On and In the Site Vicinity**

1. **Natural Environment**

   The Turkey Point Plant site is located on the west side of Biscayne Bay, 25 miles south of Miami. The site is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. The Turkey Point Plant includes the reactor buildings, turbine buildings, access/security building, auxiliary building, maintenance facilities, and miscellaneous warehouses and other buildings associated with the operation of Units 3 & 4. As a result of the approved capacity uprates, the site characteristics will not change.

2. **Listed Species**

   The construction during the uprating of the units, and operation of the units after the capacity uprating is completed, are not expected to adversely affect any rare, endangered, or threatened species. Some listed species known to occur at the site and in the nearby Biscayne National Park that could potentially utilize the site include the peregrine falcon *(Falco peregrinus)*, wood stork *(Mycteria americana)*, American crocodile *(Crocodylus acutus)*, mangrove rivulus *(Rivulus marmoratus)*, roseate spoonbill (*Ajaja ajaja*), limpkin *(Aramus guarauna)*, little blue heron *(Egretta caerulea)*, snowy egret *(Egretta thula)*, American oystercatcher *(Haematopus palliates)*, least tern *(Sterna antillarum)*, the white ibis *(Eudocimus albus)*, and bald eagle *(Haliaeetus leucocephalus)*. No bald eagle nests are known to exist in the vicinity of the site. The federally listed, threatened American Crocodile thrives at the Turkey Point site, primarily in and around the southern end of the cooling canals which lie south of the project area. The entire site is considered crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American Crocodile which is attributed with survival improvement and the downlisting of the American Crocodile from endangered to threatened.

3. **Natural Resources of Regional Significance Status**

Significant features in the vicinity of the site include Biscayne National Park, the Miami-Dade County Homestead Bayfront Park, and the Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park. Biscayne National Park contains 180,000 acres, approximately 95 percent of which is open water interspersed with more than 40 keys. The Biscayne National Park headquarters is located approximately 2 miles north of the Turkey Point Plant and is adjacent to the Miami-Dade County Homestead Bayfront Park which contains a marina and day-use recreational facilities.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

Turkey Point Units 3 & 4 uses cooling water from a closed-cycle cooling canal system to remove heat from the main (turbine) condensers, and to remove heat from other auxiliary equipment. The existing cooling canals will accommodate the increase in heat load that is associated with the increased capacity from the uprates. The maximum projected increase in water temperature entering the cooling canal system from the units resulting from the uprates is predicted to be about 2.5F, from 106.1F to 108.6F. The associated projected ma ximum increase in water temperature returning to the units is about 0.9F, from 91.9F to 92.8F.

g. **Local Government future Land Use Designations**

Local government future land use plan designates most of the site as IU-3 "(Industrial, Utilities, and Communications) Unlimited Manufacturing District." There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. **Site Selection Criteria Process**

The site has been selected as a Preferred Site for the nuclear capacity uprates because it is an existing nuclear plant site and, therefore, offers the opportunity for increased nuclear capacity.

i. **Water Resources**

Unique to the Turkey Point Plant site is the self-contained cooling canal system that supplies water to condense steam used by the plant's turbine generators. The canal system consists of 36 interconnected canals. The cooling canals occupy an area approximately two miles wide by five miles long (5,900 acres), approximately four feet deep. The system performs the same function as a giant radiator. The water is circulated through the canals in a two-day journey, ending at the plant's intake pumps.

j. **Geological Features of Site and Adjacent Areas**

The Turkey Point Plant lies upon the Floridian Plateau, a partly-submerged peninsula of the continental shelf. The peninsula is underlain by approximately 4,000 to 15,000 feet of sedimentary rocks consisting of limestone and associated formations that range in age from Paleozoic to Recent. Little is known about the basement complex of Paleozoic igneous and metamorphic rocks due to their great depth.

Generally in Miami-Dade County, the surficial aquifer (Biscayne Aquifer) consists of a wedge-shaped system of porous clastic and carbonate sedimentary materials, primarily limestone and sand deposits of the Miocene to late Quaternary age. The Biscayne Aquifer is thickest along the eastern coast and varies in thickness from 80 to 200 feet thick. The surficial aquifer is typically composed of Pamlico Sand, Miami Limestone (Oolite), the Fort Thompson and Anastasia Formations (lateral equivalents), Caloosahatchee Marl, and the Tamiami formation. The lower confining layers below the surficial aquifer range in thickness from 350 to 600 feet and are composed of the Hawthorn Group. Beneath the Hawthorn Group, the Floridan Aquifer System ranges from 2,800 to 3,400 feet thick and consists of Suwannee Limestone, Avon Park Limestone, and the Oldsmar Formations.

k. **Projected Water Quantities for Various Uses**

The addition of nuclear generating capacity as a result of the uprates will not cause any changes in the quantity or characteristics of industrial wastewaters generated by the facility; therefore, no change in that compliance achievement status is expected. The uprates will not cause any changes in hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow. The Turkey Point Nuclear Plant does not directly withdraw groundwater under its current operations and it will not do so after the capacity uprates. Locally, groundwater is present beneath the site in the surficial or Biscayne Aquifer and in deeper aquifer zones that are part of the Floridan Aquifer System. There will be no effects on those deeper aquifer zones from the capacity uprates.

l. **Water Supply Sources and Type**

The source of cooling water for Turkey Point Units 3 & 4 is the cooling canal system. There will be no increase in the amount of water withdrawn as a result of the capacity uprates. General plant service water, fire protection water, process water, and potable water are obtained from Miami-Dade County. Process water uses include demineralizer regeneration, steam cycle makeup, and general service water use for washdowns. The water use for the facility will not change as a result of the capacity uprates.

m. **Water Conservation Strategies**

The existing water resources will not change as a result of the nuclear capacity uprates.

n. **Water Discharges and Pollution Control**

Heated water discharges are dissipated using the existing closed cooling canal system.

The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

Turkey Point Units 3 & 4 utilize uranium-dioxide fuel that is slightly enriched uranium-235. The uranium-dioxide fuel is in the form of pellets contained in Zircaloy tubes with welded end plugs to confine radionuclides. The tubes are fabricated into assemblies designed for loading into the reactor core. Used fuel assemblies are stored in the onsite NRC-approved spent fuel storage facilities.

FPL currently replaces approximately one-third of the fuel assemblies in each reactor at refueling intervals of approximately 18 months. FPL operates the reactors such that the average fuel usage by the reactors is approximately 45,000 megawatt-days per metric ton of uranium. Following completion of the uprates, more nuclear fuel will be used to increase the capacity of each unit. No changes in the fuel handling facilities are required. Following completion of the uprates, approximately 11 percent more nuclear fuel will be used to increase the capacity of each unit. No changes in the fuel-handling facilities are required.

Diesel fuel is used in a number of emergency generators that include four main emergency generators, five smaller emergency generators, and various general purpose diesel engines. The emergency generators will not be changed as a result of the capacity uprates. These emergency generators are for stand-by use only and only operated for testing purposes to assure reliability and for maintenance. Diesel fuel for the emergency generators is delivered to the Turkey Point Plant by truck as needed, and stored in tanks with secondary containment.

p. <u>Air Emissions and Control Systems</u>

The normal operation of Turkey Point Units 3 & 4 does not create fossil fuel-related air emissions. However, there are nine emergency generators associated with Units 3 & 4. Four of these nine emergency generators are main plant emergency generators which are rated at 2.5 MW each. The remaining five generators are smaller emergency generators which are associated with the security system. In addition, various general purpose diesels are used as needed for Units 3 & 4.

Turkey Point Plant Units 3 & 4's associated emergency generators and diesel engines, together with Units 1, 2, & 5, are classified as a major source of air pollution. FDEP has issued a separate Title V Air Operating Permit for the Turkey Point Nuclear Plant (Permit Number 0250003-004-AV). There are no operating limits for the emergency generators or diesel engines. Emergency diesel generators are limited to ultra-low sulfur distillate (0.0015% sulfur). NOx emissions are regulated under Reasonably Available Control Technology (RACT) requirements in Rule 62-296.570(4)(b)7 F.A.C., which limit NO_x emissions to 4.75 lb/MMBtu. The use of 0.05

percent sulfur diesel fuel and good combustion practices serve to keep NO_x emissions under this limit.

q. **Noise Emissions and Control Systems**

A field survey and impact assessment of noise expected to be caused by activities associated with the uprates was conducted. Predicted noise levels are not expected to result in adverse noise impacts in the vicinity of the site.

r. **Status of Applications**

A Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act was filed in January 2008 and a final order was issued in October 2008. The FPSC voted to approve the need for the Turkey Point (and St. Lucie) uprates and the final order approving the need for this additional nuclear capacity was issued in January 2008.

A License Amendment request for the EPU was submitted to the NRC in October 2010. There are two components to that application; one is the Environmental Assessment (EA) and the other is the Safety component. The Turkey Point Plant EA was published in the Federal Register in November 2011. The Application is still in process.

Preferred Site # 3: Cape Canaveral Plant, Brevard County

This site is located on the existing FPL Cape Canaveral Plant property in unincorporated Brevard County. The site is bound to the east by the Indian River Lagoon and on the west by a four lane highway (US. 1). The city of Port St. Johns is located less than a mile away. A rail line is located near the plant.

The site previously housed two steam generating units (Units 1 & 2) with 788 MW (Summer) of generating capacity. The units formerly occupied a portion of the 43 acres that are wholly owned by FPL. FPL is in the process of modernizing the existing Cape Canaveral Plant, to be renamed the Cape Canaveral Next Generation Clean Energy Center (CCEC), by replacing the previous two steam generating units with a single modern, highly efficient, lower-emission next-generation clean energy center using advanced combined cycle (CC) technology. The old units have been taken out of service. The demolition of the Cape Canaveral Plant began in mid-2010 and was completed during the first quarter of 2011. Construction for the new CC unit began in March 2011 and is expected to be completed by June 2013.

a. **Geological Survey (USGS) Map**

A USGS map of the CCEC site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the general layout of the CCEC generating facilities at the site is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

The existing and future land uses on the site are primarily dedicated to electrical generation; i.e., FPL's former Cape Canaveral Units 1 & 2 and the future CCEC unit. The existing land uses that are adjacent to the site consist of single- and multi-family residences to the south and southwest, commercial property to the northwest, utility systems to the west, and a private medical/office facility to the north.

e. **General Environment Features On and In the Site Vicinity**

1. **Natural Environment**

The natural environment surrounding the site includes the Indian River Lagoon to the east and upland scrub, pine and hardwoods to the north and south. Vegetation with the approximately 45-acre offsite construction laydown and parking area (located west of U.S. Highway 1) consists of open land, upland scrub, pine, hardwoods along with exotic plant species.

2. **Listed Species**

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species. Federal- or state-listed terrestrial plants and animals inhabiting the offsite construction laydown and parking area are limited to the state-listed gopher tortoise and the state- and federally-listed scrub jay. The warm water discharges from the plant attract manatees, an endangered species. FPL continues to work closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process. In 2010, FPL installed a temporary heating system to warm the water for the manatees as required during manatee season. FPL has complied, and will continue to comply, with several other manatee-related conditions of certification to ensure the protection of the manatees during the modernization work and during subsequent operation of the new generating facility.

3. **Natural Resources of Regional Significance Status**

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design option is to replace the previous steam generating units (Units 1 & 2) with one new 1,210 MW (approximate) CC unit consisting of three new combustion turbines (CT), three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit is projected to be in-service in mid-2013. Natural gas delivered via pipeline is the primary fuel type for this unit with ULSD serving as a backup fuel.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the site is "Public Utilities" and the area has been rezoned to GML-U. Designations for the surrounding area are primarily "Community Commercial" and "Residential". A land use map of the site and adjacent areas is also found at the end of this chapter.

h. **Site Selection Criteria Process**

The Cape Canaveral Plant site was selected for a site modernization due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, the significant reduction in cooling water withdrawal and thermal component of cooling water discharges are environmental benefits of replacing the previous steam units with a new CC unit including a significant reduction in system fuel use, a significant reduction in system air emissions, improved aesthetics at the site, and continued warm water discharge for the manatees as required during manatee season. Further, modernizing this existing facility reduces the impact on natural resources by not requiring new land, new water sources, or additional off-site transmission siting.

i. **<u>Water Resources</u>**

Condenser cooling for the steam cycle portion of the new plant and auxiliary cooling will come from the existing cooling water intake system. Process, potable, and reclaimed water for the new plant will come from the existing City of Cocoa's potable water supply.

j. **<u>Geological Features of Site and Adjacent Areas</u>**

The site is located on the Atlantic Coastal Ridge and is at an approximate elevation of 12 feet above mean sea level (msl). The land consists primarily of fine to medium sand that parallels the coast. There is a lack of shell as it was deposited during a time of transgression. The base of the sedimentary rocks is made up of a thick, primarily carbonate sequence deposited during the Jurassic age through the Pleistocene age. Starting in the Miocene age and continuing through the Holocene age, siliciclastic sedimentation became more predominant. The basement rocks in this area consist of low-grade metamorphic and igneous intrusives, which occur several thousand feet below land surface and are Precambrian, Paleozoic, and Mesozoic in age.

k. **<u>Projected Water Quantities for Various Uses</u>**

The estimated quantity of water required for processing is approximately 0.232 million gallons per day (mgd) for uses such as process water and service water. Approximately 619 mgd of cooling water would be cycled through the once-through cooling water system. Potable water demand is expected to average .001 mgd.

l. **<u>Water Supply Sources by Type</u>**

The modernized plant will continue to use the Indian River Lagoon water as the source of once-through cooling water. Such needs for cooling water will comply with the St. John's River Water Management District (SJRWMD) conditions of certification. Process and potable water for the new plant will come from the existing City of Cocoa's potable water supply. Reclaimed water will be used for irrigation.

m. **Water Conservation Strategies Under Consideration**

No additional water resources will be required as a result of the modernization project. Combined cycle technology uses less water by design than traditional steam generation units.

n. **Water Discharges and Pollution Control**

The modernized site will utilize portions of the existing once-through cooling water systems for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system. Storm water runoff will be collected and routed to storm water ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

Natural gas for the new unit will be transported to the site via a pipeline. New off-site or on-site gas compressors will be installed to raise the gas pressure of the existing pipeline for the new unit. ULSD "light oil" will be received by truck or barge from Port Canaveral and stored in an above-ground storage tank.

p. **Air Emissions and Control Systems**

The emission rates of CCEC would decrease by over 90% from the former Cape Canaveral Plant, resulting in substantial annual emission reductions and increased air quality benefits per unit of energy produced. The use of natural gas, ULSD, and combustion controls would minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction

(SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ULSD as backup fuel. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. In total, the design of the new CCEC plant will incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida.

q. **Noise Emissions and Control Systems**

Noise from the operation of the new unit will be within allowable levels.

r. **Status of Applications**

The FPSC voted to approve the need for the modernization project and the need order was issued in September 2008. The project received final state certification on October 9, 2009, through the issuance of a final order signed by the Secretary of the Department of Environmental Protection (DEP).

Preferred Site # 4: Riviera Plant, Palm Beach County

This site is located on the former FPL Riviera Plant property primarily within Riviera Beach, Palm Beach County (with a small portion of the Site in West Palm Beach). The site is bound to the east by the Lake Worth Lagoon (Intracoastal Waterway) and on the west by a four lane highway (US. 1). The site has barge access via the Port of Palm Beach. A rail line is located near the plant.

The previous site generating capacity was made up of two 300 MW (approximate) steam generating units (Units 3 & 4) that have been taken out of service and dismantled in 2011. Units 1 & 2 were previously retired and dismantled and are no longer on the plant site.

FPL is in the process of modernizing the former Riviera Plant, to be renamed the Riviera Beach Next Generation Clean Energy Center (RBEC), by replacing the existing generating units with a modern, highly efficient, lower-emission next-generation clean energy center using advanced CC technology.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the RBEC site is found at the end of this chapter.

b. Proposed Facilities Layout

A general layout of the RBEC generating facilities is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The previous Riviera Plant consisted of two 300 MW (approximate) units with conventional dual-fuel fired steam boilers and steam turbine units. The plant site includes minimal vegetation and a landscape buffer area south of the power plant. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of facilities related to electric power generation. The site is located adjacent to the Intracoastal Waterway. The site provides warm water as required for manatees pursuant to the facility's Manatee Protection Plan.

2. Listed Species

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species. The warm water discharges from the plant attract manatees, an endangered species. FPL continues to work closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process. In 2009, FPL installed a temporary heating system to warm the water for the manatees as required pursuant to the facility's Manatee Protection Plan. FPL will also be complying with several other manatee-related conditions of certification to ensure the protection of the manatees during the modernization work and during operation of the RBEC.

3. Natural Resources of Regional Significance Status

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design option is to replace the previous steam generating units (Units 3 & 4) with one new 1,212 MW (approximate) CC unit consisting of three new combustion turbines (CT), three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit is projected to be in service in mid-2014. Natural gas delivered via pipeline is the primary fuel type for the unit with ULSD serving as a backup fuel.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the site is "Utility". The Port of Palm Beach is to the north of the site. Designation to the west of the site is "Commercial." To the south of the site is "Residential" and is in the City of West Palm Beach. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. **Site Selection Criteria Process**

This site has been selected for site modernization due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of replacing the existing steam units with a new CC unit including a significant reduction in system air emissions, improved aesthetics at the site, and continued warm water discharge for the manatees as required during manatee season. Further, modernizing this existing facility reduces the impact on natural resources by not requiring new land or new water resources.

i. **Water Resources**

Water from the Lake Worth Lagoon (Intracoastal Waterway) will be used for once-through cooling water. RBEC will utilize portions of the existing once-through cooling water intake and discharge structures. Water for cooling pump seals and irrigation will come from three onsite surficial aquifer wells. Process and potable water for the converted plant will come from the existing City of Riviera Beach potable water supply.

j. **Geological Features of Site and Adjacent Areas**

The site is underlain by the surficial aquifer system. The surficial aquifer system in eastern Palm Beach County is primarily composed of sand, sandstone, shell, silt, calcareous clay (marl), and limestone deposited during the Pleistocene and Pliocene Epochs. The sediments forming the aquifer system are the Pamlico Sand, Fort Thompson Formation (Pleistocene) and the Caloosahatchee Marl (Pleistocene and Pliocene). Permeable sediments in the upper part of the Tamiami Formation (Pliocene) are also part of the aquifer system.

The surficial aquifer is underlain by at least 600 feet the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. **Projected Water Quantities for Various Uses**

The estimated quantity of water required for processing is approximately 0.232 million gallons per day (mgd) for uses such as process water and service water. Approximately 600 mgd of cooling water would be cycled through the once-through cooling water system. Potable water demand is expected to average .001 mgd.

l. **Water Supply Sources by Type**

The modernized plant will continue to use Lake Worth Lagoon water as the source of once-through cooling water. Water for cooling pump seals and irrigation will come from on-site surficial aquifer wells currently authorized under SFWMD conditions of certification. Process and potable water for the new plant will come from the existing City of Riviera Beach's potable water supply.

m. **Water Conservation Strategies Under Consideration**

No additional water resources will be required as a result of the modernization project. Combined cycle technology uses less water by design than traditional steam generation units.

n. **Water Discharges and Pollution Control**

The modernized plant will utilize portions of the existing once-through cooling water system for heat dissipation. The heat recovery steam generator blowdown will be mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system prior to discharge. Storm water runoff will be collected and routed to storm water ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit would be transported to the site via an approximately 6 mile FPL-owned pipeline, the RBEC Lateral. New gas compressors will be installed at the existing FPL 45th Street Terminal facility in Riviera Beach to raise the gas pressure of the pipeline to the appropriate level for the new unit. ULSD would be received by truck, pipeline, or barge and stored in a new above-ground storage tank.

p. Air Emissions and Control Systems

The regulated air emission rates at the new plant would be more than 90 percent lower than the previous Riviera Plant's emission rates, resulting in significant annual emissions reductions and air quality benefits per unit of energy produced. The use of natural gas and ULSD and combustion controls would minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ULSD as backup fuel. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of RBEC would incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. Status of Applications

The FPSC voted to approve the need for the modernization project and the need order was issued in September 2008. The project received final state certification on November 24, 2009, through the issuance of a final order signed by the Secretary of the DEP. The project received final certification for the RBEC 6 mile pipeline lateral and compressor station on March 15, 2011.

Preferred Site # 5: Port Everglades, Broward County

This site is located on the existing FPL Port Everglades Plant property within the City of Hollywood, Broward County. The site is surrounded by the Port of Port Everglades. The site has barge access via the Port of Port Everglades. A rail line is located near the plant.

The previous site generating capacity was made up of two 200 MW (approximate) steam generating units (Units 1 & 2) and two 400 MW (approximate) steam generating units (Units 3 & 4). The four units are proposed to be taken out of service and dismantled in 2013 as part of the modernization of the plant site.

The Port Everglades Plant site has been listed as a Potential Site in previous FPL Site Plans for both CC and simple cycle combustion turbine (CT) generation options. On March 27, 2012, the FPSC voted to authorized the modernization of the existing Port Everglades Plant. As a result of the modernization of the site, the new generating unit - to be renamed the Port Everglades Next Generation Clean Energy Center (PEEC) – will replace the existing steam generating units with a modern, highly efficient, lower-emission next-generation clean energy center using advanced CC technology. The existing four steam units will first be removed from the site and will be replaced by a single new CC unit.

a. **U.S. Geological Survey (USGS) Map**
A USGS map of the PEEC site is found at the end of this chapter.

b. **Proposed Facilities Layout**
A general layout of the PEEC generating facilities is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**
An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

The existing Port Everglades Plant consists of two 200 MW (approximate) and two 400 MW (approximate) generating units with conventional dual-fuel fired steam boilers and steam turbine units. The plant site includes minimal vegetation. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development.

e. **General Environment Features On and In the Site Vicinity**

1. **Natural Environment**

The majority of the site is comprised of facilities related to electric power generation for the existing Port Everglades Plant generating units. The site is located adjacent to the Intracoastal Waterway. The site provides warm water as required for manatees pursuant to the facility's Manatee Protection Plan.

2. **Listed Species**

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species. The warm water discharges from the plant attract manatees, an endangered species. FPL continues to work closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process and upon operation of the new plant. FPL plans to install a temporary heating system to provide warm water for manatees as required pursuant to the facility's Manatee Protection Plan. FPL also anticipates complying with other manatee-related conditions of certification to ensure the protection of the manatees during the modernization work and during future operations of PEEC.

3. **Natural Resources of Regional Significance Status**

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design option is to replace the existing units (Units 1 through 4) with one new 1,277 MW (approximate) unit consisting of three new combustion turbines (CT), three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit is projected to be in service in mid-2016. Natural gas delivered via the existing pipeline is the primary fuel type for the unit with ULSD serving as a backup fuel.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the site is a combination of "Electrical Generating Facility" and "Utilities Use". A land use map of the site and adjacent areas is also found at the end of this chapter.

h. **Site Selection Criteria Process**

The Port Everglades Plant has been selected for site modernization due to consideration of various factors including system load, ability to provide generation in the Miami-Dade/Broward region to help balance load and generation in the region, and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of replacing the existing steam units with a new CC unit including a significant reduction in system air emissions, improved aesthetics at the site, and continued warm water discharge for the manatees as required pursuant to the facility's Manatee Protection Plan. Further, modernizing this existing facility reduces the impact on natural resources by not requiring new land or new water resources.

i. **Water Resources**

Water from the Intracoastal Waterway via the Port of Port Everglades Slip No. 3 is currently used for once-through cooling water supply. The new plant will utilize portions of the existing once-through cooling water intake and discharge structures. Process and potable water for the modernized plant will come from the existing City of Ft. Lauderdale potable water supply.

j. **Geological Features of Site and Adjacent Areas**

FPL's Port Everglades Plant site is underlain by the surficial aquifer system. The surficial aquifer system in eastern Broward County is primarily composed of sand, sandstone, shell, silt, calcareous clay (marl), and limestone deposited during the Pleistocene and Pliocene ages. The sediments forming the aquifer system are the

Pamlico Sand, Miami Oolite, Anastasia Formation, Key Largo Formation, and Fort Thompson Formation (Pleistocene) and the Tamiami Formation (Pliocene). The sediments in the eastern portion of the county are appreciably more permeable than in the west.

The surficial aquifer is underlain by at least 600 feet the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Approximately 635 mgd of cooling water would be cycled through the once-through cooling water system. Potable water demand is expected to average .001 mgd.

l. Water Supply Sources by Type

The modernized plant will continue to use the Intracoastal Waterway as the source of once-through cooling water. Process and potable water for the new plant will come from the existing City of Ft. Lauderdale potable water supply.

m. Water Conservation Strategies Under Consideration

No additional water resources will be required as a result of the modernization project. Combined cycle technology uses less water by design than traditional steam generation units.

n. Water Discharges and Pollution Control

The modernized plant will utilize portions of the existing once-through cooling water system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system prior to discharge. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit would be transported to the site via an existing natural gas pipeline to the site. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit will be installed either at the existing site or off-site. ULSD would be received by truck, pipeline, or barge and stored in a new above-ground storage tank.

p. **Air Emissions and Control Systems**

The regulated air emission rates at the new plant would be approximately 90 percent lower than the previous Port Everglades Plant's emission rates, resulting in significant annual emissions reductions and air quality benefits per unit of energy produced. The use of natural gas and ULSD and combustion controls would minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates.

Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ULSD as backup fuel. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of PEEC would incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q. **Noise Emissions and Control Systems**

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. **Status of Applications**

FPL filed a need determination with the FPSC on November 21, 2011. The FPSC authorized the need for the modernization of Port Everglades on March 27, 2012. The Site Certification Application (SCA) was submitted January 24, 2012. Concurrent with the SCA filing, FPL submitted applications for a Prevention of Significant Deterioration permit and an Industrial Wastewater Facility permit revision.

IV.F.2 Potential Sites for Generating Options

Ten (10) sites are currently identified as Potential Sites for near-term future generation additions to meet FPL's projected capacity and energy needs.[7] These sites have been identified as Potential Sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies, including both renewable energy and non-renewable energy technologies for various sites.

Each of these Potential Sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that will require further definition and attention. Solely for the purpose of estimating water requirements for sites more suited for non-renewable energy technologies, it was assumed that either one dual-fuel (natural gas and light oil) simple cycle combustion turbine (CT), or a natural gas-fired CC unit, would be constructed at these Potential Sites unless otherwise noted.

A simple cycle CT would require approximately 50 gallons per minute (gpm) for both process and cooling water (assuming a cooling tower was utilized). A CC unit would require approximately up to 150 gpm for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized). If an existing power plant site is ultimately selected for modernization (as is the case with FPL's CCEC, RBEC, and PEEC sites), the water requirements discussed above for a CC unit would be approximately correct for the modernized site. If a renewable energy generating technology is ultimately selected for one of these sites, the water requirements would be significantly less than those for CT or CC facilities.

Permits are presently considered to be obtainable for each of these sites. No significant environmental constraints are currently known for any of these sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time, FPL considers each site to be equally viable. As noted previously, FPL also considers a number of other sites as possible sites for future generation additions. These include all of the remainder of FPL's existing generation sites and other Greenfield sites.

[7] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other Greenfield sites. Greenfield sites that FPL currently does not own, or for which FPL has not currently secured the necessary rights to, are not specifically identified as Potential Sites in order to protect the economic interests of FPL and its customers.

Potential Site # 1: Babcock Ranch , Charlotte County

This site is located within the proposed Babcock Ranch Community on the north side of Tuckers Grade, approximately 10.5 miles north of the intersection of SR-80 and SR-31 and 1.1 miles east of SR-31. The project is bordered on the north by the Babcock Ranch Preserve owned by the State of Florida. This site is a possibility for an FPL photovoltaic (PV) facility. FPL has received all permits necessary to construct a 75 MW PV facility at this location.

a. **U.S. Geological Survey (USGS) Map**

A map of this site is found at the end of this chapter.

b. **Land Uses**

Existing land use on the site is the Babcock Ranch Overlay District, and it is zoned as the Babcock Ranch Overlay Zoning District. This land use and zoning allows for solar facilities.

c. **Environmental Features**

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

d. **Water Quantities**

Minimal amounts of water, if any, would be required for a PV facility.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall Any such water may be brought to the site by truck.

Potential Site # 2: DeSoto Solar Expansion, DeSoto County

The DeSoto site is located at 4051 Northeast Karson Street which is approximately 0.3 miles east of US 17 and immediately north of Bobay Road in Arcadia, Florida. The site is located in Sections 26, 27, & 35, Township 36 South, and Range 25 East. FPL owns an approximate 13,000 acre parcel in DeSoto County. FPL has designated approximately 5,177 acres for development of a photovoltaic (PV) facility.

The DeSoto site is home to a 25 MW PV facility that has been operational since 2009. Up to an additional 275 MW of PV generation could be constructed in phases on the remaining undeveloped land. FPL has initiated permitting for the additional PV facilities.

a. **U.S. Geological Survey (USGS) Map**

A map of this site is found at the end of this chapter.

b. **Land Uses**

Existing land use on the site is agricultural. The future land use is Electric Generating Facility.

c. **Environmental Features**

There are no significant environmental features on the site.

d. **Water Quantities**

Minimal amounts of water would be required for a future expansion of the existing PV facility.

e. **Supply Sources**

Minimal water would be required for an expanded PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall. Potable water will be required in the administration building and maintenance building. FPL would propose to utilize existing wells onsite to accommodate water needs.

Potential Site # 3: Florida Heartland Solar, Glades County

This site is located within Glades County off SR 78. This site is a possibility for an FPL PV facility. FPL has initiated permitting for a PV facility of approximately 125 MW to be constructed at this location.

a. **U.S. Geological Survey (USGS) Map**

A map of this site is found at the end of this chapter.

b. **Land Uses**

The existing land use on the site is agriculture.

c. **Environmental Features**

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall. Any such water may be brought to the site by truck.

Potential Site # 4: Hendry County

FPL has acquired a site in southeast Hendry County, off CR 833. This site is a possibility for a future PV facility and/or natural gas power generation. The site is approximately 3,127 acres.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

Hendry County has predominantly agricultural land use.

c. **Environmental Features**

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a power generation project constructed at this site.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility. Natural gas generation would require approximately up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized).

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water may be brought to the site by truck. The supply of water for fossil generation would be dependent upon the capacity of the generating unit(s) and the generation technology to be implemented.

Potential Site # 5: Manatee Plant Site, Manatee County

The existing FPL Manatee Plant 9,500-acre site is located in unincorporated north-central Manatee County. The existing power generating facilities are located in all or portions of Sections 18 and 19 of Township 33S, Range 20-E. The plant site lies approximately 5 miles east of Parrish, Florida. It is approximately 5 miles east of U.S. 301 and 9.5 miles east of Interstate Highway 75 (I-75). The existing plant is approximately 2.5 miles south of the Hillsborough-Manatee County line; a portion of the north property boundary of the plant site abuts the county line. State Road 62 (SR 62) is about 0.7 mile south of the plant, with the plant entrance road going north from that highway. This site is a possible location for an FPL PV facility. FPL has received the federal and state permits required to construct approximately 40 MW of PV at this location.

a. **U.S. Geological Survey (USGS) Map**

A map of the site is found at the end of this chapter.

b. **Land Uses**

Existing land use on the site is agricultural. The property is zoned Planned Development / Public Interest (PD-PI), which will allow for electrical generation.

c. **Environmental Features**

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall. Any such water may be brought to the site by truck.

Potential Site # 6: Martin County

FPL is currently evaluating potential sites in Martin County for a future PV facility. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**
A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**
This information is not available because a specific site has not been selected at this time.

c. **Environmental Features**
This information is not available because a specific site has not been selected at this time.

d. **Water Quantities**
Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**
Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall.

Potential Site # 7: Northeast Okeechobee County

FPL has purchased a 2,832 acre site in Northeast Okeechobee County for a future PV facility or natural gas generation.

a. **U.S. Geological Survey (USGS) Map**
A USGS map of the site has been included at the end of this chapter.

b. **Land Uses**
The site has predominantly agricultural land use.

c. **Environmental Features**

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

d. **Water Quantities**

Water requirements for fossil generation would be up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower would be utilized). Needed water quantities would be significantly less for a PV facility.

e. **Supply Sources**

Existing groundwater and/or regional water supply initiatives are potential water sources.

Potential Site # 8: Palatka Site, Putnam County

FPL is currently evaluating a site adjacent to the former FPL Putnam Plant site in Putnam County for future fossil-fueled generation. The approximately 170 acre site was the location of the former FPL Palatka Plant which was dismantled in the 1990s.

a. **U.S. Geological Survey (USGS) Map**

A map of the site is found at the end of this chapter.

b. **Land Uses**

The site has a land use designation of Industrial.

c. **Environmental Features**

The majority of site has been previously impacted by past power plant operations. No significant environmental features have been identified at this time.

d. **Water Quantities**

Water requirements would be up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower).

e. **Supply Sources**

The St John's River, existing groundwater, and/or regional water supply initiatives are potential water sources.

Potential Site # 9: Putnam County

FPL is currently evaluating additional potential sites in Putnam County for a future PV facility or natural gas power generation. Sites currently under investigation are approximately 2,800 acres. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

This information is not available because a specific site has not been selected at this time.

c. **Environmental Features**

This information is not available because a specific site has not been selected at this time.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility. Natural gas power generation would require approximately up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized).

e. **Supply Sources**

Existing groundwater is a potential water source.

Potential Site # 10: Space Coast Solar Expansion, Brevard County

The Space Coast site is located at NASA's Kennedy Space Center property in Brevard County. This site currently houses a 10 MW PV facility which began operating in 2010, with the potential to expand the PV generating capacity by an additional 10 MW. FPL is also evaluating the potential for further expansion beyond the existing site, within the Space Center property.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site has been included at the end of this chapter.

b. **Land Uses**

NASA, a federal agency, has approved use of the land at the site for PV generation.

c. **Environmental Features**

There are no significant environmental features on this site.

d. **Water Quantities**

Minimal amounts of water would be required for an expansion of the PV facility.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall.

Any such water would be brought to the site by truck or would come from existing onsite wells.

Environmental and Land Use Information: Supplemental Information

Preferred Site #1: St. Lucie Plant

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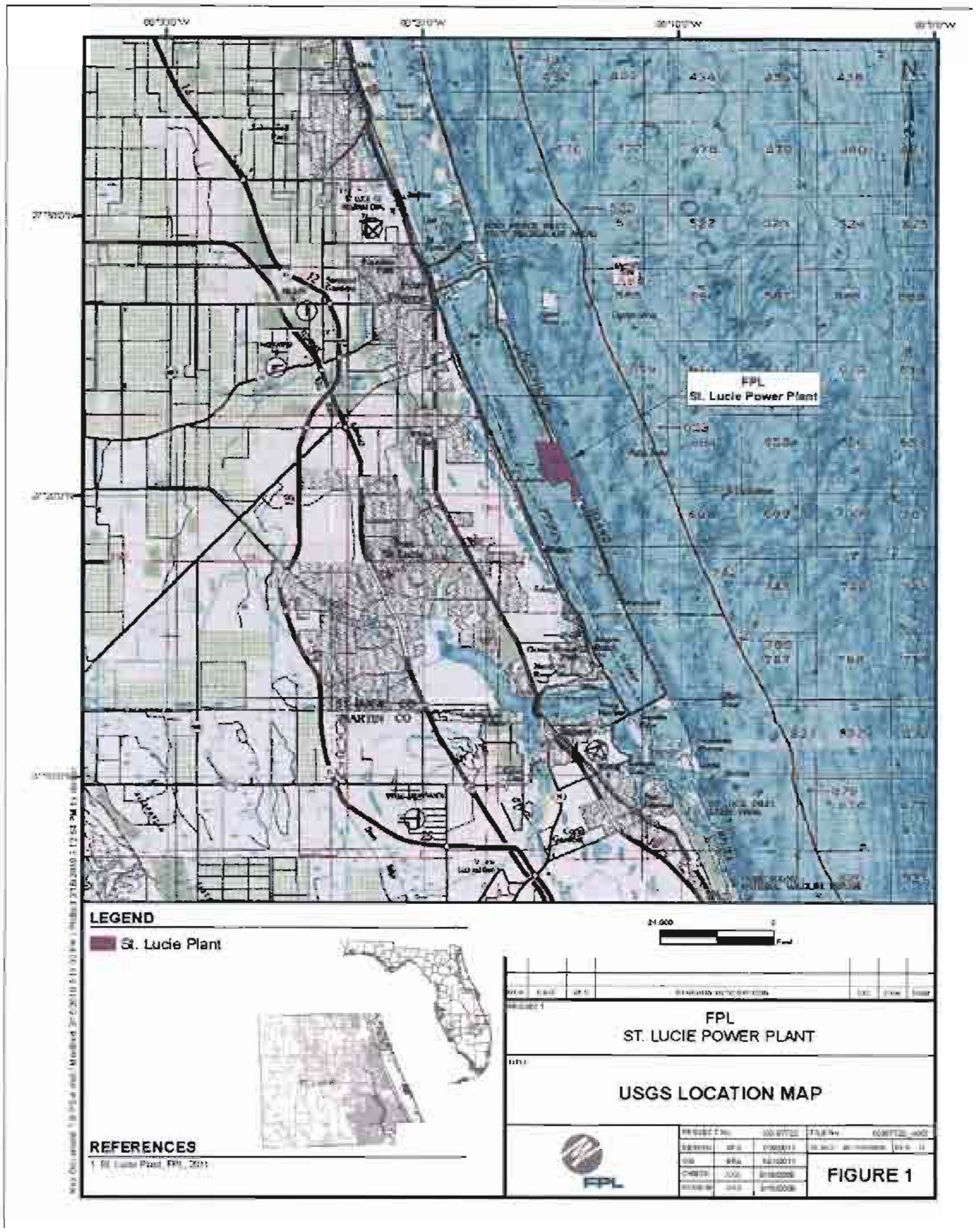
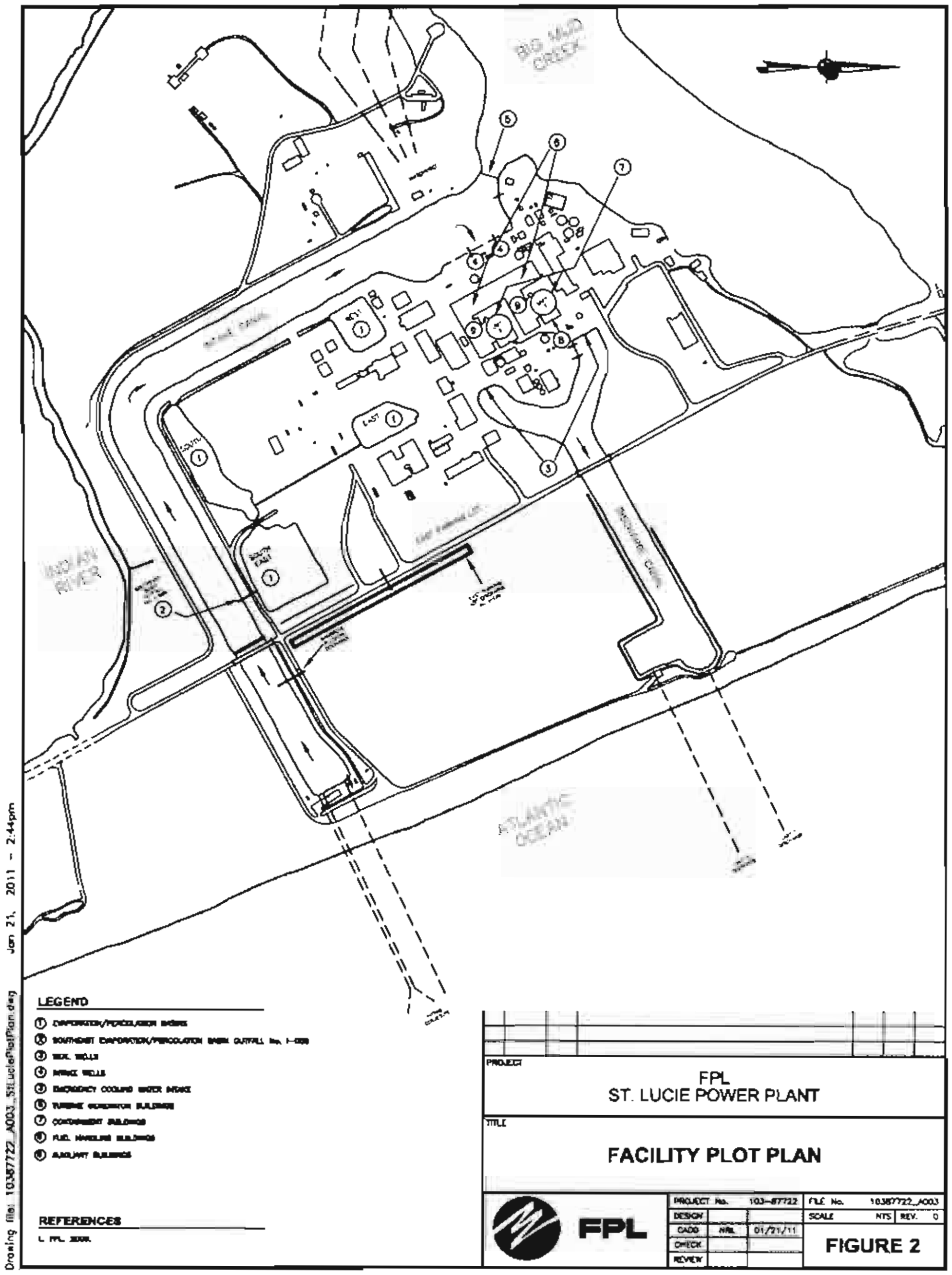

FPL
St. Lucie Power Plant
LEGEND
St. Lucie Plant
REFERENCES
FPL
ST. LUCIE POWER PLANT
USGS LOCATION MAP
FPL
FIGURE 1


BIG MUD CREEK
INDIAN RIVER
ATLANTIC OCEAN
LEGEND
REFERENCES
PROJECT
FPL
ST. LUCIE POWER PLANT
TITLE
FACILITY PLOT PLAN
FPL
FIGURE 2


N
LEGEND
REFERENCES
PROJECT
FPL
ST. LUCIE POWER PLANT
LAND USE / LAND COVER
FPL
FIGURE 3

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Environmental and Land Use Information: Supplemental Information

Preferred Site #2: Turkey Point Plant

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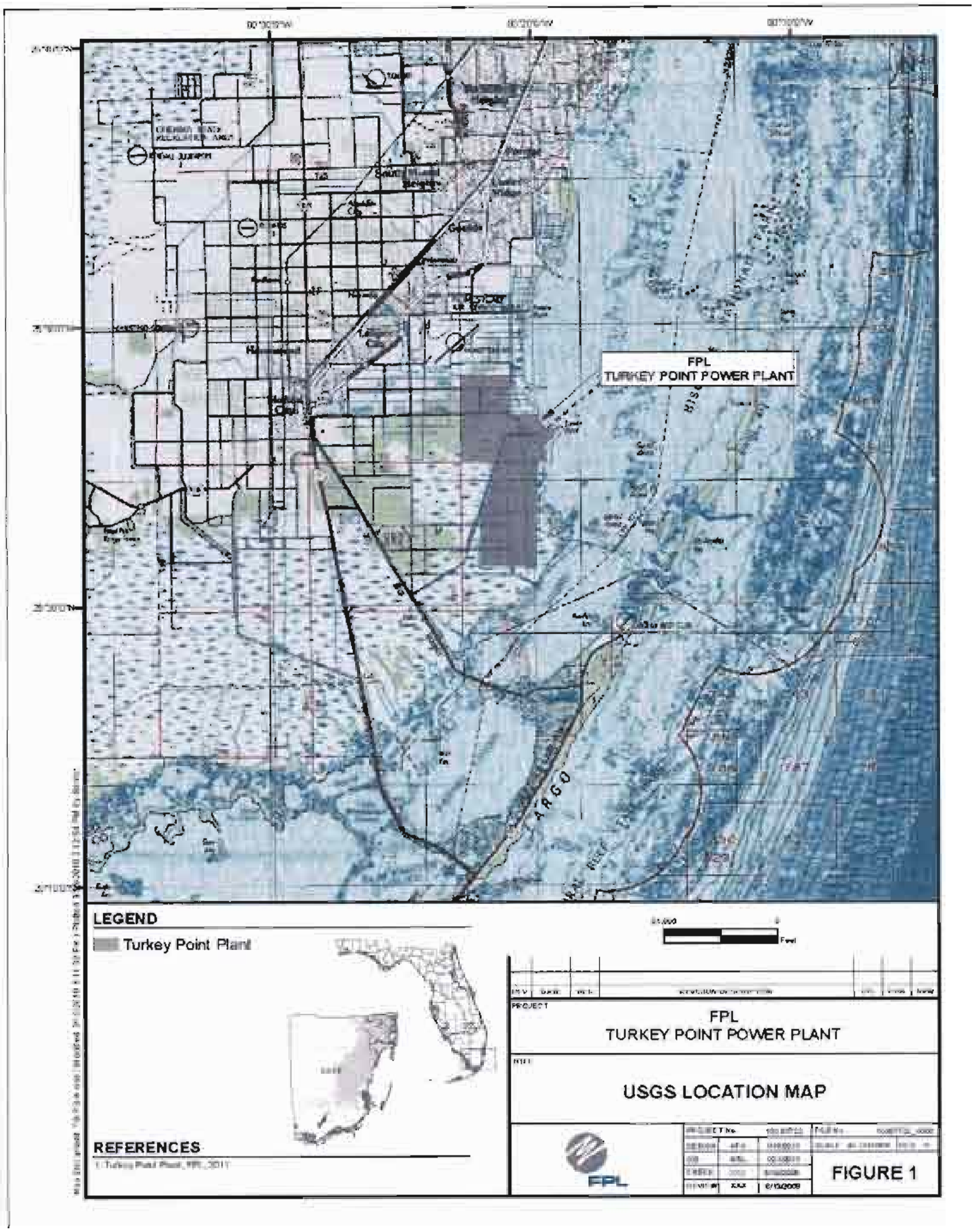
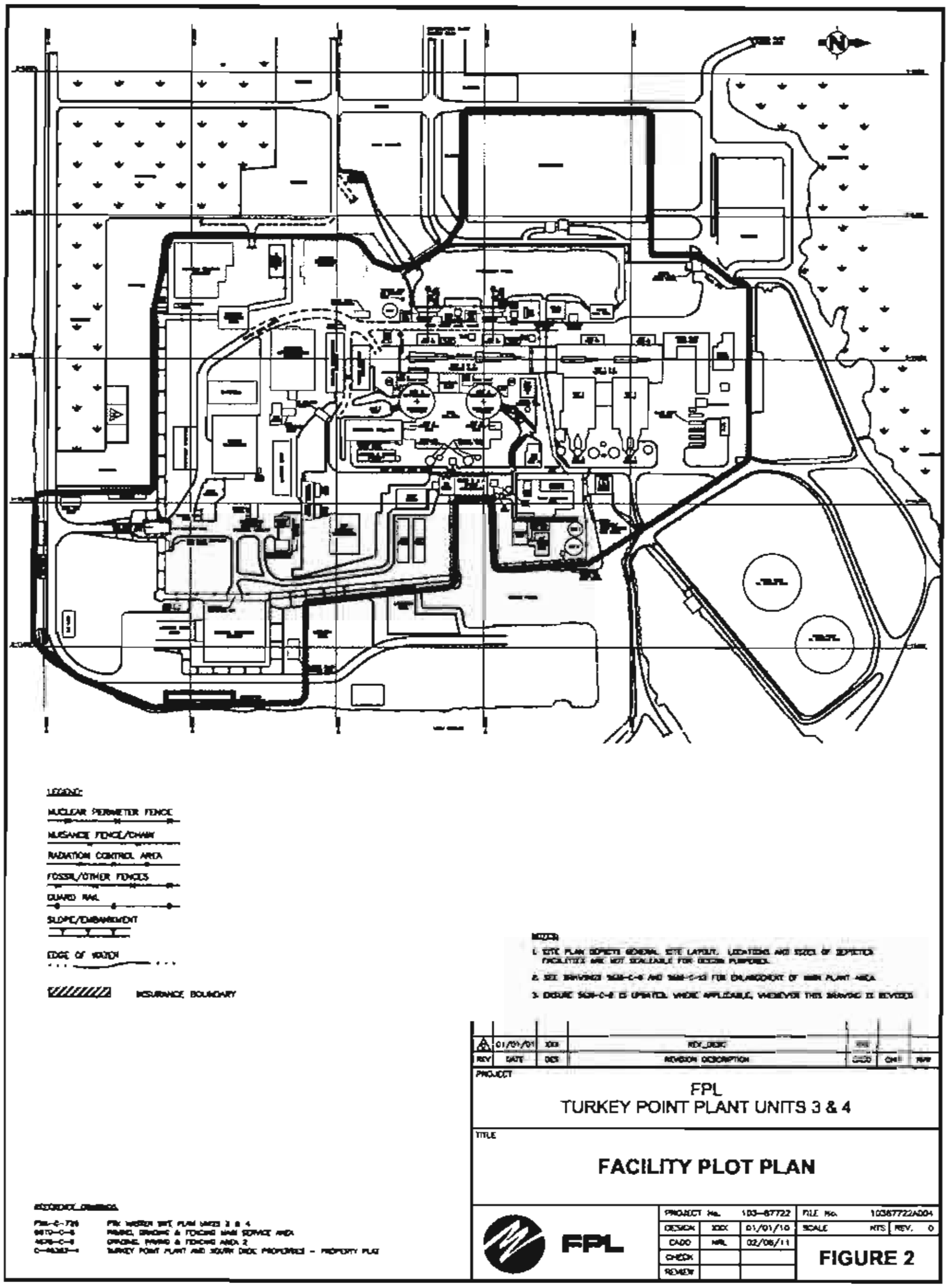
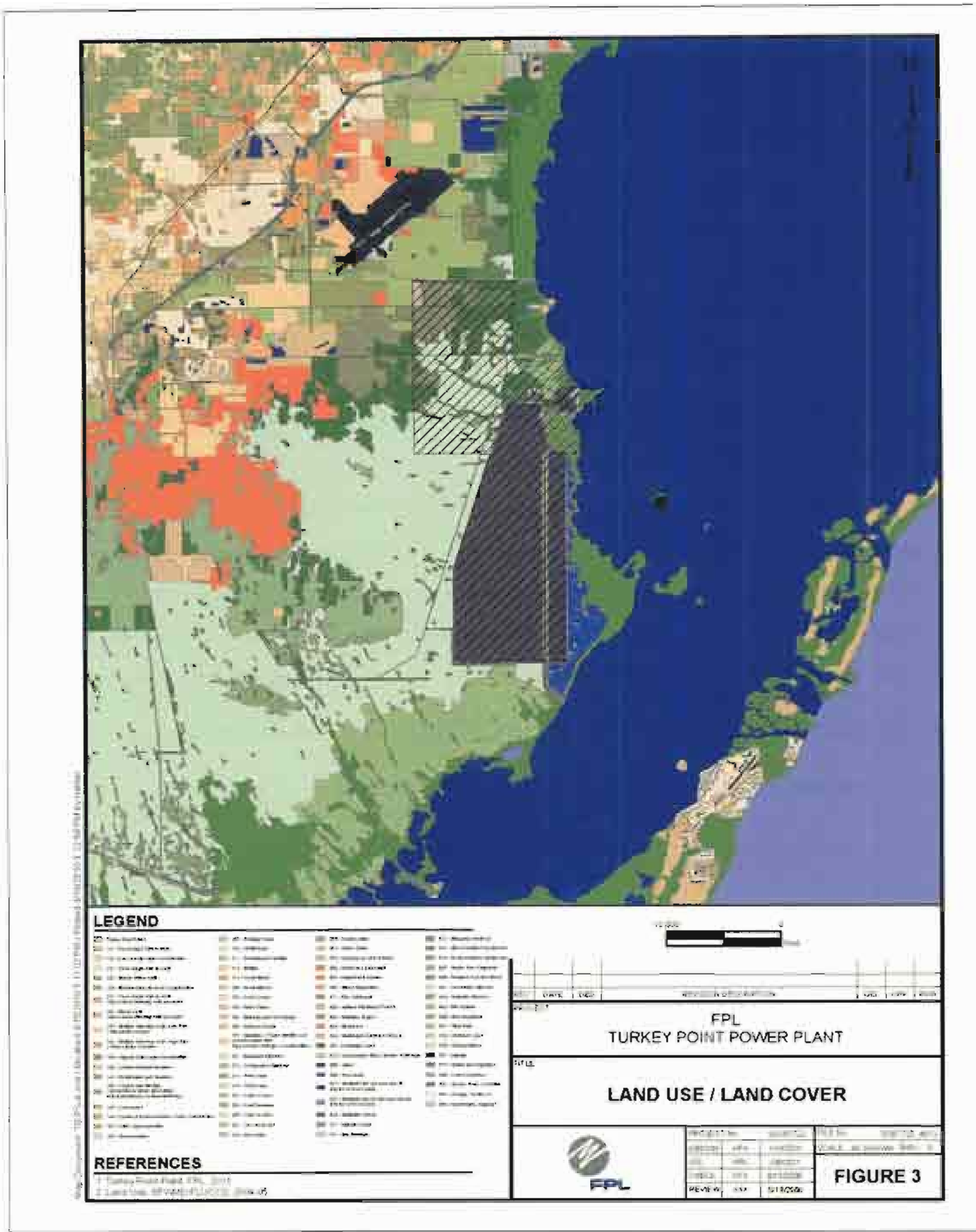

FPL
TURKEY POINT POWER PLANT
LEGEND
Turkey Point Plant
REFERENCES
FPL
TURKEY POINT POWER PLANT
USGS LOCATION MAP
FIGURE 1


LEGEND:
NUCLEAR PERIMETER FENCE
NUISANCE FENCE/CHAIN
RADIATION CONTROL AREA
FOSSIL/OTHER FENCES
GUARD RAIL
SLOPE/EMBANKMENT
EDGE OF WATER
INSURANCE BOUNDARY
PROJECT
FPL
TURKEY POINT PLANT UNITS 3 & 4
TITLE
FACILITY PLOT PLAN
FPL
FIGURE 2


LEGEND
REFERENCES
FPL
TURKEY POINT POWER PLANT
LAND USE / LAND COVER
FPL
FIGURE 3

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Environmental and Land Use Information: Supplemental Information

Preferred Site #3: Cape Canaveral Plant

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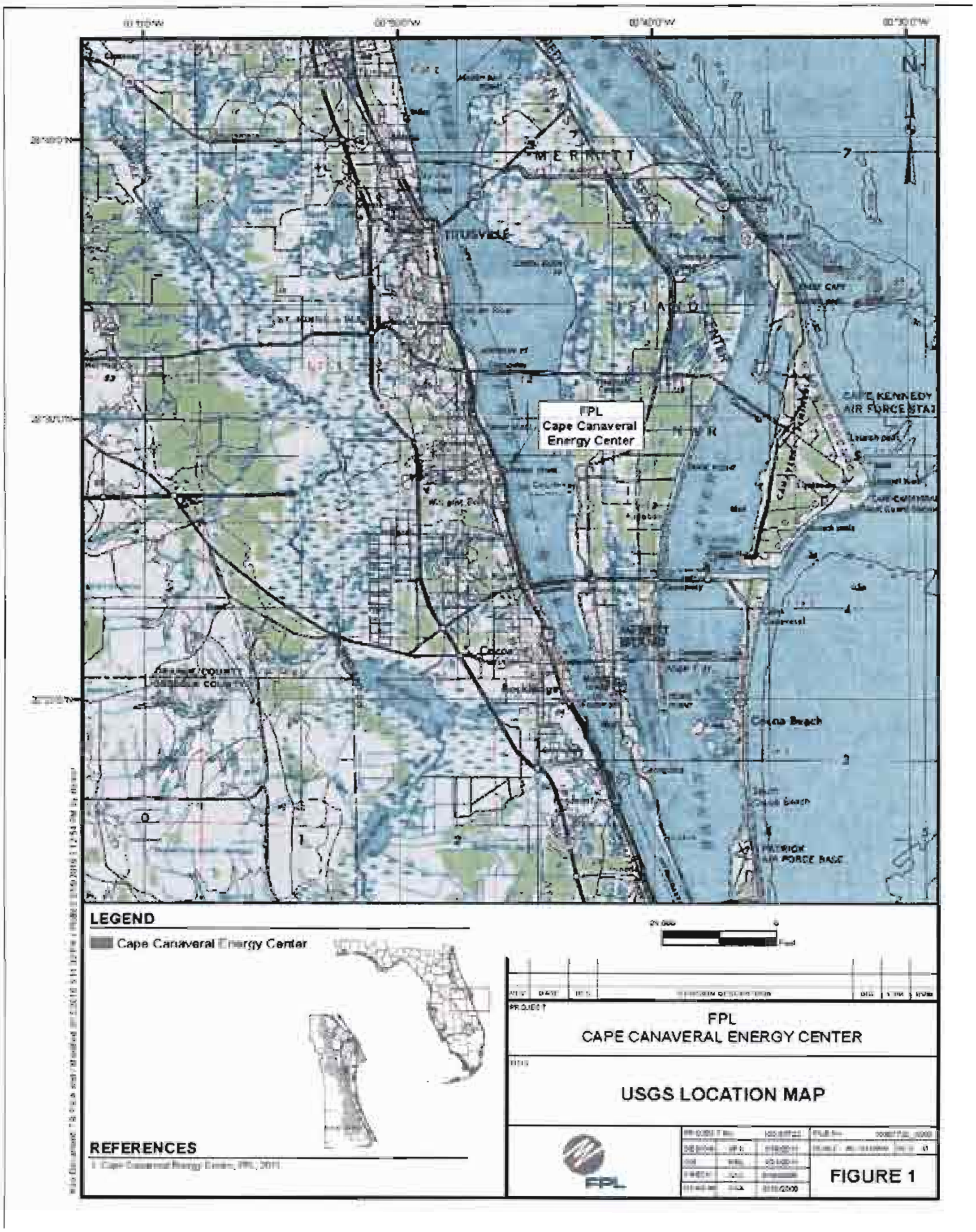
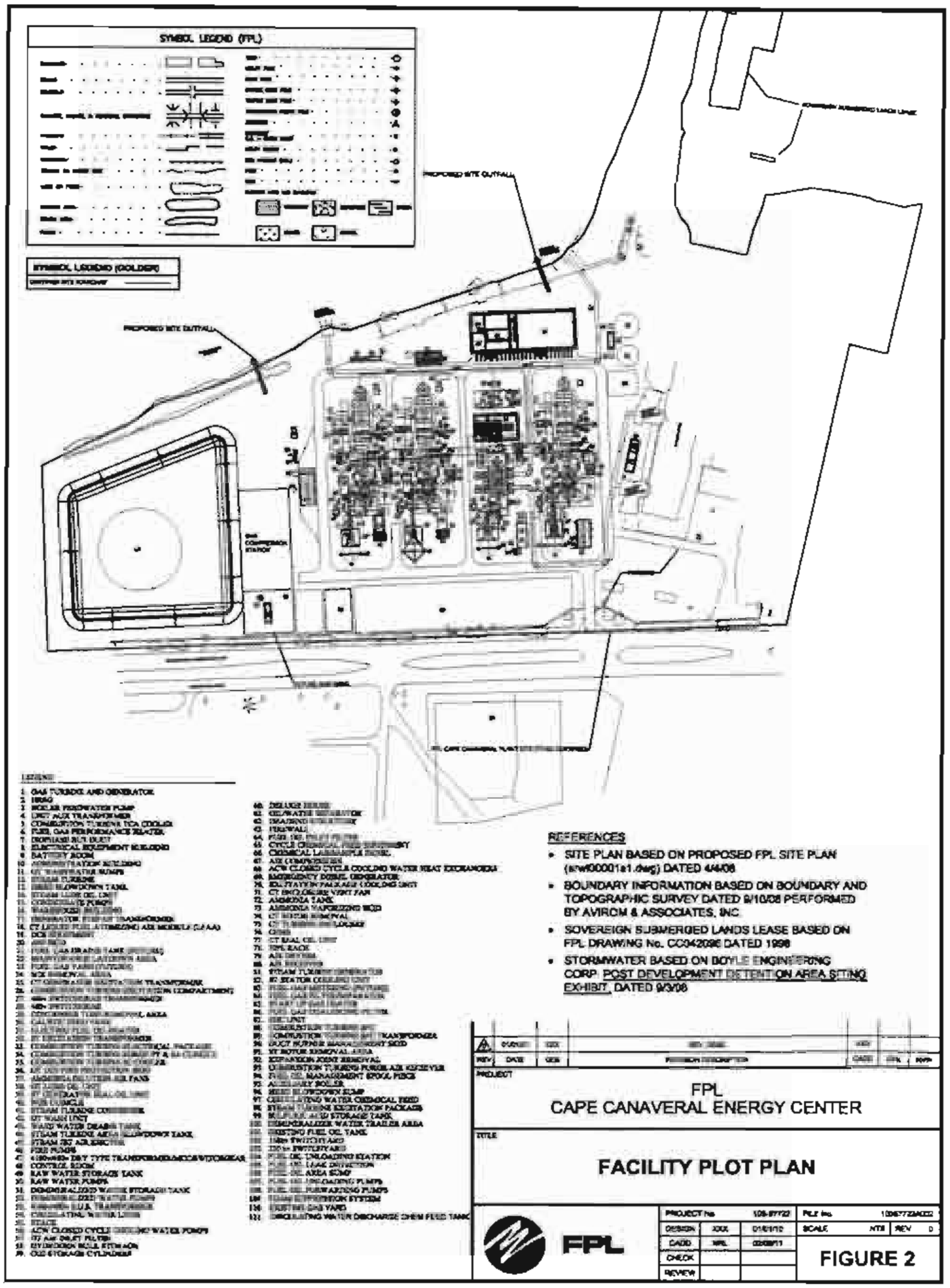

MERRITT
TITUSVILLE
FPL
Cape Canaveral
Energy Center
CAPE KENNEDY
AIR FORCE STA
Cocoa Beach
PATRICK
AIR FORCE BASE
LEGEND
Cape Canaveral Energy Center
REFERENCES
FPL
CAPE CANAVERAL ENERGY CENTER
USGS LOCATION MAP
FPL
FIGURE 1


SYMBOL LEGEND (FPL)
PROPOSED SITE OUTFALL
REFERENCES
SITE PLAN BASED ON PROPOSED FPL SITE PLAN DATED 4/4/08
BOUNDARY INFORMATION BASED ON BOUNDARY AND TOPOGRAPHIC SURVEY DATED 9/10/08 PERFORMED BY AVIROM & ASSOCIATES, INC.
SOVEREIGN SUBMERGED LANDS LEASE BASED ON FPL DRAWING No. CC042096 DATED 1998
STORMWATER BASED ON BOYLE ENGINEERING CORP. POST DEVELOPMENT DETENTION AREA SITING EXHIBIT, DATED 9/3/08
PROJECT
FPL
CAPE CANAVERAL ENERGY CENTER
TITLE
FACILITY PLOT PLAN
FPL
FIGURE 2


LEGEND
REFERENCES
FPL
CAPE CANAVERAL ENERGY CENTER
LAND USE / LAND COVER
FIGURE 3

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Environmental and Land Use Information:
Supplemental Information
Preferred Site #4: Riviera Plant

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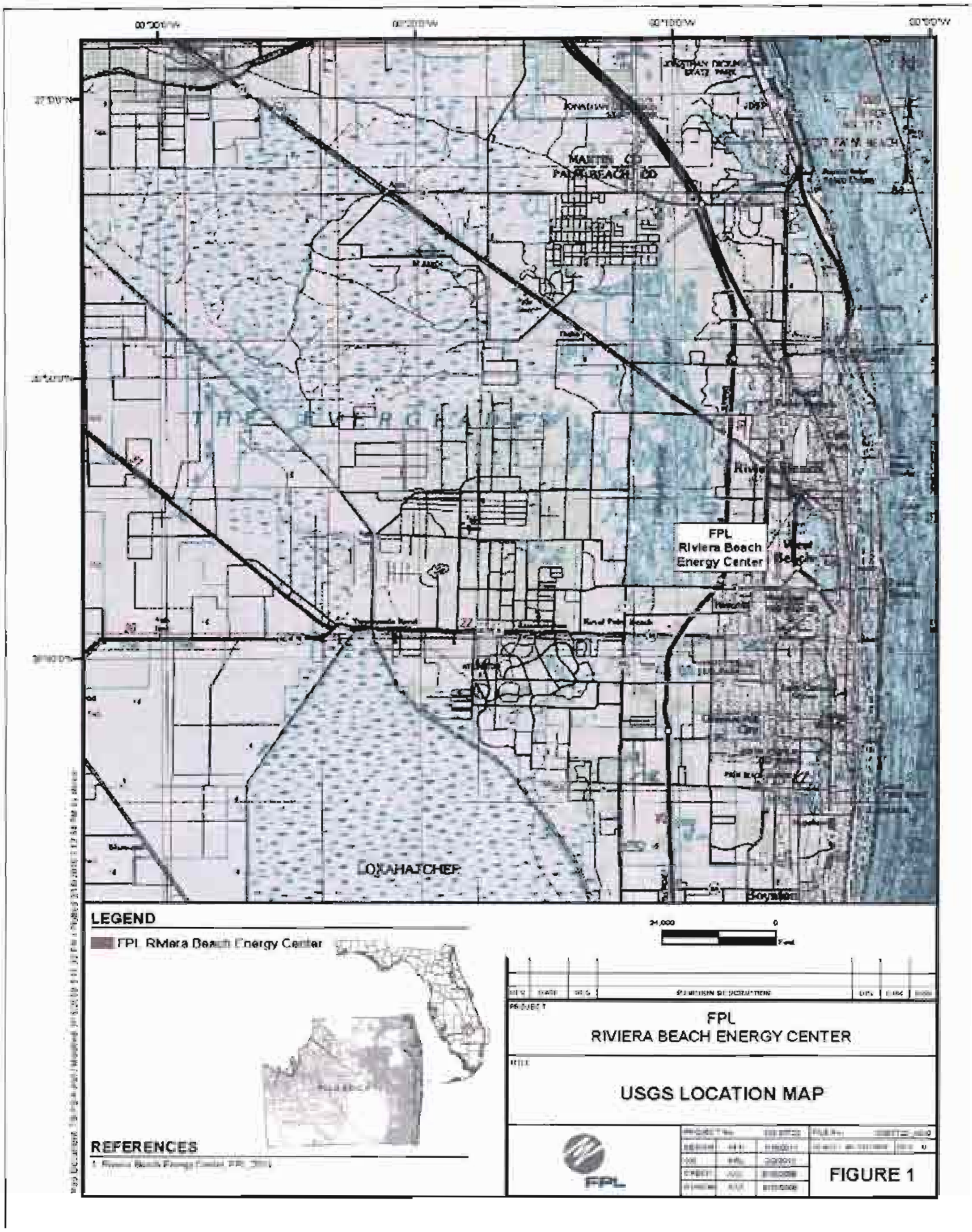
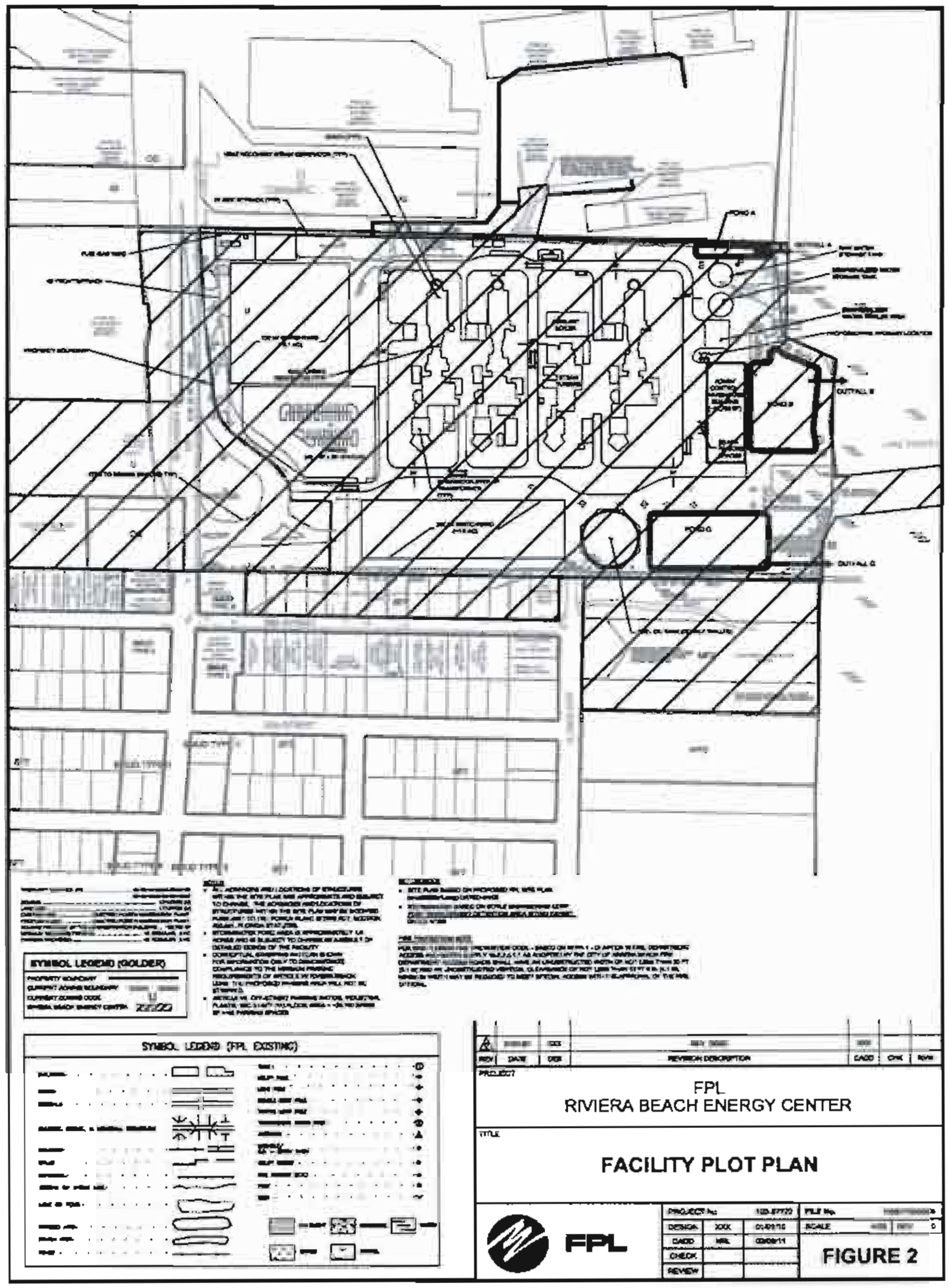
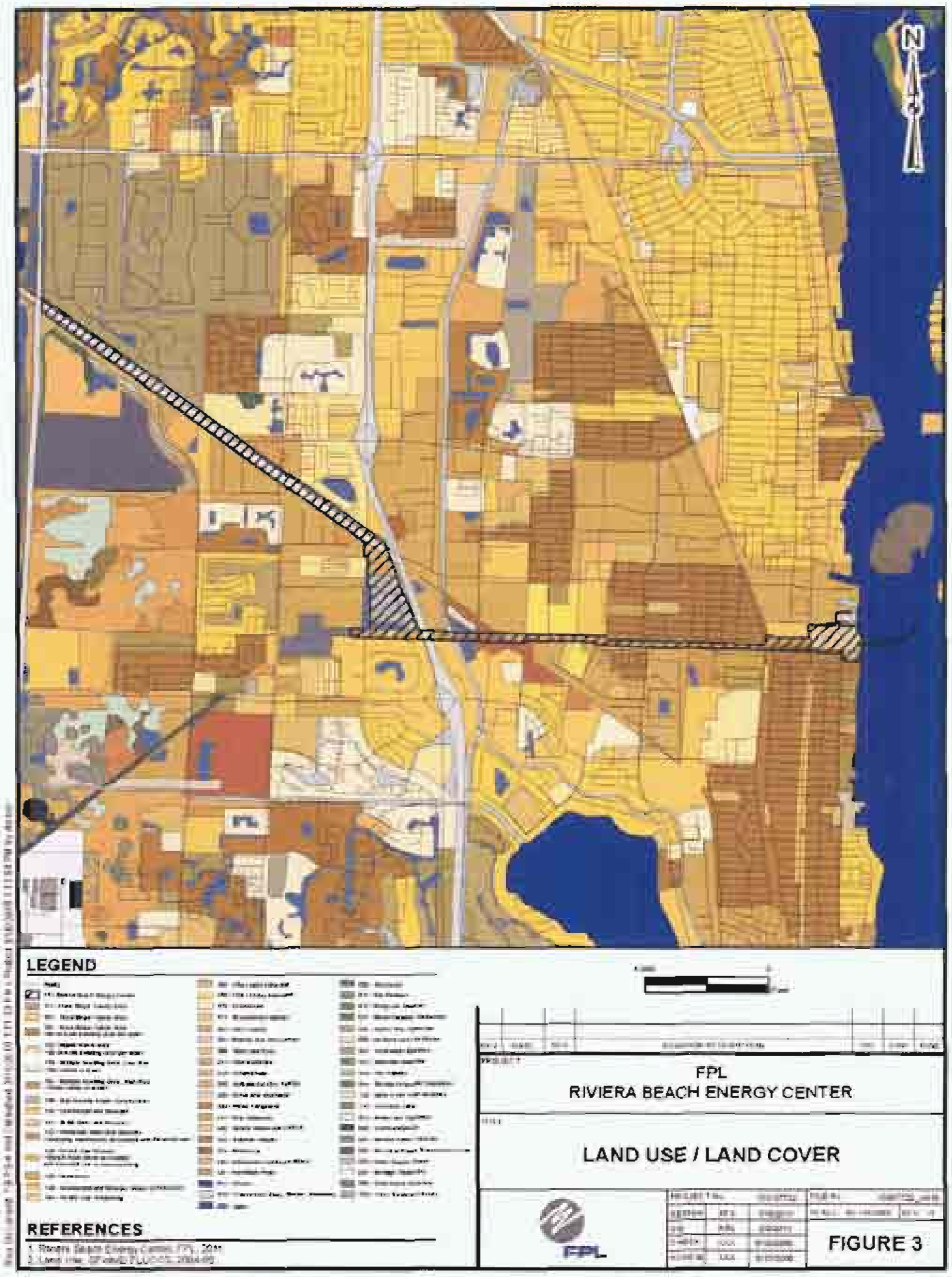

FPL
Riviera Beach
Energy Center
LOXAHATCHEE
LEGEND
FPL Riviera Beach Energy Center
REFERENCES
PROJECT
FPL
RIVIERA BEACH ENERGY CENTER
USGS LOCATION MAP
FIGURE 1


SYMBOL LEGEND (GOLDER)
SYMBOL LEGEND (FPL EXISTING)
PROJECT
FPL
RIVIERA BEACH ENERGY CENTER
TITLE
FACILITY PLOT PLAN
FPL
FIGURE 2


LEGEND
REFERENCES
FPL
RIVIERA BEACH ENERGY CENTER
LAND USE / LAND COVER
FPL
FIGURE 3

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Environmental and Land Use Information:

Supplemental Information

Preferred Site #5: Port Everglades Plant

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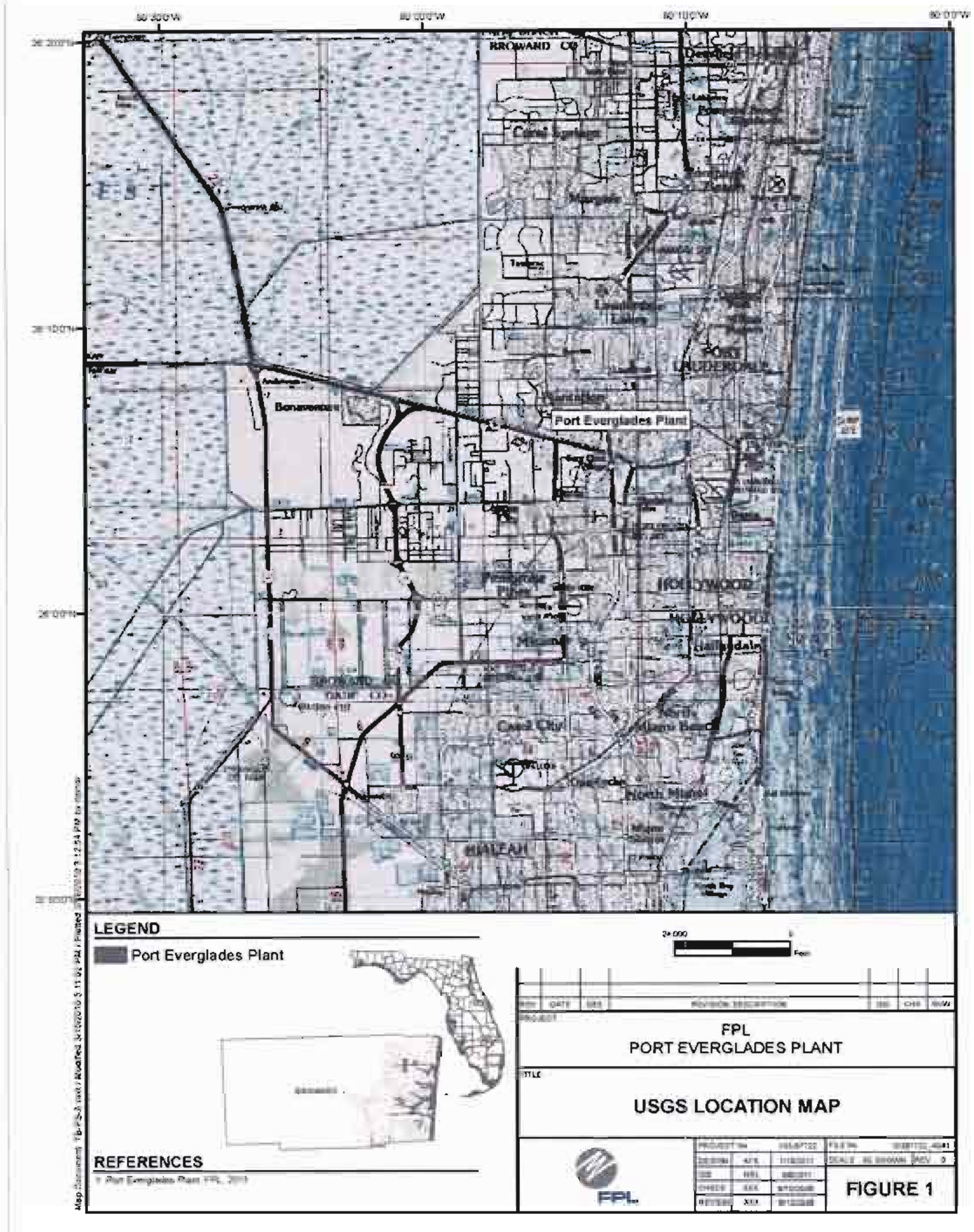
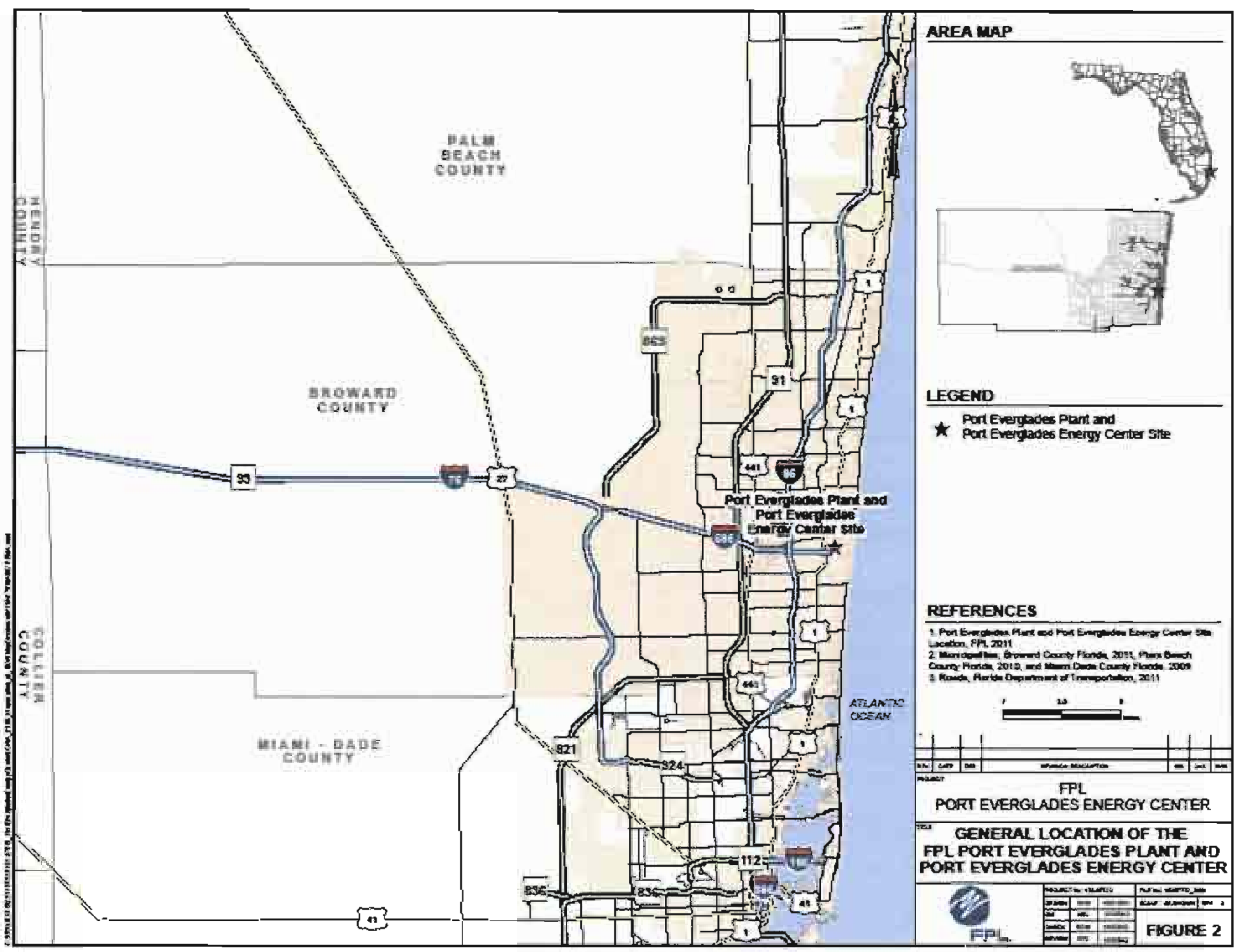
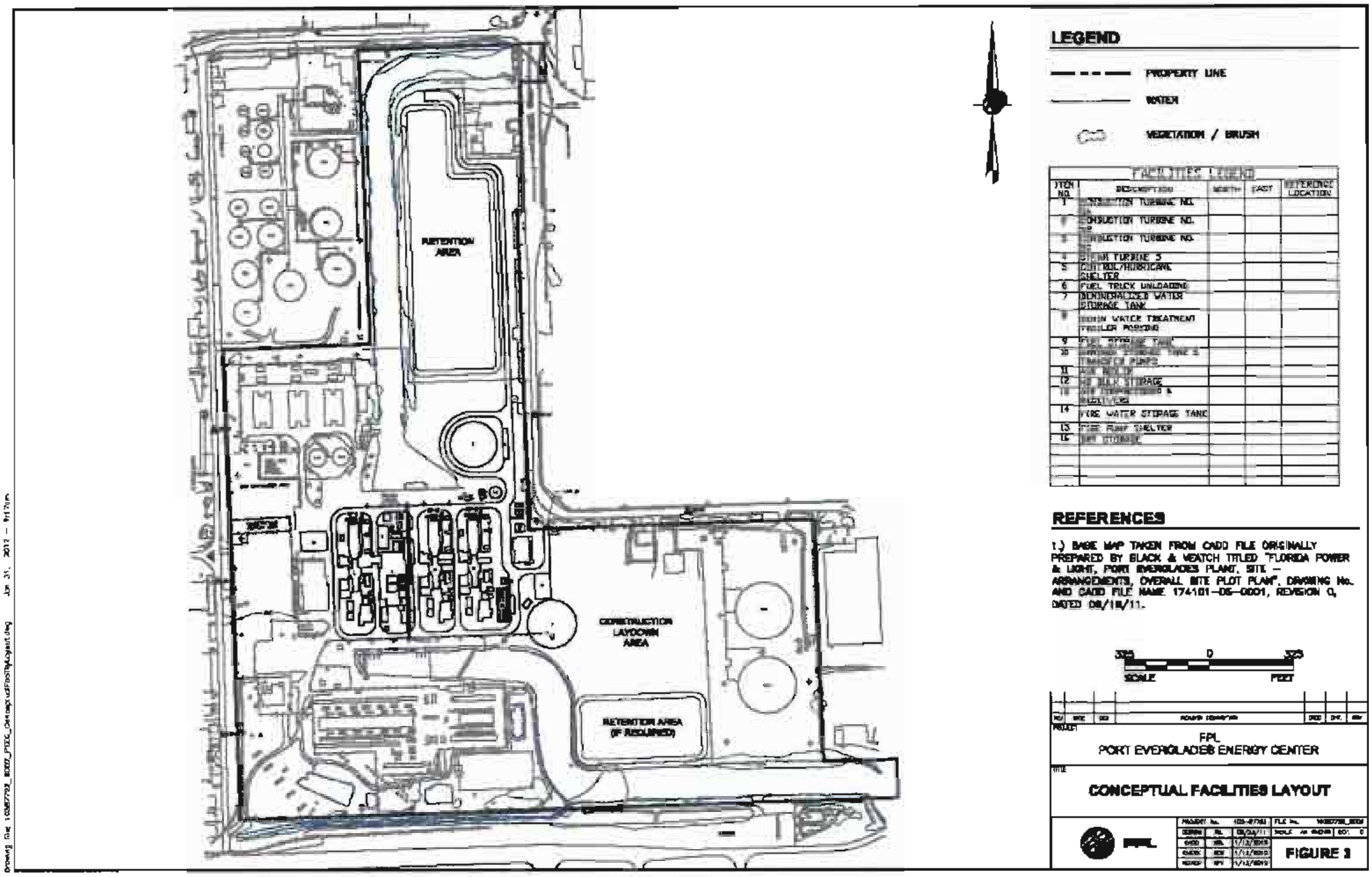
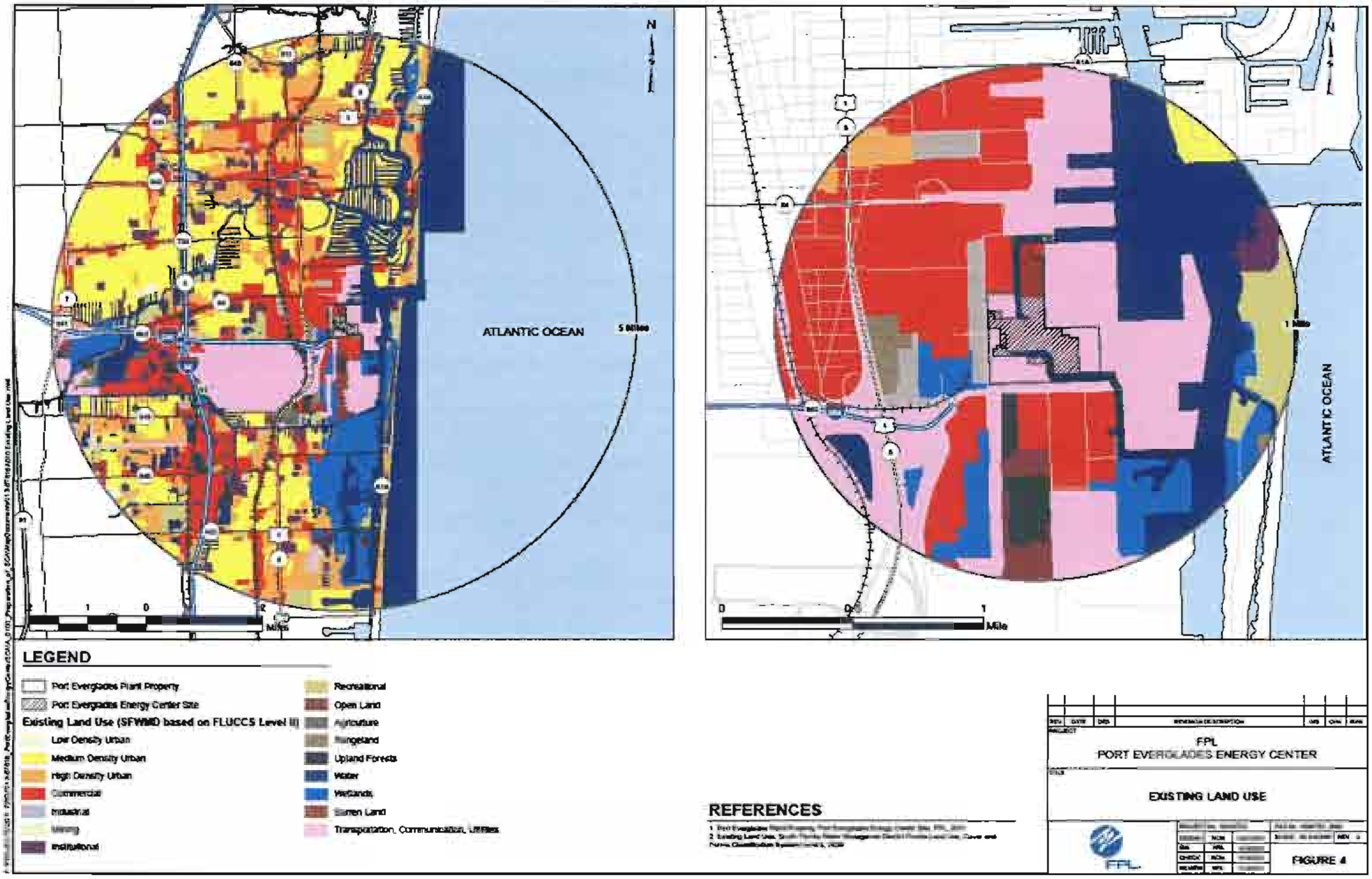

BROWARD CO
Port Everglades Plant
HOLLYWOOD
LEGEND
Port Everglades Plant
REFERENCES
FPL
PORT EVERGLADES PLANT
USGS LOCATION MAP
FIGURE 1
FPL


AREA MAP
LEGEND
Port Everglades Plant and Port Everglades Energy Center Site
REFERENCES
1. Port Everglades Plant and Port Everglades Energy Center Site Location, FPL 2011
2. Municipalities, Broward County Florida, 2011, Palm Beach County Florida, 2010, and Miami Dade County Florida, 2009
3. Roads, Florida Department of Transportation, 2011
PALM BEACH COUNTY
HENDRY COUNTY
BROWARD COUNTY
COLLIER COUNTY
MIAMI - DADE COUNTY
Port Everglades Plant and Port Everglades Energy Center Site
ATLANTIC OCEAN
FPL
PORT EVERGLADES ENERGY CENTER
GENERAL LOCATION OF THE FPL PORT EVERGLADES PLANT AND PORT EVERGLADES ENERGY CENTER
FIGURE 2


RETENTION AREA
CONSTRUCTION LAYDOWN AREA
RETENTION AREA (IF REQUIRED)
LEGEND
PROPERTY LINE
WATER
VEGETATION / BRUSH
CONTROL/HURRICANE SHELTER
FUEL TRUCK UNLOADING
DEMINERALIZED WATER STORAGE TANK
FIRE WATER STORAGE TANK
REFERENCES
1.) BASE MAP TAKEN FROM CADD FILE ORIGINALLY PREPARED BY BLACK & VEATCH TITLED "FLORIDA POWER & LIGHT, PORT EVERGLADES PLANT, SITE – ARRANGEMENTS, OVERALL SITE PLOT PLAN", DRAWING No. AND CADD FILE NAME 174101-05-0001, REVISION 0, DATED 08/18/11.
SCALE
FEET
FPL
PORT EVERGLADES ENERGY CENTER
CONCEPTUAL FACILITIES LAYOUT
FPL


ATLANTIC OCEAN
5 Miles
1 Mile
Miles
Mile
LEGEND
Port Everglades Plant Property
Port Everglades Energy Center Site
Existing Land Use (SFWMD based on FLUCCS Level II)
Low Density Urban
Medium Density Urban
High Density Urban
Commercial
Industrial
Mining
Institutional
Recreational
Open Land
Agriculture
Rangeland
Upland Forests
Water
Wetlands
Barren Land
Transportation, Communication, Utilities
REFERENCES
FPL
PORT EVERGLADES ENERGY CENTER
EXISTING LAND USE
FIGURE 4

Environmental and Land Use Information: Supplemental Information

Potential Site #1: Babcock Ranch

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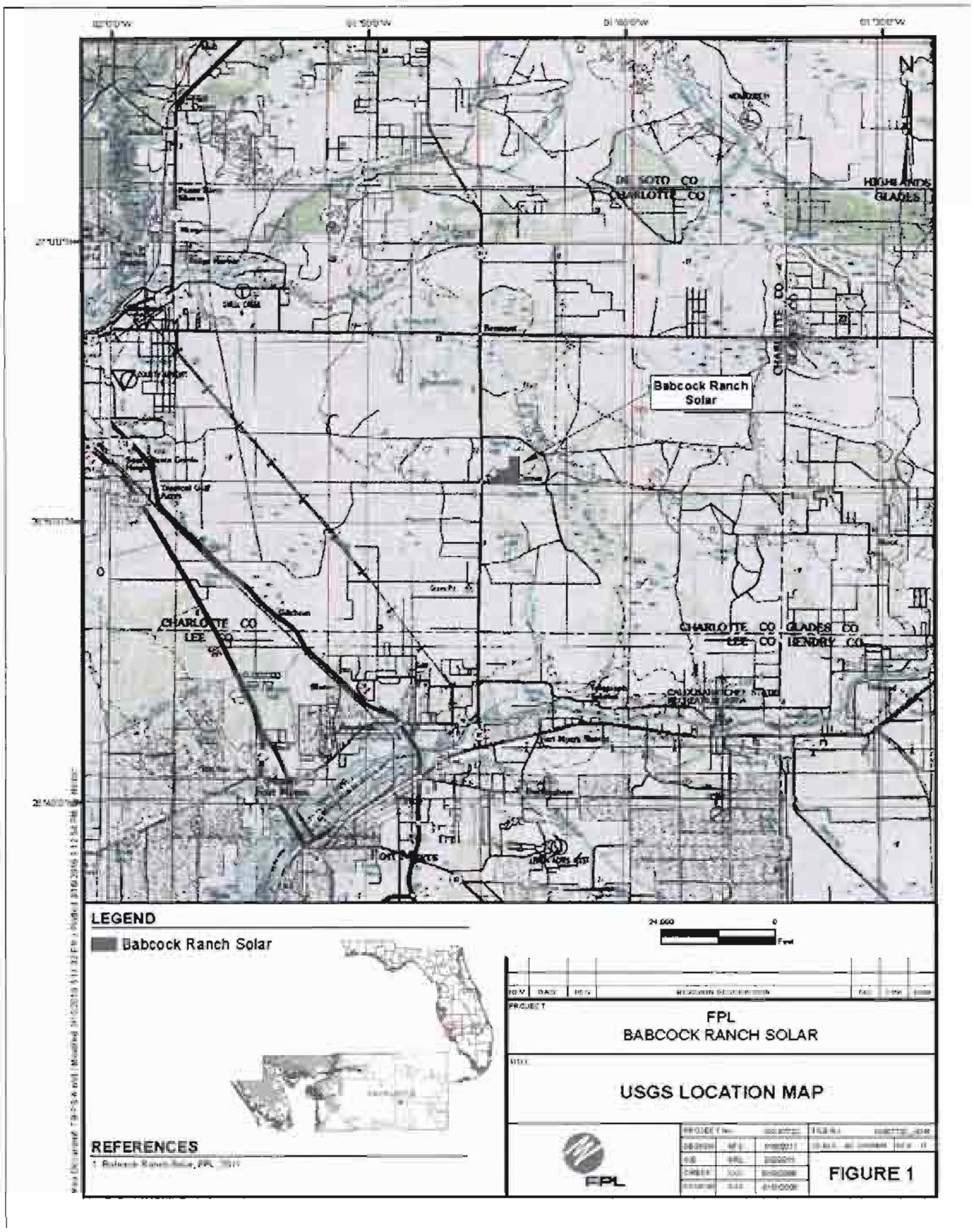
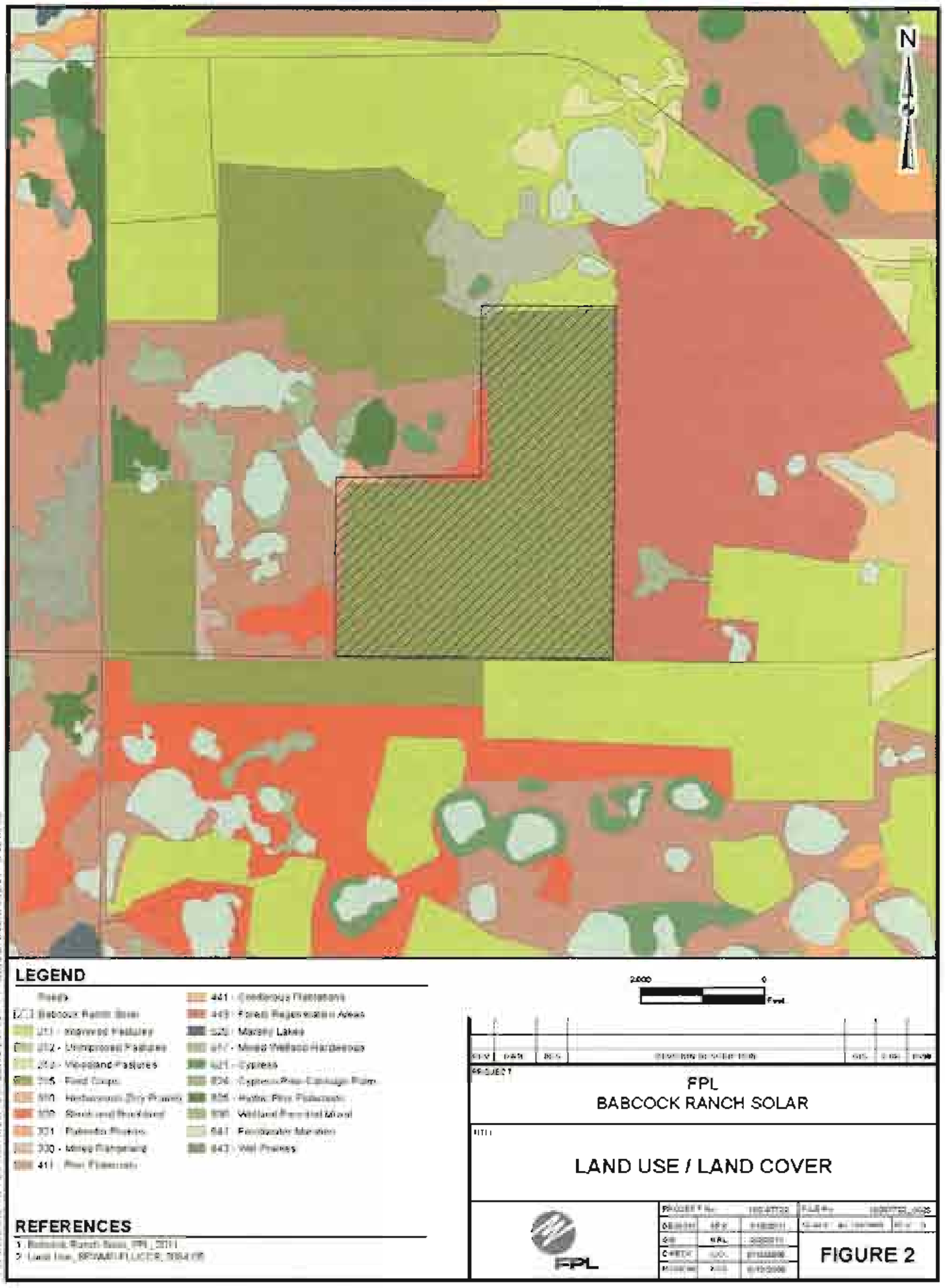

DE SOTO CO
CHARLOTTE CO
HIGHLANDS
GLADES
CHARLOTTE CO
Babcock Ranch
Solar
CHARLOTTE CO
LEE CO
CHARLOTTE CO
LEE CO
GLADES CO
HENDRY CO
LEGEND
Babcock Ranch Solar
REFERENCES
FPL
BABCOCK RANCH SOLAR
USGS LOCATION MAP
FIGURE 1


N
LEGEND
Marshy Lakes
Cypress
REFERENCES
2,000
0
FPL
BABCOCK RANCH SOLAR
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #2: Desoto Solar Expansion

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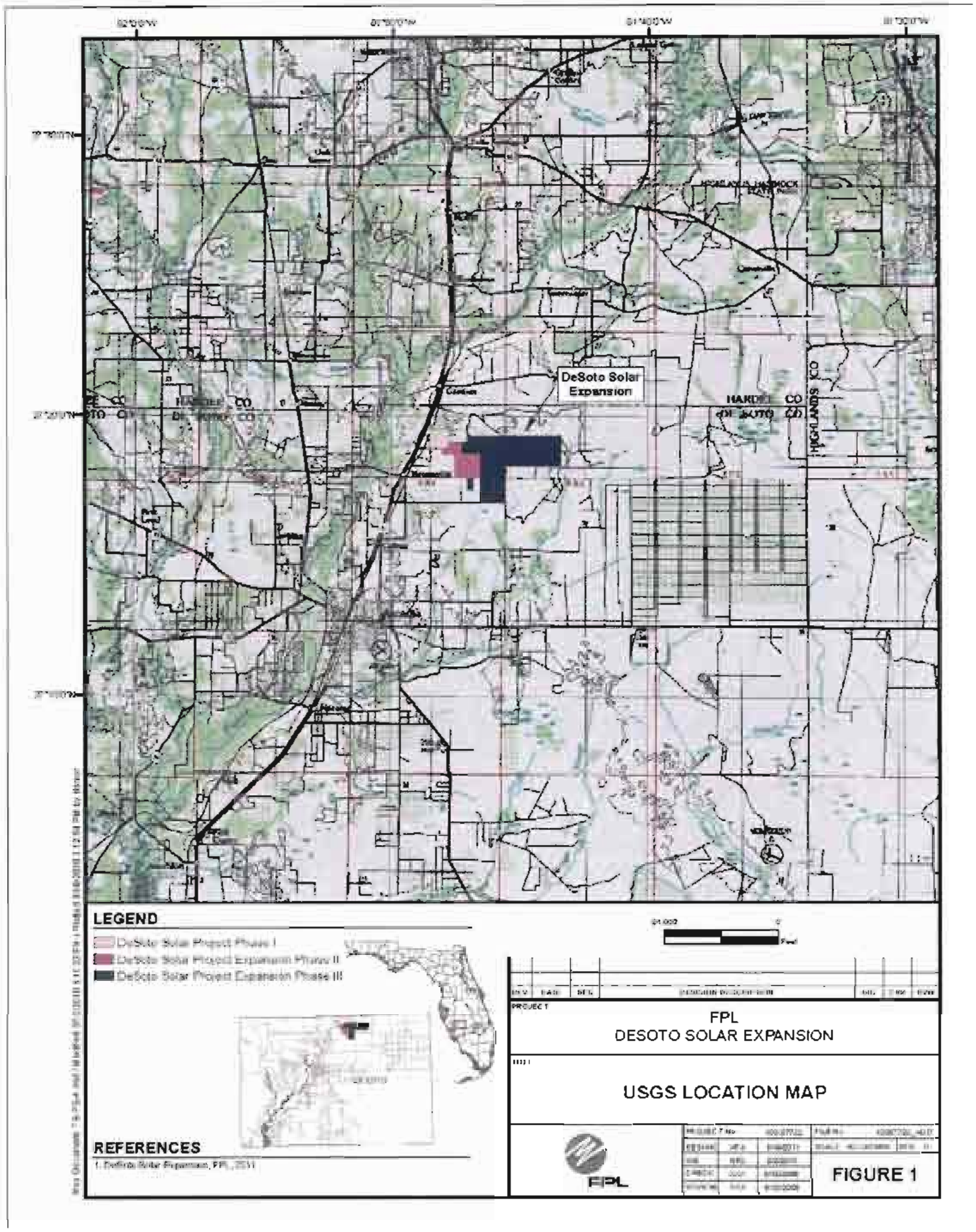
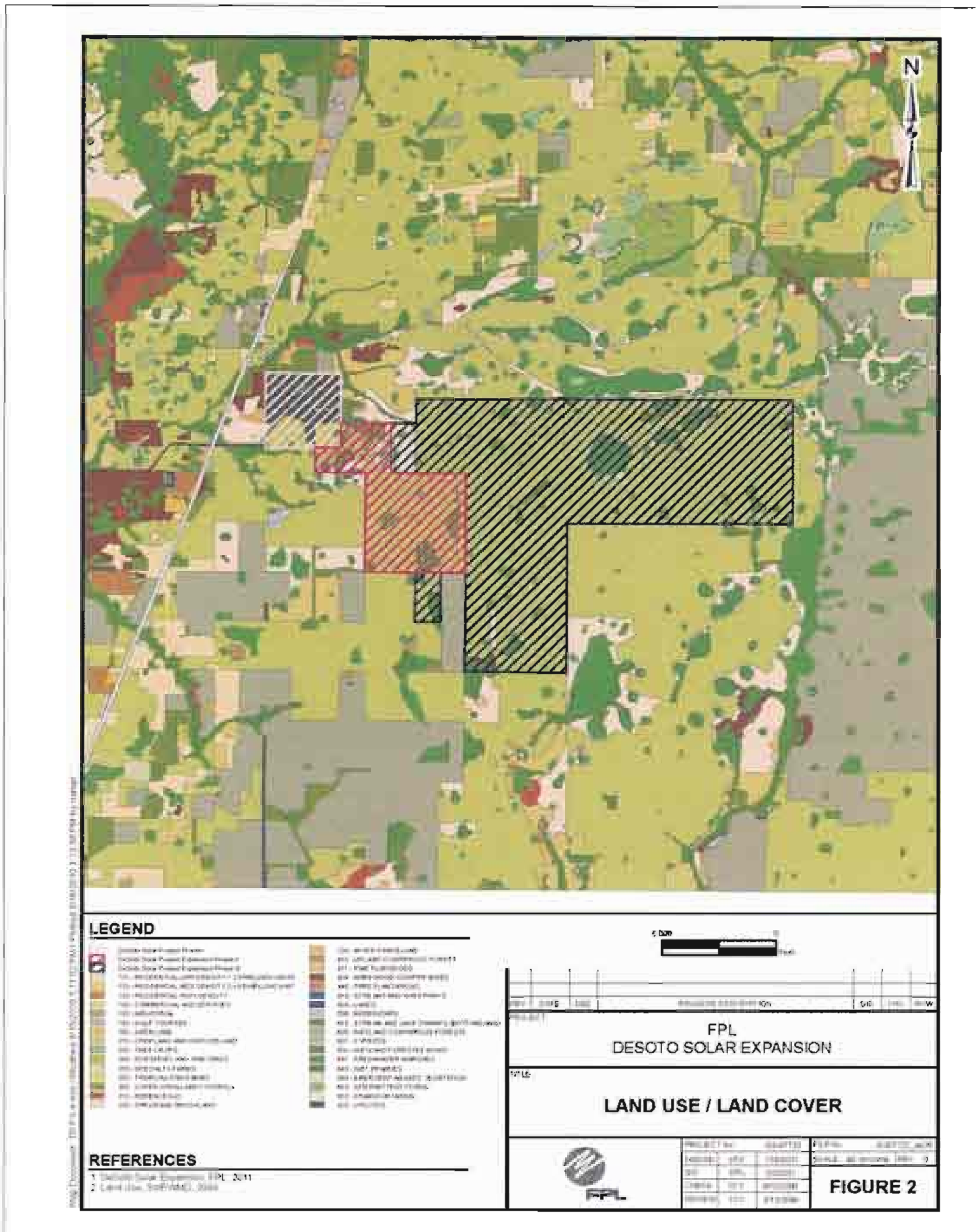

DeSoto Solar Expansion
HARDEE CO
DE SOTO CO
HIGHLANDS CO
LEGEND
DeSoto Solar Project Phase I
DeSoto Solar Project Expansion Phase II
DeSoto Solar Project Expansion Phase III
REFERENCES
PROJECT
FPL
DESOTO SOLAR EXPANSION
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
REFERENCES
FPL
DESOTO SOLAR EXPANSION
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #3: Florida Heartland Solar

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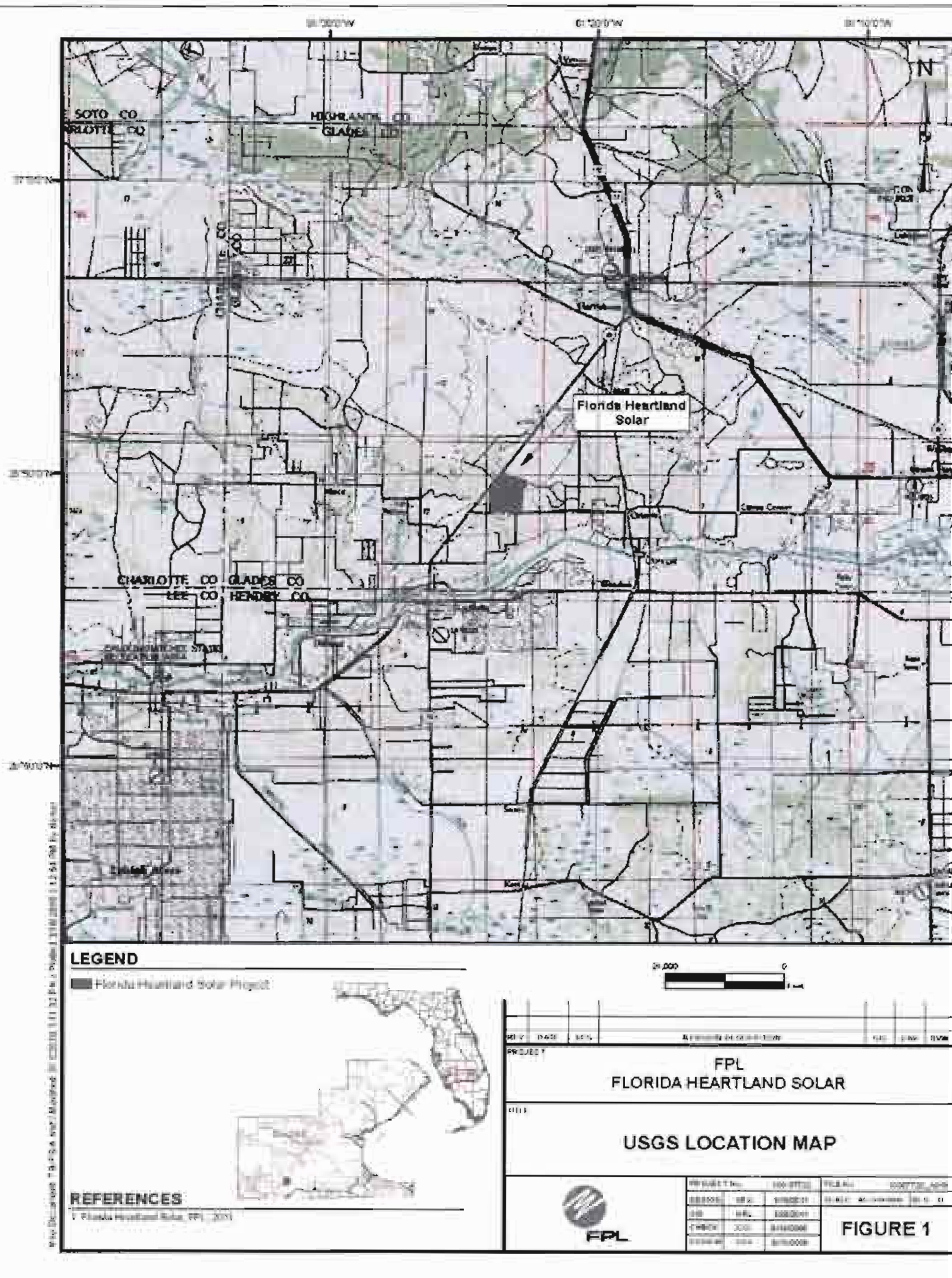
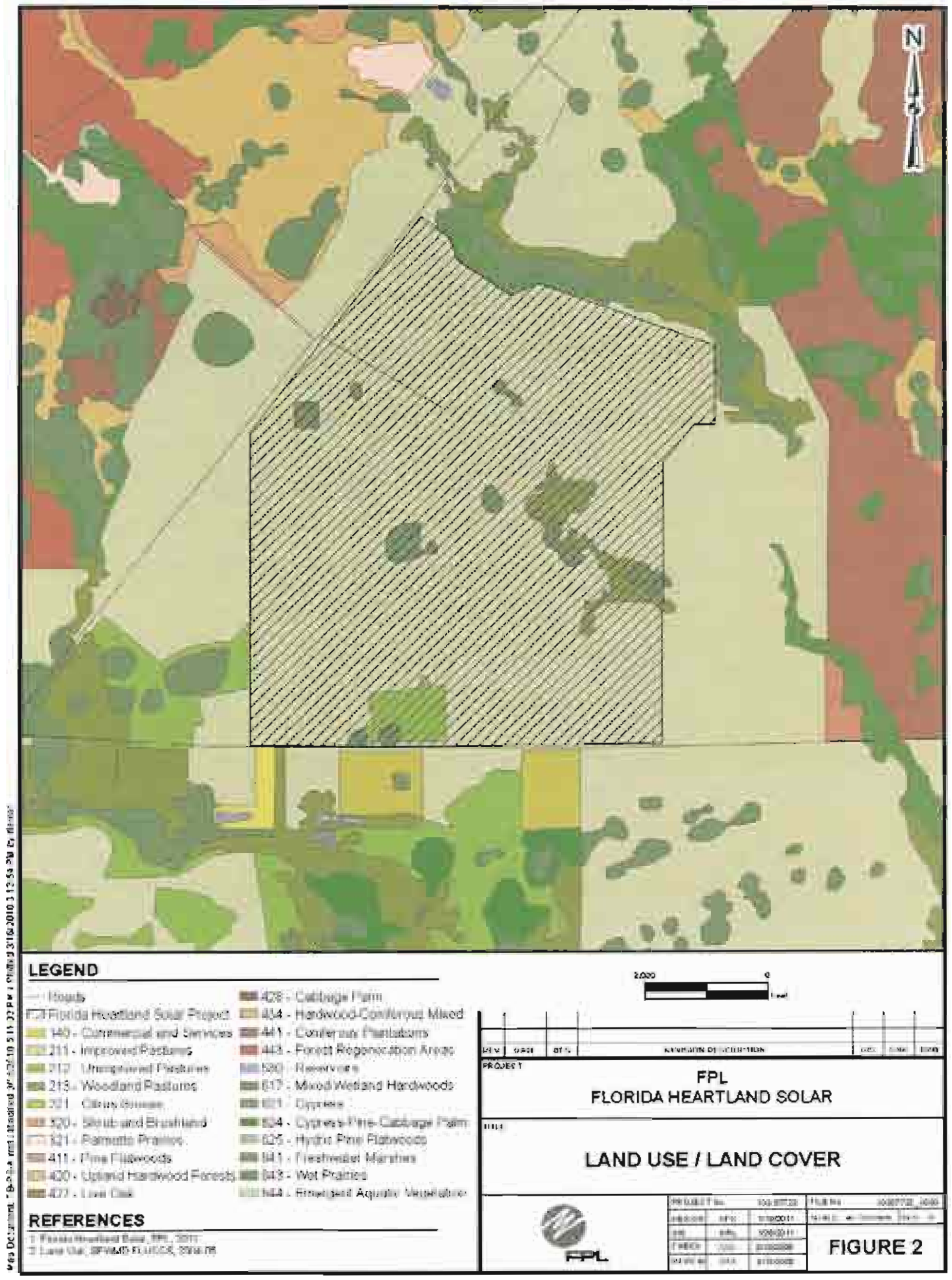

N
HIGHLANDS CO
GLADES CO
Florida Heartland Solar
CHARLOTTE CO
GLADES CO
LEE CO
HENDRY CO
LEGEND
Florida Heartland Solar Project
REFERENCES
FPL
FLORIDA HEARTLAND SOLAR
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
Roads
Florida Heartland Solar Project
140 - Commercial and Services
211 - Improved Pastures
212 - Unimproved Pastures
213 - Woodland Pastures
221 - Citrus Groves
320 - Shrub and Brushland
321 - Palmetto Prairies
411 - Pine Flatwoods
420 - Upland Hardwood Forests
427 - Live Oak
428 - Cabbage Palm
434 - Hardwood-Coniferous Mixed
441 - Coniferous Plantations
443 - Forest Regeneration Areas
530 - Reservoirs
617 - Mixed Wetland Hardwoods
621 - Cypress
624 - Cypress-Pine-Cabbage Palm
625 - Hydric Pine Flatwoods
641 - Freshwater Marshes
643 - Wet Prairies
644 - Emergent Aquatic Vegetation
REFERENCES
2,020
0
Feet
PROJECT
FPL
FLORIDA HEARTLAND SOLAR
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site # 4: Hendry County

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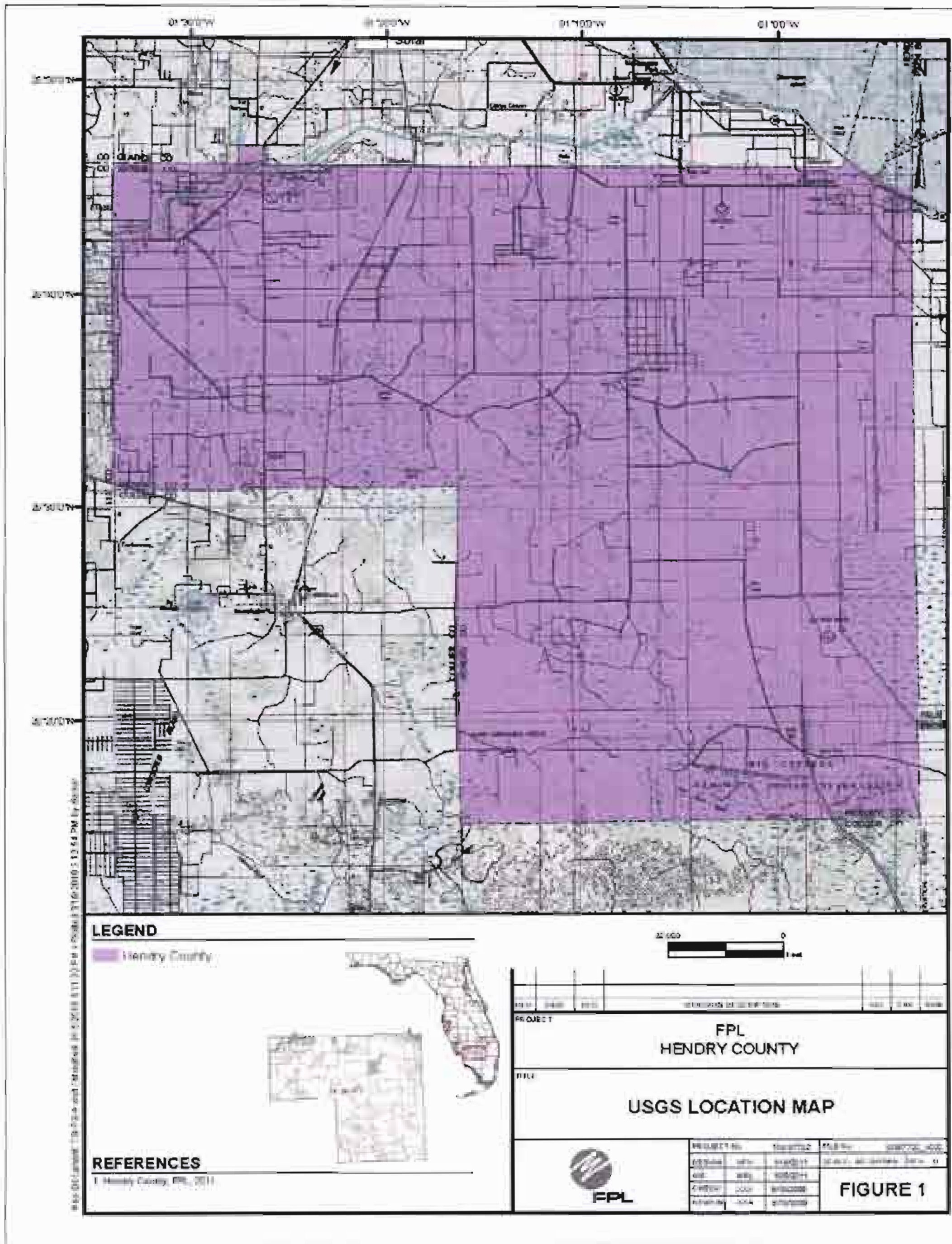
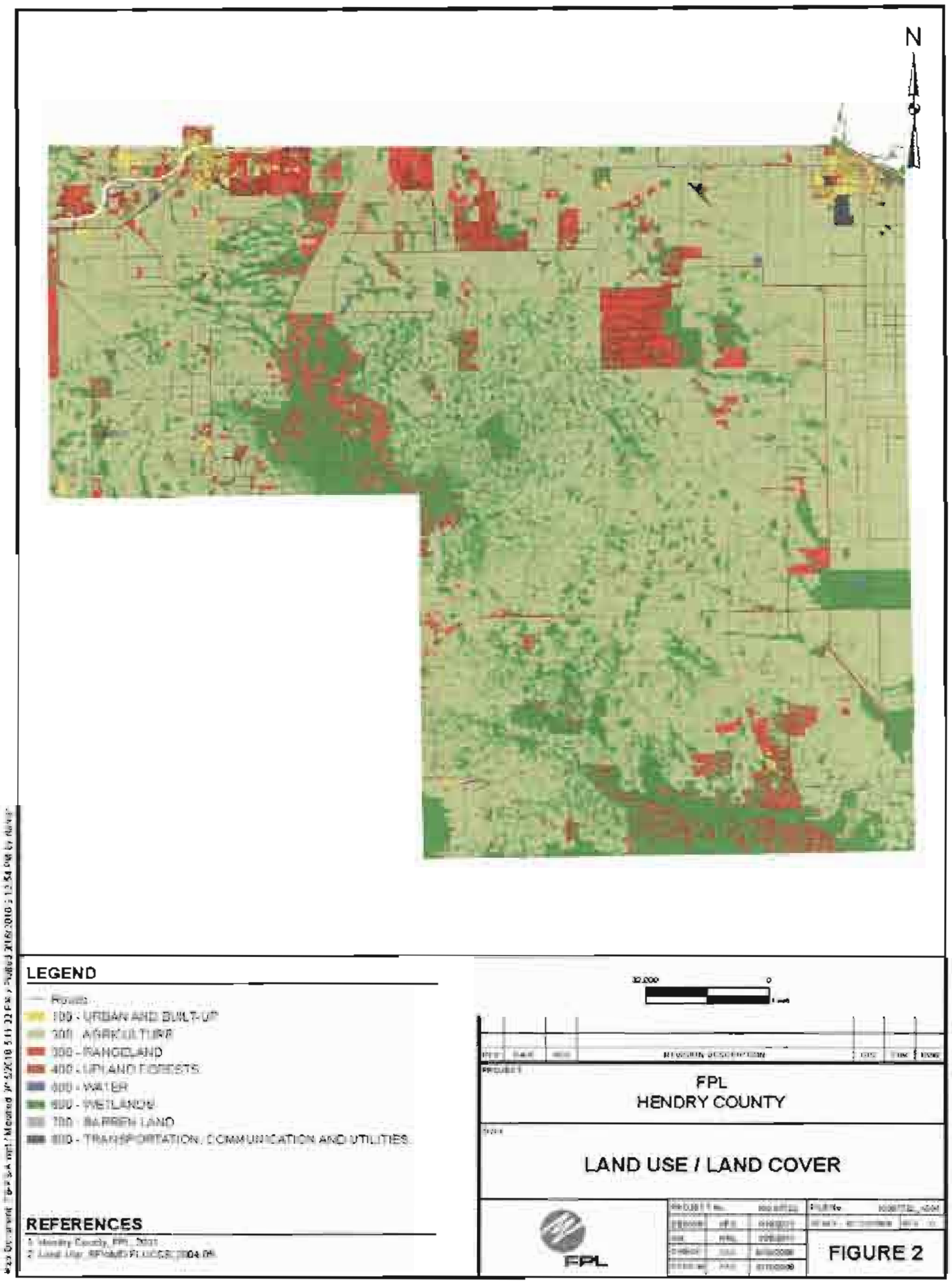

LEGEND
Hendry County
REFERENCES
FPL
HENDRY COUNTY
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
Roads
100 - URBAN AND BUILT-UP
200 - AGRICULTURE
300 - RANGELAND
400 - UPLAND FORESTS
500 - WATER
600 - WETLANDS
700 - BARREN LAND
800 - TRANSPORTATION, COMMUNICATION AND UTILITIES
REFERENCES
32,000
0
REVISION DESCRIPTION
FPL
HENDRY COUNTY
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #5: Manatee Plant Site

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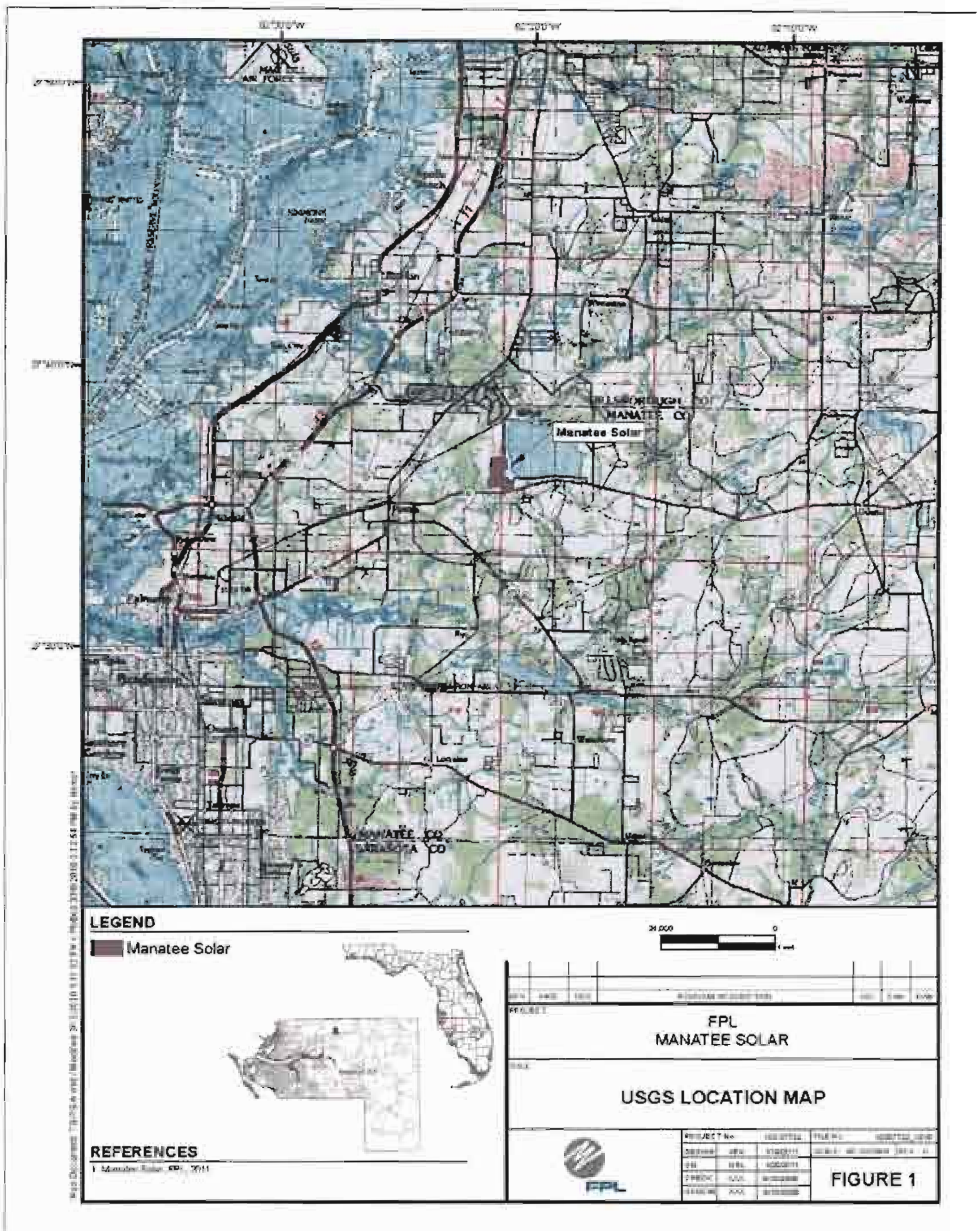
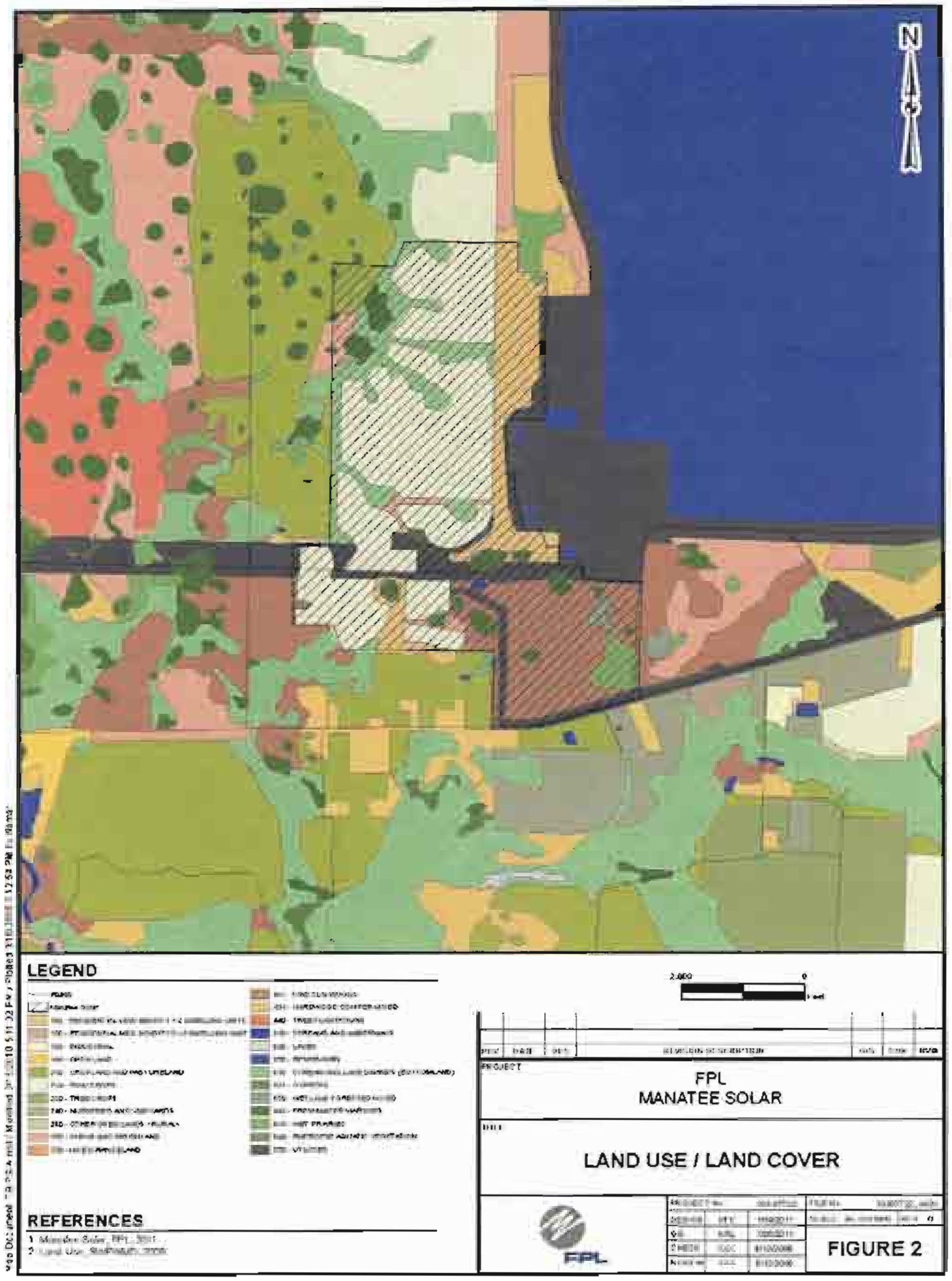

Manatee Solar
HILLSBOROUGH CO
MANATEE CO
MANATEE CO
SARASOTA CO
LEGEND
Manatee Solar
REFERENCES
FPL
MANATEE SOLAR
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
REFERENCES
FPL
MANATEE SOLAR
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #6: Martin County

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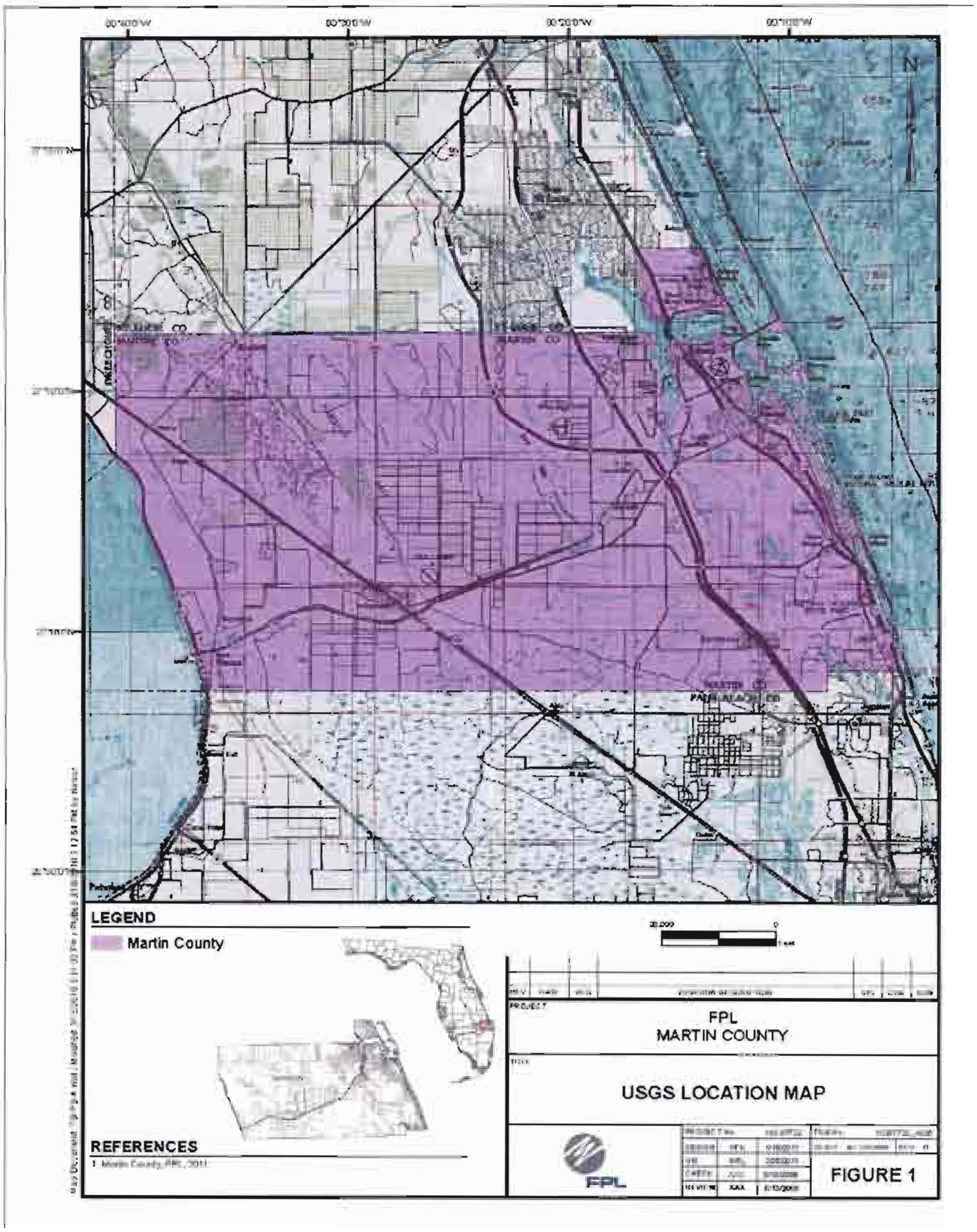
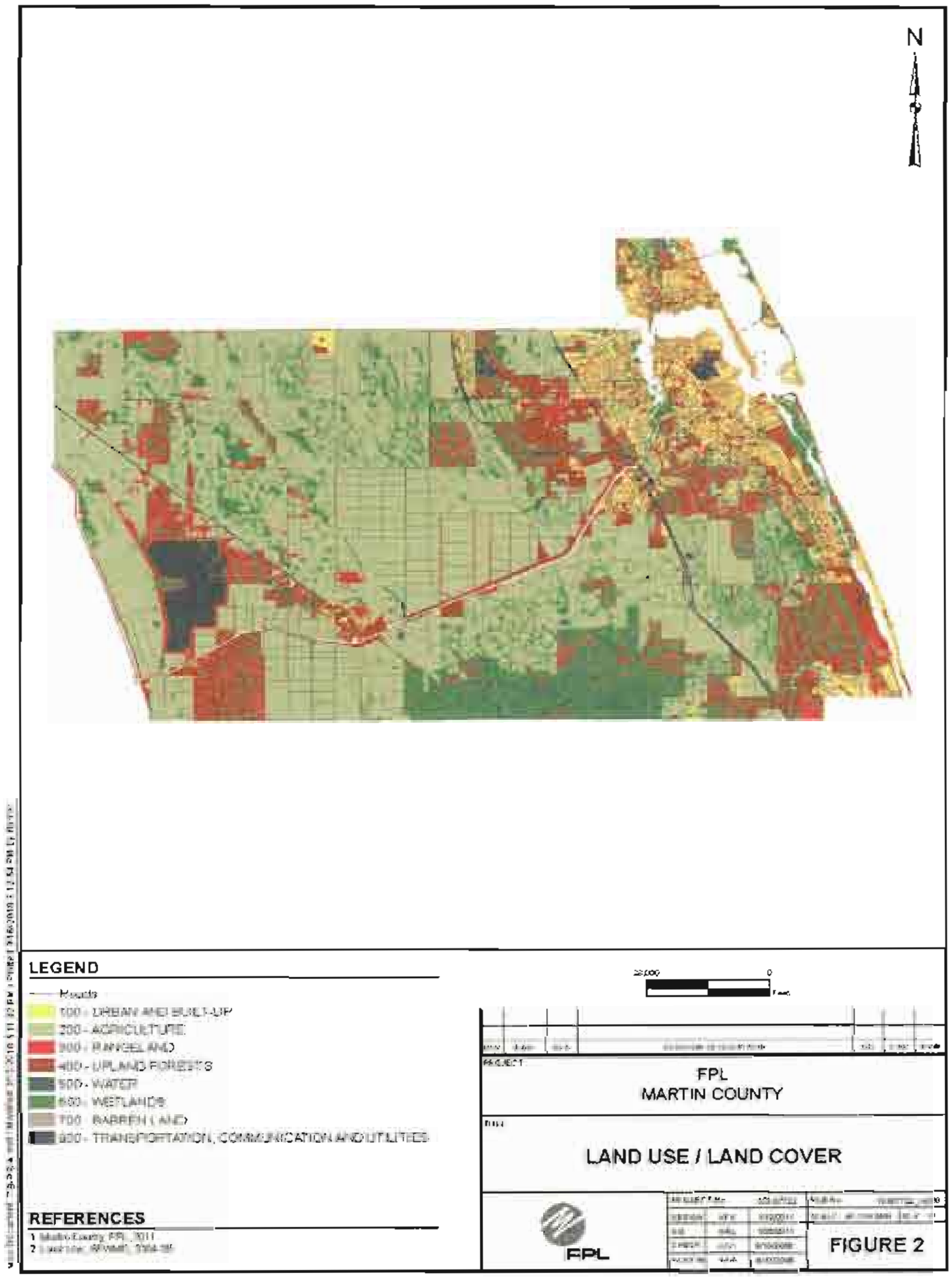

LEGEND
Martin County
FPL
MARTIN COUNTY
USGS LOCATION MAP
REFERENCES
FIGURE 1


N
LEGEND
Roads
100 - URBAN AND BUILT-UP
200 - AGRICULTURE
300 - RANGELAND
400 - UPLAND FORESTS
500 - WATER
600 - WETLANDS
700 - BARREN LAND
800 - TRANSPORTATION, COMMUNICATION AND UTILITIES
REFERENCES
FPL
MARTIN COUNTY
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #7: Northeast Okeechobee County

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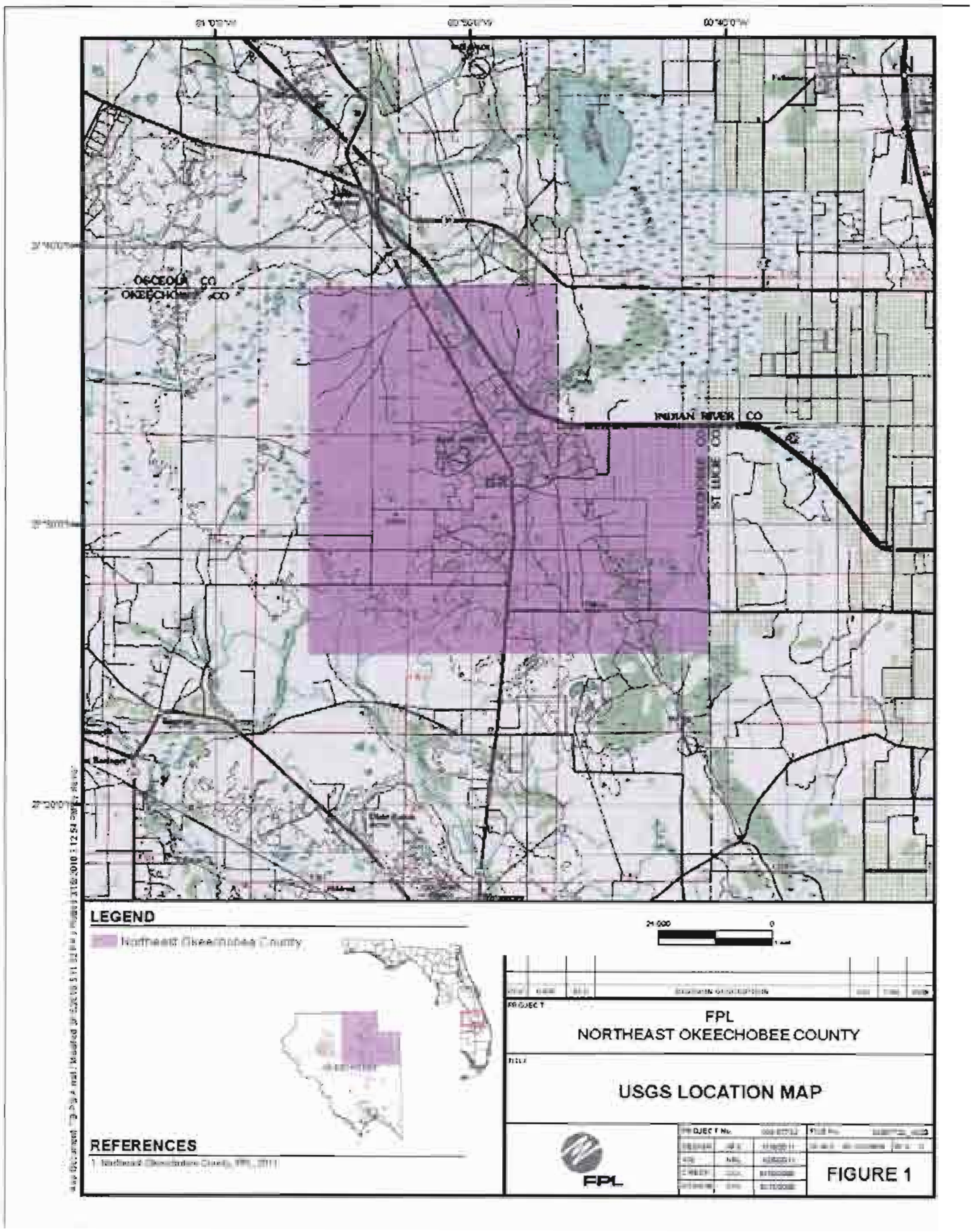
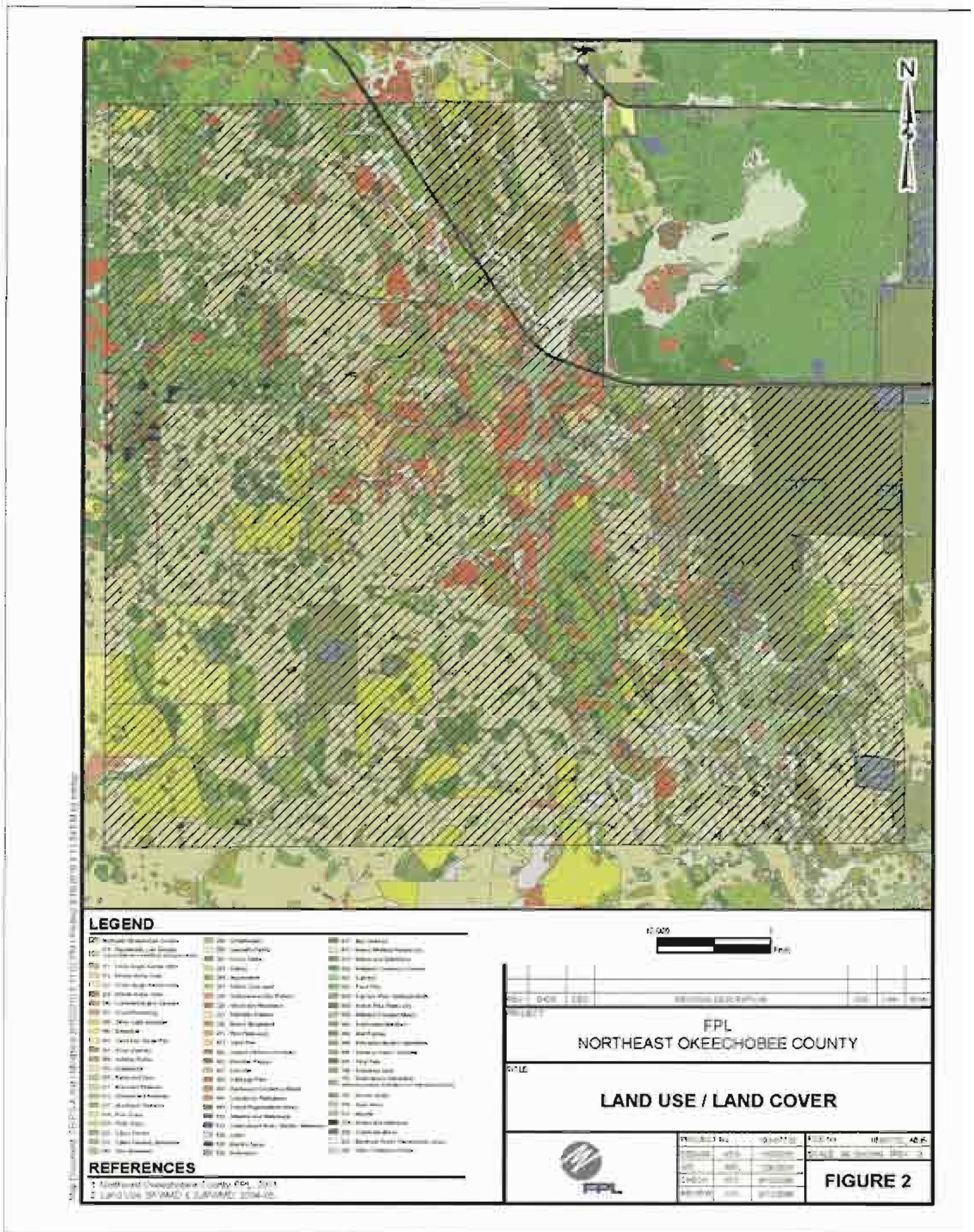

OSCEOLA CO
OKEECHOBEE CO
INDIAN RIVER CO
OKEECHOBEE CO
ST LUCIE CO
LEGEND
Northeast Okeechobee County
REFERENCES
PROJECT
FPL
NORTHEAST OKEECHOBEE COUNTY
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
REFERENCES
FPL
NORTHEAST OKEECHOBEE COUNTY
LAND USE / LAND COVER
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #8: Palatka Site

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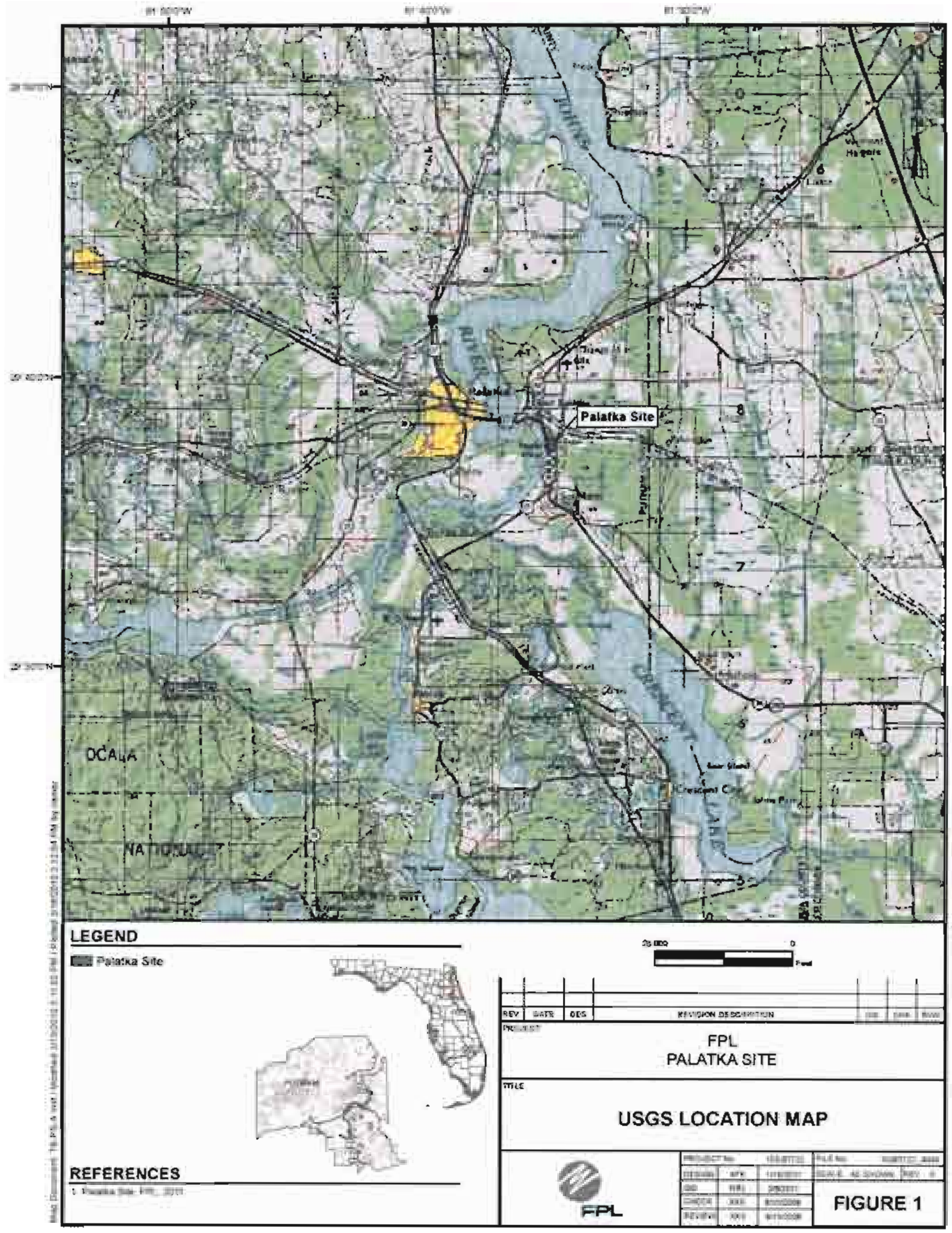
Palatka Site
OCALA
LEGEND
Palatka Site
REFERENCES
FPL
PALATKA SITE
USGS LOCATION MAP
FPL
FIGURE 1

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Environmental and Land Use Information: Supplemental Information

Potential Site #9: Putnam County

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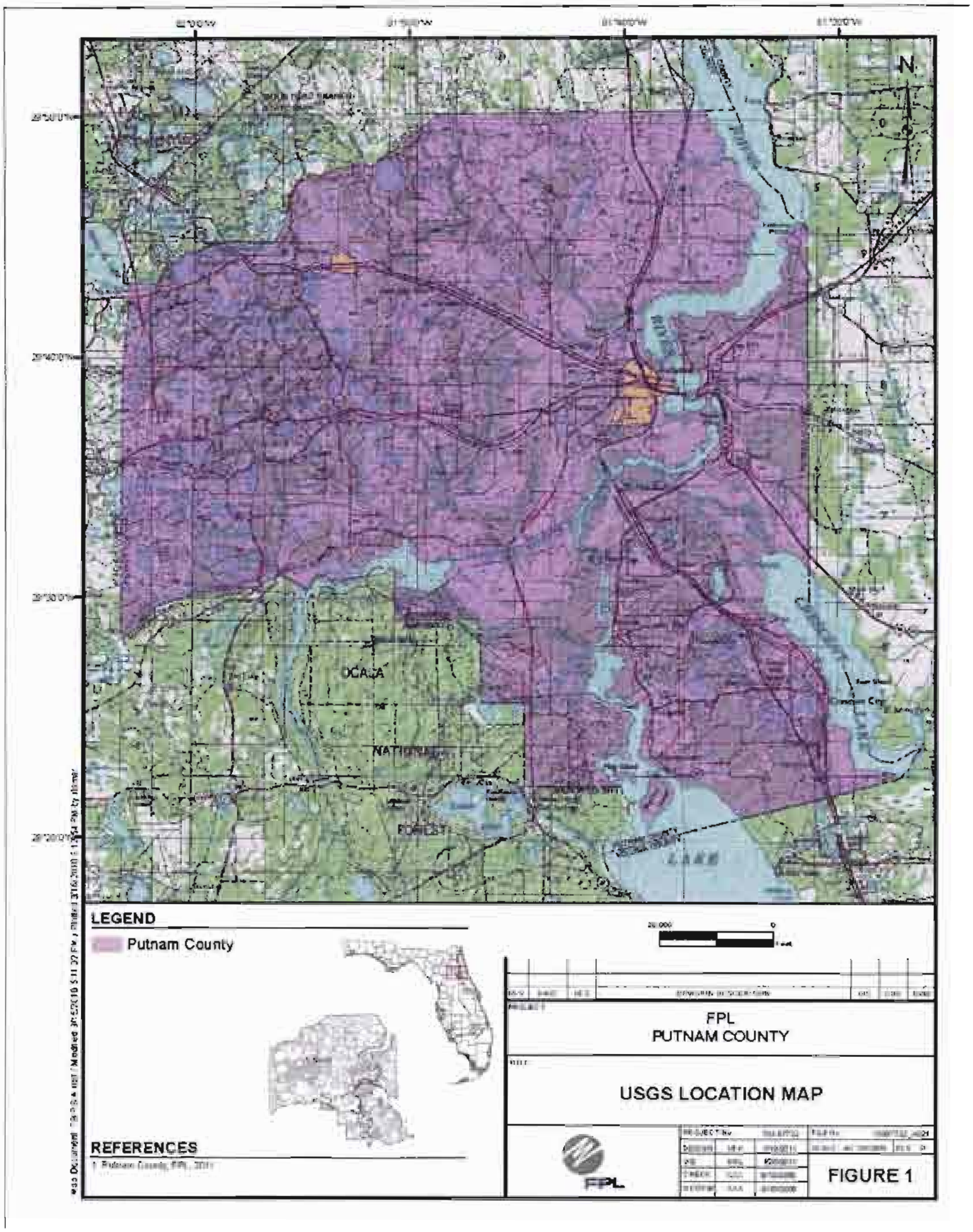
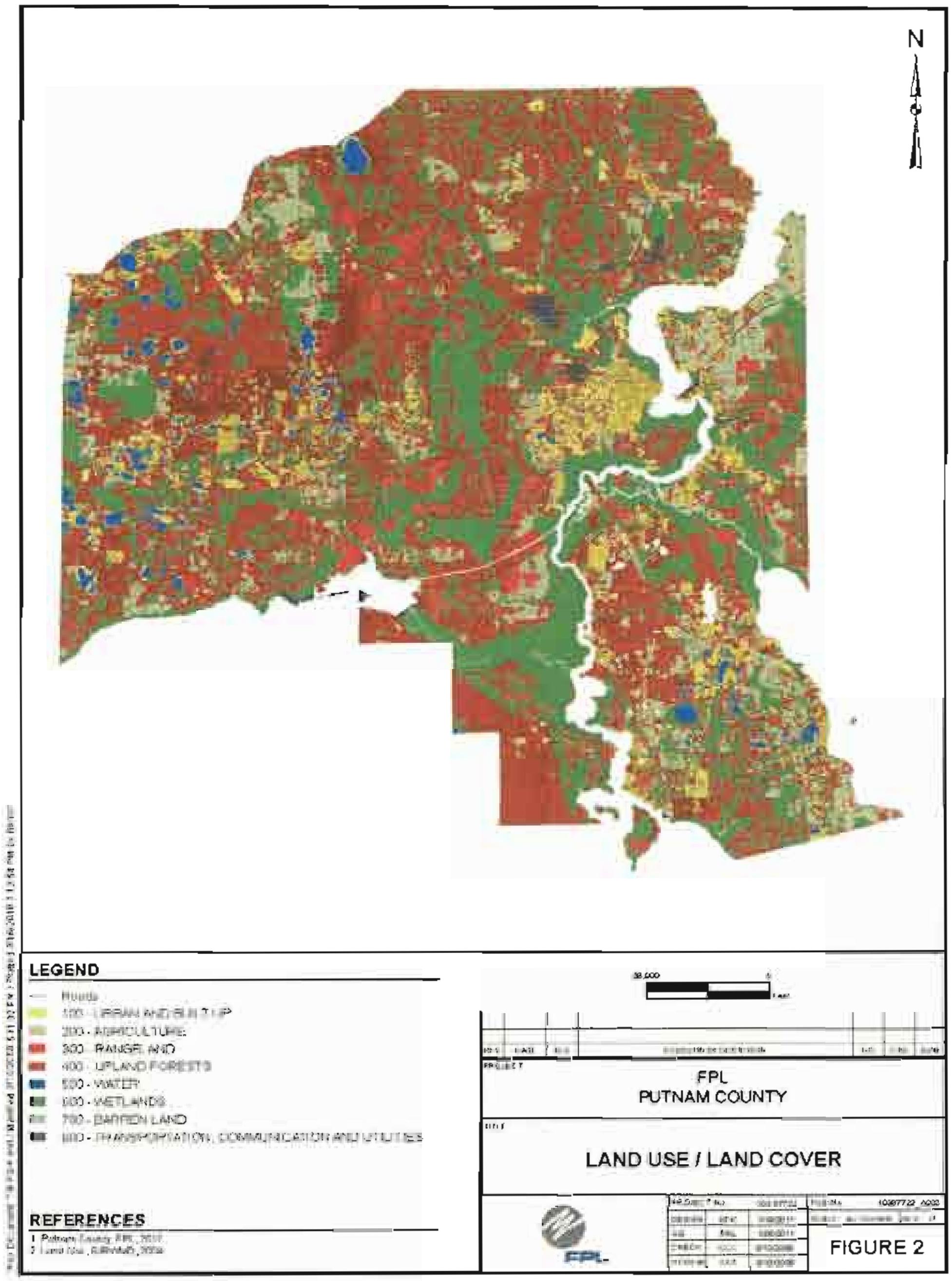

LEGEND
Putnam County
REFERENCES
OCALA
NATIONAL
FOREST
LAKE
FPL
PUTNAM COUNTY
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
Roads
100 - URBAN AND BUILT UP
200 - AGRICULTURE
300 - RANGELAND
400 - UPLAND FORESTS
500 - WATER
600 - WETLANDS
700 - BARREN LAND
800 - TRANSPORTATION, COMMUNICATION AND UTILITIES
REFERENCES
PROJECT
FPL
PUTNAM COUNTY
TITLE
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #10: Space Coast Solar Expansion

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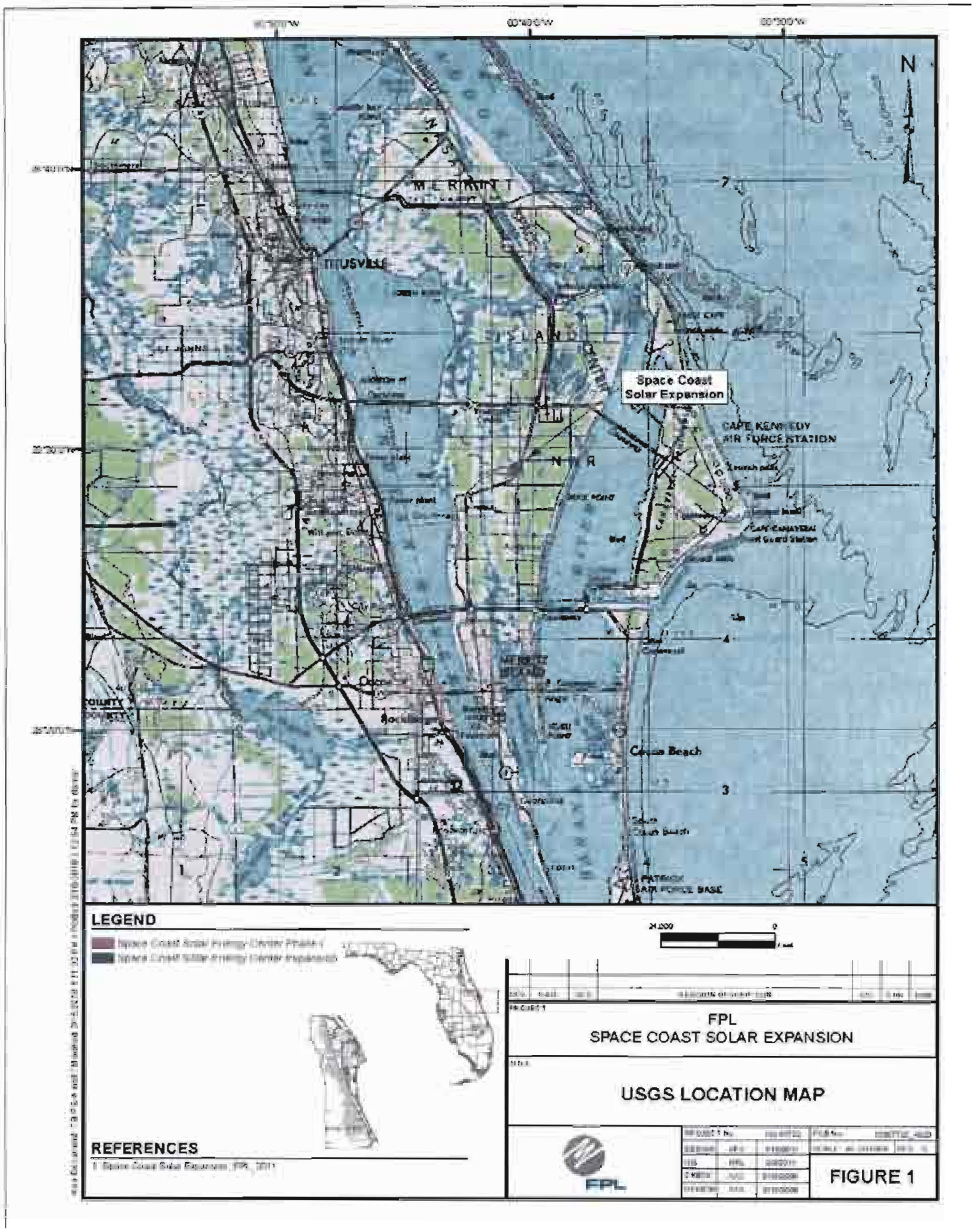
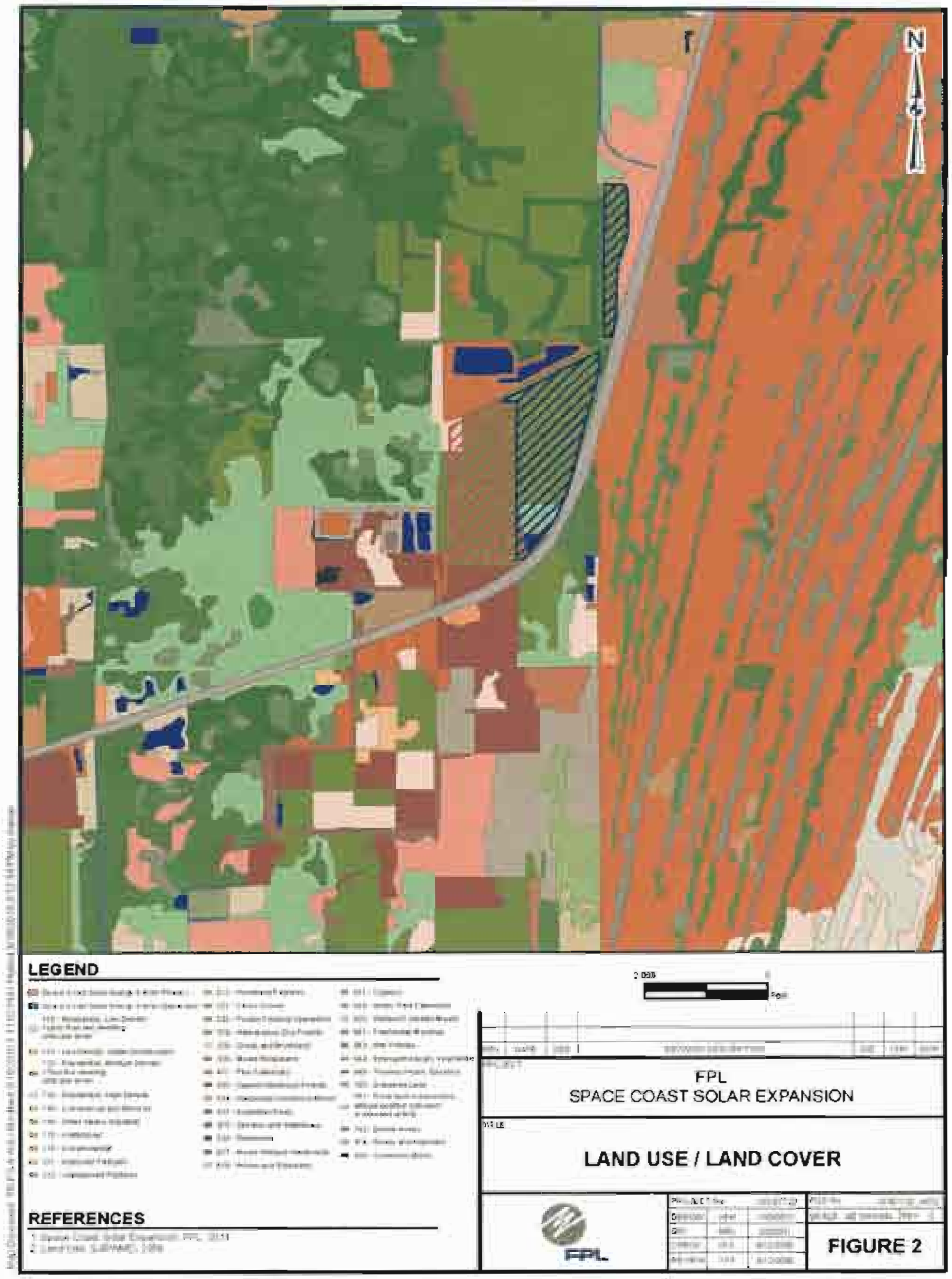

N
TITUSVILLE
Space Coast Solar Expansion
CAPE KENNEDY AIR FORCE STATION
Cocoa Beach
PATRICK AIR FORCE BASE
LEGEND
REFERENCES
FPL
SPACE COAST SOLAR EXPANSION
USGS LOCATION MAP
FIGURE 1


N
LEGEND
REFERENCES
FPL
SPACE COAST SOLAR EXPANSION
LAND USE / LAND COVER
FPL
FIGURE 2

CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information." These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints: external limitations and internal limitations. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important since they affect the development of assumptions for the amount of external assistance that is available to the FPL system as well as the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In the loss of load probability (LOLP) portion of its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new generating units that minimize adverse impacts to the flow of electricity within FPL's system. The internal transmission limitations are also addressed by developing the direct costs for siting new units at different locations, by evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system, and/or by evaluating the costs of transmission additions that may be needed to address regional concerns regarding an imbalance between load and generation in a given region. Both of these site- and system-related transmission costs are developed for each different unit/unit location option or groups of options. In addition, transfer limits for capacity and energy that can be imported into the Southeastern (Miami-Dade and Broward Counties) region of FPL's system are also developed for use in FPL's production costing analyses. (A further discussion of the Southeastern Florida region, and the need to maintain a regional balance between generation and transmission contributions to meet regional load, is found in Chapter III.)

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's planned transmission facilities to interconnect and integrate FPL's resource plans and those that must be certified under the Transmission Line Siting Act are presented in Chapter III.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements for the FPL system.[8]

The load forecast that is presented in FPL's 2012 Site Plan was developed in September 2011. The only load forecast sensitivities analyzed during 2011/early 2012 were high load forecast sensitivities developed solely to analyze the quality of FPL's future reserves and the projected frequency at which load control might be implemented. These analyses are on-going and the load forecast sensitivities have not been used to determine potential changes to the resource plan that is presented in this Site Plan document.

[8] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis (i.e., when only new generating options are considered), the lowest electric rate basis approach and the lowest system cumulative present value of revenue requirements basis approach, yield identical results in terms of which resource options are more economic. In such cases FPL evaluates resource options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its fuel price forecasts are discussed in Chapter III of this document. FPL used three fuel cost, and three environmental compliance cost, forecasts in analyses supporting its 2011 nuclear cost recovery filing. FPL also utilized one fuel cost forecast, and one environmental compliance cost forecast, in analyses supporting its 2011 Port Everglades modernization (PEEC) determination of need filing. In response to discovery requests in the PEEC need docket, sensitivity forecasts assuming low fuel costs, high fuel costs, and low environmental compliance costs were also analyzed for PEEC.

The high and low fuel cost forecasts are derived from a calculation of the historical volatility of the 12-month forward price for one year ahead. From this range of volatility, a reasonable value from the high end of the range is applied to the medium cost fuel cost forecast to develop a high cost fuel cost forecast. Similarly, a reasonable value from the low end of the range is applied to the medium cost fuel cost forecast to develop a low cost fuel cost forecast.

The resource plan presented in this Site Plan is based, in part, on those prior analyses. For that reason, this resource plan has not been further tested for different fuel cost forecasts.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item # 3, FPL used up to three fuel cost forecasts in its 2011/early 2012 resource planning analyses. While these forecasts did not represent a constant cost differential between oil/gas and coal, a variety of fuel cost differentials were represented in these forecasts.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 in Chapter I and Schedule 8 in Chapter III present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options in its resource planning work. A summary of this information for the new capacity options FPL currently projects to add over the reporting horizon for this document is presented on the Schedule 9 forms in Chapter III.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

In its 2011 resource planning work, FPL's financial assumptions were: i) a capital structure of 40.88% debt and 59.12% equity; (ii) a 5.50% cost of debt; (iii) a 10.0% return on equity; and (iv) an after-tax discount rate of 7.29%. No sensitivities of these financial assumptions were used in FPL's 2011/early 2012 resource planning work.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item # 2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective are identical when DSM levels are unchanged between competing resource plans. Therefore, in planning work in which DSM levels were unchanged, the equivalent, but simpler to calculate, cumulative present value of revenue requirements perspective was utilized.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL currently uses two system reliability criteria in its resource planning work that addresses generation, purchase, and DSM options. One of these is a minimum 20% Summer and Winter reserve margin. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These reliability criteria are discussed in Chapter III of this document. As discussed briefly in the Executive Summary, and in more detail in Chapter III, FPL will be examining the extent to which its system reserves are projected to be dependent upon DSM resources and generation resources in its 2012 resource planning work. The results of this examination could result in a change to FPL's reliability criteria.

In regard to transmission reliability analysis work, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the Reliability Standards established by the North American Electric Reliability Council (NERC). The *NERC Reliability Standards* are available on the intemet site (http://www.nerc.com/).

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Facility Rating Methodology* document that are also available on the internet under the FPL OATT Documents directory at https://www.oatioasis.com/FPL/index.html.

Generally, FPL limits its transmission facilities to 100% of the applicable thermal rating. The normal and contingency voltage criteria for FPL stations are provided below:

	Normal/Contingency	
Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09
Turkey Point (*)	1.01/1.01	1.06/1.06
St. Lucie (*)	1.00/1.00	1.06/1.06

(*) Voltage range criteria for FPL's Nuclear Power Plants

There may be isolated cases for which FPL may have determined that it is acceptable to deviate from the general criteria stated above. There are several factors that could influence these criteria, such as the overall number of potential customers that may be impacted, the probability of an outage actually occurring, or transmission system performance, as well as others.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The projected impacts of FPL's DSM programs on demand and energy consumption are revised periodically. Engineering models, calibrated with current field-metered data, are updated at regular intervals. Participation trends are tracked for all of the FPL DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants. For its load management programs, FPL conducts periodic tests of the load control equipment to ensure that the equipment is functioning correctly. These tests, plus actual, non-test load management events, also allow FPL to gauge the MW reduction capabilities of its load management programs on an on-going basis.

Survey data is collected from non-participants in order to establish the baseline efficiency. Participant data is compared against non-participant data to establish the demand and energy saving benefits of the utility DSM program versus what would be installed in the absence of the program.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The Executive Summary and Chapter III provide a discussion of a variety of system concerns/issues that influence FPL's resource planning process. Please see those chapters for a discussion of those concerns/issues.

In addition to these system concerns/issues, there are other strategic factors FPL typically considers when choosing between resource options. These include the following: (1) technology risk; (2) environmental risk, and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology, which has not achieved general commercial acceptance, has a higher risk than a technology in wide use and, therefore, assuming all else equal, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the FPL system, including environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for FPL's resource plan are those which minimize environmental impacts for the FPL system as a whole through highly efficient fuel use, state of the art environmental controls, etc.

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decisions, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As shown in this 2012 Site Plan, beyond the capacity additions for which a need determination has already been approved (nuclear uprates and the modernizations at Cape Canaveral, Riviera, and Port Everglades), FPL currently projects no new capacity additions for the years 2017 through 2021 except for a one-year power purchase of approximately 250 MW for the year 2021. FPL anticipates that this short-term purchase would be acquired after discussions and negotiations with potential capacity suppliers at some point in the future.

In regard to the capacity additions that are underway for which a need determination has already been approved, the nuclear uprates (and the new nuclear units not addressed in the reporting period of this document), do not lend themselves to an RFP approach involving bids from third parties who would build new nuclear generation capacity. In addition, nuclear capacity additions are exempted from the Commission's Bid Rule by section 403.519 (4) (c). For these nuclear projects, FPL's procurement activities are conducted to ensure the best combination of quality and cost for the delivered products. Furthermore, the modernization projects at Cape Canaveral, Riviera, and Port Everglades received Commission waivers from the Bid Rule due to attributes specific to modernization projects (such as use of existing land, water, transmission, etc.) plus other economic benefits to FPL's customers. These waivers from the Bid Rule were granted in Order No. PSC-08-0591-FOF-EI for Cape Canaveral and Riviera and in Order No. PSC-11-0360-PAA-EI for Port Everglades.

If circumstances change and another large-scale capacity addition decision needs to be made during the reporting period of this document, FPL expects that its decision-making will be conducted in a manner consistent with the Commission's Bid Rule.

Identification of self-build options, beyond those units already approved by the FPSC and Governor and Siting Board or units for which FPL may be then seeking approval, in future FPL Site Plans will not be an indication that FPL has pre-judged any capacity solicitation it may conduct. The identification of future generating units is required of FPL in its Site Plan filings and represents those alternatives that appear to be FPL's best, most cost-effective self-build options at the time. FPL reserves the right to refine its planning analyses and to identify other self-build options. Such refined analyses have the potential to yield a variety of self-build options, some of which might not require an RFP. If an RFP is issued for Supply options, FPL reserves the right to choose the best alternative for its customers, even if that option is not an FPL self-build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

(1) FPL has identified the need for a new 230 kV transmission line that required certification under the Transmission Line Siting Act which was issued in April 2006. The new line is to be completed in two phases connecting FPL's St. Johns Substation to FPL's Pringle Substation (also shown on Table III.E.1 in Chapter III). Phase 1 was completed in May 2009 and consisted of a new line connecting Pringle to a new Pellicer Substation. Phase 2 is planned to connect St. Johns to Pellicer and is scheduled to be completed by December 2016. The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

(2) FPL has identified the need for a new 230 kV transmission line (by December 2014) that required certification under the Transmission Line Siting Act which was issued on November 2008. The new line will connect FPL's Manatee Substation to FPL's proposed Bob White Substation (also shown on Table III.E.1 in Chapter III). The construction of this line, scheduled to be completed in 2014, is necessary to serve existing and future customers in the Manatee and Sarasota areas in a reliable and effective manner.

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FPL

Jessica Cano
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5226
(561) 691-7135 (Facsimile)

July 16, 2012

RECEIVED-FPSC
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VIA HAND DELIVERY

Ms. Ann Cole
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

RE: Florida Power & Light Company's 2012 Ten Year Power Plant Site Plan

Dear Ms. Cole:

Please find enclosed for filing the original and twenty-five (25) copies of three pages from Florida Power & Light Company's 2012-2021 Ten Year Power Plant Site Plan, originally filed April 1, 2012, reflecting corrected information. Specifically, pages 15, 19, and 31 are being replaced. Corrections are included in red, bold print.

Please call me if there are any questions regarding this filing.

Sincerely,

Jessica Cano

Jessica A. Cano

Enclosure

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 8.8 million people. FPL served an average of 4,547,051 customer accounts in thirty-five counties during 2011. These customers were served by a variety of resources including: FPL-owned fossil-fueled, renewable, and nuclear generating units, non-utility owned generation, demand side management (DSM), and interchange/purchased power.

I.A. FPL-Owned Resources

The existing FPL generating resources are located at seventeen generating sites distributed geographically around its service territory including one site in Georgia (partial FPL ownership of one unit) and one site in Jacksonville, Florida (partial FPL ownership of two units). The current electrical generating facilities consist of four nuclear units, three coal units, fifteen combined cycle (CC) units, twelve fossil steam units, forty-eight combustion gas turbines, one simple cycle combustion turbine, and two photovoltaic facilities[1]. The locations of these eighty-five generating units are shown on Figure I.A.1 and in Table I.A.1. Table I.A.2 provides a "break down" of the capacity provided by the combustion turbine (CT) and steam turbine (ST) components of FPL's existing CC units.

FPL's bulk transmission system is comprised of **6,543** circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 587 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3 shows FPL's interconnection ties with other utilities.

[1] FPL also has one 75 MW solar thermal facility at its Martin plant site. This facility does not generate electricity as the other units mentioned above do. Instead, it produces steam that reduces the use of fossil fuel to produce steam for electricity generation.

Table 1.A.3: Purchase Power Resources by Contract (as of December 31, 2011)

Table 1.A.3: Purchase Power Resources by Contract (as of December 31, 2011)

	Location (City or County)	Fuel	Summer MW
I. Purchases from QF's: Cogeneration/Small Power Production Facilities			
Cedar Bay Generating Co.	Duval	Coal (Cogen)	250
Indiantown Cogen., LP	Martin	Coal (Cogen)	330
Broward South	Broward	Solid Waste	4
Broward North	Broward	Solid Waste	11
		Total:	**595**
II. Purchases from Utilities:			
UPS from Southern Company	Various in Georgia	Coal	928
SJRPP	Jacksonville, FL	Coal	375
		Total:	**1,303**
III. Other Purchases:			
Oleander (Extension)	Brevard	Gas	155
			155
	Total Net Firm Generating Capability:		**2,053**

Non-Firm Energy Purchases (MWH)

Project	County	Fuel	Energy (MWH) Delivered to FPL in 2011
Okeelanta (known as Florida Crystals and New Hope Power Partners)	Palm Beach	Bagasse/Wood	**171,942**
Broward South	Broward	Garbage	**216,511**
Broward North	**Broward**	**Garbage**	**258,309**
Tomoka Farms	Volusia	Landfill Gas	0
Waste Management - Renewable Energy	Broward	Landfill Gas	59,719
Waste Management - Collier County Landfill	Broward	Landfill Gas	18,046
Tropicana	Manatee	Natural Gas	30,532
Calnetix	Palm Beach	Natural Gas	0
Georgia Pacific	Putnam	Paper by-product	**2,015**
Rothenbach Park (known as MMA Bee Ridge)	Sarasota	PV	**323**
First Solar	Miami	PV	**9**
Customer - Owned PV & Wind	Various	PV/Wind	415
Palm Beach SWA	Palm Beach	Solid Waste	**346,719**

Schedule 3.1
History and Forecast of Summer Peak Demand (MW)
(Historical)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2002	19,219	261	18,958	0	879	754	489	517	17,851
2003	19,668	253	19,415	0	892	798	577	554	18,200
2004	20,545	258	20,287	0	894	846	588	577	19,063
2005	22,361	264	22,097	0	902	895	600	611	20,858
2006	21,819	256	21,563	0	928	948	635	640	20,256
2007	21,962	261	21,701	0	952	982	716	683	20,295
2008	21,060	181	20,879	0	966	1,042	760	706	19,334
2009	22,351	249	22,102	0	981	1,097	811	732	20,558
2010	22,256	419	21,837	0	990	1,181	815	758	**20,451**
2011	21,618	427	21,191	0	1,002	1,252	821	776	**19,795**

Historical Values (2002 - 2011):

Col. (2) - Col. (4) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) represent actual DSM capabilities starting from January 1988 and are annual (12-month) values except for 2011 values which are through August. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC), CILC, and Commercial /Industrial Demand Reduction (CDR).

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.1
History and Forecast of Summer Peak Demand (MW)
(Projected)

(1) August of Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management*	(7) Residential Conservation	(8) C/I Load Management*	(9) C/I Conservation	(10) Net Firm Demand
2012	21,623	432	21,191	0	1,036	64	865	26	19,632
2013	21,931	389	21,542	0	1,048	125	884	58	19,817
2014	23,243	1,187	22,056	0	1,075	190	922	90	20,966
2015	23,786	1,194	22,592	0	1,088	257	940	123	21,378
2016	24,315	1,201	23,114	0	1,101	324	959	155	21,775
2017	24,529	1,195	23,334	0	1,114	391	978	188	21,858
2018	24,674	1,202	23,472	0	1,127	458	996	221	21,871
2019	25,041	1,210	23,832	0	1,140	526	1,015	253	22,107
2020	25,499	1,217	24,282	0	1,156	579	1,028	280	22,456
2021	25,960	1,225	24,735	0	1,172	626	1,042	303	22,816

Projected Values (2012 - 2021):

Col. (2) - Col. (4) represent FPL's forecasted peak w/o incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected August values. The projections for 2012 through 2019 are based on the FPSC's 2011 order in the DSM Plan docket. Projected DSM values for 2020 and 2021 assume 100 MW/year of incremental DSM.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County.

FPL

April 1, 2013

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VIA HAND DELIVERY

Ms. Ann Cole
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

RE: Florida Power & Light Company's 2013 Ten-Year Power Plant Site Plan

Dear Ms. Cole:

In accordance with Rule 25-22.071, F.A.C., please find enclosed for filing the original and twenty-five (25) copies of Florida Power & Light Company's 2013-2022 Ten-Year Power Plant Site Plan.

Sincerely,

Lynne A. Adams for

Jessica A. Cano
Principal Attorney

Enclosures

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 48
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-M

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Florida Power & Light Company
Law Department, 700 Universe Blvd., Juno Beach, FL 33408-0420 Phone: (561) 304-5226 | Fax: (561) 691-7135

Ten Year Power Plant Site Plan 2013-2022

FPL

FPL

Ten Year Power Plant Site Plan

2013-2022

Submitted To:

Florida Public
Service Commission

Miami, Florida
April 2013

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Table of Contents

List of Figures and Tables

List of Schedules

Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan. This plan should include an estimate of the utility's future electric power generating needs, a projection of how these estimated generating needs might be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The information contained in this Site Plan is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

This Ten Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) integrated resource planning (IRP) analyses that were carried out in 2012 and that were on-going in the first Quarter of 2013. The forecasted information presented in this plan addresses the years 2013 through 2022.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains uncertain forecasts and tentative planning information. Forecasts evolve, and all planning information is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, based on FPL's IRP work in 2012 and

early 2013. This chapter also discusses a number of issues that may change the resource plan presented in this Site Plan. Furthermore, this chapter discusses FPL's current DSM programs, renewable energy efforts, transmission planning additions, and fuel cost forecasts.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as Preferred and Potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional information that is included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	***Abbreviation***	***Definition***
Unit Type	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	IC	Internal Combustion
	ST	Nuclear Power
	PV	Photovoltaic
	ST	Steam Unit
Fuel Type	NP	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	Solar	Solar Energy
	SUB	Sub Bituminous Coal
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	P	Planned Unit
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	ESP	Electrostatic Precipitators

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Executive Summary

Florida Power & Light Company's (FPL) 2013 Ten Year Power Plant Site Plan (Site Plan) presents FPL's current plans to augment and enhance its electric generation capability (owned or purchased) as part of its efforts to meet its projected incremental resource needs for the 2013 - 2022 time period. By design, the primary focus of this document is on supply side additions; i.e., electric generation capability and the sites for these additions. The supply side additions discussed in this document are resources projected to be needed after accounting for FPL's demand side management (DSM) resource additions previously approved by the Florida Public Service Commission (FPSC) and the significant energy efficiency contributions from the current federal appliance and lighting efficiency standards. The projected impacts of the federal and state appliance and lighting efficiency standards are accounted for in FPL's load forecast as discussed below and in Chapter II. The projected impacts of FPL's DSM efforts are addressed as projected reductions to the forecasted load in Chapters II and III. A discussion of FPL's current DSM programs is presented in Chapter III.

The resource plan that is presented in FPL's 2013 Site Plan contains three key similarities to the resource plan presented in FPL's 2012 Site Plan. However, there are several factors that have contributed to differences between the resource plan presented in the 2013 Site Plan and the resource plan that was previously presented in FPL's 2012 Site Plan. Additional factors will continue to influence FPL's on-going resource planning work and could result in changes in the resource plan presented in this document. A brief discussion of these similarities and factors is provided below. Additional information regarding these topics is presented in Chapter III.

I. Similarities Between the Current Resource Plan and the Resource Plan Previously Presented in FPL's 2012 Site Plan:

There are three key similarities between the current resource plan presented in this document and the resource plan presented in the 2012 Site Plan.

Similarity # 1: The modernizations of FPL's existing Cape Canaveral and Riviera Beach plant sites are underway and are projected to be completed on time in 2013 and 2014, respectively. In addition, the modernization of FPL's existing Port Everglades plant site has begun and it is projected to be completed in 2016.

FPL's 2012 Site Plan projected that the modernizations of two existing sites would be completed in 2013 (Cape Canaveral) and 2014 (Riviera Beach). FPL received need determination approval from the FPSC for both of these modernizations in September 2008 in Order No. PSC-08-0591-FOF-EI. Site Certification was received for Cape Canaveral in October 2009 in Order No. DEP 09-1015. Site Certification was received for Riviera Beach in November 2009 in Order No. DEP 09-1245. The work to complete these modernizations is underway and is proceeding as scheduled. These modernizations are again reflected in this Site Plan with no changes to the projected completion dates. In addition, work regarding a similar modernization at the existing Port Everglades site has begun and the project is projected to be completed in 2016. FPL received need determination approval from the FPSC for the Port Everglades modernization in April 2012 in Order No. PSC-12-0187-FOF-EI. The Site Certification order for the project, DOAH Case No. 12-0422EPP, was received for the Port Everglades project in October 2012.

Similarity # 2: FPL continues to pursue additional nuclear energy generation to significantly (i) reduce its use of fossil fuels, (ii) lower system fuel costs, (iii) lower system air emissions, and (iv) provide a valuable hedge against future increases in fuel costs and environmental compliance costs.

By the date this 2013 Site Plan is filed (April 1, 2013), FPL is projected to have completed essentially all of the work necessary to increase the generation capacity at the fourth of its four existing nuclear generating units, Turkey Point Unit 4. Similar work to increase the generation capacity at FPL's three other nuclear units, St. Lucie Units 1 & 2, and Turkey Point Unit 3 was completed in 2012 and FPL's customers are already benefitting from completion of that work. The total project, called the Extended Power Uprate (EPU) project, will have increased FPL's total nuclear generating capacity by over 500 MW, the equivalent of approximately one-half of a new nuclear unit. The addition of this nuclear generation capacity was accomplished in less than half the time that would be needed to license and construct a new nuclear unit.

In addition, FPL is continuing its work to obtain all of the licenses, permits, and approvals that will be necessary to construct and operate two new nuclear units at its Turkey Point site in the future. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. FPL received need determination approval from the FPSC for the two new nuclear units, Turkey Point Units 6 & 7, in April 2008 in Order No. PSC-08-0237-FOF-EI. The earliest practical deployment dates for these two new units are currently projected to be 2022 and 2023, respectively. Because 2022 is the last year of the 10-year reporting window for this Site Plan, Turkey Point Unit 6 is addressed in this document (while Turkey Point Unit 7, due to its projected in-service date of 2023, is not addressed in this document).

Similarity # 3: Five generating units were retired in 2012, two other generating units are scheduled to be retired in 2013, and two other generating units have been/will be switched to operate as synchronous condensers.

FPL's 2012 Site Plan discussed FPL's plans to retire specific generation units and to convert other generation units to synchronous condenser operation. Sanford Unit 3, Cutler Unit 5, Cutler Unit 6, and Port Everglades Units 1 & 2 were retired in the fourth quarter of 2012. Two other generating units, Port Everglades Units 3 & 4, are scheduled to be retired in 2013 as part of the Port Everglades Modernization project which will be completed in 2016. In addition, Turkey Point Unit 2 has been converted to operate in synchronous condenser mode to provide voltage support for the transmission system in Southeastern Florida. FPL also projects that Turkey Point Unit 1 will be similarly converted to run in synchronous condenser mode starting in 2016.

II. Factors Influencing FPL's Resource Planning Work Which Have Impacted, or Which Could Impact, FPL's Resource Plan:

There are a number of factors that influence FPL's resource planning work. Eight (8) of these are briefly discussed below and are discussed again in Chapter III.

Two of these factors are on-going system concerns that FPL has considered in its resource planning work for a number of years. These two on-going system concerns are: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward Counties.

The third and fourth factors that will be discussed are factors that directly impacted the resource plan presented in this document because they affect FPL's forecast of its future load. The third factor is the projection that FPL will begin serving Vero Beach's electrical load beginning January 1, 2014. An agreement to this effect was reached between Vero Beach and FPL on February 19, 2013, and a referendum was held on March 12, 2013 that resulted in a majority of Vero Beach voters approving the agreement.

The fourth factor is an updated projection of the impact of mandated efficiency standards for appliances, lighting, and other electrical equipment. This updated projection of the impact of these efficiency standards has been incorporated into FPL's load forecast. The magnitude of efficiency that is being delivered to FPL's customers through these standards is significant. For example, by the year 2022, FPL's Summer peak is projected to be lower by approximately 2,900 MW compared to what the projected load would have been without the efficiency standards. This represents a decrease of approximately 10% in the forecasted Summer peak load for 2022. Likewise, FPL's forecasted net energy for load (NEL) in the year 2022 is projected to be approximately 11,850 GWh lower compared to what the projected NEL would have been without the efficiency standards. This represents a decrease of approximately 8% in the forecasted NEL for 2022. These significant reductions in FPL's peak load and NEL have been achieved solely through mandated efficiency standards and have been incremental to the reductions FPL has achieved through its DSM programs.

In addition to lowering FPL's forecast from what it otherwise would have been, and thus lowering FPL's projected resource needs, this projection of increased efficiency from the efficiency standards also affects FPL's resource planning in another way. The mandated higher efficiency standards lower the potential for future MW and GWh reductions from FPL's DSM programs that address the specific appliances and equipment covered by the standards.

The fifth factor is FPL's projected increasing dependence upon DSM resources to maintain system reliability. This factor has been previously discussed in FPL's 2011 and 2012 Site Plans, and it is discussed again in this 2013 Site Plan. In these previous Site Plans, FPL has discussed this projection of increasing dependence upon DSM resources using a new type of reserve margin projection as an indicator: a "generation-only reserve margin" (gen-only RM). In calculating the values for this indicator, all of FPL's projected incremental load management and energy efficiency program capabilities, and its existing load management capability, are removed from the reserve margin calculation. The resulting gen-only RM values indicate what FPL's reserve margin values are projected to be based solely on generation resources. The lower the gen-only RM values, the greater FPL's dependence is upon DSM resources.

The gen-only RM projections from the 2011, 2012, and 2013 Site Plans consistently show that these values are projected to significantly decrease throughout the 10-year reporting period of the Site Plans, and decline to single-digit values in the latter years of the reporting periods. These projections indicate a steadily growing dependence on DSM resources to maintain system reliability. Because of the various voluntary aspects associated with customer participation in DSM programs, FPL believes that system reliability risk increases as dependence on DSM resources increases.

There are additional factors that did not impact the resource plan presented in this document, but which could result in future in changes to this resource plan. For example, a sixth factor is the timing of when the Nuclear Regulatory Commission (NRC) will issue a new schedule for its review of FPL's application for a Combined Operating License (COL) for the Turkey Point Units 6 & 7 nuclear units and the potential impact that schedule may have on the overall project schedule. FPL must obtain a COL from the NRC before it could proceed with construction of the two new nuclear units planned for the Turkey Point site. During 2012, the NRC placed several review schedules "under review", including FPL's COL application. At the time this Site Plan is being finalized, the NRC has not identified a date by which it will issue a new schedule. Once the NRC's new review schedule is issued, FPL will conduct a project schedule review, integrating this information with other relevant information, to determine the earliest practicable in-service date for Turkey Point Unit 6 (and Unit 7).

The seventh factor is environmental regulation. As developments occur in regard to either new environmental regulations, and/or in how environmental regulations are interpreted and applied, the potential exists for such developments to affect FPL's resource plan that is presented in this document. For example, FPL has become aware of potential impacts to generating units of recent EPA changes to the National Ambient Air Quality Standards that include shorter duration 1-hour standards for nitrogen dioxide (NO_2) and sulfur dioxide (SO_2). FPL has begun the process of evaluating the impact of these standards on the fossil generating fleet, especially the higher emitting peaking gas turbines that have short emission stacks. The results of this analysis could potentially change FPL's resource plan information that is presented in this document.

The eighth factor that will be discussed is the possibility of the establishment of a Florida standard for renewable energy or clean energy. A Renewable Portfolio Standard (RPS) proposal was prepared by the FPSC, and then sent to the Florida Legislature for consideration, with a possible change to a Clean Portfolio Standard (CPS), during the 2009 legislative session. However, no RPS or CPS legislation was enacted in that session or in subsequent legislative sessions. Furthermore, during the 2012 legislative session, the legislature deleted a now obsolete directive to the FPSC that had instructed them to adopt RPS rules. RPS or CPS legislation, or other legislative initiatives regarding renewable or clean energy contributions, may still occur in the future at either the state or national level. If such legislation is enacted in later years, FPL would then determine what steps need to be taken to address the legislation. Such steps would then be discussed in FPL's Site Plan in the year following the enactment of such legislation.

Each of these factors will continue to be examined in FPL's on-going resource planning work during the rest of 2013 and in future years.

Table ES-1 presents a current projection of major changes to specific generating units and firm capacity purchases for 2013 – 2022 in terms of Summer MW. Table ES-2 then expands upon the information presented in Table ES-1 by adding projections of Winter MW impacts, Summer reserve margins, Winter reserve margins, etc. (Although neither table specifically identifies the impacts of projected DSM additions on FPL's resource needs and resource plan, FPL's projected DSM additions have been fully accounted for in the resource plan presented in this Site Plan.)

Table ES-1: Projected Capacity & Firm Purchase Power Changes

Year *	***Projected Capacity & Firm Purchase Power Changes***	***Summer MW***	***Date***
2013	Changes to existing purchases	(425)	December-12
	Port Everglades Units 3 & 4 retired for Modernization	(761)	January-13
	Turkey Point Unit 2 synchronous condenser	(392)	January-13
	Sanford Unit 5 CT Upgrade	9	February-13
	Turkey Point Unit 4 Uprate - completed	115	March-13
	Sanford Unit 4 CT Upgrade	16	April-13
	Martin Unit 1 ESP - Outage	(826)	June-13
	Cape Canaveral Next Generation Clean Energy Center	1,210	June-13
	Total of MW changes to Summer firm capacity:	**(1,054)**	
2014	Sanford Unit 5 CT Upgrade	10	September-13
	Changes to existing purchases	37	December-13
	Vero Beach Combined Cycle 1/	44	January-14
	Martin Unit 1 ESP - Outage	826	March-14
	Martin Unit 2 ESP - Outage	(826)	March-14
	Manatee Unit 3 CT Upgrade	19	May-14
	Turkey Point Unit 5 CT Upgrade	33	June-14
	Riviera Beach Next Generation Clean Energy Center	1,212	June-14
	Total of MW changes to Summer firm capacity:	**1,355**	
2015	Manatee Unit 3 CT Upgrade	20	September-14
	Martin Unit 2 ESP - Outage	826	December-14
	Palm Beach SWA - additional capacity	70	January-15
	Fort Myers Unit 2 CT Upgrades	51	May-15
	Total of MW changes to Summer firm capacity:	**967**	
2016	UPS Replacement	(928)	December-15
	Port Everglades Next Generation Clean Energy Center	1,277	June-16
	Total of MW changes to Summer firm capacity:	**349**	
2017	Vero Beach Combined Cycle 1/	(44)	January-17
	Changes to existing purchases	(37)	January-17
	Turkey Point Unit 1 synchronous condenser	(396)	October-16
	Total of MW changes to Summer firm capacity:	**(477)**	
2018	SJRPP suspension of energy	(381)	November-17
	Total of MW changes to Summer firm capacity:	**(381)**	
2019	---	---	
	Total of MW changes to Summer firm capacity:	**0**	
2020	---	---	
	Total of MW changes to Summer firm capacity:	**0**	
2021	Eco-Gen PPA	180	January-21
	Total of MW changes to Summer firm capacity:	**180**	
2022	Turkey Point Nuclear Unit 6	1,100	June-22
	Total of MW changes to Summer firm capacity:	**1,100**	

* Year shown reflects when the MW change begins to be accounted for in Summer reserve margin calculations. (Note that addition of MW values for each year will not yield a current cumulative value.)

1/ This unit will be added as part of the agreement that FPL will serve Vero Beach's electric load starting January, 2014. This unit is expected to be retired within 3 years.

Table ES-2: Projected Capacity Changes and Reserve Margins for FPL

Projected Capacity Changes and Reserve Margins for FPL (1)					
		Net Capacity Changes (MW)		Reserve Margin (%) After Maintenance	
Year	Projected Capacity Changes	Winter (2)	Summer (3)	Winter	Summer
2013	Changes to Existing Purchases (4)	(545)	(425)		
	Port Everglades Units 3 & 4 retired for Modernization	(765)	(761)		
	Turkey Point Unit 2 operation changed to synchronous condenser	(394)	(392)		
	Sanford Unit 5 CT Upgrade	---	9		
	Turkey Point Unit 4 Uprate - Completed	---	115		
	Turkey Point Unit 4 Uprate - Outage (5)	(717)	---		
	Sanford Unit 4 CT Upgrade	---	16		
	Manatee Unit 2	(3)	---		
	Scherer Unit 4	(28)	---		
	Cape Canaveral Next Generation Clean Energy Center (6)	---	1,210		
	Manatee Unit 1 ESP - Outage (7)	(822)	---		
	Martin Unit 1 ESP - Outage (7)	--	(826)	30.6%	28.0%
2014	Sanford Unit 5 CT Upgrade	19	10		
	Cape Canaveral Next Generation Clean Energy Center (6)	1,355	---		
	Changes to Existing Purchases (4)	22	37		
	Manatee Unit 1 ESP - Outage (7)	822	---		
	Sanford Unit 4 CT Upgrade	16	---		
	Vero Beach Combined Cycle (8)	46	44		
	Martin Unit 1 ESP - Outage (7)	(832)	826		
	Martin Unit 2 ESP - Outage (7)	---	(826)		
	Manatee Unit 3 CT Upgrade	---	19		
	Turkey Point Unit 5 CT Upgrade	---	33		
	Turkey Point Unit 4 Uprate - Completed (5)	115	---		
	Riviera Beach Next Generation Clean Energy Center (6)	---	1,212	34.1%	28.5%
2015	Manatee Unit 3 CT Upgrade	39	20		
	Martin Unit 1 ESP - Outage (7)	832	---		
	Martin Unit 2 ESP - Outage (7)	---	826		
	Turkey Point Unit 5 CT Upgrade	33	---		
	Changes to Existing Purchases (4)	70	70		
	Ft. Myers Unit 2 CT Upgrade	---	51		
	Riviera Beach Next Generation Clean Energy Center (6)	1,344	---	42.2%	31.2%
2016	Changes to Existing Purchases (4)	(858)	(928)		
	Ft. Myers Unit 2 CT Upgrade	51	---		
	Port Everglades Next Generation Clean Energy Center (6)	---	1,277	36.5%	31.3%
2017	Turkey Point Unit 1 operation changed to synchronous condenser	(398)	(396)		
	Changes to Existing Purchases (4)	(37)	(37)		
	Vero Beach Combined Cycle (8)	(46)	(44)		
	Port Everglades Next Generation Clean Energy Center (6)	1,429	---	40.0%	27.5%
2018	Changes to Existing Purchases (4)	(388)	(381)	37.0%	24.3%
2019	---	---	---	36.0%	22.7%
2020	---	---	---	34.9%	21.1%
2021	Changes to Existing Purchases (4)	180	180	34.5%	21.0%
2022	Turkey Point Nuclear Unit 6 (6)	---	1,100	34.4%	23.5%

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are forecasted values for January of the year shown.
(3) Summer values are forecasted values for August of the year shown.
(4) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(5) Outages for uprate work.
(6) All new unit additions are scheduled to be in-service in June of the year shown. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.
(7) Outages for ESP work.
(8) This unit will be added as part of the agreement that FPL will serve Vero Beach's electric load starting January, 2014. This unit is expected to be retired within 3 years.

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 8.9 million people. FPL served an average of 4,576,449 customer accounts in thirty-five counties during 2012. These customers were served by a variety of resources including: FPL-owned fossil-fueled, renewable, and nuclear generating units, non-utility owned generation, demand side management (DSM), and interchange/purchased power.

I.A. FPL-Owned Resources

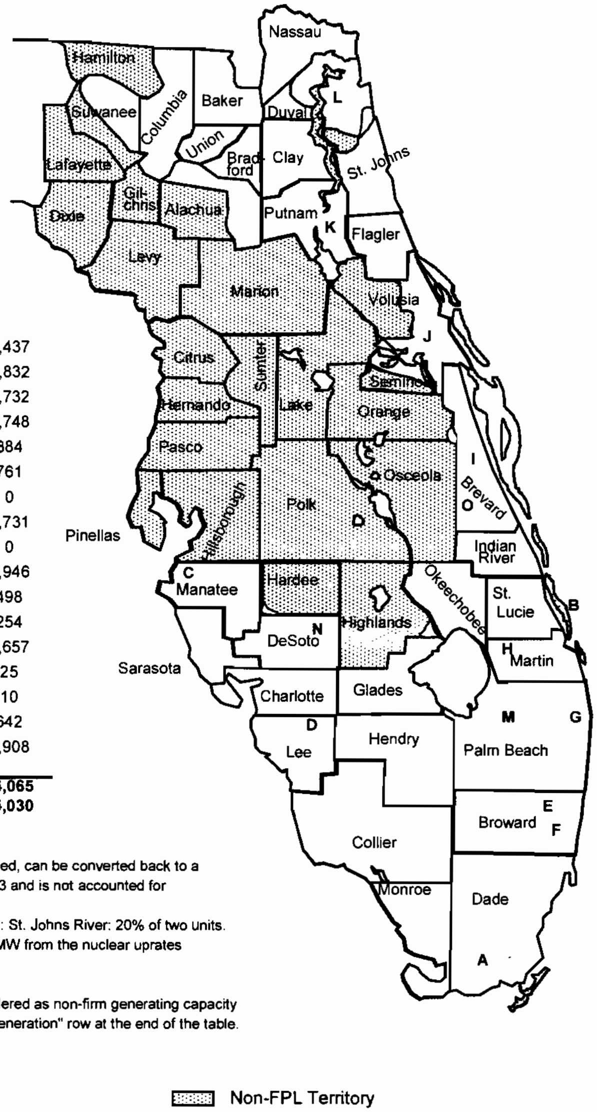
The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory, plus one site in Georgia (partial FPL ownership of one unit) and one site in Jacksonville, Florida (partial FPL ownership of two units). The current electrical generating facilities consist of four nuclear units, three coal units, fifteen combined cycle (CC) units, eight fossil steam units, forty-eight combustion gas turbines, two simple cycle combustion turbines, and two photovoltaic facilities[1]. The locations of these eighty-two generating units are shown on Figure I.A.1 and in Table I.A.1. Table I.A.2 provides a further "break down" of the capacity provided by the combustion turbine (CT) and steam turbine (ST) components of FPL's existing CC units.

FPL's bulk transmission system is comprised of 6,558 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 591 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3 shows FPL's interconnection ties with other utilities.

1 FPL also has one 75 MW solar thermal facility at its Martin plant site. This facility does not generate electricity as the other units mentioned above do. Instead, it produces steam that reduces the use of fossil fuel to produce steam for electricity generation.

FPL Generating Resources by Location



A	Turkey Point [1/]	5	3,437
B	St. Lucie [2/]	2	1,832
C	Manatee	3	2,732
D	Fort Myers	3	1,748
E	Lauderdale	2	884
F	Port Everglades [3/]	2	761
G	Riviera [3/]	0	0
H	Martin	5	3,731
I	Cape Canaveral [3/]	0	0
J	Sanford	2	1,946
K	Putnam	2	498
L	St. John's River Power Park [2/]	2	254
M	West County	3	3,657
N	DeSoto [4/]	1	25
O	Space Coast [4/]	1	10
	Scherer [5/]	1	642
	Gas Turbines	48	1,908
	Total System Generation =	**82**	**24,065**
	System Firm Generation =	**80**	**24,030**

1/ Turkey Point Unit 2 is currently operating as a synchronous condenser. If needed, can be converted back to a generating unit per the existing Title V operating permit through the end of 2013 and is not accounted for in Reserve Margin Calculation.
2/ Represents FPL's ownership share: St Lucie nuclear: 100% Unit 1, 85% Unit 2: St. Johns River: 20% of two units. The 1,832 MW value shown incorporates the latest projection for incremental MW from the nuclear uprates available at the time this document is being finalized.
3/ Will be site of new Modernization Plants.
4/ The 25 MW of PV at DeSoto and the 10 MW of PV at Space Coast are considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generation" row at the end of the table.
5/ The Scherer unit is located in Georgia and is not shown on this map.

Figure I.A.1: Capacity Resources by Location (as of December 31, 2012)

Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2012)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Nuclear				
St. Lucie 1/	Hutchinson Island, FL	2	Nuclear	1,832
Turkey Point	Florida City, FL	2	Nuclear	1,501
Total Nuclear:		**4**		**3,333**
Coal Steam				
Scherer	Monroe County, Ga	1	Coal	642
St. John's River Power Park 2/	Jacksonville, FL	2	Coal	254
Total Coal Steam:		**3**		**896**
Combined-Cycle 3/				
Fort Myers	Fort Myers, FL	1	Gas	1,432
Manatee	Parrish, FL	1	Gas	1,111
Martin	Indiantown, FL	3	Gas	2,079
Sanford	Lake Monroe, FL	2	Gas	1,946
Lauderdale	Dania, FL	2	Gas/Oil	884
Putnam	Palatka, FL	2	Gas/Oil	498
Turkey Point	Florida City, FL	1	Gas/Oil	1,148
West County	Palm Beach County, FL	3	Gas/Oil	3,657
Total Combined Cycle:		**15**		**12,755**
Oil/Gas Steam				
Manatee	Parrish, FL	2	Oil/Gas	1,621
Martin	Indiantown,FL	2	Oil/Gas	1,652
Port Everglades	Port Everglades, FL	2	Oil/Gas	761
Turkey Point 4/	Florida City, FL	2	Oil/Gas	788
Total Oil/Gas Steam:		**8**		**4,822**
Gas Turbines(GT)				
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Total Gas Turbines/Diesels:		**48**		**1,908**
Combustion Turbines 3/				
Fort Myers	Fort Myers, FL	2	Gas/Oil	316
Total Combustion Turbines:		**2**		**316**
PV				
DeSoto 5/	DeSoto, FL	1	Solar Energy	25
Space Coast 5/	Brevard County, FL	1	Solar Energy	10
Total PV:		**2**		**35**
Total System Generation as of December 31, 2012 =		**82**		**24,065**
System Firm Generation as of December 31, 2012 =		**80**		**24,030**

1/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 843/862. FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively.

2/ Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit. Represents FPL's ownership share: SJRPP coal: 20% of two units).

3/ The Combined Cycles and Combustion Turbines are broken down by components on Table 1.A.2.

4/ Turkey Point 2 is currently operating as a synchronous condenser. If needed, can be converted back to a generating unit per the existing Title V operating permit through the end of 2013 and is not accounted for in Reserve Margin Calculation.

5/ The 25 MW of PV at DeSoto and the 10 MW of PV at Space Coast are considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generation" row at the end of the table.

Table I.A.2: Combined Cycle and Combustion Turbine Components

		Summer MW *									
Combined-Cycle	Plant Name/ Unit No.	CT A	CT B	CT C	CT D	CT E	CT F	Steam 1	Steam 2	BOP Aux	Total Unit MW
	Ft Myers 2	159	159	159	159	159	159	60	437	(20)	1,432
	Lauderdale 4	158	158	---	---	---	---	131	---	(5)	442
	Lauderdale 5	158	158	---	---	---	---	131	---	(5)	442
	Manatee 3	167	167	167	167	---	---	458	---	(17)	1,109
	Martin 3	166	166	---	---	---	---	144	---	(6)	469
	Martin 4	166	166	---	---	---	---	144	---	(6)	469
	Martin 8	173	173	173	173	---	---	474	---	(23)	1,142
	Putnam 1	71	71	---	---	---	---	112	---	(5)	249
	Putnam 2	71	71	---	---	---	---	112	---	(5)	249
	Sanford 4	163	163	163	163	---	---	333	---	(12)	973
	Sanford 5	163	163	163	163	---	---	336	---	(13)	975
	Turkey Point 5	174	174	174	174	---	---	478	---	(26)	1,149
	West County 1	248	248	248	---	---	---	499	---	(25)	1,219
	West County 2	248	248	248	---	---	---	499	---	(25)	1,219
	West County 3	248	248	248	---	---	---	499	---	(25)	1,219
Combustion Turbines											
	Ft. Myers 3A	158	---	---	---	---	---	---	---	(1)	157
	Ft. Myers 3B	---	158	---	---	---	---	---	---	(1)	157

This table shows the breakdown of total MW for each unit by CT and steam component.

* The total MW values shown in this table may differ slightly from values shown in other tables due to rounding of per-component values.

Table 1.A.3: Purchase Power Resources by Contract (as of December 31, 2012)

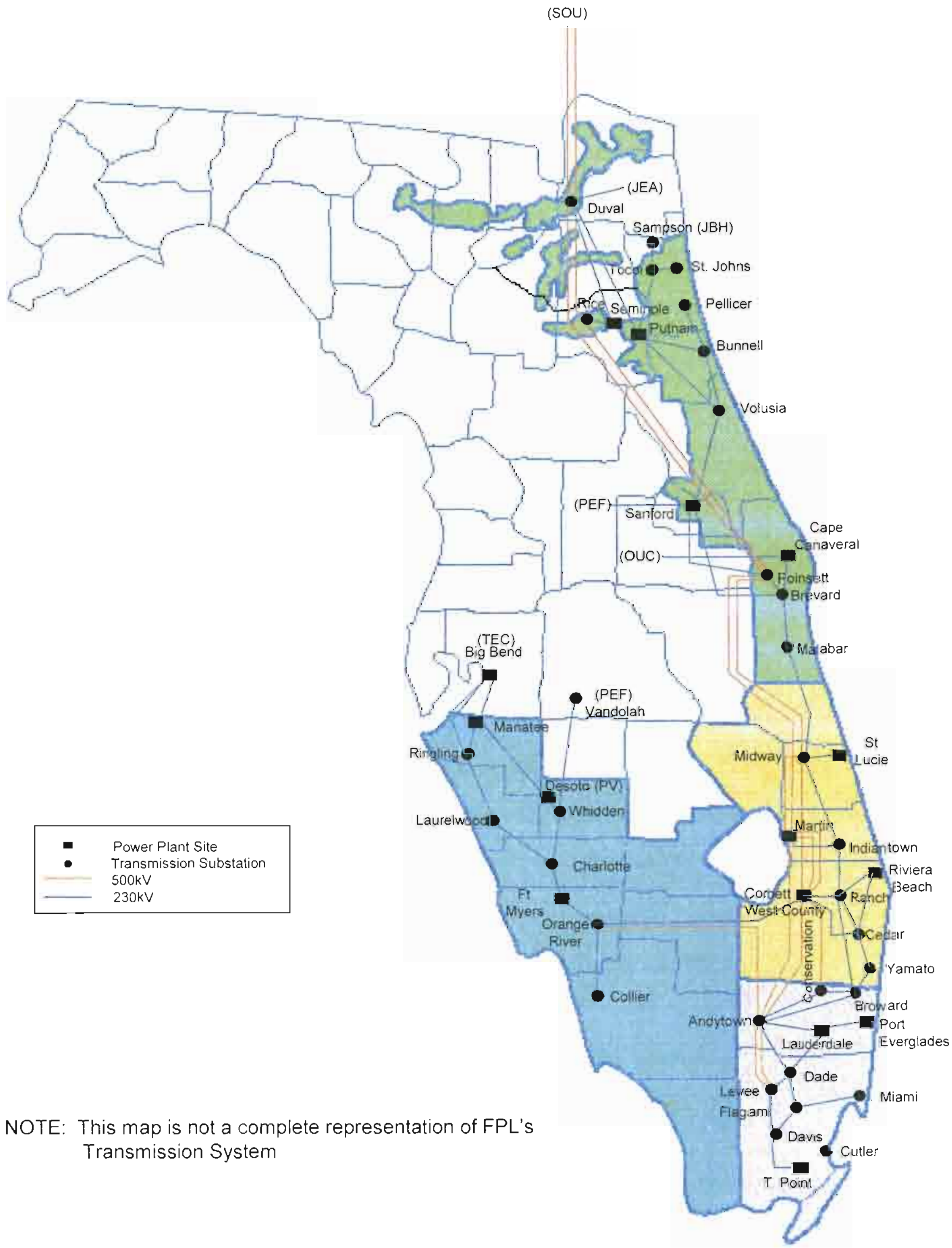
Table 1.A.3: Purchase Power Resources by Contract (as of December 31, 2012)

	Location (City or County)	Fuel	Summer MW
I. Purchases from QF's: Cogeneration/Small Power Production Facilities			
Cedar Bay Generating Co.	Duval	Coal (Cogen)	250
Indiantown Cogen., LP	Martin	Coal (Cogen)	330
Broward South	Broward	Solid Waste	4
Broward North	Broward	Solid Waste	11
Palm Beach SWA - extension			40
		Total:	**635**
II. Purchases from Utilities:			
UPS from Southern Company	Various in Georgia	Coal	928
SJRPP	Jacksonville, FL	Coal	381
TECO	Tampa	Coal	125
		Total:	**1,434**
III. Other Purchases:			
DeSoto Unit 1	DeSoto	Natural Gas	150
DeSoto Unit 2	DeSoto	Natural Gas	155
			305
		Total Net Firm Generating Capability:	**2,374**

Non-Firm Energy Purchases (MWH)

Project	County	Fuel	Energy (MWH) Delivered to FPL in 2012
Okeelanta (known as Florida Crystals and New Hope Power Partners) *	Palm Beach	Bagasse/Wood	141,594
Broward South *	Broward	Solid Waste	127,533
Broward North *	Broward	Solid Waste	119,168
Tomoka Farms *	Volusia	Landfill Gas	0
Waste Management - Renewable Energy *	Broward	Landfill Gas	45,371
Waste Management - Collier County Landfill *	Broward	Landfill Gas	29,303
Tropicana	Manatee	Natural Gas	22,935
Calnetix	Palm Beach	Natural Gas	0
Georgia Pacific	Putnam	Paper by-product	9,550
Rothenbach Park (known as MMA Bee Ridge)	Sarasota	PV	320
First Solar	Miami	PV	67
Customer - Owned PV & Wind	Various	PV/Wind	877
Palm Beach SWA	Palm Beach	Solid Waste	370,109
INEOS Bio *	Indian River	Wood	70

* These Non-Firm Energy Purchases are Renewable and are reflected on Schedule 11.1 row 9 column 6.



NOTE: This map is not a complete representation of FPL's Transmission System

Figure I.A.2: FPL Substation and Transmission System Configuration

FPL Interconnection Diagram

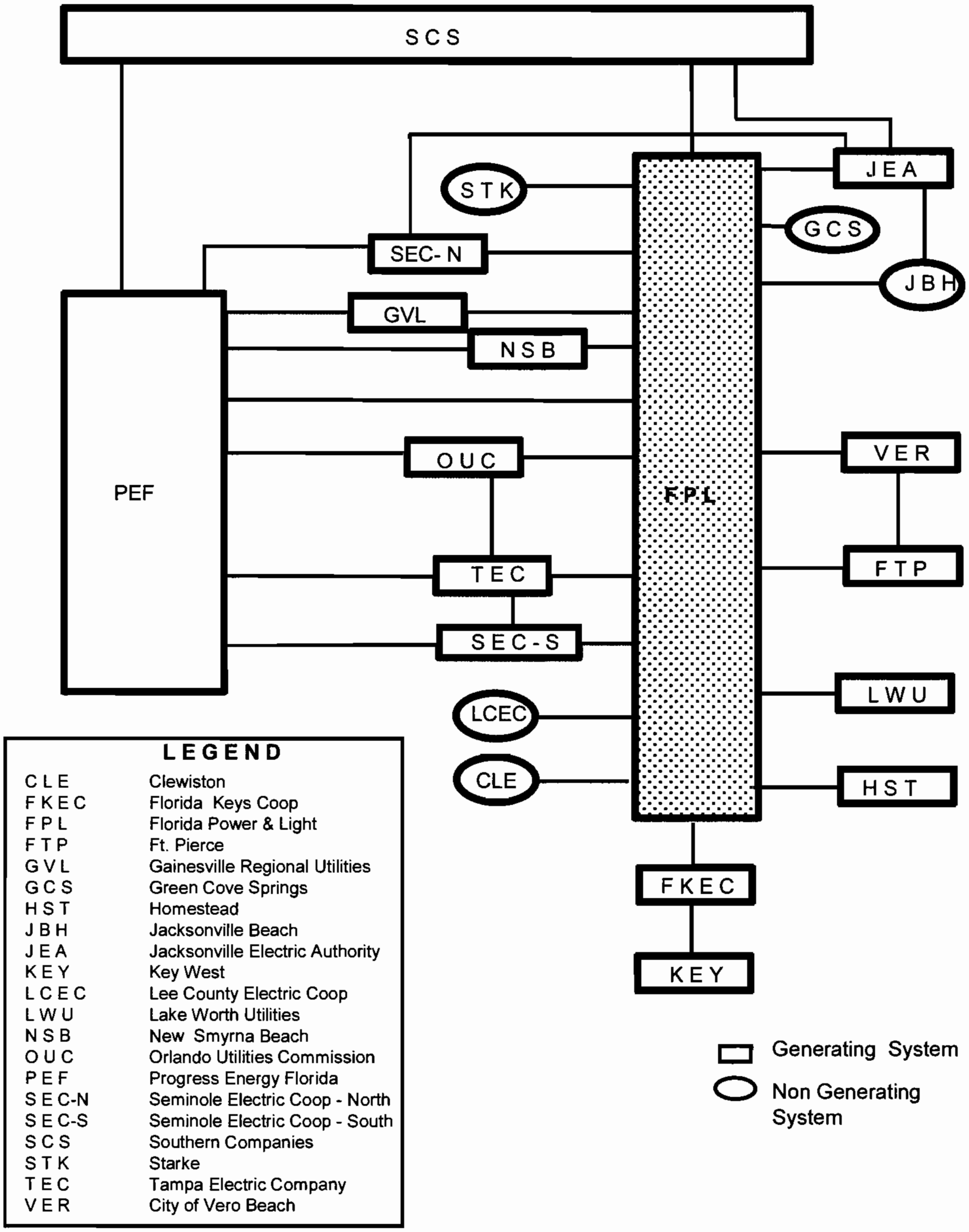


Figure I.A.3: FPL Interconnection Diagram

Description of Existing Resources

I.B Firm Capacity Power Purchases

Purchases from Qualifying Facilities (QF):

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has contracts with eight qualifying facilities; i.e., cogeneration/small power production facilities, to purchase firm capacity and energy during the 10-year reporting period of this Site Plan as shown in Table I.A.3, Table I.B.1, and Table I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source solar, wind, waste, geothermal, or other renewable resources.

Purchases from Utilities:

FPL has a Unit Power Sales (UPS) contract to purchase 928 MW from the Southern Company (Southern) through the end of December 2015. This capacity is being supplied by Southern from a mix of gas-fired and coal-fired units.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 381 MW (Summer) and 388 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. However, due to Internal Revenue Service (IRS) regulations, the total amount of energy that FPL may receive from this purchase is limited. FPL currently assumes, for planning purposes, that this limit will be reached in November of 2017. Once this limit is reached, FPL will be unable to receive firm capacity and energy from these purchases. (However, FPL will continue to receive firm capacity and energy from its ownership portion of the SJRPP units.)

As part of the agreement that FPL will begin serving Vero Beach's electrical needs beginning in January 2014, FPL has acquired two existing power purchase agreements totaling approximately 37 MW of coal-fired capacity. These agreements will run through the end of 2016.

These purchases are shown in Table I.A.3, Table I.B.1, and Table I.B.2. FPL also has ownership interest in the SJRPP units. The ownership amount is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.

Other Purchases:

FPL has two other firm capacity purchase contracts with non-QF, non-utility suppliers. These contracts with the Palm Beach Solid Waste Authority were previously listed as QFs; however, the addition of a second unit will cause both units to no longer meet the statutory definition of a QF. These contracts are therefore listed as "Other Purchases" after the current estimated in-service date of the new unit. Table I.B.1 and I.B.2 present the Summer and Winter MW, respectively, resulting from these contracts under the category heading of Other Purchases.

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA -extension 1/	01/01/12	04/01/32	40	40	0	0	0	0	0	0	0	0
U.S. EcoGen - Clay 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	0	60	60
U.S. EcoGen -Okeechobee 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	0	60	60
U.S. EcoGen - Martin 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	0	60	60
QF Purchases Sub Total:			**635**	**635**	**595**	**595**	**595**	**595**	**595**	**595**	**775**	**775**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
UPS Replacement	06/01/10	12/31/15	928	928	928	0	0	0	0	0	0	0
SJRPP 3/	04/02/82	11/01/17	381	381	381	381	381	0	0	0	0	0
OUC - Stanton 1 4/	01/01/14	12/31/16	0	21	21	21	0	0	0	0	0	0
OUC - Stanton 2 4/	01/01/14	12/31/16	0	16	16	16	0	0	0	0	0	0
Utility Purchases Sub Total:			**1,309**	**1,346**	**1,346**	**418**	**381**	**0**	**0**	**0**	**0**	**0**
Total of QF and Utility Purchases =			**1,944**	**1,980**	**1,940**	**1,012**	**976**	**595**	**595**	**595**	**775**	**775**

III. Other Purchases:

	Contract Start Date	Contract End Date	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Palm Beach SWA -extension 1/	01/01/12	04/01/32	0	0	40	40	40	40	40	40	40	40
Palm Beach SWA - additional	01/01/15	04/01/32	0	0	70	70	70	70	70	70	70	70
Other Purchases Sub Total:			**0**	**0**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**
Total "Non-QF" Purchase =			**1,309**	**1,346**	**1,456**	**528**	**491**	**110**	**110**	**110**	**110**	**110**

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Summer Firm Capacity Purchases Total MW:	**1,944**	**1,980**	**2,050**	**1,122**	**1,086**	**705**	**705**	**705**	**885**	**885**

1/ When the second unit comes into service at the Palm Beach SWA, neither unit will meet the standards to be a small power producers, and both units then will be accounted for under "Other Purchases".

2/ The EcoGen units will enter service in 2019, and initially provide non-firm energy. Firm capacity delivery will commence in 2021.

3/ Contract End Date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.

4/ These units are part of the purchase of the Vero Beach Electric System.

Table I.B.2: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA -extension 1/	01/01/12	04/01/32	40	40	0	0	0	0	0	0	0	0
U.S. EcoGen - Clay 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	0	60	60
U.S. EcoGen -Okeechobee 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	0	60	60
U.S. EcoGen - Martin 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	0	60	60
		QF Purchases Sub Total:	**635**	**635**	**595**	**595**	**595**	**595**	**595**	**595**	**775**	**775**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
UPS Replacement	06/01/10	12/31/15	928	928	928	0	0	0	0	0	0	0
SJRPP 3/	04/02/82	11/01/17	388	388	388	388	388	0	0	0	0	0
OUC - Stanton 1 4/	01/01/14	12/31/16	0	21	21	21	0	0	0	0	0	0
OUC - Stanton 2 4/	01/01/14	12/31/16	0	16	16	16	0	0	0	0	0	0
		Utility Purchases Sub Total:	**1,316**	**1,353**	**1,353**	**425**	**388**	**0**	**0**	**0**	**0**	**0**
		Total of QF and Utility Purchases =	**1,951**	**1,987**	**1,947**	**1,019**	**983**	**595**	**595**	**595**	**775**	**775**

III. Other Purchases:

	Contract Start Date	Contract End Date	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Palm Beach SWA -extension 1/	01/01/12	04/01/32	0	0	40	40	40	40	40	40	40	40
Palm Beach SWA - additional	01/01/15	04/01/32	0	0	70	70	70	70	70	70	70	70
		Other Purchases Sub Total:	**0**	**0**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**
		"Non-QF" Purchase =	**1,316**	**1,353**	**1,463**	**535**	**498**	**110**	**110**	**110**	**110**	**110**

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Winter Firm Capacity Purchases Total MW:	**1,951**	**1,987**	**2,057**	**1,129**	**1,093**	**705**	**705**	**705**	**885**	**885**

1/ When the second unit comes into service at the Palm Beach SWA, neither unit will meet the standards to be a small power producers, and both units then will be accounted for under "Other Purchases".

2/ The EcoGen units will enter service in 2019, and initially provide non-firm energy. Firm capacity delivery will commence in 2021.

3/ Contract End Date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.

4/ These units are part of the purchase of the Vero Beach Electric System.

I.C Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. Table I.C.1 shows the amount of energy purchased in 2012 from these facilities.

Table 1.C.1: As-Available Energy Purchases from Non-Utility Generators in 2012

Project	County	Fuel	In-Service Date	Energy (MWH) Delivered to 2012
Okeelanta (known as Florida Crystals and New Hope Power Partners) *	Palm Beach	Bagasse/Wood	11/95	141,594
Broward South *	Broward	Solid Waste	9/09	127,533
Broward North *	Broward	Solid Waste	1/12	119,168
Tomoka Farms *	Volusia	Landfill Gas	7/98	0
Waste Management - Renewable Energy *	Broward	Landfill Gas	1/10	45,371
Waste Management - Collier County Landfill *	Broward	Landfill Gas	5/11	29,303
Tropicana	Manatee	Natural Gas	2/90	22,935
Calnetix	Palm Beach	Natural Gas	7/05	0
Georgia Pacific	Putnam	Paper by-product	2/94	9,550
Rothenbach Park (known as MMA Bee Ridge)	Sarasota	PV	10/07	320
First Solar	Miami	PV	4/11	67
Customer - Owned PV & Wind	Various	PV/Wind	Various	877
Palm Beach SWA	Palm Beach	Solid Waste	4/10	370,109
INEOS Bio *	Indian River	Wood	9/12	70

* These Non-Firm Energy Purchases are Renewable and are reflected on Schedule 11.1 row 9 column 6.

I.D Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include a number of conservation/energy efficiency and load management initiatives. FPL's DSM efforts through 2012 have resulted in a cumulative Summer peak reduction of approximately 4,652 MW at the generator and an estimated cumulative energy saving of approximately 62,653 Gigawatt-hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2012 have eliminated the need to construct the equivalent of approximately 14 new 400 MW generating units. DSM is discussed further in Chapter III.

Schedule 1

Existing Generating Facilities
As of December 31, 2012

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability [1/] Winter MW	(14) Net Capability [1/] Summer MW
DeSoto [2/]		DeSoto County											
		27/36S/25E									27,000	25	25
	1		PV	N/A	N/A	N/A	N/A	Unknown	Oct-09	Unknown	27,000	25	25
Fort Myers		Lee County											
		35/43S/25E									3,198,770	2,552	2,396
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,701,890	1,490	1,432
	3A		CT	NG	FO2	PL	TK	Unknown	Jun-03	Unknown	376,380	176	158
	3B		CT	NG	FO2	PL	TK	Unknown	Jun-03	Unknown	376,380	176	158
	1-12		GT	FO2	No	TK	No	Unknown	May-74	Unknown	744,120	710	648
Lauderdale		Broward County											
		30/50S/42E									1,873,968	1,884	1,724
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	483	442
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	483	442
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
Manatee		Manatee County											
		18/33S/20E									2,951,110	2,809	2,732
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	822	812
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	819	809
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,168	1,111
Martin		Martin County											
		29/29S/38E									4,317,510	3,870	3,731
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	832	826
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	832	826
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	489	469
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	489	469
	8 [3/]		CC	NG	FO2	PL	TK	Unknown	Jun-05	Unknown	1,224,510	1,228	1,141
Port Everglades		City of Hollywood											
		23/50S/42E									1,214,834	1,224	1,181
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Jan-13	402,050	389	387
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Jan-13	402,050	376	374
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	459	420
Putnam		Putnam County											
		16/10S/27E									580,008	530	498
	1		CC	NG	FO2	PL	TK	Unknown	Apr-78	Unknown	290,004	265	249
	2		CC	NG	FO2	PL	TK	Unknown	Aug-77	Unknown	290,004	265	249

1/ These ratings are peak capability.

2/ The capacity shown for the PV facility at DeSoto is considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generating Capacity as of December 31, 2012" row at the end of the table.

3/ Martin Unit 8 is also partially fueled by a 75 MW solar thermal facility that supplies steam when adequate sunlight is available, thus reducing fossil fuel use.

Schedule 1

Existing Generating Facilities
As of December 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt.		Actual/			
						Fuel		Fuel	Commercial	Expected	Gen.Max.	Net Capability [1/]	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Sanford		Volusia County											
		16/19S/30E									2,377,720	2,125	1,946
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,860	1,062	973
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	1,063	973
Scherer [2/]		Monroe, GA									680,368	651	642
	4		ST	SUB	No	RR	No	Unknown	Jul-89	Unknown	680,368	651	642
Space Coast [3/]		Brevard County											
		13/23S/36E									10,000	10	10
	1		PV	N/A	N/A	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10
St. Johns River		Duval County											
Power Park [4/]		12/15/28E											
		(RPC4)									271,836	260	254
	1		ST	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	130	127
	2		ST	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	130	127
St. Lucie [5/]		St. Lucie County									1,000		
		16/36S/41E									1,743,775	1,873	1,832
	1 [7/]		ST	NP	No	TK	No	Unknown	May-76	Unknown	1,020,000	1,009	987
	2 [7/]		ST	NP	No	TK	No	Unknown	Jun-83	Unknown	723,775	864	845
Turkey Point		Miami Dade County											
		27/57S/40E									3,783,010	3,519	3,437
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	398	396
	2 [6/]		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	394	392
	3 [7/]		ST	NP	No	TK	No	Unknown	Nov-72	Unknown	877,200	832	808
	4 [7/]		ST	NP	No	TK	No	Unknown	Jun-73	Unknown	877,200	717	693
	5		CC	NG	FO2	PL	TK	Unknown	May-07	Unknown	1,224,510	1,178	1,148
West County		Palm Beach County											
		29&32/43S/40E									2,733,600	4,005	3,657
	1		CC	NG	FO2	PL	TK	Unknown	Aug-09	Unknown	1,366,800	1,335	1,219
	2		CC	NG	FO2	PL	TK	Unknown	Nov-09	Unknown	1,366,800	1,335	1,219
	3		CC	NG	FO2	PL	TK	Unknown	May-11	Unknown	1,366,800	1,335	1,219
											Total System Generating Capacity as of December 31, 2012 [8/] =	**25,337**	**24,065**
											System Firm Generating Capacity as of December 31, 2012 [9/] =	**25,302**	**24,030**

1/ These ratings are peak capability.

2/ These ratings represent Florida Power & Light Company's share of Scherer Unit 4, adjusted for transmission losses.

3/ The capacity shown for the PV facility at Space Coast is considered as non-firm generating capacity due to the intermittent nature of the solar resource.

4/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Units 1 and 2, excluding the Jacksonville Electric Authority (JEA) share of 80%.

5/ Total capability of St. Lucie 1 is 987/1,009 MW. FPL's share of St. Lucie 2 is 845/864.FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively, as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.

6/ Currently operating as a synchronous condenser. If needed, it can be converted back to a generating unit per the existing Title V operating permit through the end of 2013 and is not accounted for in Reserve Margin Calculation.

7/ Values for the Nuclear Units are approximate due to the on going testing after the EPU work has been completed.

8/ The Total System Generating Capacity value shown includes FPL-owned firm and non-firm generating capacity.

9/ The System Firm Generating Capacity value shown includes only firm generating capacity.

CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

II. A. Overview of the Load Forecasting Process

Long-term forecasts of sales, net energy for load (NEL), and peak loads are typically developed on an annual basis for resource planning work at FPL. New long-term forecasts were developed by FPL in early 2013 that replaced the previous long-term load forecasts that were used by FPL during 2012 in much of its resource planning work and which were presented in FPL's 2012 Site Plan. These new load forecasts are utilized throughout FPL's 2013 Site Plan. These forecasts are a key input to the models used to develop FPL's integrated resource plan.

The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads. Consistent with past forecasts, the primary drivers to develop these forecasts include economic conditions and weather.

The projections for the national and Florida economies are obtained from the consulting firm IHS Global Insight. Population projections are obtained from the Florida Legislature's Office of Economic and Demographic Research (EDR). These projections are developed in conjunction with the Bureau of Economic and Business Research (BEBR) of the University of Florida. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects FPL's energy sales and peak demand. Three sets of weather variables are developed and used in FPL's forecasting models:

1. Cooling degree-hours based on 72° F, winter heating degree-days based on 66° F, and heating degree-days based on 45° F are used to forecast energy sales.
2. The maximum temperature on the peak day, along with the build-up of cooling degree-hours prior to the peak, are used to forecast Summer peaks.
3. The minimum temperature on the peak day, along with the build-up of heating degree-hours based on 66° F on the day prior to the peak, are used to forecast Winter peaks.

The cooling degree-hours and winter heating degree-days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. Heating degree-days based on 45° F are used to capture heating load resulting from sustained periods of unusually cold weather not fully captured by heating degree-days based on 66° F. A composite hourly temperature profile is derived using hourly temperatures across FPL's service territory. Miami, Ft.Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained. In developing the composite hourly profile, these regional temperatures are weighted by regional energy sales. The resulting composite temperature is used to derive projected cooling and heating degree-hours and heating degree-days. Similarly, composite temperature and hourly profiles of temperatures are used to calculate the weather variables used in the Summer and Winter peak models.

II. B. Comparison of FPL's Current and Previous Load Forecasts

While reflecting somewhat lower growth for a number of years, FPL's current load forecast is generally in line with the load forecast presented in its 2012 Site Plan. There are four primary factors that are driving the current load forecast: projected customer growth, a projection of gradual recovery following the economic recession in Florida, energy efficiency standards, and the additional load expected as a result of the acquisition of the City of Vero Beach electric utility.

In early 2013, FPL came to an agreement with the City of Vero Beach to purchase the City's electric system. This agreement was approved by the City voters on March 12' 2013. Beginning in January 2014, NEL, customers, and peaks for Vero Beach are included in FPL's forecasts and are reflected in FPL's 2013 Site Plan.

The customer forecast is based on recent population projections as well as the actual levels of customer growth experienced historically and the additional customers expected as a result of the acquisition of Vero Beach. Population projections are derived from the EDR's February 2013 Demographic Estimating Conference. This forecast is generally consistent with previous forecasts indicating a gradual rebound in Florida's population growth. Net migration into Florida fell to a record low in 2009 during the height of the recession. Florida has since experienced some rebound in net migration, but population growth rates have remained low by historical standards. Moderately higher rates of population growth are projected from 2013 until 2017 when the projected rate of population growth gradually begins to decelerate. Consistent with past population projections, the rates of population growth in the later years of the forecast are below the rates historically experienced in Florida.

Effective January 2014 FPL is expected to begin providing electric service to more than 34,000 customers formerly served by the City of Vero Beach. Reflecting this increase, the current forecast shows a significant increase in customer growth in 2014. Thereafter, customer growth is expected to mirror the overall level of population growth in the state. By 2019, the total number of customers served by FPL is expected to exceed five million. Between 2012 and 2022 the total number of customers is projected to increase at an annual rate of 1.4%, the same increase projected in the 2012 Site Plan.

The economic projections incorporated into FPL's load forecast are provided by IHS Global Insight, a leading economic forecasting firm. The economic projections from IHS Global Insight incorporated into the current load forecast indicate less robust growth than that assumed in the 2012 Site Plan forecast. Although IHS Global Insight remains cautiously optimistic on the Florida economy, their current projections for employment and income growth are lower than those incorporated into the 2012 Site Plan forecast.

Estimates of savings from energy efficiency standards are developed by ITRON, a leading expert in this area. Included in these estimates are savings from federal and state energy efficiency standards, including the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the savings occurring from the use of compact fluorescent bulbs[2]. The impact of these savings began in 2005 and their cumulative impact on the Summer peak is expected to reach 2,898 MW by 2022. The cumulative impact from these savings on NEL is expected to reach 11,850 GWH over the same period while the cumulative impact on the Winter peak is expected to be 1,650 MW by 2022.

Consistent with the forecast presented in FPL's 2012 Site Plan, the total growth projected for the ten-year reporting period of this document is significant. The Summer peak is projected to increase to 26,105 MW by 2022, an increase of 4,665 MW over the 2012 actual Summer peak. Likewise, NEL is projected to reach 130,965 GWH in 2022, an increase of 20,099 GWH from the actual 2012 value.

II.C. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for the major revenue classes and are adjusted to match the NEL forecast. The results of these sales forecasts for the

[2] Note that in addition to the fact that these energy efficiency standards lower the forecasted load (as described later in this chapter), these standards also lower the potential for efficiency gains that would otherwise be available through utility DSM programs.

years 2013 - 2022 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and NEL forecast are outlined below.

1. Residential Sales

Residential electric usage per customer is estimated by using an econometric model. Residential sales are a function of the following variables: cooling degree-hours, winter heating degree-days, heating degree-days based on 45° F, lagged cooling degree-hours, lagged heating degree-days, retail gasoline prices, and Florida real per capita income weighted by the percent of the population employed. The impact of weather is captured by the cooling degree-hours, heating degree-days, and the one month lag of these variables. The impact energy prices have on electricity consumption is captured through retail gasoline prices. As energy prices rise, less disposable income is available for all goods and services, electricity included. To capture economic conditions, the model includes a composite variable based on Florida real per capita income and the percent of the state's population that is employed. Because of the relatively large percentage of Florida's population that was unemployed during the recession, real per capita income alone did not capture the full magnitude of the economic downturn. The composite variable more fully reflects economic conditions. Residential energy sales are forecasted by multiplying the forecasted residential use per customer by the number of residential customers forecasted.

2. Commercial Sales

The commercial sales forecast is also developed using an econometric model. Commercial sales are a function of the following variables: Florida real per capita income weighted by the percent of the population employed, cooling degree-hours, heating degree-hours, lagged cooling degree-hours, a variable designed to reflect the impact of empty homes, dummy variables for the month of December and for the specific months of January 2007 and November 2005, and an autoregressive term. Cooling degree-hours, heating degree-hours, and the one month lag of cooling degree-hours are used to capture weather-sensitive load in the commercial sector.

3. Industrial Sales

The industrial class is comprised of three distinct groups: very small accounts (those with less than 20 kW of demand), medium accounts (those with 21 kW to 499 kW of demand), and large accounts (those with demands of 500 kW or higher). As such, the forecast is developed using a separate econometric model for each group of industrial customers. The small industrial sales model utilizes the following variables: cooling degree-hours, heating degree-hours, dummy variables for the specific months of February 2009 and August 2004, and an autoregressive term. The medium industrial sales model utilizes the following variables: cooling degree-hours, Florida real per capita income, a dummy variable for the specific month of February 2006, two autoregressive terms, and a moving average term. The large industrial sales model utilizes the following variables: Florida real per capita income, the Consumer Price Index, and dummy variables for the specific months of October 2004, November 2004, and October 2005.

4. **Railroad and Railways Sales and Street and Highway Sales**

This class consists solely of Miami-Dade County's Metrorail system. The projections for railroad and railways sales are based on historical average use per customer which is multiplied by the forecasted number of customers. The number of customers is based on the planned addition of new Metrorail stations.

The forecast for street and highway sales is developed by first developing a trended use per customer value, then multiplying this value by the number of forecasted customers.

5. **Other Public Authority Sales**

This revenue class is closed to new customers. This class consists of sports fields and one government account. The forecast for this class is based on its historical usage characteristics.

6. **Total Sales to Ultimate Customer**

Sales forecasts by revenue class are summed to produce a total sales forecast.

7. **Sales for Resale**

Sales for resale (wholesale) customers are composed of municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers. Currently there are six customers in this class: the Florida Keys Electric Cooperative; City of Key West; Metro-Dade County; Lee County Electric

Cooperative; Wauchula; and Blountstown. In addition, FPL will begin making sales to Seminole Electric Cooperative in June 2014 under a long term agreement[3].

Beginning in May 2011, FPL began providing service to the Florida Keys Electric Cooperative under a long-term full requirements contract. Previously FPL was serving the Florida Keys under a partial requirements contract. The sales to Florida Keys Electric Cooperative are based on customer-supplied information and historical load factors.

FPL's sales to the City of Key West are expected to terminate in 2013. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor.

Metro-Dade County sells 60 MW to Progress Energy Florida. Line losses are billed to Metro-Dade under a wholesale contract. This contract expires in 2013.

Lee County has contracted with FPL for FPL to supply a portion of their load through 2013, then to begin serving their entire load beginning in 2014. This contract began in January 2010. Lee County provides a forecast of their sales by delivery point which is used to derive their sales forecast.

FPL's sales to Wauchula began in October 2011 and will continue through December 2016.

Blountstown became an FPL wholesale customer in May 2012. FPL's contract with Blountstown expires in April 2017.

A new contract with Seminole Electric Cooperative is included in the forecast which includes delivery of 200 MW beginning in June 2014 and continuing through May 2021.

II.D. Net Energy for Load (NEL)

An econometric model is developed to produce a NEL per customer forecast. The inputs to the model include Florida real per capita income weighted by the percent of the

[3]FPL is currently evaluating the possibility of serving the electrical loads of several entities (including Lake Worth) at the time the 2013 Site Plan is being prepared. Because these possibilities are still being evaluated, the load forecast presented in this Site Plan does not include these potential loads.

population employed, and a proxy for energy prices. The model also includes three weather variables: cooling degree-hours, winter heating degree-days, and heating degree-days based on 45° F. In addition, the model also includes variables for energy efficiency standards and a variable designed to capture the impact of empty homes. Seasonal dummy variables are included for the months of February, April, June, September, and November and the specific months of March 2003, May 2004, and November 2005. There is also an autoregressive term in the model.

The energy efficiency variable is included to capture the impacts of the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the savings occurring from the use of compact fluorescent bulbs. The impact of these savings began in 2005 and their cumulative impact on NEL is expected to reach 11,850 GWH by 2022. This reduction is inclusive of engineering estimates and any resulting behavioral changes. The cumulative 2022 reduction from these energy efficiency standards effectively reduces FPL's NEL for that year by 8.3%. On an incremental basis, net of the reduction already experienced through 2012, the reduction in 2022 is expected to reach 7,883 GWH.

The decline in the number of empty homes resulting from the current housing recovery has affected use per customer and is captured in a separate variable. The forecast was also adjusted for additional load estimated from hybrid vehicles, beginning in 2013, which resulted in an increase of approximately 1,408 GWH by the end of the ten-year reporting period. Other adjustments to the forecast include incremental load resulting from FPL's economic development riders which will impact the forecast beginning in 2013, and result in an increase, on average, of 418 GWH per year between 2013 and 2022, and incremental load from the acquisition of the Vero Beach electric system. The Vero Beach acquisition will add, on average, 824 GWH per year between 2014 and 2022.

The NEL forecast is developed by first multiplying the NEL per customer forecast by the total number of customers forecasted (excluding the customers formerly served by Vero Beach) and then adjusting the forecasted results for the expected incremental load resulting from hybrid vehicles, new wholesale contracts, the Vero Beach acquisition, and FPL's economic development riders. Once the NEL forecast is obtained, total billed sales are computed using a historical ratio of sales to NEL. The sales by class forecasts previously discussed are then adjusted to match the total billed sales. The forecasted NEL values for 2013 - 2022 are presented in Schedule 3.3 that appears at the end of this chapter.

II.E. System Peak Forecasts

The rate of absolute growth in FPL system peak load has been a function of the size of the customer base, varying weather conditions, projected economic conditions, changing patterns of customer behavior, and more efficient appliances and lighting. FPL developed the peak forecast models to capture these behavioral relationships. In addition, FPL's peak forecast also reflects changes in load expected a result of the acquisition of Vero Beach, changes in wholesale contracts, and the expected number of hybrid vehicles.

The savings from energy efficiency standards incorporated into the peak forecast include the impacts from the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the use of compact fluorescent light bulbs. The impact from these energy efficiency standards began in 2005 and their cumulative impact on the Summer peak is expected to reach 2,898 MW by 2022. This reduction is inclusive of engineering estimates and any resulting behavioral changes. The cumulative 2022 impact from these energy efficiency standards effectively reduces FPL's Summer peak for that year by 10%. On an incremental basis, net of the reduction already experienced through 2012, the impact on the Summer peak from these energy efficiency standards is expected to reach 1,826 MW in 2022. By 2022, the Winter peak is expected to be reduced by 1,650 MW as result of the cumulative impact from these energy efficiency standards since 2005. On an incremental basis, net of the reduction already experienced through 2012, the impact on the Winter peak from these energy efficiency standards is expected to reach 1,126 MW in 2022.

The forecast was also adjusted for additional load estimated from hybrid vehicles which resulted in an increase of approximately 357 MW in the Summer and 151 MW in the Winter by the end of the ten-year reporting period and for the acquisition of the Vero Beach electric system. The Vero Beach acquisition will add 181 MW to the Summer peak, and 201 MW to the Winter peak, forecast by the end of the ten-year reporting period.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2013 – 2022 are presented at the end of this chapter in Schedules 3.1 and 3.2, and in Chapter III in Schedules 7.1 through 7.4.

1. System Summer Peak

The Summer peak forecast is developed using an econometric model. The variables included in the model are the 3-month average CPI for Energy, Florida real per capita disposable income, cooling degree-hours in the day prior to the peak, the maximum temperature on the day of the peak, a dummy variables for the year 1994, a variable for energy efficiency standards, and a moving average term. The model is based on the Summer peak contribution per customer which is multiplied by total customers (excluding the customers that have been served by Vero Beach), and adjusted to account for incremental loads resulting from hybrid vehicles, new wholesale contracts, the Vero Beach acquisition, and FPL's economic development riders to derive FPL's system Summer peak.

2. System Winter Peak

Like the system Summer peak model, this model is also an econometric model. The model consists of two weather-related variables: the minimum temperature on the peak day and heating degree-hours for the prior day squared. The model also includes a dummy variable for Winter peaks occurring on weekends and a dummy variable for the year 2008. The forecasted results are adjusted for the impact of energy efficiency standards. The model is based on the Winter peak contribution per customer which is multiplied by total customers (excluding the customers that have been served by Vero Beach), and then adjusted for the expected incremental loads resulting from hybrid vehicles, new wholesale contracts, the Vero Beach acquisition, and FPL's economic development riders.

3. Monthly Peak Forecasts

The forecasting process for monthly peaks consists of the following actions:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to the appropriate seasonal peak.

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.F. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2013 - 2022 are produced using a System Load Forecasting "shaper" program. This model uses years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model generates a projection of hourly load values based on these load shapes and the forecast of monthly peaks and energy.

II.G. Uncertainty

In order to address uncertainty in the forecasts of aggregate peak demand and NEL, FPL first evaluates the assumptions underlying the forecasts. FPL takes a series of steps in evaluating the input variables, including comparing projections from different sources, identifying outliers in the series, and assessing the series' consistency with past forecasts. As needed, FPL reviews additional factors which may affect the input variables.

Uncertainty is also addressed in the modeling process. Generally, econometric models are used to forecast the aggregate peak demand and NEL. During the modeling process, the relevant statistics (goodness of fit, F-statistic, P-values, mean absolute deviation (MAD), mean absolute percentage error (MAPE), etc.) are scrutinized to ensure that the models adequately explain historical variation. Once a forecast is developed, it is compared with past forecasts. Deviations from past forecasts are examined in light of changes in input assumptions to ensure that the drivers underlying the forecast are well understood. Finally, forecasts of aggregate peak demand and NEL are compared with the actual values as these become available. An ongoing process of variance analyses is performed. To the extent that the variance analysis identifies large unexplained deviations between the forecast and actual values, revisions to the econometric model may be considered.

The inherent uncertainty in load forecasting is addressed in different ways in regard to FPL's overall resource planning and operational planning work. In regard to FPL's resource planning work, FPL's utilization of a 20% reserve margin criterion (approved by the FPSC) is designed, in part, to maintain reliable electric service to FPL's customers in light of forecasting uncertainty. In addition, banded forecasts of the projected Summer peak and net energy for load are produced based on an analysis of past forecasting errors. In regard to operational planning, a banded forecast for the projected Summer and Winter peak days is developed based on the historical weather variations. These bands are then used to develop similar bands for the monthly peaks.

II.H. DSM

The effects of FPL's DSM energy efficiency programs implementation through August 2012 are assumed to be imbedded in the actual usage data for forecasting purposes. The impacts of incremental energy efficiency that FPL plans to implement in the future, plus the cumulative and projected incremental impacts of FPL's load management programs, are accounted for as "line item reductions" to the forecasts as part of the IRP process as shown in Chapter III in Schedules 7.1 through 7.4. After making these adjustments to the load forecasts, the resulting "firm" load forecast is then used in FPL's IRP work.

Schedule 2.1
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2003	8,079,316	2.21	53,485	3,652,663	14,643	41,425	444,650	93,163
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,620,855	2.21	54,570	3,906,267	13,970	44,487	478,867	92,901
2007	8,729,806	2.19	55,138	3,981,451	13,849	45,921	493,130	93,121
2008	8,771,694	2.20	53,229	3,992,257	13,333	45,561	500,748	90,987
2009	8,732,591	2.19	53,950	3,984,490	13,540	45,025	501,055	89,860
2010	8,762,399	2.19	56,343	4,004,366	14,070	44,544	503,529	88,464
2011	8,860,158	2.20	54,642	4,026,760	13,570	45,052	508,005	88,685
2012	8,948,850	2.21	53,434	4,052,174	13,187	45,220	511,887	88,340

Historical Values (2003 - 2012):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent actual energy sales including the impacts of existing conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.1
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2013	8,987,099	2.20	54,824	4,085,045	13,421	46,019	519,848	88,523
2014	9,162,108	2.20	56,113	4,164,594	13,474	47,387	528,330	89,691
2015	9,284,559	2.20	57,122	4,220,254	13,535	48,441	537,176	90,178
2016	9,418,917	2.20	57,976	4,281,326	13,542	49,579	546,026	90,799
2017	9,557,516	2.20	58,469	4,344,325	13,459	50,224	554,623	90,555
2018	9,696,552	2.20	59,084	4,407,524	13,405	50,912	562,886	90,449
2019	9,834,273	2.20	59,668	4,470,124	13,348	51,493	570,924	90,193
2020	9,967,411	2.20	60,439	4,530,641	13,340	52,250	578,931	90,252
2021	10,092,586	2.20	61,011	4,587,539	13,299	52,858	586,989	90,049
2022	10,217,742	2.20	61,832	4,644,428	13,313	53,676	595,193	90,182

Projected Values (2013 - 2022):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent forecasted energy sales that do not include the impact of incremental conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.2
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads	Street &	Sales to	Sales to
		Average	Average kWh	&	Highway	Public	Ultimate
		No. of	Consumption	Railways	Lighting	Authorities	Consumers
Year	GWh	Customers	Per Customer	GWh	GWh	GWh	GWh
2003	4,004	17,029	235,135	93	425	64	99,496
2004	3,964	18,512	214,139	93	413	58	99,095
2005	3,913	20,392	191,873	95	424	49	102,296
2006	4,036	21,211	190,277	94	422	49	103,659
2007	3,774	18,732	201,499	91	437	53	105,415
2008	3,587	13,377	268,168	81	423	37	102,919
2009	3,245	10,084	321,796	80	422	34	102,755
2010	3,130	8,910	351,318	81	431	28	104,557
2011	3,086	8,691	355,104	82	437	27	103,327
2012	3,024	8,743	345,871	81	441	25	102,226

Historical Values (2003 - 2012):

Col. (10) and Col.(15) represent actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.2
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
		Industrial		Railroads	Street &	Sales to	Sales to
		Average	Average kWh	&	Highway	Public	Ultimate
		No. of	Consumption	Railways	Lighting	Authorities	Consumers
Year	GWh	Customers	Per Customer	GWh	GWh	GWh	GWh
2013	2,936	8,909	329,522	93	453	26	104,350
2014	2,909	9,192	316,531	93	461	26	106,988
2015	2,892	9,734	297,117	93	468	25	109,042
2016	2,868	10,247	279,865	93	475	25	111,016
2017	2,830	10,594	267,174	93	482	25	112,123
2018	2,775	10,703	259,320	93	488	25	113,378
2019	2,726	10,667	255,544	93	494	24	114,498
2020	2,665	10,596	251,510	93	500	24	115,970
2021	2,598	10,520	246,957	93	505	24	117,089
2022	2,540	10,573	240,208	93	510	24	118,674

Projected Values (2013 - 2022):

Col. (10) and Col.(15) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2003	1,511	7,386	108,393	2,879	4,117,221
2004	1,531	7,467	108,093	3,029	4,224,509
2005	1,506	7,498	111,301	3,156	4,321,895
2006	1,569	7,909	113,137	3,218	4,409,563
2007	1,499	7,401	114,315	3,276	4,496,589
2008	993	7,092	111,004	3,348	4,509,730
2009	1,155	7,394	111,303	3,439	4,499,067
2010	2,049	7,870	114,475	3,523	4,520,328
2011	2,176	6,950	112,454	3,596	4,547,051
2012	2,237	6,403	110,866	3,645	4,576,449

Historical Values (2003 - 2012):

Col. (19) represents actual energy sales including the impacts of existing conservation.

Col. (19) = Col. (16) + Col. (17) + Col. (18). Historical NEL includes the impacts of existing conservation and agrees to Col. (5) on schedule 3.3. Historical GWH, prior to 2011, are based on a fiscal year beginning 12/29 and ending 12/28. The 2011 value is based on 12/29/10 to 12/31/11. The 2012 value is based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 2.3
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2013	2,174	6,512	113,036	3,707	4,617,509
2014	4,924	6,806	118,718	3,763	4,705,879
2015	5,573	6,730	121,345	3,817	4,770,981
2016	5,620	6,817	123,453	3,867	4,841,466
2017	5,593	6,870	124,586	3,913	4,913,456
2018	5,636	6,944	125,957	3,958	4,985,069
2019	5,696	7,006	127,200	3,999	5,055,714
2020	5,763	7,095	128,829	4,039	5,124,207
2021	5,342	7,112	129,543	4,075	5,189,124
2022	5,059	7,231	130,965	4,110	5,254,304

Projected Values (2013 - 2022):

Col. (19) represents forecasted energy sales that do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

Col. (19) = Col. (16) + Col. (17) + Col. (18). These values are based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 3.1
History of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2003	19,668	253	19,415	0	892	798	577	554	18,200
2004	20,545	258	20,287	0	894	846	588	577	19,063
2005	22,361	264	22,097	0	902	895	600	611	20,858
2006	21,819	256	21,563	0	928	948	635	640	20,256
2007	21,962	261	21,701	0	952	982	716	683	20,295
2008	21,060	181	20,879	0	966	1,042	760	706	19,334
2009	22,351	249	22,102	0	981	1,097	811	732	20,558
2010	22,256	419	21,837	0	990	1,181	815	758	20,451
2011	21,619	427	21,192	0	1,000	1,281	821	781	19,798
2012	21,440	425	21,015	0	1,027	1,328	827	797	19,586

Historical Values (2003 - 2012):

Col. (2) - Col. (4) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) represent actual DSM capabilities starting from January 1988 and are annual (12-month) values except for 2012 values which are through August.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.1
Forecast of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
August of Year	Total	Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2013	21,790	399	21,391	0	1,056	64	854	32	19,785
2014	22,928	1,184	21,744	0	1,072	128	889	64	20,775
2015	23,359	1,191	22,168	0	1,081	194	907	96	21,080
2016	23,733	1,197	22,536	0	1,090	261	925	128	21,329
2017	24,122	1,182	22,940	0	1,099	327	943	160	21,593
2018	24,493	1,189	23,304	0	1,109	393	961	192	21,839
2019	24,901	1,196	23,705	0	1,118	459	979	224	22,121
2020	25,302	1,203	24,099	0	1,127	506	996	250	22,422
2021	25,560	1,010	24,550	0	1,136	557	1,014	273	22,580
2022	26,105	1,017	25,088	0	1,145	608	1,032	295	23,025

Projected Values (2013 - 2022):

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected August values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC.

Schedule 3.2
History of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2003	20,190	246	19,944	0	802	546	453	206	18,935
2004	14,752	211	14,541	0	813	567	534	227	13,405
2005	18,108	225	17,883	0	816	583	542	233	16,751
2006	19,683	225	19,458	0	823	600	550	240	18,311
2007	16,815	223	16,592	0	846	620	577	249	15,392
2008	18,055	163	17,892	0	868	644	636	279	16,551
2009	20,081	207	19,874	0	881	666	676	285	18,524
2010	24,346	500	23,846	0	895	687	721	291	22,730
2011	21,126	383	20,743	0	903	717	723	303	19,501
2012	17,934	382	17,552	0	856	755	722	314	16,356

Historical Values (2003 - 2012):

Col. (2) - Col. (4) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand. For year 2011, the actual peaked occurred in December of 2010.

Col. (5) - Col. (9) for 2003 through 2012 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.2
Forecast of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
January of Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2013	20,270	410	19,860	0	863	27	578	12	18,790
2014	21,593	941	20,652	0	880	66	603	23	20,022
2015	22,154	1,142	21,012	0	887	108	612	33	20,513
2016	22,430	1,143	21,287	0	895	151	621	44	20,719
2017	22,662	1,130	21,532	0	902	193	630	55	20,882
2018	22,898	1,123	21,775	0	910	235	638	66	21,049
2019	23,125	1,123	22,002	0	917	278	647	76	21,207
2020	23,356	1,124	22,233	0	924	311	656	85	21,380
2021	23,601	1,125	22,476	0	932	341	665	93	21,571
2022	23,670	925	22,745	0	939	371	673	100	21,587

Projected Values (2013 - 2022):

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected January values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC.

Schedule 3.3
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1) Year	(2) Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) **Actual** Net Energy For Load GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Total Billed Retail Energy Sales (GWh)	(9) Load Factor(%)
2003	111,784	1,773	1,619	108,393	1,511	7,386	99,496	62.9%
2004	111,659	1,872	1,693	108,093	1,531	7,467	99,095	60.1%
2005	115,065	1,970	1,793	111,301	1,506	7,498	102,296	56.8%
2006	117,116	2,078	1,901	113,137	1,569	7,909	103,659	59.2%
2007	118,518	2,138	2,066	114,315	1,499	7,401	105,415	59.4%
2008	115,379	2,249	2,126	111,004	993	7,092	102,919	60.2%
2009	115,844	2,345	2,196	111,303	1,155	7,394	102,755	56.8%
2010	119,220	2,487	2,259	114,475	2,049	7,870	104,557	58.7%
2011	117,460	2,683	2,324	112,454	2,176	6,950	103,327	59.4%
2012	116,083	2,823	2,394	110,866	2,237	6,403	102,226	59.0%

Historical Values (2003 - 2012):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5).

Col. (3) & Col. (4) are DSM values starting in January 1988 and are annual (12-month) values. Col. (3) and Col. (4) for 2012 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWh reductions experienced each year .

Col. (5) is the actual Net Energy for Load (NEL) for years 2003 - 2012.

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 3.3
Forecast of Annual Net Energy for Load (GWh)
(All values are "at the generator"values except for Col (8))

(1) Year	(2) **Forecasted** Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Net Energy For Load Adjusted for DSM GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) **Forecasted** Total Billed Retail Energy Sales w/o DSM GWh	(9) Load Factor(%)
2013	113,036	48	26	112,962	2,174	6,512	104,350	59.2%
2014	118,718	147	78	118,493	4,924	6,806	106,988	59.1%
2015	121,345	248	131	120,966	5,573	6,730	109,042	59.3%
2016	123,453	348	186	122,919	5,620	6,817	111,016	59.2%
2017	124,586	449	241	123,896	5,593	6,870	112,123	59.0%
2018	125,957	549	296	125,112	5,636	6,944	113,378	58.7%
2019	127,200	650	351	126,199	5,696	7,006	114,498	58.3%
2020	128,829	730	406	127,692	5,763	7,095	115,970	58.0%
2021	129,543	801	450	128,292	5,342	7,112	117,089	57.9%
2022	130,965	871	488	129,605	5,059	7,231	118,674	57.3%

Projected Values (2013 - 2022):

Col. (2) represents Forecasted Net Energy for Load and does not include incremental DSM from 2013 - on. The Col. (2) values are extracted from Schedule 2.3, Col(19). The effects of conservation implemented prior to September 2012 are incorporated into the load forecast values in Col. (2).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation from Jan 2013 - on and are mid-year (6-month) values reflecting DSM signups occurring evenly thoughout each year.

Col. (5) is the forecasted Net Energy for Load (NEL) after adjusting for impacts of incremental DSM for years 2013 - 2022 using the formula:
Col. (5) = Col. (2) - Col. (3) - Col. (4)

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7).
These values are at the meter.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of
Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2012 Actual		2013 FORECAST		2014 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	17,934	7,979	20,270	8,426	21,593	8,842
FEB	16,228	7,702	16,551	7,547	17,632	7,942
MAR	16,310	8,640	16,717	8,499	17,808	8,903
APR	18,108	8,509	17,342	8,649	18,247	9,030
MAY	19,981	9,895	19,375	9,962	20,386	10,378
JUN	20,351	10,243	20,696	10,378	21,776	10,873
JUL	21,343	11,226	21,277	11,228	22,387	11,748
AUG	21,440	11,203	21,790	11,266	22,928	11,792
SEP	19,711	10,234	20,993	10,471	22,089	11,005
OCT	19,337	9,654	19,654	9,812	20,680	10,351
NOV	14,282	7,423	18,105	8,309	18,576	8,829
DEC	16,025	8,157	18,008	8,489	18,476	9,026
Annual Values:		**110,866**		**113,036**		**118,718**

Col. (3) annual value shown is consistent with value shown in Col.(5) of Schedule 3.3.

Cols. (4) - (7) do not include the impacts of cumulative load management, incremental conservation, and incremental load management.

Cols. (5) and Col. (7) annual values shown are consistent with values shown in Col.(2) of Schedule 3.3.

CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL utilizes its well established integrated resource planning (IRP) process in whole or in part as analysis needs are warranted, to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of new power plants, the primary subjects of this document, are determined as part of the IRP process work.

This section describes FPL's basic IRP process. Some of the key assumptions, in addition to a new load forecast, that were used in developing the resource plan presented in this Site Plan are also discussed.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental steps to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Evaluate the competing options and resource plans in regard to system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process

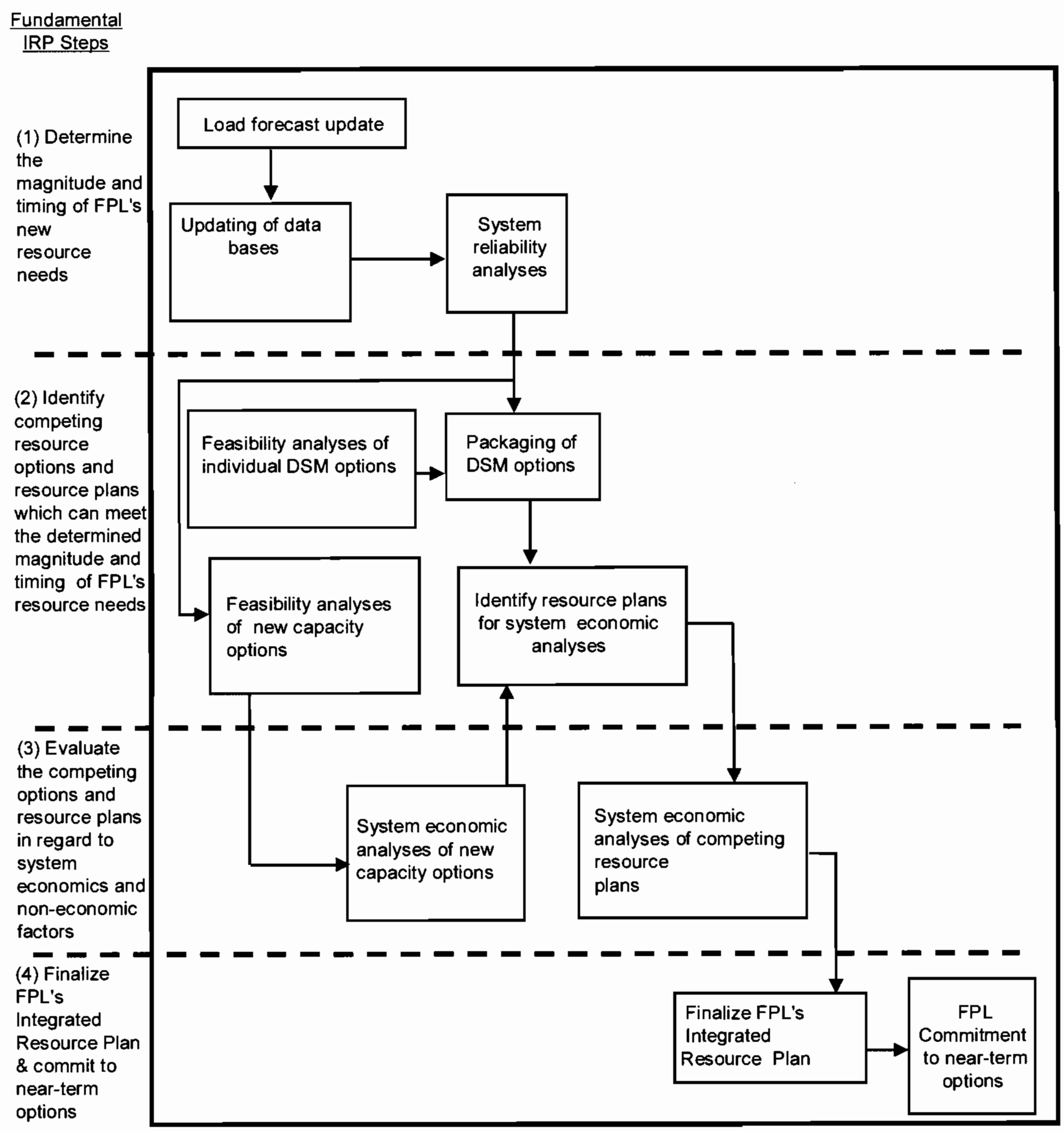

Figure III.A.1: Overview of FPL's IRP Process

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of the four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed to maintain system reliability. Also determined in this step is when the MW additions are needed to meet FPL's reliability criteria. This step is often referred to as a reliability assessment, or resource adequacy, analysis for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include, but are not limited to: delivered fuel price projections, current financial and economic assumptions, and power plant capability and operating assumptions. FPL also includes key assumptions regarding three specific resource areas: (1) near-term construction capacity additions, (2) firm capacity power purchases, and (3) demand side management (DSM) implementation.

The first of these assumptions is based on new generating capacity additions that have been approved by the Florida Public Service Commission (FPSC) either through Determination of Need proceedings that evaluated both the need for, and the cost-effectiveness of, each of the new capacity additions or through other FPSC dockets. These generating capacity additions have also either received the necessary Site Certification approvals from either the Secretary of the Florida Department of Environmental Protection (FDEP) or the Governor and Cabinet (acting as the Siting Board), or these approvals have been applied for. There is also work in progress to obtain the necessary federal and state licenses, permits, and approvals for construction and operation of two new nuclear units. The earliest practical deployment date for the first of the two new nuclear units, Turkey Point Unit 6, is currently projected to be 2022, a date within the reporting period of this Site Plan.

These generating capacity additions include:

- The completion of the extended power uprates (EPU) project at FPL's existing Turkey Point Unit 4 nuclear unit. Similar EPU projects were completed during 2012 at FPL's three other existing nuclear power plants (St. Lucie Units 1 & 2 and Turkey Point Unit 3). The completion of the EPU project at Turkey Point Unit 4 is projected to add approximately 115 MW of incremental nuclear capacity and the total incremental nuclear capacity from the EPU project for all four nuclear plants is projected to be more than 500 MW. The FPSC approved the need for the EPU project in April 2008.

- Two existing generating plant sites, each featuring two older fossil fuel-fired steam generating units, are currently in the process of being modernized. The steam generating units originally at these sites have been removed and are in the process of being replaced with one new, highly efficient combined cycle (CC) unit at each site. The new CC plant at FPL's Cape Canaveral site is projected to be placed in-service in mid-2013. This new CC unit (called the Cape Canaveral Next Generation Clean Energy Center (CCEC)) is projected to have a peak Summer output of 1,210 MW. The new CC unit at FPL's Riviera Beach site (called the Riviera Beach Next Generation Clean Energy Center (RBEC)) is projected to be placed in-service in mid-2014 and it is expected to have a peak Summer output of 1,212 MW. These modernizations were approved by the FPSC in September 2008. The site certification application for Cape Canaveral was granted in October 2009. The site certification application for Riviera Beach was granted in November 2009.
- Similar to the two modernization projects mentioned above, the four existing steam units at the Port Everglades site are being removed and will be replaced with a new highly efficient CC unit. Two of these four existing steam units were removed in the fourth quarter of 2012 and the other two steam units are projected to be removed in the first half of 2013. The new generating unit, called the Port Everglades Next Generation Clean Energy Center (PEEC), is projected to be in-service in mid-2016 and is projected to have a peak Summer output of 1,277 MW. The FPSC provided the final need order for this modernization project on April 9th, 2012. The site certification application for Port Everglades was granted in October 2012.
- In the fourth quarter of 2011, FPL started upgrading the 7FA combustion turbines (CT) that are components at a number of its existing CC units. These upgrades will economically benefit FPL's customers by increasing the MW output of these CC units by approximately 228 MW (Summer peak value) in total. As reflected in Schedule 1 in Chapter I, 70 MW of the increased capacity from these CT upgrades is already in service. The work for the remaining upgrades is continuing and the project is projected to be completed in 2015.
- FPL is continuing its work to obtain all of the licenses, permits, and approvals that will be necessary to construct and operate two new nuclear units at its Turkey Point site. These licenses, permits, and approvals will provide FPL with the opportunity to

construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. FPL received need determination approval from the FPSC for the two nuclear units in April 2008 in Order No. PSC-08-0237-FOF-EI. The earliest practical deployment dates for the first of these two new units, Turkey Point Unit 6, is currently projected to be 2022. This new nuclear unit is projected to have a peak Summer output of 1,100 MW.

- As part of FPL's acquisition of Vero Beach's electric utility system, FPL will take ownership of Vero Beach's five existing generating units starting January 2014. The current plan is to immediately retire three of these older generating units and operate the remaining two, which supply approximately 44 MW (Summer) of combined cycle capacity, for a maximum of three years.

These new generating units and generating capacity additions were selected for a variety of reasons including cost-effectiveness, significant system fuel savings, fuel diversity, mitigation of regional generation/load imbalances, and significant system emission reductions, including greenhouse gas emission reductions.

The second of these assumptions involves firm capacity power purchases. FPL's current projection of firm capacity purchases has changed from the projection in the 2012 Site Plan. FPL's current projection includes an additional 70 MW from the Palm Beach Solid Waste Authority (SWA) starting in year 2015 which is a year earlier than projected in the 2012 Site Plan. Also, FPL now projects that its purchase agreement with Jacksonville Electric Authority (JEA) for St. Johns Regional Power Park (SJRPP)-based capacity and energy will allow FPL to continue to receive purchased capacity and energy until November 2017. At that time, FPL projects that Internal Revenue Service (IRS) regulations regarding the amount of energy that FPL can receive will result in the suspension of any further capacity and energy by FPL.[4] As part of the agreement that FPL will begin serving Vero Beach's electrical needs beginning in January 2014, FPL has acquired two existing power purchase agreements totaling approximately 37 MW of coal-fired capacity. These agreements will run through the end of 2016. In addition, FPL projects that it will begin receiving a total of 180 MW of firm capacity in 2021 from biomass-based power purchase agreements with EcoGen.

[4] FPL's projected suspension date for the SJRPP purchase is based on a system reliability perspective and represents the earliest projected date at which the suspension of capacity and energy could occur.

In total, the projected firm capacity purchases are from a combination of utility and independent power producers. Details, including the annual total capacity values for these purchases, are presented in Chapter I in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's resource planning work.

The third of these assumptions involves a projection of the amount of additional DSM that is anticipated to be implemented annually over the ten-year period. Since 1994, FPL's resource planning work has assumed that, at a minimum, the DSM MW called for in FPL's approved DSM Plan will be achieved. The resource plan presented in FPL's 2013 Site Plan fully accounts for the annual DSM implementation direction provided by the FPSC in 2011 that addresses the years through 2019. In addition, for planning purposes in this document, FPL also assumes an additional 100 MW per year of DSM for the remaining years addressed in this Site Plan, 2020 through 2022.

These key assumptions, plus the other updated information described above, are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's future resource needs. This determination is accomplished by system reliability analyses which for FPL have traditionally been based on dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry.

Historically, two types of methodologies, deterministic and probabilistic, have been utilized in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Among the most widely used is loss-of-load probability (LOLP) which FPL utilizes. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of the "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

The result of the first fundamental step of resource planning is a projection of how many new MW of resources are needed to meet both reserve margin and LOLP criteria, and thus maintain system reliability, and when the MW are needed. Information regarding the timing and magnitude of these resource needs is then used in the second fundamental step: identifying resource options and resource plans that can meet the determined magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, preliminary economic screening analyses of new capacity options that are identical, or virtually identical, in regard to certain key characteristics may be conducted to determine which new capacity options appear to be the most competitive on FPL's system. This preliminary analysis work can also help identify capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. Similarly, preliminary economic screening analyses of new DSM options and/or continued growth in existing DSM options are often conducted.

FPL typically utilizes the P-MArea production cost model and a Fixed Cost Spreadsheet, and/or the Strategist model, as well as spreadsheet analyses, to perform the preliminary economic screening of generation resource options. For the preliminary economic screening analyses of DSM resource options, FPL typically uses its DSM cost-effectiveness model which is an FPL spreadsheet model utilizing the FPSC's approved methodology for performing preliminary cost-effectiveness screening of individual DSM measures and programs. FPL also utilizes its non-linear programming model for analyzing the potential for lowering system peak loads through additional load management/demand response capability. Then FPL typically utilizes its linear programming model to develop DSM portfolios that are subsequently used in developing resource plans for final system analyses of DSM-based resource plans.

The individual new resource options emerging from these preliminary economic screening analyses are then typically "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's projected new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet and/or dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans in Regard to System Economics and Non-Economic Factors:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for evaluating these resource options and resource plans in final, or system, economic analyses that attempt to account for all of the impacts to the FPL system from the competing resource options/resource plans. (A number of these system impacts are typically not accounted for in preliminary economic screening analyses.) In FPL's 2012 and early 2013 resource planning work, once the resource plans were developed, FPL utilized the P-MArea production cost model and a Fixed Cost Spreadsheet, and/or the Strategist model, to perform the system economic analyses.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM methodology). In cases in which the DSM contribution was assumed as a given and the only competing options were new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and resource plans in such cases can be evaluated on a system cumulative present value revenue requirement (CPVRR) basis.

Other factors are also included in FPL's evaluation of resource options and resource plans. While these factors may have an economic component or impact, they are often discussed in quantitative, but non-economic, terms such as percentages, tons, etc. rather than in terms of dollars. These factors are often referred to by FPL as "system concerns" that include (but are not limited to) maintaining/enhancing fuel diversity in the FPL system, system emission levels, and maintaining a regional balance between load and generating capacity, particularly in the Southeastern Florida counties of Miami-Dade and Broward. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL's system, the non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan. These, and other, factors are discussed later in this chapter in section III.C.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps are typically used to develop the current resource plan. This plan is presented in the following section.

III.B Projected Incremental Resource Additions/Changes

FPL's projected incremental generation capacity additions/changes for 2013 through 2022 are depicted in Table III.B.1. These capacity additions/changes result from a variety of actions that primarily consist of: (i) changes to existing units (which are frequently achieved as a result of plant component replacements during major overhauls and through other uprates to existing capacity), (ii) changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, (iii) the modernizations of FPL's existing Cape Canaveral, Riviera Beach, and Port Everglades sites by the removal of the steam generating units that were previously, or are currently, on the sites and the addition of one new, very fuel-efficient CC generating unit at each site, (iv) upgrades to the CTs at a number of existing combined cycle plants, (v) the switching of Turkey Point 1 and 2 from generation to synchronous condenser operation, and (vi) the addition of the new Turkey Point Unit 6 nuclear unit in 2022 (i.e., the year currently projected at the time this document is being finalized to be the earliest practical in-service date for this new nuclear unit).

Although the DSM additions that are consistent with the FPSC's directions regarding FPL's DSM program implementation are not explicitly presented in this table, these DSM additions have been fully accounted for in all of FPL's resource planning work reflected in this document. The FPSC's directions regarding FPL's DSM program implementation address the years through 2019. For planning purposes in this document, FPL currently projects an additional 100 MW (Summer) of DSM per year for the subsequent three years (2020 through 2022) addressed in this Site Plan. In addition, the projected MW reductions from these DSM additions are reflected in the projected reserve margin values shown in the table below and in Schedules 7.1 and 7.2 presented later in this chapter. (Subsequent analyses, particularly analyses that will be conducted in preparation for the 2014 DSM Goals docket, will ultimately determine the actual levels of DSM that FPL should implement in the 2015 through 2022 time frame.)

Table III.B.1: Projected Capacity Changes for FPL

Projected Capacity Changes for FPL (1)			
		Net Capacity Changes (MW)	
Year	**Projected Capacity Changes**	**Winter (2)**	**Summer (3)**
2013	Changes to Existing Purchases (4)	(545)	(425)
	Port Everglades Units 3 & 4 retired for Modernization	(765)	(761)
	Turkey Point Unit 2 operation changed to synchronous condenser	(394)	(392)
	Sanford Unit 5 CT Upgrade	---	9
	Turkey Point Unit 4 Uprate - Completed	---	115
	Turkey Point Unit 4 Uprate - Outage (5)	(717)	---
	Sanford Unit 4 CT Upgrade	---	16
	Manatee Unit 2	(3)	---
	Scherer Unit 4	(28)	---
	Cape Canaveral Next Generation Clean Energy Center (6)	---	1,210
	Manatee Unit 1 ESP - Outage (7)	(822)	---
	Martin Unit 1 ESP - Outage (7)	--	(826)
2014	Sanford Unit 5 CT Upgrade	19	10
	Cape Canaveral Next Generation Clean Energy Center (6)	1,355	---
	Changes to Existing Purchases (4)	22	37
	Manatee Unit 1 ESP - Outage (7)	822	---
	Sanford Unit 4 CT Upgrade	16	---
	Vero Beach Combined Cycle (8)	46	44
	Martin Unit 1 ESP - Outage (7)	(832)	826
	Martin Unit 2 ESP - Outage (7)	---	(826)
	Manatee Unit 3 CT Upgrade	---	19
	Turkey Point Unit 5 CT Upgrade	---	33
	Turkey Point Unit 4 Uprate - Completed (5)	115	---
	Riviera Beach Next Generation Clean Energy Center (6)	---	1,212
2015	Manatee Unit 3 CT Upgrade	39	20
	Martin Unit 1 ESP - Outage (7)	832	---
	Martin Unit 2 ESP - Outage (7)	---	826
	Turkey Point Unit 5 CT Upgrade	33	---
	Changes to Existing Purchases (4)	70	70
	Ft. Myers Unit 2 CT Upgrade	---	51
	Riviera Beach Next Generation Clean Energy Center (6)	1,344	---
2016	Changes to Existing Purchases (4)	(858)	(928)
	Ft. Myers Unit 2 CT Upgrade	51	---
	Port Everglades Next Generation Clean Energy Center (6)	---	1,277
2017	Turkey Point Unit 1 operation changed to synchronous condenser	(398)	(396)
	Changes to Existing Purchases (4)	(37)	(37)
	Vero Beach Combined Cycle (8)	(46)	(44)
	Port Everglades Next Generation Clean Energy Center (6)	1,429	---
2018	Changes to Existing Purchases (4)	(388)	(381)
2019	---	---	---
2020	---	---	---
2021	Changes to Existing Purchases (4)	180	180
2022	Turkey Point Nuclear Unit 6 (6)	---	1,100

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are forecasted values for January of the year shown.
(3) Summer values are forecasted values for August of the year shown.
(4) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(5) Outages for uprate work.
(6) All new unit additions are scheduled to be in-service in June of the year shown. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.
(7) Outages for ESP work.
(8) This unit will be added as part of the agreement that FPL will serve Vero Beach's electric load starting January, 2014. This unit is expected to be retired within 3 years.

III.C Discussion of the Projected Resource Plan and Issues Impacting FPL's Resource Planning Work

As indicated in the Executive Summary, FPL's resource planning efforts in 2012 and early 2013 were influenced by a number of factors. These factors are expected to continue to influence FPL's resource planning work for the foreseeable future. In addition, other factors may also influence FPL's on-going resource planning work in the future and may result in changes to the resource plan discussed in this document. Eight (8) of these factors are discussed below (in no particular order of importance).

1) Maintaining/enhancing fuel diversity in the FPL system;
2) Maintaining a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward Counties;
3) FPL will begin to provide electric service to Vero Beach;
4) The projected impacts of mandated energy efficiency standards;
5) FPL's growing dependence upon DSM resources to maintain system reliability;
6) The Nuclear Regulatory Commission's schedule for reviewing applications for Combined Operating Licenses for new nuclear units;
7) Environmental regulation and/or legislation; and,
8) Possible establishment of "Clean Energy Standards" or another mechanism to promote large scale utilization of renewable energy.

These 8 factors, and their various impacts on FPL's resource planning efforts including the current resource plan that is presented in this Site Plan, are briefly discussed below.

1. Maintaining/Enhancing System Fuel Diversity;

FPL is currently dependent upon using natural gas to generate approximately 2/3 of the total electricity it delivers to its customers. In the future, the percentage of FPL's electricity that is generated by natural gas is projected to increase. Therefore, FPL is continually seeking opportunities to maintain and enhance the fuel diversity of its system.

In 2007, following express direction by the Commission to do so, FPL sought approval from the FPSC to add two new advanced technology coal units to its system. These two new units would have been placed in-service in 2013 and 2014. However, in part due to concerns over potential greenhouse gas emission legislation/regulation, FPL was unable to obtain approval for these units. Several other factors are currently unfavorable to new coal units compared to new CC units. The first of these factors is a significant reduction in the fuel cost difference between coal and natural gas compared to the fuel cost difference projected in 2007 that favored coal; i.e., the projected cost advantage of coal versus natural gas has been significantly reduced. Second is the continuation of significantly higher capital costs for coal units compared to capital costs for CC units. Third is the increased fuel efficiency of new CC units compared to projected CC unit efficiencies in 2007. Fourth are the stricter environmental regulations, and the possibility of other environmental regulations that address greenhouse gas emissions, that are more unfavorable to new coal units than to new CC units. Consequently, FPL does not believe that new advanced technology coal units are currently economically, politically, or environmentally viable fuel diversity enhancement options in Florida.

Therefore, FPL has turned its attention to nuclear energy and renewable energy to enhance its fuel diversity and to using natural gas more efficiently. In regard to nuclear energy, in 2008 the FPSC approved the need to increase capacity at FPL's four existing nuclear units and authorized FPL to recover project-related expenditures that are approved as a result of annual nuclear cost recovery filings. In April of this year FPL will have completed this Extended Power Uprate (EPU) project and more than 500 MW of additional nuclear capacity will have been achieved to benefit FPL's customers.[5]

FPL is continuing its work to obtain all of the licenses, permits, and approvals that would be necessary to construct and operate two new nuclear units at its Turkey Point site in the future. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. At the time this document is being finalized, the earliest practical deployment date for the first of the two new nuclear units, Turkey Point Unit 6, is projected to be 2022.

FPL also has been involved in activities to investigate adding or maintaining renewable resources as a part of its generation supply. One of these activities is a

[5] The value for the increased capacity delivered by the EPU project will be known once the final testing at all of the four nuclear units is completed. At the time this document was being finalized, this testing had not yet been completed. However, for resource planning analysis purposes, a specific MW value is needed for calculations. For these analysis purposes, FPL is assuming the EPU project will have delivered a nominal 510 MW which equates to approximately 501 MW Summer and 516 MW Winter.

variety of discussions with the owners of existing facilities aimed at maintaining or extending current agreements that are scheduled to end during the ten-year reporting period of this document. As previously mentioned, FPL has recently signed power purchase agreements with EcoGen that will result in FPL receiving 180 MW of firm capacity from biomass facilities beginning in 2021.

FPL also sought and received approval from the FPSC in 2008 to add 110 MW through three new FPL-owned solar facilities: one solar thermal facility and two photovoltaic (PV) facilities. One 25 MW PV facility began commercial operation in 2009. The remaining two solar facilities, a 10 MW PV facility and a 75 MW solar thermal steam generating facility, began commercial operation in 2010. The addition of these renewable energy facilities was made possible due to enabling legislation from the Florida Legislature in 2008. FPL remains strongly supportive of Federal and/or State legislation that enables electric utilities to add renewable energy resources and authorize the utilities to recover appropriate costs for these resources.

In regard to using natural gas more efficiently, FPL received approvals in 2008 from the FPSC to modernize the existing Cape Canaveral and Riviera Beach plant sites with new, highly efficient CC units that replace the former steam generating units on each of those sites. The modernizations of Cape Canaveral and Riviera Beach are currently underway and are projected to go in-service on time in mid-2013 and mid-2014, respectively. On April 9th, 2012, FPL received FPSC approval to proceed with a similar modernization project at the Port Everglades site which is scheduled for completion in mid-2016. The modernization of Port Everglades will retain the capability of receiving water-borne delivery of oil as a backup fuel.

In regard to natural gas delivery, FPL issued a request for proposals (RFP) in December 2012 for new natural gas pipeline capacity into Florida and FPL's service territory. A third pipeline utilizing a new route would result in a more reliable, more economic, and more diverse natural gas supply for FPL's customers and the state of Florida. Proposals to this RFP are due in early April 2013.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity. Moreover, FPL is also maintaining the ability to utilize fuel oil at existing units that have that capability. In this regard, FPL is in the process of installing electrostatic precipitators (ESPs) at its four 800 MW steam generating units at the Martin and Manatee sites which will enable FPL to retain the ability to burn oil, as needed, at these sites while retaining the flexibility to use natural gas when economically attractive.

2. Maintaining a Balance Between Load and Generation in Southeastern Florida:

In recent years, an imbalance was projected to develop between regionally installed generation and regional peak load in Southeastern Florida. With such an imbalance, a significant amount of energy required in the Southeastern Florida region during peak periods would need to be provided either by operating less efficient generating units located in Southeastern Florida out of economic dispatch, or by importing the energy through the transmission system from plants located outside the region. FPL's prior planning work concluded that either additional installed generating capacity in this region, or additional installed transmission capacity capable of delivering more electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location, four recent capacity addition decisions (Turkey Point Unit 5 and WCEC Units 1, 2, & 3) were determined to be the most cost-effective options to meet FPL's capacity needs in the near-term. In addition, FPL has added increased capacity at FPL's existing two nuclear units at Turkey Point as part of the previously mentioned EPU project. The recently approved Port Everglades modernization project scheduled for completion in 2016 will also significantly aid in mitigating this imbalance. Adding the additional generation capacity through the projects mentioned above contributes to addressing the imbalance between generation and load in Southeastern Florida for approximately the remainder of this decade.

The planned addition of two new nuclear units at FPL's Turkey Point site, Turkey Point Unit 6 in 2022 and Turkey Point Unit 7 in 2023, will also address the imbalance issue for an additional period of time beginning in the next decade. Due to steadily increasing load in the Southeastern region, the Southeastern Florida imbalance issue will remain an important consideration in FPL's on-going resource planning work in future years.

3. FPL Will Begin to Provide Electric Service to Vero Beach:

FPL will begin serving Vero Beach's electrical load beginning January 1, 2014. An agreement to this effect was reached between Vero Beach and FPL on February 19, 2013, and a referendum was held on March 12, 2013 resulted in a majority of Vero Beach voters approving the agreement. The additional peak load that FPL will serve is projected to be 155 MW (Summer) in 2014 with additional growth in this peak load expected thereafter.

4. The Impacts of Mandated Energy Efficiency Standards:

Recent increases in the level of federal- and state-mandated energy efficiency standards for appliances, lighting, and other electric equipment began in 2005 with the passage of the National Energy Policy Act. These mandated efficiency standards have been periodically raised and extended since that time. FPL accounts for the impacts of these efficiency standards on projected peak load and annual energy usage in its load forecast.

The magnitude of efficiency that is being delivered to FPL's customers through these standards is significant. For example, by the year 2022, the cumulative impact of these standards since 2005 is expected to result in a reduction in FPL's Summer peak of approximately 2,900 MW compared to what the projected load would have been without the efficiency standards. This represents a decrease of approximately 10% in the forecasted Summer peak load for 2022. Likewise, FPL's forecasted net energy for load (NEL) in the year 2022 is projected to be approximately 11,850 GWh lower compared to what the projected NEL would have been without the efficiency standards. This represents a decrease of approximately 8% in the forecasted NEL for 2022.

In addition to lowering FPL's forecast from what it otherwise would have been, and thus lowering FPL's projected resource needs, this projection of increased efficiency from the efficiency standards also affects FPL's resource planning in another way. The mandated higher efficiency standards lower the potential for future MW and GWh reductions from FPL's demand side management (DSM) programs that address the specific appliances and equipment covered by the standards. FPL will take this fact into consideration in the aspects of its resource planning work that involve consideration of both the magnitude and type of DSM resources in its DSM portfolio.

5. FPL's Increasing Dependence On DSM Resources to Maintain System Reliability:

With its 2013 Site Plan, FPL continues to project that it will become increasingly dependent upon DSM resources to maintain system reliability. This projected trend has been previously discussed in FPL's 2011 and 2012 Site Plans. This trend is largely a result of two things: (1) high levels of DSM implementation by FPL required by the FPSC, and (2) relatively low growth in forecasted load.[6]

In regard to these two factors, in late 2009 the FPSC imposed significantly higher 10-year DSM Goals than had been deemed appropriate in previous DSM Goals dockets. For example, the 2009 Goals level was set at approximately 150 MW per year, almost double the previous 2004 Goals level of approximately 80 MW per year. The FPSC's 2011 DSM Plan decision subsequently lowered these required levels of DSM, but only by a relatively small amount to approximately 120-to-130 MW per year. As a consequence, FPL's resource planning is projecting DSM implementation of approximately 120-to-130 MW per year through the year 2019. During this time frame, FPL's projected load growth is considerably lower than the load growth projected when the 2004 Goals target of approximately 80 MW per year was set.

Consequently, DSM growth is projected to continue at a high level while FPL's projected load growth has slowed. As a result, the FPL system is becoming increasingly dependent upon DSM to maintain system reliability.

In its 2011 and 2012 Site Plans, FPL discussed this projected trend of increasing dependence upon DSM resources using a new type of reserve margin projection as an indicator: a "generation-only reserve margin" (gen-only RM). In calculating the values for this indicator, all of FPL's projected incremental load management and energy efficiency program capabilities, and its existing load management capability, are removed from the reserve margin calculation.

[6] Other contributing factors include the expiration of existing PPAs such as UPSR, the effective expiration of the SJRPP PPA, and the retirement of several older FPL generating units for economic reasons.

The resulting gen-only RM values indicate what FPL's reserve margin values are projected to be based solely on generation resources. The lower the gen-only RM values, the greater FPL's dependence is upon DSM resources.

The gen-only RM projections from the 2011 and 2012 Site Plans were presented in Schedules 7.3 and 7.4 in those Site Plans. These schedules consistently showed that FPL's gen-only RM values were projected to significantly decrease throughout the 10-year reporting period of those Site Plans, and to decline to single-digit values in the latter years of the reporting periods. These projections indicate a steadily growing dependence on DSM resources to maintain system reliability. Schedule 7.3 in this year's Site Plan, presented near the back of this chapter, shows a similar projection. FPL's gen-only RM is projected to be in the general range of 16.3% to 18.0% for the period of 2013 through 2016, then decrease steadily until 2021 when the projected gen-only RM value is 6.9%. In 2022, the projected gen-only RM value is 4.7% if potential delays (see discussion below) preclude FPL from bringing Turkey Point Unit 6 into service as currently planned in 2022. Schedule 7.4 presents the projection of FPL's gen-only RM after accounting for the planned addition of Turkey Point Unit 6 in 2022. This addition increases the projected gen-only RM value to 8.9%.

These consistent projections of increasing dependence on DSM resources to maintain system reliability are of concern to FPL because of the various voluntary aspects associated with customer participation in DSM programs, FPL believes that system reliability risk increases as dependence on DSM resources increases. Therefore, this issue will continue to be analyzed in FPL's on-going resource planning work.

6. The Nuclear Regulatory Commission's Schedule for Review of Applications for New Nuclear Units:

As the 2013 Site Plan is being finalized, it is unclear when the Nuclear Regulatory Commission (NRC) will issue a new schedule for its review of FPL's application for a Combined Operating License (COL) for the Turkey Point Units 6 & 7 nuclear units and the potential impact that revised schedule may have on the overall project schedule. FPL will require a Combined Operating License (COL) from the Nuclear Regulatory Commission (NRC) before construction of the two new nuclear units planned for the Turkey Point site. During 2012, the NRC placed several review schedules "under review", including FPL's COL application. At the time this Site Plan is being finalized, the NRC has not identified a date by which it will issue a new schedule. Once the NRC's new review schedule is issued, FPL will conduct a project schedule review, integrating this information with other relevant information, to determine earliest practicable in-service date for Turkey Point Unit 6.

7. Environmental Regulation and/or Legislation:

As developments occur in regard to new environmental regulations and/or laws, and in how current environmental regulations/laws are interpreted and applied, the potential exists for changes to occur in FPL's resource plan that is presented in this document. For example, FPL has become aware of potential impacts to generating units of recent EPA changes to the National Ambient Air Quality Standards that include shorter duration 1-hour standards for NO_2 and SO_2. FPL has begun the process of evaluating the impact of these standards on the fossil generating fleet, especially the higher emitting peaking gas turbines that have short emission stacks. The results of this analysis could potentially change FPL's resource plan information that is contained in this document.

8. Possible Establishment of "Clean Energy Standards":

Another factor that could influence FPL's resource planning, and could result in changes to the resource plan presented in this Site Plan, is the possibility of the establishment of a Florida standard for renewable energy or clean energy. A Renewable Portfolio Standard (RPS) proposal was prepared by the FPSC, and then sent to the Florida Legislature for consideration, with a possible change to a Clean Portfolio Standard (CPS), during the 2009 legislative session. However, no RPS or CPS legislation was enacted in that session or in subsequent legislative sessions. Furthermore, during the 2012 legislative session, the legislature deleted a now obsolete directive to the FPSC that had instructed them to adopt RPS rules. RPS or CPS legislation, or other legislative initiatives regarding renewable or clean energy contributions, may still occur in the future at either the state or national level. If such legislation is enacted in later years, FPL would then determine what steps need to be taken to address the legislation. Such steps would then be discussed in FPL's Site Plan in the year following the enactment of such legislation.

III.D Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include both conservation initiatives and load management. FPL's DSM efforts through 2012 have resulted in a cumulative Summer peak reduction of approximately 4,652 MW (Summer) at the generator and an estimated cumulative energy saving of approximately 62,653 Gigawatt Hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2012 have eliminated the need to construct the equivalent of approximately 14 new 400 MW generating units.

FPL has consistently been among the leading utilities nationally in DSM achievement. For example, according to the U.S. Department of Energy's 2011 data (the last year for which the DOE data was available at the time this Site Plan is being developed), FPL ranked # 2 nationally in cumulative DSM demand reduction. And, importantly, FPL has achieved these significant DSM accomplishments while seeking to lessen the DSM-based impact on electric rates for all of its customers.

During 2012 and early 2013, FPL offered the following DSM programs to its customers:

Residential DSM Programs

1. **Air-Conditioning:** This program is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to install high-efficiency central air-conditioning systems.

2. **Load Management (On Call):** This program is designed to reduce the Summer and Winter coincident peak demand and energy by turning off customers' appliances for varying durations. Load control equipment is installed at selected customer end-use equipment, allowing FPL to control these loads. Qualifying equipment includes central electric air conditioners, central electric heaters, conventional electric water heaters, and swimming pool pumps.

3. **Building Envelope:** This program is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to improve the thermal efficiency of the building structure.

4. **New Construction (BuildSmart®):** This program is designed to reduce energy consumption and growth of coincident peak demand through the design and

construction of energy-efficient homes. The program encourages builders and developers to achieve the ENERGY STAR®qualification.

5. **Duct System Testing and Repair:** This program is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to repair air leaks identified in air-conditioning duct systems.

6. **Low Income Weatherization:** This program is designed to reduce energy consumption and growth of coincident peak demand by partnering with government and non-profit agencies to assist eligible low income FPL residential customers to reduce the cost of heating and cooling their homes. The agencies include weatherization agency providers (WAPS), non-weatherization agency providers (non-WAPS), and other providers approved by FPL. The rebates are used by these providers to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting.

7. **Home Energy Survey:** This program is designed to reduce energy consumption and growth of coincident peak demand by offering home energy surveys to customers. This objective is accomplished by educating customers on energy efficiency and encouraging customers to perform recommended practices and measures, even if they are not included in FPL's DSM Plan. The energy survey is also used to identify customers for other residential rebate programs dependent upon survey findings. (Note, FPL does not count demand and energy savings from this program towards achieving its DSM Goals.)

Business DSM Programs

1. **Heating, Ventilating, and Air Conditioning (HVAC):** This program is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to install high-efficiency HVAC systems. The current FPL program includes rebates for: 1) thermal storage; 2) chillers; 3) energy recovery ventilator units; 4) direct expansion (DX) units and efficient air conditioning room units; 5) demand control ventilation systems including kitchen hood control; and 6) electrically commutated motors for air conditioning systems.

2. **Commercial Industrial Demand Reduction (CDR):** This program is designed to reduce the growth of coincident peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand, capacity shortages, or system emergencies.

3. **Commercial/Industrial Load Control (CILC):** This program is designed to reduce the growth of coincident peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand, capacity shortages, or system emergencies. This program was closed to new participants as of December 31, 2000,

4. **Building Envelope:** This program is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to install eligible building envelope measures (e.g., roof/ceiling insulation, reflective roof coatings and window treatments).

5. **Business On Call:** This program is designed to reduce the summer coincident peak demand and energy by turning off customers' direct expansion central electric air-conditioning units.

6. **Efficient Lighting:** This program is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to install high-efficiency lighting systems.

7. **Business Custom Incentive:** This program is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to install unique high-efficiency systems not addressed by other FPL DSM programs.

8. **Water Heating:** This program is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to install high-efficiency water heating systems.

9. **Refrigeration:** This program is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to install high-efficiency refrigeration systems.

10. **Business Energy Evaluation (BEE):** This program is designed to reduce energy consumption and growth of coincident peak demand by offering energy audits to business customers. This objective is accomplished by educating customers on energy efficiency and encouraging customers to perform recommended practices and measures, even if these are not addressed by other FPL DSM programs. The BEE is also used to qualify customers for other FPL business rebate programs dependent upon audit findings. (Note, FPL does not count demand or energy savings from this program towards achieving its DSM Goals.)

11. **Cogeneration and Small Power Production:** Facilitates FPL compliance with all regulatory requirements concerning qualifying facilities and small power producers. Assists customers in the evaluation of potential cogeneration projects, including self-generation. (Note, FPL does not count demand or energy savings from this program towards achieving its DSM Goals)

Solar Pilot Programs

1. **Residential Photovoltaic (PV) Pilot:** This pilot is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to install PV systems in residential homes.

2. **Residential Solar Water Heating Pilot:** This pilot is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to install solar water heating systems in homes.

3. **Residential Solar Water Heating (Low Income New Construction) Pilot:** This pilot is designed to reduce energy consumption and growth of coincident peak demand, increase the efficiency of low income housing, and demonstrate the practical application of solar water heating in residential new construction by providing solar water heating systems to selected low income housing developments throughout FPL's service territory.

4. **Business Photovoltaic (PV) Pilot:** This pilot is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to install PV systems in businesses.

5. **Business Photovoltaic (PV) for Schools Pilot:** This pilot is designed to reduce energy consumption and growth of coincident peak demand and demonstrate and educate future generations on the practical applications of PV by providing PV systems and educational materials for selected schools in all public school districts throughout FPL's service territory.

6. **Business Solar Water Heating Pilot:** This pilot is designed to reduce energy consumption and growth of coincident peak demand by encouraging customers to install solar water heating systems in businesses.

DSM Research and Development:

Conservation Research and Development (CRD): CRD is an umbrella research project under which potential new DSM technologies are analyzed. Several FPL DSM programs have emerged from the CRD project including Business Building Envelope, Business On Call, and Residential New Construction (BuildSmart®) programs. This project has also resulted in the addition of cost-effective measures to existing programs, such as the inclusion of Energy Recovery Ventilators to the Business HVAC Program.

DSM Goals:

The FPSC in late 2009 imposed significantly higher DSM Goals for FPL for 2010 – 2019 than were deemed appropriate in prior DSM Goals dockets. The DSM Goals imposed by the FPSC have three components: Summer MW reductions, Winter MW reductions, and GWh reductions. The Summer MW component, and to a much lesser degree the Winter MW reduction component, impacts FPL's need for future resources such as those discussed in this document. The GWh reduction component has no impact on FPL's need for future resources.

In 2011, based on concerns over the projected higher electric rates that would result if a new DSM Plan to meet the new 2009 DSM Goals were implemented, the FPSC instructed FPL to continue executing its currently existing DSM programs (FPSC Order PSC-11-0590-FOF-EG). The projected demand reduction impact of these DSM programs from 2013 through 2019, plus an assumed additional 100 MW per calendar year for 2020 through 2022, is presented below in Table III.D.1. (Subsequent analyses will ultimately determine the actual levels of DSM that should be added in these later years.)

Table III.D.1: FPL's Projected DSM Summer MW Reduction for 2013 - 2022

August MW values (at the Generator)

Year	Cumulative Summer DSM MW for FPL (at Generator)
2013	124
2014	243
2015	369
2016	494
2017	619
2018	745
2019	870
2020	970
2021	1,070
2022	1,170

FPL's intent is to follow the FPSC's directions regarding DSM implementation and to continue its national leadership role in DSM. In doing so, FPL will maintain focus on lessening the DSM-based impact on electric rates for all of FPL's customers and ensuring that FPL's system reliability does not become too dependent upon DSM resources.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy to FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV bulk transmission lines that must be certified under the Transmission Line Siting Act.

Table III.E.1: List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	St. Johns 1/	Pringle	25	Dec – 17	230	759
FPL	Manatee 2/	Bob White	30	Dec – 14	230	1195

1/ Final order certifying the corridor was issued on April 21, 2006. This project is to be completed in two phases. Phase I consisted of 4 miles of new 230 kV line (Pringle to Pellicer) and was completed in May-2009. Phase II consists of 21 miles of new 230 kV line (St. Johns to Pellicer) and is scheduled to be completed by Dec-2017.

2/ Final order certifying the corridor was issued on November 6, 2008. This project consists of 30 miles of new 230 kV line (Manatee to Bob White) and is scheduled to be completed by Dec-2014

In addition, there will be transmission facilities needed to connect several of FPL's projected generating capacity additions to the system transmission grid. These transmission facilities (described on the following pages) are for the remaining capacity increase (uprate) at the existing Turkey Point Unit 4 nuclear generating unit, the generating capacity additions with the Cape Canaveral, Riviera Beach and Port Everglades modernizations, and the planned new nuclear capacity addition at the Turkey Point site from Turkey Point Unit 6.

III.E.1 Transmission Facilities for Turkey Point Unit 4 Capacity Uprate

The work that was required to address the remainder of the Turkey Point Unit 4 uprate in 2013 in regard to the FPL grid consisted of the following:

I. Substation:

1. At Turkey Point Switchyard, install two 5-Ohm series phase inductors combined with external shunt capacitors on the southeast and southwest 230 kV operating busses.
2. At Turkey Point Switchyard, replace twelve 230 kV disconnect switches. Also upgrade associated jumpers, bus work and equipment connections.
3. Uprate the Unit 4 main step-up transformer to 970 MVA.
4. Replace spare main step-up transformer with 1028 MVA transformer.
5. Add relays and other protective equipment.
6. Replace breaker failure panels at Davis Substation.
7. Replace breaker failure panels at Flagami Substation.

II. Transmission:

1. Upgrade the existing string busses for Unit 4 between the main step-up transformer and the switchyard with spacers between the conductors.

III.E.2 Transmission Facilities for Cape Canaveral Next Generation Clean Energy Center (Modernization)

The work required to connect the Cape Canaveral Next Generation Clean Energy Center in 2013 to the FPL grid is as follows:

I. Substation:

1. Build new collector yard containing two collector busses with four breakers to connect the three combustion turbines (CT), and one steam turbine (ST).
2. Construct two string busses to connect the collector busses to Cape Canaveral 230 kV Substation.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. At Cape Canaveral Switchyard replace eight 230 kV disconnect switches. Also upgrade associated jumpers, bus work and equipment connections.
5. Expand switchyard relay vault and add relays and other protective equipment.

II. Transmission:

1. Relocate the Cape Canaveral-Grissom 115 kV line.

III.E.3 Transmission Facilities for Riviera Beach Next Generation Clean Energy Center (Modernization)

The work required to connect the Riviera Beach Next Generation Clean Energy Center in 2014 to the FPL grid is as follows:

I. Substation:

1. Expand the Riviera Beach 230 kV Switchyard five breakers to accommodate terminals for one combustion turbine (CT), and one steam turbine (ST).
2. Construct a new 138 kV Riviera Beach Switchyard - five bays, 14 breakers with terminals to connect two CT units and seven 138 kV lines.
3. Add four main step-up transformers (3-370 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. Add relays and other protective equipment.
5. At Ranch Substation, add a new 230 kV bay 5 and upgrade bay 4 to 3000 Amperes.
6. At Sugar Substation, install one set of 2.5 Ohm phase inductors on the Corbett-Sugar 230 kV line.
7. Breaker replacements:
   Ranch Substation – Replace one 230 kV breaker
   Broward Substation – Replace one 230 kV breaker

II. Transmission:

1. Break the Indiantown-Riviera Beach 230 kV and extend each of the line segments south (approx. 4 miles) to connect to the Ranch 230 kV Substation forming Indiantown-Ranch and a Ranch-Riviera Beach 230 kV circuits.
2. Remove Corbett-Ranch #2 230 kV line at Ranch and:
   a. extend to meet the Cedar-Lauderdale 230 kV line N/S corridor (approx. 10 miles).
3. Break Cedar-Corbett 230 kV (near Ranch Sub in Corbett-Jog section) and:
   a. Extend Cedar side to Riviera Beach, (approx. 15 miles) creating new Cedar-Riviera Beach 230 kV.
   b. Extend Corbett side to meet the Cedar-Lauderdale 230 kV N/S corridor (approx. 10 miles).
4. Break Cedar-Lauderdale 230 kV (near 230 corridor running N/S)
   a. Connect Cedar side to meet 3.b. to create a Cedar to Corbett 230 kV.
   b. Connect Lauderdale side to meet 2.a. to create a Corbett to Lauderdale 230 kV.
5. Upgrade the existing IBM-Yamato 138 kV line to 1200 Amperes.

6. New underground 138 kV tie line between new Riviera Beach 138 kV Switchyard and 560 MVA, 230/138 kV autotransformer in the expanded Riviera Beach 230 kV Substation.
7. Relocate six existing 138 kV lines from existing Riviera Beach 138 kV Switchyard to new Riviera Beach 138 kV Switchyard.

III.E.4 Transmission Facilities for Port Everglades Next Generation Clean Energy Center (Modernization)

The work required to connect the Port Everglades Next Generation Clean Energy Center in 2016 to the FPL grid is projected to be:

I. Substation:

1. Construct two string busses to connect two combustion turbines (CT) to the Port Everglades 138 kV Substation.
2. Construct two string busses to connect one CT, and one steam turbine (ST) to the Port Everglades 230 kV Substation.
3. Add four main step-up transformers (3-450 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. Replace ten (10) 138 kV breakers
5. Replace eight (8) 230 kV breakers
6. At Port Everglades Switchyard replace twenty-two 138 kV disconnect switches. Also upgrade associated jumpers, bus work, and equipment connections.
7. Expand switchyard relay vault and add relays and other protective equipment.

II. Transmission:

1. Upgrade of existing transmission facilities:
   - An ampacity upgrade up to 1905 amps on the Port Everglades-Port Everglades Tap 138kV line section.
   - An ampacity upgrade up to 1905 amps on the Port Everglades Tap-Port Everglades Tap 2 138 kV line section.
   - An ampacity upgrade up to 1695 amps on the Port Everglades Tap 1-Dania 138 kV line section.
   - An ampacity upgrade up to 1695 amps on the Dania-Hollywood 138 kV line section.

III.E.5 Transmission Facilities for Turkey Point Nuclear Unit 6

The work required to connect the Turkey Point Nuclear Unit 6 by Summer 2022 to the FPL grid is projected to be:

I. Substation:

1. Build new Clear Sky 500/230kV Switchyard with six (6) bays on the 230 kV section for generator main step-up transformer connection, reserve auxiliary transformer connections, four (4) 230 kV line terminals, two (2) autotransformers and two (2) 500 kV line terminals.
2. At Turkey Point Switchyard add a new bay to accommodate the Turkey Point-Clear Sky 230 kV line terminal.
3. At Gratigny Substation install a second 230/138 kV autotransformer with one (1) 230 kV breaker and one (1) 138 kV breaker.
4. At Pennsuco Substation install a fourth line terminal to accommodate the Pennsuco-Clear Sky 230 kV line by converting the ring bus to a breaker and a half scheme and adding four (4) 230 kV breakers.
5. At Davis Substation construct two (2) new 230kV line terminals for the Clear Sky-Davis 230 kV line and the Davis-Miami 230 kV line with a switch-able inductor to be installed on the Davis-Miami 230 kV line
6. At Levee Substation expand 500 kV section to accommodate the two (2) Levee-Clear Sky 500 kV lines.
7. At Andytown Substation install two (2) 5-Ohm inductors combined with external shunt capacitors on the 230kV side of the 500/230 autotransformers (one per auto).
8. At Miami Substation expand the 230kV section to a double bus configuration and add a new 230kV line terminal for Davis line and replace one (1) autotransformer.
9. At Flagami Substation install a small inductor on one end of the Flagami-Miami 230kV #2 circuit.
10. Breaker replacements:
    Flagami Substation – Replace five (5) 230 kV breakers and three (3) 138 kV breakers
    Miami Substation – Replace one (1) 230 kV breaker and four (4) 138 kV breakers
    Davis Substation - Replace two (2) 230 kV breakers
    Dade Substation - Replace seven (7) 230 kV breakers
    Court Substation – Replace one (1) 138 kV breaker.

II. Transmission:

1. FPL will design and construct two (2) 500kV transmission lines from the new Clear Sky Substation to the existing FPL Levee 500kV Substation switchyard. The lines will be approximately 43 miles long.
2. Construct a new Clear Sky-Davis 230kV line (approximately 19 miles) with a rating of 2990 Amperes.
3. Construct a new Clear Sky-Pennsuco 230kV line (approximately 52 miles) with a rating of 2990 Amperes.
4. Construct a new Davis-Miami 230kV line (approximately 18 miles) with a rating of 2297 Amperes.
5. Construct a new Clear Sky-Turkey Point 230kV line (approximately 0.5 miles) with a rating of 2990 Amperes.

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to effectively utilize renewable energy technologies to serve its customers. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. For purposes of discussing FPL's renewable energy efforts in this document, those efforts will be placed into five categories.

Two of these categories are Supply-Side Efforts – Power Purchases, and Supply-Side Efforts – FPL Facilities. Starting in 2011, the energy (MWh) total output from these renewable energy sources was greater than the energy produced from oil-fired generation. This was also true in 2012. The renewable energy information is presented in Schedule 11.1, and the oil-based energy information is presented in Schedule 6.1. Both of these schedules are presented at the end of this chapter.

1) <u>Early Research & Development Efforts:</u>

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970s in demonstrating the first residential PV system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-kilowatt (kW) system was placed into operation in 1984. (The system was removed in 1990 at the conclusion of the PV testing to make room for substation expansion.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. This FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site became the home for PV capacity which was installed as a result of FPL's earlier "green pricing" efforts.

2) **Demand Side & Customer Efforts:**

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers who chose solar water heaters. Before the program ended (due to the fact that it was no longer projected to be cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for six passive home designs with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code was one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the FPSC to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test were deemed to be solvable, particularly when new pools are constructed. However, the high initial cost of PV, the significant percentage of sites with unacceptable shading, and various customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

FPL has since continued to analyze and promote the utilization of PV. These efforts have included PV research, development, and education, as well as development and implementation of the FPL Next Generation Solar Station Program. This initiative also delivers teacher training and curriculum that is tied to the Sunshine Teacher Standards in Florida. Additionally, the program provides teacher grants to promote and fund projects in the classrooms.

In addition, FPL assists customers who are interested in installing PV equipment at their facilities. Consistent with Florida Administrative Code Rule 25-6.065, Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned PV systems. Through December 2012, approximately 2,117 customer systems (predominantly residential) have been interconnected.

As part of its 2009 DSM Goals decision, the FPSC imposed a requirement for Florida's investor-owned utilities to spend up to a set, not-to-exceed amount of money annually to facilitate demand side solar water heater and photovoltaic applications. FPL's not-to-exceed amount of money for these applications is approximately $15.5 million per year through 2014. In regard to this direction, FPL received approval from the FPSC in 2011 to initiate a solar pilot portfolio that consists of three PV-based programs and three solar water heating-based programs, plus Conservation Research and Development. These programs are currently projected to be offered through 2014. FPL is evaluating the results to-date from these programs.

FPL has also been investigating fuel cell technologies through monitoring of industry trends, discussions with manufacturers, and direct field trials. From 2002 through the end of 2005, FPL conducted field trials and demonstration projects of Proton Exchange Membrane (PEM) fuel cells with the objectives of serving customer end-uses while evaluating the technical performance, reliability, economics, and relative readiness of the PEM technology. The demonstration projects were conducted in partnership with customers and included five locations. The research projects were useful to FPL in identifying specific issues that can occur in field applications and the current commercial viability of this technology. FPL will continue to monitor the progress of these technologies and conduct additional field evaluations as significant developments in fuel cell technologies occur.

3) **Supply Side Efforts – Power Purchases:**

FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy, and as-available energy, have been purchased by FPL from these types of facilities. (Please refer to Tables I.B.1, I.B.2, and I.C.1 in Chapter I).

Periodically, FPL invites renewable energy suppliers to provide proposals for renewable power and energy at or below avoided costs in response to FPL's Requests for Proposals (RFPs). FPL issued Renewable RFPs in 2007 and 2008 soliciting proposals to provide firm capacity and energy, and energy only, at or below avoided costs, from renewable generators. FPL also promptly responds to inquiries for information from prospective renewable energy suppliers either by e-mail or phone.

With regard to existing contracts that have recently ended, FPL and the Solid Waste Authority of Palm Beach (SWA) agreed to extend their contract that expired March 31, 2010 for a 20-year term beginning in April 1, 2012 through April 1, 2032. However, the SWA refurbished their generating unit ahead of schedule and, as of January 2012, this unit began delivering firm capacity to FPL. In 2011, the FPSC approved a contract for an additional 70 MW between FPL and SWA for a new unit to be constructed and to begin delivering firm capacity and energy beginning on January 1, 2015. At the end of December 2011, the contract between FPL and Okeelanta (New Hope) expired. However, Okeelanta continues to deliver energy to FPL as an as-available, non-firm supplier of renewable energy.

4) **Supply Side Efforts – FPL Facilities:**

With regard to solar generating facilities, FPL has three such facilities: (i) a 75 MW steam generation solar thermal facility in Martin County (the Martin Next Generation Solar Energy Center); (ii) a 25 MW PV electric generation facility in DeSoto County (the DeSoto Next Generation Solar Energy Center); and (iii) a 10 MW PV electric generation facility in Brevard County at NASA's Kennedy Space Center (the Space Coast Next Generation Solar Energy Center). The DeSoto County project was completed in 2009 and the other two projects were completed in 2010. These three solar facilities were constructed in response to the Florida Legislature's House Bill 7135 which was signed into law by the Governor in June 2008.

House Bill 7135 was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in the State of Florida. Specifically, the bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land, zoning, and transmission rights in place. FPL's three solar projects met the specified criteria, and were granted approval for cost recovery in 2008. Each of the three solar facilities is discussed below.

a. **The Martin Next Generation Solar Energy Center:**

This facility began commercial operation in 2010 and provides 75 MW of solar thermal capacity in an innovative way that directly displaces fossil fuel usage on the FPL system. This facility consists of solar thermal technology which generates steam that is integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired CC plant. This project is the first "hybrid" solar plant in the world, and, at the time the facility came in-service, was the second largest solar facility in the world and the largest solar plant of any kind in the U.S. outside of California.

b. **The DeSoto Next Generation Solar Energy Center:**

This PV facility began commercial operation in 2009 and provides 25 MW of non-firm capacity and energy, making it one of the largest PV facilities in the U.S. The facility utilizes a tracking PV array that is designed to follow the sun as it traverses across the sky.

c. **The Space Coast Next Generation Solar Energy Center:**

Located at the Kennedy Space Center, this facility is part of an innovative public/private partnership with NASA. This non-tracking PV facility began commercial operation in 2010 and provides 10 MW of non-firm capacity and energy.

For resource planning purposes, FPL currently projects that the output from these renewable facilities will be "as available," non-firm energy only. This is due to several factors. First, the Martin solar thermal facility is a "fuel-substitute" facility, not a facility that provides additional capacity and energy. The solar thermal facility displaces the use of fossil fuel to produce steam on the FPL system when the solar thermal facility is operating. Second, in regard to the two PV facilities, the intermittent nature of the solar resource makes it difficult to accurately determine what contribution the PV facilities at these specific locations can consistently make at FPL's late Summer afternoon and early Winter morning peak load hours. Once site-specific operating data has been gathered for an appropriate amount of time, FPL will then re-evaluate the actual output from each PV facility to determine what portion, if any, of its output can be projected as firm capacity at the projected peak hours in FPL's resource planning work.

In addition to these three solar facilities, FPL is currently in the process of identifying other potential solar sites in the state. FPL is evaluating existing FPL generation sites along with potential Greenfield sites within FPL's service territory. These sites are discussed further in Chapter IV.

5) **Ongoing Research & Development Efforts:**

FPL has developed alliances with several Florida universities to promote development of emerging technologies. For example, an alliance has been established with the newly formed Southeast National Marine Renewable Energy Center (SNMREC) at Florida Atlantic University (FAU), which will focus on the commercialization of ocean current, ocean thermal (i.e., energy conversion as well as cold water air conditioning), and hydrogen technologies. FPL has been taking the lead in assisting FAU with the discussions being held with the U.S. Department of the Interior's Minerals Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE). BOEMRE is working to establish the permitting process for ocean energy development on the outer continental shelf.

FPL has also developed an alliance with the University of Florida to support its biomass-related studies to determine improved vegetative management techniques for use in minimizing maintenance costs at FPL's current and future solar sites and to perform wind studies within the state. In addition, FPL has partnered with the Florida Institute of Technology on fuel cell technology and with the Florida State Universities Center for Applied Power System in regard to grid integration of ocean energy and other renewables.

FPL has also developed a "Living Lab" to demonstrate FPL's solar energy commitment to employees and visitors at its Juno Beach office facility. To-date, FPL has installed five different PV arrays (different technologies) of rooftop PV totaling 24 kW at the Living Lab. In addition, two PV-covered parking structures with a total of approximately 90 kW of PV were constructed at the FPL Juno office parking lot. Through these Living Lab projects, FPL is able to evaluate multiple solar technologies and applications for the purpose of developing a renewable business model resulting in the most cost-effective and reliable uses of solar energy for FPL's customers. FPL plans to continue to expand the Living Lab as new solar products come to market.

FPL has also been in discussions with several private companies on multiple emerging technology initiatives including ocean current, ocean thermal, hydrogen, fuel cell technology, biomass, biofuels, and energy storage.

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fired generation. In the early 1980s, FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership (20%) and additional purchases (30%) from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit 4 which began serving FPL's customers in 1991. Starting in 1997, petroleum coke was added to the fuel mix as a blend stock with coal at SJRPP when economic.

The trend since the early 1990s has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective CC generating units and the ready availability of natural gas. This planning document reflects an evolution in that trend in recognition that, although efficient gas-fired generation continues to provide significant benefits to FPL's customers, adding natural gas-fired additions exclusively would, in the long term, create an unbalanced generation portfolio. In 2009, FPL placed into commercial operation two new gas-fired CC units at the West County Energy Center (WCEC) site. A third new CC unit was added to the WCEC site in 2011. In addition, FPL is currently modernizing its existing Cape Canaveral, Riviera Beach, and Port Everglades plant sites by removing the steam generating units previously on the sites and replacing them with three highly efficient new CC units, one at each site. These new CC units will provide highly efficient generation that will dramatically improve the efficiency of FPL's generation system in general, and, more specifically, the efficiency at which natural gas is utilized.

In addition, FPL is increasing its utilization of nuclear energy through capacity uprates of its four existing nuclear units. The uprates have been completed at three of the four units, and the uprate work is projected to be completed at the fourth unit at approximately the time this Site Plan is completed. With these uprates, more than 500 MW of additional nuclear capacity have been added to the FPL system. FPL is also pursuing plans to obtain licenses, permits, and approvals to construct and operate two new nuclear units at its existing Turkey Point site that, in total, would add approximately 2,200 MW of new nuclear generating capacity. The earliest date by which the first of these two new nuclear units could practically be deployed is currently projected to be 2022.

In regard to utilizing renewable energy, FPL has added 110 MW of solar generating capacity through a 75 MW solar thermal steam generating facility at FPL's existing Martin site, a 25 MW PV facility in DeSoto County, and a 10 MW PV facility in Brevard County. The DeSoto facility was placed into commercial operation in 2009. The other two solar facilities were placed into commercial operation in 2010.

FPL's future resource planning work will continue to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance FPL's long-term fuel diversity. These fuel diverse alternatives may include: the purchase of power from renewable energy facilities, additional FPL-owned renewable energy facilities, obtaining additional access to diversified sources of natural gas such as liquefied natural gas (LNG) and natural gas from the Mid-Continent unconventional reserves, preserving FPL's ability to utilize fuel oil at its existing units, and increased utilization of nuclear energy. (As previously discussed, new advanced technology coal generating units are not currently considered as viable options in Florida in the ten-year reporting period of this document due, in part, to current projections of relatively small differences in fuel costs between coal and natural gas, significantly higher capital costs for coal units compared to CC units, greater efficiencies of CC units, and concerns over non-greenhouse gas environmental regulations that would impact coal units more negatively than CC units.) The evaluation of the feasibility and cost-effectiveness of these, and other possible fuel diversity alternatives, will be part of FPL's on-going resource planning efforts.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2022 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

FPL's Fossil Fuel Cost Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future resource needs. FPL's forecasts are generally consistent with other published contemporary forecasts.

Future oil and natural gas prices, and to a lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, coal, and petroleum coke. These drivers include U.S. and worldwide demand, production capacity, economic growth, environmental legislation, and politics.

The inherent uncertainty and unpredictability in these factors today and tomorrow clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal and petroleum coke) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed and utilized Low, Medium, and High price forecasts for fossil fuels in some of its 2012 and early 2013 resource planning work, particularly in regard to analyses conducted as part of the nuclear cost recovery filing work.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

a. For 2013 through 2015, the methodology used the February 4, 2013 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil, ultra low sulfur diesel fuel oil, and Henry Hub natural gas commodity prices;

b. For the next two years (2016 and 2017), FPL used a 50/50 blend of the February 4, 2013 forward curve and the most current projections at the time from The PIRA Energy Group;

c. For the 2018 through 2030 period, FPL used the annual projections from The PIRA Energy Group; and,

d. For the period beyond 2030, FPL used the real rate of escalation from the Energy Information Administration (EIA). In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach:

a. Delivered price forecasts for Central Appalachian (CAPP), Illinois Basin (IB), Powder River Basin (PRB), and South American coal and petroleum coke were provided by JD Energy; and,

b. The coal price forecast for SJRPP and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for oil, natural gas, coal, and petroleum coke prices were based on the historical volatility of the 12-month forward price, one year ahead. FPL developed these forecasts to account for the uncertainty which exists within each commodity as well as across commodities. These forecasts reflect a range of reasonable forecast outcomes.

3. Natural Gas Storage

FPL is under contract through March 2013 for 2 billion cubic feet (Bcf) of firm natural gas storage capacity in the Bay Gas storage facility located in Alabama. The Bay Gas storage facility is interconnected with the Florida Gas Transmission (FGT) pipeline. Starting on April 1, 2013, FPL will have entered into a new deal with Bay Gas Storage for one year for 2.5 billion cubic feet (Bcf) of firm natural gas storage capacity. FPL has predominately utilized natural gas storage to help mitigate gas supply problems caused by severe weather and/or infrastructure problems. Over the past several years, FPL has acquired upstream transportation capacity on several pipelines to help mitigate the risk of off-shore supply problems caused by severe weather in the Gulf of Mexico. While this transportation capacity has reduced FPL's off-shore exposure, a portion of FPL's supply portfolio remains tied to off-shore natural gas sources. Therefore, natural gas storage remains an important tool to help mitigate the risk of supply disruptions. For these reasons, FPL has typically maintained nearly full natural gas inventory during normal operations from June through November (hurricane season). From December through March, FPL typically maintains lower levels of natural gas inventory as compared to Summer peak months.

As FPL's reliance on natural gas has increased, its ability to manage the daily "swings" that can occur on its system due to weather and unit availability changes has become more challenging, particularly from oversupply situations. Natural gas storage is a valuable tool to help manage the daily balancing of supply and demand. From a balancing perspective, injection and withdrawal rights associated with storage have become an increasingly important part of the evaluation of overall storage requirements.

As FPL's system grows to meet customer needs, it must maintain adequate storage capacity to continue to help mitigate supply and/or infrastructure problems and to provide FPL the ability to manage its supply and demand on a daily basis. FPL will continue to evaluate its storage portfolio and enter into arrangements that will help increase reliability, provide the necessary flexibility to respond to demand changes, and diversify the overall portfolio.

4. Securing Additional Natural Gas:

The recent trend of increasing reliance upon natural gas to produce electricity for FPL's customers is projected to continue due to FPL's growing load. The addition of the highly fuel-efficient Cape Canaveral, Riviera Beach, and Port Everglades modernizations will serve to reduce the growth in natural gas use from what it otherwise might have been due to the high fuel-efficiency levels of these new CC units, but these efficiencies do not fully offset the effects of FPL's growing load. Therefore, FPL will need to secure more natural gas supply and more gas transportation capacity. The issue is how to secure these additional natural gas resources in a manner that is economical for FPL's customers and which maintains and/or enhances the reliability of natural gas supply and deliverability to FPL's generating units.

FPL has historically purchased the gas transportation capacity required for new natural gas supply from two existing natural gas pipeline companies. As more natural gas is delivered through these two pipelines, the impact of a supply disruption on either pipeline becomes more problematic. Therefore, FPL issued a Request for Proposals (RFP) in December 2012 for gas transportation capacity to meet FPL's system natural gas requirements beginning in 2017. The RFP encourages bidders to propose new gas transportation infrastructure to meet Florida's growing need for natural gas. A third pipeline would have benefits for FPL and its customers by increasing the diversity of FPL's fuel supply sources, increasing the physical reliability of the pipeline delivery system, and enhancing competition among pipelines. Responses to this RFP are due in early April 2013.

5. Nuclear Fuel Cost Forecast

This section reviews the various steps needed to fabricate nuclear fuel for delivery to the nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

a) Steps Required for Nuclear Fuel to be delivered to FPL's Plants

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

(1) Mining: Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U3O8 (sometimes referred to as yellowcake).

(2) Conversion: During the second step, the U3O8 is chemically converted into UF6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

(3) Enrichment: The third step is called enrichment. Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 3% to as high as 5%). The output of this enrichment process is enriched uranium in the form of UF6.

(4) Fabrication: During the last step, fuel fabrication, the enriched UF6 is changed to a UO2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) Mining: The impact of the earthquake and tsunami that struck the Fukushima nuclear complex in Japan in March 2011 is still having a significant impact on the uranium market. Current demand has declined and several of the production facilities have announced delays. Factors of importance are:

- Hedge funds are still very active in the market. This causes more speculative demand that is not tied to market fundamentals and causes the market price to move up or down just based on news that might affect future demand.
- Some of the uranium inventory from the U.S. Department of Energy (DOE) is finding its way into the market periodically to fund cleanup of certain Department of Energy facilities.
- Although a limited number of new nuclear units are scheduled to start production in the U.S. during the next 5 to 10 years, other countries, more specifically China, have announced an increase in construction of new units which may cause uranium prices to trend up in the near future.

Over a 10-year horizon, FPL expects the market to be more consistent with market fundamentals. The supply picture is more stable, with laws enacted to resolve the import of Russian-enriched uranium, by allowing some imports of Russian-enriched uranium to meet about 20-25% of needs for currently operating units, but with no restriction on the first core for new units and no restrictions after 2020. New and current facilities continue to add capacity to meet demands. Actual demand tends to grow over time because of the long lead time to build nuclear units. However, FPL cannot discount the possibility of future periodic sharp increase in prices, but believes such occurrences will likely be temporary in nature.

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies.

(2) Conversion: The conversion market is also in a state of flux due to the Fukushima events. Insufficient planned production is currently forecasted after 2013 to meet the higher demand scenario, but it is projected to be sufficient to meet most reference case scenarios. As with additional raw uranium production, supply will expand beyond current level once more firm commitments are made including commitments to building new nuclear units. FPL expects long term price stability for conversion services to support world demand.

(3) Enrichment: As a result of the Fukushima events in March 2011, the near-term price of enrichment services has been declining for the last two years. However, plans for several of the new facilities that were expected to come on-line in the next few years have been delayed. Also, some of the current high operating cost diffusion plants have shut down. As with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand. Meanwhile, world supply and demand will continue to be balanced such that FPL expects adequate supply of enrichment services. The tight supply/demand profile will most likely result in the price of enrichment services remaining stable or declining for the next few years before starting to increase.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the Nuclear Regulatory Commission (NRC), not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand is expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast

The calculations for the nuclear fuel cost forecasts used in FPL's 2012 and early 2013 resource planning work were performed consistent with the method then used for FPL's Fuel Clause filings, including the assumption of refueling outages every 18 months and plant operation at power uprate levels. The costs for each step to fabricate the nuclear fuels were added to come up with the total costs of the fresh fuel to be loaded at each refueling (acquisition costs). The acquisition cost for each group of fresh fuel assemblies were then amortized over the energy produced by each group of fuel assemblies. FPL also added 1 mill per kilowatt hour net to reflect payment to DOE for spent fuel disposal.

Schedule 5
Fuel Requirements
(for FPL only)

			Actual 1/		Forecasted									
	Fuel Requirements	**Units**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
(1)	Nuclear	Trillion BTU	241	188	291	298	300	306	303	300	306	302	300	357
(2)	Coal	1,000 TON	3,135	2,692	2,879	3,048	3,451	3,121	3,509	3,417	3,695	3,822	3,896	3,888
(3)	Residual (FO6) - Total	1,000 BBL	1,141	459	401	339	489	629	283	405	314	382	417	282
(4)	Steam	1,000 BBL	1,141	459	401	339	489	629	283	405	314	382	417	282
(5)	Distillate (FO2) - Total	1,000 BBL	332	23	5	39	56	214	63	23	5	15	22	5
(6)	Steam	1,000 BBL	2	4	0	0	0	0	0	0	0	0	0	0
(7)	CC	1,000 BBL	290	15	4	24	52	153	49	2	1	1	3	1
(8)	CT	1,000 BBL	40	4	1	15	4	62	14	21	4	14	18	4
(9)	Natural Gas - Total	1,000 MCF	555,988	595,396	527,468	551,511	554,210	572,447	585,028	599,799	587,485	596,930	601,354	571,252
(10)	Steam	1,000 MCF	61,272	46,112	2,905	2,159	3,486	5,250	4,590	6,571	5,073	6,115	6,560	4,636
(11)	CC	1,000 MCF	486,116	546,386	523,796	548,510	549,998	565,976	579,234	592,222	581,374	589,516	593,419	565,588
(12)	CT	1,000 MCF	8,600	2,899	767	843	727	1,221	1,204	1,006	1,038	1,299	1,375	1,028

1/ Source: A Schedules.
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 1/ 2011	2012	Forecasted 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	Annual Energy Interchange 2/	GWH	6,008	5,186	2,175	2,730	3,061	1,241	109	0	0	0	0	0
(2)	Nuclear	GWH	21,510	16,916	27,184	27,812	27,986	28,609	28,295	27,967	28,568	28,193	27,977	33,482
(3)	Coal	GWH	5,634	4,745	4,884	5,211	5,931	5,400	6,069	6,088	6,609	6,890	7,073	7,066
(4)	Residual(FO6) -Total	GWH	630	378	246	198	309	368	162	228	174	213	230	157
(5)	Steam	GWH	630	378	246	198	309	368	162	228	174	213	230	157
(6)	Distillate(FO2) -Total	GWH	123	54	4	23	44	139	46	8	2	5	8	2
(7)	Steam	GWH	1	2	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	107	49	3	19	43	123	42	2	0	1	2	0
(9)	CT	GWH	15	4	1	4	1	16	4	6	1	4	6	1
(10)	Natural Gas -Total	GWH	74,388	80,505	74,686	78,694	79,346	82,585	84,751	86,762	85,118	86,353	86,933	82,739
(11)	Steam	GWH	5,429	5,543	231	176	272	439	376	552	423	514	555	383
(12)	CC	GWH	68,328	74,668	74,387	78,455	79,017	82,044	84,274	86,121	84,602	85,721	86,254	82,264
(13)	CT	GWH	631	295	67	63	57	103	101	90	93	117	123	92
(14)	Solar 3/	GWH	71	159	183	188	157	188	187	186	186	186	176	185
(15)	PV	GWH	71	71	72	72	71	71	70	70	69	69	68	68
(16)	Solar Thermal 4/	GWH	0	89	111	117	86	117	117	117	117	117	107	117
(17)	Other 5/	GWH	4,090	2,922	3,675	3,862	4,512	4,924	4,968	4,717	6,543	6,990	7,146	7,334
	Net Energy For Load 6/	GWH	112,454	110,866	113,036	118,718	121,345	123,453	124,586	125,957	127,200	128,828	129,543	130,964

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report
2/ The projected figures are based on estimated energy purchases from SJRPP, the Southern Companies (UPS contract), and other utilities.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ For 2011, the Martin 8 Solar Thermal GWh output is rolled into row (12) for reporting purposes. In 2012, the GWh output is presented in row (16). The projected GWh contributions for 2013-2022 are also provided on row (16).
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
6/ Net Energy For Load values for the years 2013 - 2022 are also shown in Col. (19) on Schedule 2.3.

Schedule 6.2
Energy Sources % by Fuel Type

Energy Source	Units	Actual [1/] 2011	2012	Forecasted 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1) Annual Energy Interchange [2/]	%	5.3	4.7	1.9	2.3	2.5	1.0	0.1	0.0	0.0	0.0	0.0	0.0
(2) Nuclear	%	19.1	15.3	24.0	23.4	23.1	23.2	22.7	22.2	22.5	21.9	21.6	25.6
(3) Coal	%	5.0	4.3	4.3	4.4	4.9	4.4	4.9	4.8	5.2	5.3	5.5	5.4
(4) Residual (FO6) -Total	%	0.6	0.3	0.2	0.2	0.3	0.3	0.1	0.2	0.1	0.2	0.2	0.1
(5) Steam	%	0.6	0.3	0.2	0.2	0.3	0.3	0.1	0.2	0.1	0.2	0.2	0.1
(6) Distillate (FO2) -Total	%	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
(7) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8) CC	%	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
(9) CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10) Natural Gas -Total	%	66.1	72.6	66.1	66.3	65.4	66.9	68.0	68.9	66.9	67.0	67.1	63.2
(11) Steam	%	4.8	5.0	0.2	0.1	0.2	0.4	0.3	0.4	0.3	0.4	0.4	0.3
(12) CC	%	60.8	67.3	65.8	66.1	65.1	66.5	67.6	68.4	66.5	66.5	66.6	62.8
(13) CT	%	0.6	0.3	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(14) Solar [3/]	%	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1
(15) PV	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(16) Solar Thermal [4/]	%	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(17) Other [5/]	%	3.6	2.6	3.3	3.3	3.7	4.0	4.0	3.7	5.1	5.4	5.5	5.6
		100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report
2/ The projected figures are based on estimated energy purchases from SJRPP, the Southern Companies (UPS contract), and other utilities.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ For 2011, the Martin 8 Solar Thermal GWh output is rolled into row (12) for reporting purposes. In 2012, the GWh output is presented in row (16). The projected GWh contributions for 2013-2022 are also provided on row (16).
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled
Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2013	24,215	1,309	0	635	26,159	21,790	2,006	19,785	6,374	32.2	826	5,548	28.0
2014	25,533	1,346	0	635	27,513	22,928	2,153	20,775	6,738	32.4	826	5,912	28.5
2015	25,604	1,456	0	595	27,654	23,359	2,279	21,080	6,574	31.2	0	6,574	31.2
2016	26,881	528	0	595	28,003	23,733	2,404	21,329	6,674	31.3	0	6,674	31.3
2017	26,441	491	0	595	27,527	24,122	2,529	21,593	5,933	27.5	0	5,933	27.5
2018	26,441	110	0	595	27,146	24,493	2,655	21,839	5,307	24.3	0	5,307	24.3
2019	26,441	110	0	595	27,146	24,901	2,780	22,121	5,024	22.7	0	5,024	22.7
2020	26,441	110	0	595	27,146	25,302	2,880	22,422	4,723	21.1	0	4,723	21.1
2021	26,441	110	0	775	27,326	25,560	2,980	22,580	4,746	21.0	0	4,746	21.0
2022	27,541	110	0	775	28,426	26,105	3,080	23,025	5,401	23.5	0	5,401	23.5

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2013 load forecast without incremental DSM or cumulative load management.
Col. (8) represents cumulative load management capability, plus incremental conservation, from 1/2013-on intended for use with the 2013 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of: an additional 826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin Unit 1) and in the Summer of 2014 (at Martin Unit 2) due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
January of Year	Firm Installed Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2013	24,135	1,316	0	635	26,086	20,270	1,480	18,790	7,295	38.8	1,539	5,756	30.6
2014	25,686	1,353	0	635	27,673	21,593	1,572	20,022	7,652	38.2	832	6,820	34.1
2015	27,102	1,463	0	595	29,159	22,154	1,641	20,513	8,646	42.2	0	8,646	42.2
2016	27,153	535	0	595	28,282	22,430	1,710	20,719	7,563	36.5	0	7,563	36.5
2017	28,138	498	0	595	29,231	22,662	1,780	20,882	8,348	40.0	0	8,348	40.0
2018	28,138	110	0	595	28,843	22,898	1,849	21,049	7,793	37.0	0	7,793	37.0
2019	28,138	110	0	595	28,843	23,125	1,918	21,207	7,636	36.0	0	7,636	36.0
2020	28,138	110	0	595	28,843	23,356	1,977	21,380	7,463	34.9	0	7,463	34.9
2021	28,138	110	0	775	29,023	23,601	2,030	21,571	7,452	34.5	0	7,452	34.5
2022	28,138	110	0	775	29,023	23,670	2,083	21,587	7,436	34.4	0	7,436	34.4

Col. (2) represents capacity additions and changes projected to be in-service by January 1st. These MW are generally considered to be available to meet winter peak loads which are forecasted to occur during January of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2013 load forecast without incremental DSM or cumulative load management. 2013 load is an actual load value.
Col. (8) represents cumulative load management capability, plus incremental conservation, from 1/2013-on intended for use with the 2013 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Winter peak period. This value is comprised of: (i) 717 MW (at Turkey Point Unit 4) that will be out-of-service in Winter of 2013 due to an extended planned outage as part of the capacity uprates project; (ii) an additional 822 MW that will be out-of-service in the Winter of 2013 (at Manatee Unit 1) due to the installation of electrostatic precipitators; and (iii) an additional 832 MW (at Martin Unit 1) that will be out-of-service during the Winter of 2014 due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Schedule 7.3
Projection of Generation - Only Reserves
At Time Of Summer Peak (Assuming no additions in 2022)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2013	24,215	1,309	0	635	26,159	21,790	**0**	21,790	4,368	20.0	826	3,542	**16.3**
2014	25,533	1,346	0	635	27,513	22,928	**0**	22,928	4,585	20.0	826	3,759	**16.4**
2015	25,604	1,456	0	595	27,654	23,359	**0**	23,359	4,295	18.4	0	4,295	**18.4**
2016	26,881	528	0	595	28,003	23,733	**0**	23,733	4,270	18.0	0	4,270	**18.0**
2017	26,441	491	0	595	27,527	24,122	**0**	24,122	3,404	14.1	0	3,404	**14.1**
2018	26,441	110	0	595	27,146	24,493	**0**	24,493	2,652	10.8	0	2,652	**10.8**
2019	26,441	110	0	595	27,146	24,901	**0**	24,901	2,244	9.0	0	2,244	**9.0**
2020	26,441	110	0	595	27,146	25,302	**0**	25,302	1,843	7.3	0	1,843	**7.3**
2021	26,441	110	0	775	27,326	25,560	**0**	25,560	1,765	6.9	0	1,765	**6.9**
2022	26,441	110	0	775	27,326	26,105	**0**	26,105	1,221	4.7	0	1,221	**4.7**

Col. (2) represents capacity additions and changes, **assuming no generation addition in 2022 in order to demonstrate FPL's gen-only RM trend.**
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the load forecast without incremental DSM or cumulative load management.
Col. (8) shows zero contribution from DSM in order to calculate FPL's reserves that are supplied only by generation resources.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of 826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin Unit 1) and in the Summer of 2014 (at Martin Unit 2) due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Note that although there are no planned generating additions in this reserve margin calculation, the total firm capacity available in Col. (6) rises in 2021 due to the addition of 180MW of capacity from the EcoGen PPA.

Schedule 7.4
Projection of Generation - Only Reserves
At Time Of Summer Peak (Assuming TP6 is added in 2022)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2013	24,215	1,309	0	635	26,159	21,790	**0**	21,790	4,368	20.0	826	3,542	**16.3**
2014	25,533	1,346	0	635	27,513	22,928	**0**	22,928	4,585	20.0	826	3,759	**16.4**
2015	25,604	1,456	0	595	27,654	23,359	**0**	23,359	4,295	18.4	0	4,295	**18.4**
2016	26,881	528	0	595	28,003	23,733	**0**	23,733	4,270	18.0	0	4,270	**18.0**
2017	26,441	491	0	595	27,527	24,122	**0**	24,122	3,404	14.1	0	3,404	**14.1**
2018	26,441	110	0	595	27,146	24,493	**0**	24,493	2,652	10.8	0	2,652	**10.8**
2019	26,441	110	0	595	27,146	24,901	**0**	24,901	2,244	9.0	0	2,244	**9.0**
2020	26,441	110	0	595	27,146	25,302	**0**	25,302	1,843	7.3	0	1,843	**7.3**
2021	26,441	110	0	775	27,326	25,560	**0**	25,560	1,765	6.9	0	1,765	**6.9**
2022	27,541	110	0	775	28,426	26,105	**0**	26,105	2,321	8.9	0	2,321	**8.9**

Col. (2) represents capacity additions and changes, withTurkey Point Unit 6 added in 2022.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the load forecast without incremental DSM or cumulative load management.
Col. (8) shows zero contribution from DSM in order to calculate FPL's reserves that are supplied only by generation resources.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of 826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin Unit 1) an in the Summer of 2014 (at Martin Unit 2) due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability [1]		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2013														
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(389)	(387)	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(376)	(374)	OT
Turkey Point [2]	2	Miami Dade County	ST	FO6	NG	WA	PL	—	—	Dec-13	402,050	(394)	(392)	OT
Sanford CT Upgrade	5C	Volusia County	CC	NG	No	PL	No	Jan-13	Feb-13	Unknown	1,188,860	—	9	OT
Turkey Point (Uprate) [4]	4	Miami Dade County	ST	NP	No	TK	No	—	Mar-13	Unknown	759,900	—	115	V
Sanford CT Upgrade	4D	Volusia County	CC	NG	No	PL	No	Mar-13	Mar-13	Unknown	1,188,860	—	8	OT
Sanford CT Upgrade	4C	Volusia County	CC	NG	No	PL	No	Mar-13	Apr-13	Unknown	1,168,860	—	8	OT
Manatee [3]	1	Manatee County	ST	FO6	NG	WA	PL	Sep-12	Jun-13	Unknown	863,300	(822)	(3)	OT
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	TK	WA	Jun-11	May-13	Unknown	1,296,750	—	1,210	V
Martin [3]	1	Martin County	ST	FO6	NG	PL	PL	Jun-13	Mar-14	Unknown	934,500		(826)	OT
											2013 Changes/Additions Total:	(1,981)	(632)	
2014														
Sanford CT Upgrade	5B	Volusia County	CC	NG	No	PL	No	Aug-13	Sep-13	Unknown	1,188,860	10	—	OT
Turkey Point (Uprate)	4	Miami Dade County	ST	NP	No	TK	No	—	Mar-13	Unknown	759,900	115	—	V
Sanford CT Upgrade	5C	Volusia County	CC	NG	No	PL	No	Jan-13	Feb-13	Unknown	1,188,860	9	10	OT
Sanford CT Upgrade	4D	Volusia County	CC	NG	No	PL	No	Mar-13	Mar-13	Unknown	1,188,860	8	—	OT
Sanford CT Upgrade	4C	Volusia County	CC	NG	No	PL	No	Mar-13	Apr-13	Unknown	1,188,860	8	—	OT
Vero Beach Combined Cycle	1	Indian River	CC	NG	DFO	PL	TK	—	Jan-14	Unknown	—	46	44	OT
Manatee CT Upgrade	3C	Manatee County	CC	NG	No	PL	No	Apr-14	May-14	Unknown	1,224,510	—	10	OT
Manatee CT Upgrade	3D	Manatee County	CC	NG	No	PL	No	Apr-14	May-14	Unknown	1,224,510	—	9	OT
Turkey Point CT Upgrade	5A	Miami Dade County	CC	NG	FO2	PL	TK	Jan-14	Feb-14	Unknown	1,224,510	—	8	OT
Turkey Point CT Upgrade	5B	Miami Dade County	CC	NG	FO2	PL	TK	Jan-14	Feb-14	Unknown	1,224,510	—	8	OT
Turkey Point CT Upgrade	5C	Miami Dade County	CC	NG	FO2	PL	TK	Feb-14	Mar-14	Unknown	1,224,510	—	8	OT
Turkey Point CT Upgrade	5D	Miami Dade County	CC	NG	FO2	PL	TK	Feb-14	Mar-14	Unknown	1,224,510	—	9	OT
Manatee [3]	1	Manatee County	ST	FO6	NG	WA	PL	Sep-12	Jun-13	Unknown	863,300	819		OT
Martin [3]	1	Martin County	ST	FO6	NG	PL	PL	Jun-13	Mar-14	Unknown	934,500	(832)	826	OT
Martin [3]	2	Martin County	ST	FO6	NG	PL	PL	Mar-14	Dec-14	Unknown	934,500		(826)	OT
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	TK	WA	Jun-11	Jun-13	Unknown	1,296,750	1,355	—	V
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	TK	WA	Jun-12	Jun-14	Unknown	1,296,750	—	1,212	U
											2014 Changes/Additions Total:	1,538	1,318	
2015														
Turkey Point CT Upgrade	5A	Miami Dade County	CC	NG	FO2	PL	TK	Jan-14	Feb-14	Unknown	1,224,510	8	—	OT
Turkey Point CT Upgrade	5B	Miami Dade County	CC	NG	FO2	PL	TK	Jan-14	Feb-14	Unknown	1,224,510	8	—	OT
Turkey Point CT Upgrade	5C	Miami Dade County	CC	NG	FO2	PL	TK	Feb-14	Mar-14	Unknown	1,224,510	8	—	OT
Turkey Point CT Upgrade	5D	Miami Dade County	CC	NG	FO2	PL	TK	Feb-14	Mar-14	Unknown	1,224,510	9	—	OT
Martin [3]	1	Martin County	ST	FO6	NG	PL	PL	Jun-13	Mar-14	Unknown	934,500	632	—	OT
Manatee CT Upgrade	3C	Manatee County	CC	NG	No	PL	No	Apr-14	May-14	Unknown	1,224,510	10	—	OT
Manatee CT Upgrade	3D	Manatee County	CC	NG	No	PL	No	Apr-14	May-14	Unknown	1,224,510	9	—	OT
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	TK	WA	Jun-12	Jun-14	Unknown	1,296,750	1,344	—	U
Manatee CT Upgrade	3A	Manatee County	CC	NG	No	PL	No	Aug-14	Sep-14	Unknown	1,224,510	10	10	OT
Manatee CT Upgrade	3B	Manatee County	CC	NG	No	PL	No	Aug-14	Sep-14	Unknown	1,224,510	10	10	OT
Martin [3]	2	Martin County	ST	FO6	NG	PL	PL	Mar-14	Dec-14	Unknown	934,500		826	OT
Ft. Myers CT Upgrade	2B	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	1,775,390	—	8	OT
Ft. Myers CT Upgrade	2F	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	1,775,390	—	9	OT
Ft. Myers CT Upgrade	2D	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	1,775,390	—	8	OT
Ft. Myers CT Upgrade	2E	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	1,775,390	—	9	OT
Ft. Myers CT Upgrade	2A	Lee County	CC	NG	No	PL	No	Jun-15	Jul-15	Unknown	1,775,390	—	8	OT
Ft. Myers CT Upgrade	2C	Lee County	CC	NG	No	PL	No	Jul-15	Aug-15	Unknown	1,775,390	—	9	OT
											2015 Changes/Additions Total:	2,248	897	

(1) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring after August each year will be picked up for reserve margin calculation purposes in the following year.
(2) This generating unit is currently serving as a synchronous condenser and is not included in reserve margin calculation.This unit can be brought back if needed in 2013 but for planning purposes it is not available for reserve margin calculations.
(3) Outages for ESP work.
(4) Turkey Point Nuclear Uprate will be performed during the extended outage.

Note: Schedule 8 shows only planned and prospective changes to generating facilities and does not reflect changes to existing purchases. Those changes are reflected on Tables ES-1, ES-2, I.B.1 and I.B.2.

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(5) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Const. Start Mo./Yr.	(10) Comm. In-Service Mo./Yr.	(11) Expected Retirement Mo./Yr.	(12) Gen. Max. Nameplate KW	(13) Firm Net Capability (1) Winter MW	(14) Firm Net Capability (1) Summer MW	(15) Status
ADDITIONS/ CHANGES														
2016														
Ft. Myers CT Upgrade	2B	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	1,775,390	8	—	OT
Ft. Myers CT Upgrade	2F	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	1,775,390	9	—	OT
Ft. Myers CT Upgrade	2D	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	1,775,390	8	---	OT
Ft. Myers CT Upgrade	2E	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	1,775,390	9	—	OT
Ft. Myers CT Upgrade	2A	Lee County	CC	NG	No	PL	No	Jun-15	Jul-15	Unknown	1,775,390	8	—	OT
Ft. Myers CT Upgrade	2C	Lee County	CC	NG	No	PL	No	Jul-15	Aug-15	Unknown	1,775,390	9	—	OT
Port Everglades Next Generation Clean Energy Center	1	City of Hollywood	CC	NG	FO2	TK	WA	Jun-14	Jun-16	Unknown	Unknown	---	1,277	U
											2016 Changes/Additions Total:	**51**	**1,277**	
2017														
Vero Beach Combined Cycle	1	Indian River	CC	NG	DFO	PL	TK	—	---	Jan-17	---	(46)	(44)	OT
Port Everglades Next Generation Clean Energy Center	1	City of Hollywood	CC	NG	FO2	TK	WA	Jun-14	Jun-16	Unknown	Unknown	1,429	—	U
Turkey Point Synchronous Condenser	1	Miami Dade County	ST	FO6	NG	WA	PL	—	---	Jun-16	402,050	(398)	(396)	OT
											2017 Changes/Additions Total:	**1,031**	**(396)**	
2018														
												---	---	
											2018 Changes/Additions Total:	**0**	**0**	
2019														
												—	---	
											2019 Changes/Additions Total:	**0**	**0**	
2020														
												—	—	
											2020 Changes/Additions Total:	**0**	**0**	
2021														
												---	—	
											2021 Changes/Additions Total:	**0**	**0**	
2022														
Turkey Point	6	Miami Dade County	ST	NP	No	TK	No	2014	Jun-22	Unknown	Unknown	---	1,100	T
											2022 Changes/Additions Total:	**0**	**1,100**	

(1) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring after August each year will be picked up for reserve margin calculation purposes in the following year.

Note: Schedule 8 shows only planned and prospective changes to generating facilities and does not reflect changes to existing purchases. Those changes are reflected on Tables ES-1. ES-2, I.B.1 and I.B.2.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point 4 Nuclear (Uprate)

(2) **Capacity**

a. Summer	115	MW (Incremental)
b. Winter	115	MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**

a. Field construction start-date:	During scheduled refueling outage
b. Commercial In-service date:	2013

(5) **Fuel**

a. Primary Fuel	Uranium
b. Alternate Fuel	---

(6)	**Air Pollution and Control Strategy:**		No change from existing unit
(7)	**Cooling Method:**		No change from existing unit
(8)	**Total Site Area:**		No change from existing unit
(9)	**Construction Status:**	V	(Under construction, more than 50% complete)
(10)	**Certification Status:**	V	(Under construction, more than 50% complete)
(11)	**Status with Federal Agencies:**	V	(Under construction, more than 50% complete)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data *,****

Book Life (Years):	21	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:

(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2013 Nuclear Cost Recovery filing.

(2) Not applicable due to early recovery of capital carrying costs.

(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.

** $/incremental kW

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Cape Canaveral Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,210 MW
b. Winter 1,355 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2011
b. Commercial In-service date: 2013

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 43 Acres

(9) **Construction Status:** V (Under construction, more than 50% complete)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.5%	
Resulting Capacity Factor (%):	Approx. 90 %	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,484	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2013 $/kW):	921	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	98	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2013 $)	13.29	
Variable O&M ($/MWH): (2013 $)	0.16	
K Factor:	1.484	

* $/kW values are based on Summer capacity for in service year.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing plant are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Riviera Beach Next Generation Clean Energy Center

(2) **Capacity** *

a. Summer	1,212	MW
b. Winter	1,344	MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2012
b. Commercial In-service date:	2014

(5) **Fuel**

a. Primary Fuel	Natural Gas
b. Alternate Fuel	Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 33 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.5%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,480	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data** *,**

Book Life (Years):	30 years
Total Installed Cost (2014 $/kW):	1,053
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	121
Escalation ($/kW):	
Fixed O&M ($/kW-Yr): (2014 $)	13.67
Variable O&M ($/MWH): (2014 $)	0.13
K Factor:	1.509

* $/kW values are based on Summer capacity for in service year.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.Demolition costs of existing plant are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Vero Beach Combined Cycle Capacity

(2) **Capacity**
a. Summer 46 MW
b. Winter 44 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: Not Applicable - See Note 1 below.
b. Commercial In-service date: 2014

(5) **Fuel**
a. Primary Fuel Gas
b. Alternate Fuel Oil

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 16 Acres

(9) **Construction Status:** See note 1 below

(10) **Certification Status:** See note 1 below

(11) **Status with Federal Agencies:** See note 1 below

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	20.5%	
Forced Outage Factor (FOF):	0.0%	
Equivalent Availability Factor (EAF):	72.5%	
Resulting Capacity Factor (%):	3.88%	
Average Net Operating Heat Rate (ANOHR):	9,397	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data**

Book Life (Years):	TBD	years
Total Installed Cost ($/kW):	Not Applicable	
Direct Construction Cost ($/kW):	Not Applicable	
AFUDC Amount ($/kW):	Not Applicable	
Escalation ($/kW):	Not Applicable	
Fixed O&M ($/kW-Yr): ($)	Not Applicable	
Variable O&M ($/MWH): ($)	Not Applicable	
K Factor:	Not Applicable	

NOTE 1: The combined cycle capacity consists of two units. FPL is also taking ownership of three other steam units.The three units will be retired as soon as they aquired.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:**	Port Everglades Next Generation Clean Energy Center	
(2) **Capacity**		
a. Summer	1,277 MW	
b. Winter	1,429 MW	
(3) **Technology Type:**	Combined Cycle	
(4) **Anticipated Construction Timing**		
a. Field construction start-date:	2014	
b. Commercial In-service date:	2016	
(5) **Fuel**		
a. Primary Fuel		Natural Gas
b. Alternate Fuel		Ultra-low sulfur distillate
(6) **Air Pollution and Control Strategy:**		Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate
(7) **Cooling Method:**		Once-through cooling water
(8) **Total Site Area:**	Existing Site	Acres
(9) **Construction Status:**	U	(Under construction, less than or equal to 50% complete)
(10) **Certification Status:**	---	
(11) **Status with Federal Agencies:**	---	
(12) **Projected Unit Performance Data:**		
Planned Outage Factor (POF):		3.5%
Forced Outage Factor (FOF):		1.1%
Equivalent Availability Factor (EAF):		95.4%
Resulting Capacity Factor (%):		Approx. 90% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):		6,330 Btu/kWh
Base Operation 75F,100%		
(13) **Projected Unit Financial Data *,****		
Book Life (Years):		30 years
Total Installed Cost (2016 $/kW):		928
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		87
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2016 $)		30.00
Variable O&M ($/MWH): (2016 $)		0.10
K Factor:		1.51

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing plant are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Turkey Point Nuclear Unit 6	
(2)	**Capacity**		
	a. Summer	1,100 MW	
	b. Winter	1,100 MW	
(3)	**Technology Type:**	Nuclear	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2015	
	b. Commercial In-service date:	2022	
(5)	**Fuel**		
	a. Primary Fuel	Uranium Dioxide	
	b. Alternate Fuel	N/A	
(6)	**Air Pollution and Control Strategy:**	N/A	
(7)	**Cooling Method:**	Mechanical Draft Cooling Towers	
(8)	**Total Site Area:**	211 Acres	
(9)	**Construction Status:**	T	(Regulatory approval received, but not under construction)
(10)	**Certification Status:**	T	(Regulatory approval received, but not under construction)
(11)	**Status with Federal Agencies:**	T	(Regulatory approval received, but not under construction)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	TBD	
	Forced Outage Factor (FOF):	TBD	
	Equivalent Availability Factor (EAF):	TBD	
	Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):	TBD	Btu/kWh
	Base Operation 75F,100%		
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	TBD	years
	Total Installed Cost ($/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount ($/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr): ($)	TBD	
	Variable O&M ($/MWH): ($)	TBD	
	K Factor:	TBD	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing plant are not included.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point 4 Nuclear (Uprate)

The Turkey Point 4 Nuclear (Uprate) does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Cape Canaveral Next Generation Clean Energy Center (Modernization)

The Cape Canaveral Next Generation Clean Energy Center which will result from the modernization of the Cape Canaveral power plant site does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Riviera Beach Next Generation Clean Energy Center (Modernization)

The Riviera Beach Energy Center which will result from the modernization of the Riviera Beach power plant site will require one new line and existing lines to be extended and reconfigured to accommodate the increased capacity.

(1)	Point of Origin and Termination:	Riviera Beach – Cedar Substation
(2)	Number of Lines:	1
(3)	Right-of-way	Existing, FPL - Owned
(4)	Line Length:	15 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 2012 End date: 2014
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$12,100,000
(8)	Substations:	Riviera Beach Substation and Cedar Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Vero Beach Existing Combined Cycle Capacity

The Vero Beach existing combined cycle capacity that FPL will take ownership of starting January 1, 2014 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Port Everglades Next Generation Clean Energy Center

The Port Everglades Next Generation Clean Energy Center which will result from the modernization of the Port Everglades power plant site does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 6

The Turkey Point New Nuclear Project starting with the addition of Turkey Point Unit 6 will require a new substation and five new transmission lines terminating at existing substations.

(1)	Point of Origin and Termination:	New Clear Sky Substation – Levee Substation
(2)	Number of Lines:	2
(3)	Right-of-way	FPL Owned
(4)	Line Length:	43 miles
(5)	Voltage:	500 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Levee Substation
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	New Clear Sky Substation – Pennsuco Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	52 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Pennsuco Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 6 (continued)

(1)	Point of Origin and Termination:	New Clear Sky Substation – Davis Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	19 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Davis Substation
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	Davis Substation – Miami Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	18 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	Davis Substation and Miami Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 6 (continued)

(1)	Point of Origin and Termination:	New Clear Sky Substation – Turkey Point Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	0.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Turkey Point Substation
(9)	Participation with Other Utilities:	None

Schedule 11.1

Existing FIRM and NON-FIRM Capacity and Energy by Primary Fuel Type
Actuals for the Year 2012

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	Summer (MW)	Summer (%)	Winter (MW)	Winter (%)	GWh [(2)]	%
(1)	Coal	896	3.4%	911	3.3%	4,745	4.3%
(2)	Nuclear	3,333	12.8%	3,422	12.5%	16,916	15.3%
(3)	Residual	4,822	18.5%	4,862	17.8%	378	0.3%
(4)	Distillate	648	2.5%	710	2.6%	54	0.0%
(5)	Natural Gas	14,331	55.1%	15,397	56.3%	80,594	72.7%
(6)	Solar	35	0.1%	35	0.1%	71	0.1%
(7)	***FPL Existing Units Total [(1)]:***	***24,065***	***92.5%***	***25,337***	***92.7%***	***102,758***	***92.7%***
(8)	Renewables (Purchases)- Firm	61.0	0.2%	112.0	0.4%	496	0.4%
(9)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	867	0.8%
(10)	***Renewable Total:***	61.0	0.2%	112.0	0.4%	1,363	1.23%
(11)	***Purchases Other :***	1,889.0	7.3%	1,896.0	6.9%	6,746	6.1%
(12)	***Total:***	*26,015.0*	*100.0%*	*27,345.0*	*100.0%*	*110,867*	*100.0%*

Note:

(1) FPL Existing Units Total values on row (7), columns (2) and (4), match the System Firm Generating Capacity values found on Schedule 1 for Summer and Winter.

(2) Net Energy for Load GWh values on row (12), column (6), matches Schedule 6.1 value for 2012.

Schedule 11.2

Existing NON-FIRM Self-Service Renewable Generation Facilities
Actuals for the Year 2012

1	2	3	4	5	6 = 3 + 4 - 5
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh)	Annual Energy Purchased from FPL (MWh)	Annual Energy Sold to FPL (MWh)	Projected Annual Energy Used by Customers (MWH)
Customer-Owned Renewable Generation (0 kW to 10 kW)	9.9	11,601	103,518	408	114,710
Customer-Owned Renewable Generation (> 10 kW to 100 kW)	5.5	6,454	170,710	298	176,866
Customer-Owned Renewable Generation (> 100 kW - 2 MW)	3.6	4,647	111,472	180	115,938
Total	19	22,702	385,699	886	407,514

Notes:

(1) There were 2,117 customers with renewable generation facilities interconnected with FPL on December 31, 2012.

(2) The Installed Capacity value is the sum of the nameplate ratings (DC MW) for all of the customer-owned renewable generation facilities connected as of Dec. 31,2012.

(3) The Projected Annual Output value is based on NREL's PV Watts 1 program and the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.

(4) The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2012.

(5) The Annual Energy Sold to FPL is an actual value from FPL's metered data for 2012.

(6) The Projected Annual Energy Used by Customers is a projected value that equals: (Renewable Projected Annual output + Annual Energy Purchased from FPL) minus the Annual Energy Sold to FPL.

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

Florida is a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered or threatened plant and animal species. Florida's communities and ecology require the same air, land, and water resources that are necessary to meet the demand for the generation, transmission, and distribution of electricity. The general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner that minimizes demands on the natural environment.

FPL has been recognized for many years as one of the leaders among electric utilities for its commitment to the environment. Being responsible stewards of the environment is ingrained in FPL's corporate culture. FPL has one of the lowest emissions profiles among U.S. utilities and in 2012 its carbon dioxide (CO_2) emission rate was 29% lower (better) than the industry average.

The environmental leadership of FPL and its parent company, NextEra Energy, Inc., has been heralded by many outside organizations as demonstrated by a few recent examples. NextEra Energy, Inc. was named to the 2012 Dow Jones Sustainability Index (DJSI) of the leading companies in North America for corporate sustainability for the fourth consecutive year. The DJSI North America selects the top 20 percent of companies in sustainability performance from the 600 largest companies in North America. According to Sustainable Asset Management, the investment research firm that conducts the DJSI research, the evaluation is continuously adapted to capture the sustainability trends that are at the forefront of each industry sector and are likely to have an impact on the companies' competitive landscape.

According to the 2013 "World's Most Admired Companies" report released by Fortune magazine, NextEra Energy, Inc. ranked, for a record seventh consecutive year, No. 1 in its industry. Being ranked first, for six consecutive years, is unprecedented in the industry and according to *Fortune*, America's Most Admired Companies is "the definitive report card on corporate reputations". In the same report, NextEra Energy, Inc. ranked in the top 10 among the most admired companies in the state of Florida.

FPL's responsible tree care practices across its 35-county service area have been recognized for almost a decade. FPL has been the recipient of the Tree Line USA award annually from 2003 - 2012. This award is sponsored by the Arbor Day Foundation in cooperation with the National Association of State Foresters. The recognition is given to utilities that demonstrate quality tree care practices, annual worker training, and public education programs.

In 2012, FPL continued to support the Loggerhead Marinelife Center with a $25,000 donation toward the acquisition of a larger tank to assist in sea turtle rehabilitation. In past years FPL has won the Loggerhead Marinelife Center's "Blue Business of the Year" award. This award is given to those who are leading the way in raising awareness about, and have made significant contributions to improve and protect, South Florida's oceans, beaches, and wildlife. The award recognized FPL's protection and conservation of the endangered Florida manatee and its fostering of public and employee education and support.

FPL employees serve as board members for many organizations that focus on environmental restoration, preservation, and stewardship. A partial list of these organizations includes: Audubon Florida, the Everglades Foundation, the Arthur R. Marshall Foundation, and the Palm Beach Zoo.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Statement in 1992 to clearly define its position, and FPL continues to hold that position. This statement reflects how FPL incorporates environmental values into all aspects of its activities and serves as a framework for new environmental initiatives throughout the company.

FPL's Environmental Statement

It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:

- Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards;
- Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities;

- Encourage the wise use of energy to minimize the impact on the environment;
- Communicate effectively on environmental issues; and
- Conduct periodic self-evaluations and report performance.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL has an Environmental Management System to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program. Other components of the system include: executive management support and commitment, a dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

As part of its commitment to excellence and continuous improvement, FPL will begin to implement an enhanced environmental data management information system (EDMIS) in 2013. Environmental data management software systems are increasingly viewed as an industry best-management practice for environmental compliance needs. FPL's top goal is to improve the flow of environmental data between site operations and corporate services to ensure compliance and improve operating efficiencies. In addition, the EDMIS will help in standardizing data collection, reducing the time to generate state and federal agency reports, and improving external reporting to the public.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities that are designed to evaluate environmental performance, verify compliance with corporate policy as well as legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and FPL policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2012 environmental outreach activities are summarized below in Table IV.E.1.

Table IV.E.1: 2012 FPL Environmental Outreach Activities

Activity	# of Participants (Approx.)
Visitors to FPL's Energy Encounter at St. Lucie	15,000
Visitors to Manatee Park, Ft. Myers	198,000
Number of website visits to FPL's Environmental & Corporate Responsibility Websites	>200,000
Number of pieces of Environmental literature distributed	>20,000
Visitors to Barley Barber Swamp	>3000
Martin Energy Center Solar Tours	500
Solar Schools Program (# of schools participating)	1 school and 2 non-profits

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified seven (7) Preferred Sites and five (5) Potential Sites for future generation additions. Preferred Sites are those locations where FPL has conducted significant reviews and has either taken action, is currently committed to take action, or is likely to take action, to site new generating capacity. Potential Sites are those sites that have attributes that support the siting of generation and are under consideration as a location for future generation. Some of these sites are currently in use as existing generation sites and some are not. The identification of a Potential Site does not indicate that FPL has made a definitive decision to pursue generation (or generation expansion in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of a generator has been determined. The Preferred Sites and Potential Sites are discussed in separate sections below.

As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for adding future power generation. These include the remainder of FPL's existing generation sites and other Greenfield sites. FPL is also analyzing the potential for modernizing additional existing power plant sites such as is now being done at the Cape Canaveral, Riviera Beach, and Port Everglades sites. Analyses of any modernization candidates would include evaluation of numerous factors including: fuel delivery, transmission, permitting, etc.

IV.F.1 Preferred Sites

FPL currently identifies seven (7) Preferred Sites. Four of these are existing sites: Turkey Point, Cape Canaveral, Riviera Beach, and Port Everglades; two are new plant sites: Hendry County and Northeast Okeechobee County; and one is the site of a former FPL generating unit: Palatka. The Turkey Point site is discussed in regard to two generation projects. The first Turkey Point project discussed is the Extended Power Uprate (EPU) project to increase capacity at the existing Turkey Point Unit 4. This project is expected to be completed at about the time this document is filed. The second Turkey Point project discussed is the first of two new nuclear units. Turkey Point Unit 6 is currently projected in the resource plan discussed in this Site Plan to come in-service in 2022. The 2022 date represents the current projection of the earliest practical in-service date for this unit.

The Cape Canaveral, Riviera Beach, and Port Everglades sites are locations where the modernization work to replace older steam generating units with new combined cycle (CC) technology is in progress. The modernization work at these three sites is scheduled to be completed in 2013, 2014, and 2016, respectively. The Hendry County, Okeechobee County, and Palatka sites are the likely next locations for new CC units after the modernization projects have been completed. In addition, the Hendry County and Okeechobee County sites are also likely sites for new photovoltaic (PV) facilities.

The first four Preferred Sites are discussed below in general chronological order with respect to when the capacity additions are projected to occur. The remaining three Preferred Sites are discussed in alphabetical order.

<u>Preferred Site # 1: Turkey Point Plant, Miami-Dade County</u>

The Turkey Point Plant (Turkey Point) is located on the west side of Biscayne Bay, 25 miles south of Miami. Turkey Point is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. The land surrounding Turkey Point is owned by FPL and acts as a buffer zone. Turkey Point is comprised of two natural gas/oil conventional steam units (Units 1 & 2), two nuclear units (Units 3 & 4), one combined cycle natural gas unit (Unit 5), nine small diesel generators, and the cooling canals. The Everglades Mitigation Bank (EMB), an approximately 13,000 acre, FPL-maintained natural wildlife and wetlands area that has been set aside, is located to the south and west of the site.

As mentioned above, the Turkey Point Plant site is discussed in this document in regard to two generation projects: the EPU project for an existing nuclear unit (Turkey Point Unit 4), and a new nuclear unit (Turkey Point Unit 6).

Turkey Point Unit 4 has been in operation since 1973. An EPU project for Unit 4 is being completed at the time this document is being finalized. Similar EPU projects were completed during 2012 for three other existing FPL nuclear units: St. Lucie Unit 1, St. Lucie Unit 2, and Turkey Point Unit 3. The EPU work involves changes to several existing main components within the existing facilities to increase their capability to produce steam for the generation of electricity. This capacity uprate, along with similar capacity uprates of FPL's three other existing nuclear units, was included in a final order approved by the Secretary of the Florida Department of Environmental Protection in October 2008.

In regard to Turkey Point Unit 6, FPL is pursuing licensing for two new nuclear units at Turkey Point. Each of these two units would provide 1,100 MW of capacity. The current projections for the earliest practical in-service dates for the two new units are 2022 (for Turkey Point Unit 6) and 2023 (for Turkey Point Unit 7). Because the in-service date for Turkey Point Unit 7 is beyond the 2013 - 2022 reporting time frame of this document, only Turkey Point Unit 6 is discussed in this report. In addition to the two generating units, supporting buildings, facilities and equipment, will be located on the Turkey Point Units 6 & 7 site, along with a construction laydown area. Proposed associated facilities include: a nuclear administration building, a training building, a parking area; an FPL reclaimed water treatment facility and reclaimed water pipelines; radial collector wells and delivery pipelines; an equipment barge unloading area; transmission lines (and transmission system improvements elsewhere within Miami-Dade County), access roads and bridges, and potable water pipelines.

a. U.S. Geological Survey (USGS) Map

USGS maps of the Turkey Point area, with the location of Turkey Point Units 3, 4, 6 and 7 identified, are found at the end of this chapter.

b. Proposed Facilities Layout

Maps of the general layout of Turkey Point Unit 4 (which also includes Turkey Point Unit 3), and of Turkey Point Unit 6 (which also includes Turkey Point Unit 7), are found at the end of this chapter.

c. Map of Site and Adjacent Areas

Land Use / Land Cover overview maps of the Turkey Point Units 3 & 4 and Turkey Point Units 6 & 7 sites and adjacent areas are also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

Turkey Point Plant is currently home to five generating units and support facilities that occupy approximately 150 acres of the approximately 9,400-acre Turkey Point property. Prominent features beyond the power block area include the intake system, cooling canal system, switchyard, spent fuel storage facilities, and technical and administrative support facilities The cooling canal system occupies approximately 5,900 acres.

The two 400-megawatt (MW) (nominal) fossil fuel-fired steam electric generation units at Turkey Point have been in service since 1967 (Unit 1) and 1968 (Unit 2). These units have historically burned residual fuel oil and/or natural gas with a maximum equivalent sulfur content of one percent. Unit 2 is currently serving, not as a power generating unit, but as a synchronous condenser to provide voltage support to the southeastern end of FPL's transmission system. The two original 700-MW (nominal) nuclear units have been in service since 1972 (Unit 3) and 1973 (Unit 4). Turkey Point Units 3 and 4 are pressurized water reactor (PWR) units. Turkey Point Unit 5 is a nominal 1,150-MW natural gas-fired combined cycle unit that began operation in 2007. The site for the new Unit 6 (and Unit 7) is south of existing Units 3 and 4 and occupies approximately 300 acres within the existing cooling canal system.

Properties adjacent to Turkey Point property are almost exclusively undeveloped land. The FPL-owned EMB is adjacent to most of the western and southern boundaries of Turkey Point property. The South Florida Water Management District

(SFWMD) Canal L-31E is also situated to the west of Turkey Point property. The eastern portions of Turkey Point property are adjacent to Biscayne Bay, the Biscayne National Park (BNP), and Biscayne Bay Aquatic Preserve. The southeastern portion of Turkey Point property is bounded by state-owned land located on Card Sound. The Homestead Bayfront Park, owned and operated by Miami-Dade County, is situated to the north of the Turkey Point property.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

Turkey Point is located directly on the northwest, west, and southwest shoreline of Biscayne Bay and the Biscayne National Park, 25 miles south of Miami. Biscayne National Park was first established in 1968 as a National Monument and was expanded in 1980 to approximately 173,000 acres of water, coastal lands, and 42 keys. A portion of Biscayne Bay Aquatic Preserve, a state-owned preserve, is adjacent to the eastern boundary of the Turkey Point plant property. The Biscayne Bay Aquatic Preserve is a shallow, subtropical lagoon consisting of approximately 69,000 acres of submerged State land that has been designated as an Outstanding Florida Water.

The Turkey Point Unit 4 EPU project is located within the area of the existing Turkey Point Unit 4 site, which currently includes a nuclear generation unit and supporting facilities. The approximately 300-acre Turkey Point Units 6 & 7 site consists of the plant area and adjacent areas designated for laydown and ancillary facilities. The site includes hypersaline mud flats, man-made active cooling canals, man-made remnant canals, previously filled areas/roadways, mangrove heads associated with historical tidal channels, dwarf mangroves, open water /discharge canal associated with the cooling canals on the western portion of the site, wet spoil berms associated with remnant canals, and upland spoil areas.

2. Listed Species

Threatened, endangered, and/or animal species of special concern known to occur at the site, and in the nearby Biscayne National Park, include the peregrine falcon *(Falco peregrinus)*, wood stork *(Mycteria americana)*, American crocodile *(Crocodylus acutus)*, mangrove rivulus *(Rivulus marmoratus)*, roseate spoonbill (*Ajaja ajaja)*, little blue heron *(Egretta caerulea),* snowy egret *(Egretta thula),* American oystercatcher *(Haematopus palliates),* least tern *(Sterna antillarum)*, the white ibis *(Eudocimus albus)*, and bald eagle *(Haliaeetus leucocephalus)*. No bald eagle nests are known to exist in the vicinity of the site. The federally listed, threatened American crocodile thrives at Turkey Point, primarily in and around the southern end of the cooling canals which lie south of the Turkey Point Unit 4 and Turkey Point Unit 6 areas. The majority of Turkey Point is considered American crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American Crocodile and the program is credited with survival improvement and contributing to the downlisting of the American Crocodile from endangered to threatened.

Some listed flora species likely to occur at the site or vicinity include golden leather fern (Acrostichum aureum), pinepink (Bletia purpurea), Florida brickell-bush (Brickellia mosieri), Florida lantana (Lantana depressa var. depressa), mullien nightshade (Solanum donianum), and lamarck's trema (Trema lamarckianum).

During the construction and operation after construction, neither the Turkey Point Unit 4 EPU project nor the new Turkey Point Unit 6 project are expected to adversely affect any rare, endangered, or threatened species.

3. <u>Natural Resources of Regional Significance Status</u>

Significant features within the vicinity of the site include Biscayne National Park, the Biscayne Bay Aquatic Preserve, Miami-Dade County Homestead Bayfront Park, and Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park. Biscayne National Park contains 180,000 acres, approximately 95 percent of which is open water interspersed with more than 40 keys. The Biscayne National Park headquarters is located approximately two miles north of Turkey Point and is adjacent to the Miami-Dade County Homestead Bayfront Park, which contains a marina and day-use recreational facilities.

4. <u>Other Significant Features</u>

FPL is not aware of any other significant features of the site.

f. <u>Design Features and Mitigation Options</u>

In regard to the EPU project for Turkey Point Unit 4, this unit uses cooling water from a closed-loop cooling canal system to remove heat from the main (turbine) condensers, and to remove heat from other auxiliary equipment. The existing cooling canals will accommodate the slight increase in heat load that is associated with the increased capacity from the uprate. The maximum projected increase in water temperature entering the cooling canal system resulting from the nuclear uprate project is predicted to be about 3°F, from 106°F to 109°F. The associated projected maximum increase in water temperature returning to the unit is about 1°F, from 92°F to 93°F.

For Turkey Point Unit 6, the technology proposed is the Westinghouse AP1000 pressurized water reactor (PWR).[7] This design is certified by the NRC under 10 CFR 52 and incorporates the latest technology and more advanced safety features than today's nuclear plants that have already achieved record safety levels. The Westinghouse AP1000 unit consists of the reactor, steam generators, pressurizer, and steam turbine/electric generator. Condenser cooling for the Unit 6 steam turbine will be accomplished using three circulating water cooling towers. The makeup water reservoir is the reinforced concrete structure beneath the circulating water system cooling towers that will contain reserve reclaimed water capacity to be used for the circulating water system. The structures for the Westinghouse AP1000 are the nuclear island (containment building, shield building, and auxiliary building), turbine building, annex building, diesel generator building, and radwaste building. The plant area will also contain the Clear Sky substation (switchyard) that will connect Unit 6 to FPL's transmission system.

g. <u>Local Government future Land Use Designations</u>

The Turkey Point Plant site is designated by the Miami-Dade County Comprehensive Development Management Plan as an IU-3 (Industrial, Utilities, and Communications) Unlimited Manufacturing District that carries a dual designation of MPA (Mangrove Protection Area) in portions of the property. There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

[7] Unless otherwise noted, the information presented for Turkey Point Unit 6 will also apply for Turkey Point Unit 7 whose currently projected in-service date is outside of the 2013-2022 reporting period addressed in this document.

h. Site Selection Criteria Process

The site has been selected as a Preferred Site for the EPU project for existing Unit 4 because it is an existing nuclear plant site and, therefore, offers the opportunity for increased nuclear capacity. For Turkey Point Unit 6, FPL conducted an extensive site selection analysis leading to the selection of the Turkey Point site as the site that, on balance, provided the most favorable location for developing new nuclear generation to serve FPL's customers. The Site Selection Study employed the principles of the Electric Power Research Institute (EPRI) siting guidelines and is modeled upon applicable NRC site suitability and National Environmental Policy Act (NEPA) criteria regarding the consideration of alternative sites. The study convened a group of industry and FPL subject matter experts to develop and assign weighting factors to a broad range of site selection criteria. Twenty-three candidate sites were then ranked using the siting criteria. This review allowed the list of candidates to be reduced until the best site emerged. Key factors contributing to the selection of the Turkey Point site include the existing transmission and transportation infrastructure to support new generation, the large size and seclusion of the site while being relatively close to the load center, and the long-standing record of safe and secure operation of nuclear generation at the site since the early 1970s.

i. Water Resources

Unique to Turkey Point is the closed-loop cooling canal system that supplies water to condense steam used by the plant's turbine generators. The canal system consists of 36 interconnected canals. The cooling canals occupy an area approximately two miles wide by five miles long (5,900 acres) and are approximately four feet deep. The system performs the same function as a car radiator. The water is circulated through the canals in a two-day journey, ending at the plant's intake pumps. The cooling canal system is utilized for cooling by Turkey Point Units 3 and 4 nuclear units.

In regard to Turkey Point Unit 6, the primary source of cooling water makeup will be reclaimed water from the Miami-Dade County Water and Sewer Department (MDWASD), with potable water also from MDWASD. When reclaimed water is not available in sufficient quantity and quality of water needed for cooling, makeup water will be saltwater supplied by radial collector wells that are recharged from the marine environment of Biscayne Bay. Horizontal collector wells (radial collector wells) have become widely used for the purpose of inducing infiltration from surface water bodies into hydraulically-connected aquifer systems in order to develop moderate to high capacity water supplies.

Turkey Point Unit 6 wastewater will be discharged via on-site deep injection wells.

j. Geological Features of Site and Adjacent Areas

Turkey Point lies upon the Floridian Plateau, a partly-submerged peninsula of the continental shelf. The peninsula is underlain by approximately 4,000 to 15,000 feet of sedimentary rocks consisting of limestone and associated formations that range in age from Paleozoic to Recent. Little is known about the basement complex of Paleozoic igneous and metamorphic rocks due to their great depth.

Generally in Miami-Dade County, the surficial aquifer (Biscayne Aquifer) consists of a wedge-shaped system of porous clastic and carbonate sedimentary materials, primarily limestone and sand deposits of the Miocene to late Quaternary age. The Biscayne Aquifer is thickest along the eastern coast and varies in thickness from 80 to 200 feet thick. The surficial aquifer is typically composed of Pamlico Sand, Miami Limestone (Oolite), the Fort Thompson and Anastasia Formations (lateral equivalents), Caloosahatchee Marl, and the Tamiami formation. The lower confining layers below the surficial aquifer range in thickness from 350 to 600 feet and are composed of the Hawthorn Group. Beneath the Hawthorn Group, the Floridan Aquifer System ranges from 2,800 to 3,400 feet thick and consists of Suwannee Limestone, Avon Park Limestone, and the Oldsmar Formations.

k. Projected Water Quantities for Various Uses

There will be no increase in the amount of water required due to the additional capacity that will result from the EPU project for existing Turkey Point Unit 4.

The estimated quantity of water required for the new Turkey Point Unit 6 for industrial processing is approximately 468 gallons per minute (gpm) for uses such as process water and service water. Approximately 27.7 million gallons per day (mgd) of cooling water would be cycled through the cooling towers. Water quantities needed for other uses such as potable water are estimated to be approximately 25,200 gallons per day (gpd) for Unit 6.

l. Water Supply Sources and Type

The source of cooling water for Turkey Point Unit 4 is the cooling canal system. There will be no increase in the amount of water withdrawn as a result of the additional capacity that will result from the EPU project. General plant service water, fire protection water, process water, and potable water are obtained from Miami-

Dade County. Process water uses include demineralizer regeneration, steam cycle makeup, and general service water use for washdowns. The water use for the facility will not change as a result of the EPU project.

In regard to Turkey Point Unit 6, the water for the various plant water needs will be obtained from a reclaimed water supply, a saltwater supply, and a potable water supply. Reclaimed water will be used as makeup water to the cooling water system with saltwater from radial collector wells as a back-up water source to be used when reclaimed water is not available in sufficient quantity or quality.

Potable water will be used as makeup water for the service water system. The potable water supply will also provide water to the fire protection system, demineralized water treatment system, and other miscellaneous uses.

m. <u>Water Conservation Strategies</u>

The existing water resources will not change as a result of the EPU project at Turkey Point Unit 4. Regarding Turkey Point Unit 6, use of reclaimed water from MDWASD is a beneficial and cost-effective means of increasing the use of reclaimed water. This use of reclaimed water helps Miami-Dade County meet approximately half of its wastewater reuse goals and will provide environmental benefits by reducing the volume of wastewater discharged by the County. In the absence of reuse opportunities, this treated domestic wastewater would likely continue to be discharged to the ocean or into deep injection wells.

Miami-Dade County is required to eliminate ocean outfalls and increase the amount of water that is reclaimed for environmental benefit and other beneficial uses. Turkey Point Unit 6 will use reclaimed water 24 hrs per day, 365 days per year when operating and water is available in sufficient quantity and quality.

n. <u>Water Discharges and Pollution Control</u>

Heated water discharges from Turkey Point Unit 4 are dissipated using the existing closed-loop cooling canal system. The additional generating capacity as a result of the EPU project for Turkey Point Unit 4 will not cause any changes in the quantity or characteristics of industrial wastewaters generated by the facility. Nor will the increased generating capacity at Turkey Point Unit 4 cause any changes in hydrologic or water quality conditions due to diversion, interception, or additions to surface water flow. The existing units at Turkey Point do not directly withdraw groundwater under current operations and they will not do so after the EPU project is completed. Locally, groundwater is present beneath the site in the surficial or Biscayne Aquifer and in deeper aquifer zones that are part of the Floridan Aquifer System. There will be no effects on those deeper aquifer zones from the EPU project.

Turkey Point Unit 6 will dissipate heat from the power generation process using cooling towers. Blowdown water or discharge from the cooling towers, along with other wastestreams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Storm water runoff will be released to the closed-loop cooling canal system.

Turkey Point Unit 4 employs, and Turkey Point Unit 6 will employ, Best Management Practices (BMP) plans and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o. <u>Fuel Delivery, Storage, Waste Disposal, and Pollution Control</u>

Turkey Point Unit 4 utilizes uranium-dioxide fuel that is slightly enriched uranium-235. The uranium-dioxide fuel is in the form of pellets contained in Zircaloy tubes with welded end plugs to confine radionuclides. The tubes are fabricated into assemblies designed for loading into the reactor core. Used fuel assemblies are stored in the onsite NRC-approved spent fuel storage facilities.

FPL currently replaces approximately one-third of the fuel assemblies in each reactor at refueling intervals of approximately 18 months. FPL operates each reactor such that the average fuel usage by a reactor is approximately 45,000 megawatt-days per metric ton of uranium. Following completion of the EPU project for Turkey Point Unit 4, more nuclear fuel will be used due to the increased generating capacity. No changes in the fuel handling facilities are required.

In regard to Turkey Point Unit 6, the reactor will contain enriched uranium fuel assemblies. A fuel assembly consists of 264 fuel rods in a 17-by-17 square array. The fuel rods consist of enriched uranium, in the form of cylindrical pellets of sintered uranium dioxide contained in ZIRLO™ tubing.

New fuel assemblies will be transported to Turkey Point for use in Unit 6 by truck from a fuel fabrication facility in accordance with U.S. Department of Transportation

(DOT) and NRC regulations. Spent fuel assemblies being discharged will remain in the spent fuel pool while short half-life isotopes decay.

After a sufficient decay period, the fuel would be transferred to an on-site independent spent fuel storage installation facility or an off-site disposal facility. Packaging of the fuel for off-site shipment will comply with the applicable DOT and NRC regulations for transportation of radioactive material.

The U.S. Department of Energy (DOE) is responsible for spent fuel transportation from reactor sites to a repository under the Nuclear Waste Policy Act of 1982, as amended. FPL has executed a standard spent nuclear fuel disposal contract with DOE for fuel used in Unit 6.

At Turkey Point Unit 4 diesel fuel is used in a number of emergency generators that include four main emergency generators, five smaller emergency generators, and various general purpose diesel engines. The emergency generators will not be changed as a result of the EPU project. These emergency generators are for stand-by use only and only operated for testing purposes to assure reliability and for maintenance. Diesel fuel for the emergency generators is delivered to Turkey Point by truck as needed, and stored in tanks with secondary containment.

p. **Air Emissions and Control Systems**

The normal operation of Turkey Point Unit 4 does not create fossil fuel-related air emissions. However, there are emergency generators associated with Unit 4. Four of these nine emergency generators are main plant emergency generators which are rated at 2.5 MW each. The remaining five generators are smaller emergency generators which are associated with the security system. In addition, various general purpose diesels are used as needed. No additional generators are required as part of the EPU project for Turkey Point Unit 4.

The Turkey Point Unit 4 associated emergency generators and diesel engines, together with Turkey Point Units 1, 2, and 5, are classified as a major source of air pollution. FDEP has issued a separate Title V Air Operating Permit for Turkey Point (Permit Number 0250003-004-AV). There are no operating limits for the emergency generators or diesel engines. Emergency diesel generators are limited to use ultra-low sulfur diesel fuel (0.0015% sulfur). NOx emissions are regulated under Reasonably Available Control Technology (RACT) requirements in Rule 62-296.570(4) (b) 7 F.A.C., which limit NO_x emissions to 4.75 lb/MMBtu. The use of 0.05

percent sulfur diesel fuel and good combustion practices serve to keep NO_x emissions under this limit.

Regarding Turkey Point Unit 6, the unit will also minimize FPL system air pollutant emissions by using nuclear fuel to generate electric power. This includes avoiding emissions of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon monoxide (CO), carbon dioxide (CO_2), and volatile organic compounds (VOC). The circulating water cooling towers will be equipped with high-efficiency drift or mist eliminators to minimize emissions of PM to 0.0005 percent of the circulating water; this is over 99.99-percent control of potential drift emissions based on the circulating water flow.

The diesel engines necessary to support Turkey Point Unit 6 and fire pump engines will be purchased from manufacturers whose engines meet the EPA's NSPS Subpart IIII emission limits.

q. **Noise Emissions and Control Systems**

Field surveys and impact assessments of noise expected to be caused by activities associated with the Turkey Point Unit 4 EPU project and the Turkey Point Unit 6 project were conducted. Predicted noise levels associated with these projects are not expected to result in adverse noise impacts in the vicinity of the site.

r. **Status of Applications**

The Turkey Point Unit 4, EPU Site Certification Application (SCA), under the Florida Electrical Power Plant Siting Act, was filed in January 2008 and a final order was issued in October 2008. The FPSC voted to approve the need for additional generating capacity at Turkey Point and the final order approving the need for this additional nuclear capacity was issued in January 2008. In addition, a License Amendment request for the EPU was submitted to the NRC in October 2010. The License Amendment was approved in June 2012.

The Turkey Point Unit 6 Site Certification Application (SCA), under the Florida Electrical Power Plant Siting Act, was filed in June 2009 and a final order is currently expected in January 2014. The FPSC issued the final order approving the need for this additional nuclear capacity in April 2008.

A License Amendment request for Unit 6 was submitted to the NRC in June 2009. There are two components to that application; one is the Environmental Assessment (EA) and the other is the Safety component. The Application is still in process.

Besides the certification and the license amendment, additional permits have been issued for Turkey Point Units 6 & 7 including Miami-Dade County Unusual Use approvals that were issued in 2007 and 2013 and the Prevention of Significant Deterioration (Air permit) that was issued in 2009. In addition, a permit to construct an exploratory well and a dual zone monitoring well, under the Underground Injection Control Program, was issued in 2010. Permits from the FAA for the containment structure were originally issued in 2009 and renewed in 2012.

Preferred Site # 2: Cape Canaveral Plant, Brevard County

This site is located on the existing FPL Cape Canaveral Plant property in unincorporated Brevard County. The site is bound to the east by the Indian River Lagoon and on the west by a four-lane highway (U.S. Highway 1). The city of Port St. Johns is located less than a mile away. A rail line is located near the plant.

The site previously housed two steam generating units (Units 1 & 2) with 788 MW (Summer) of generating capacity. The units formerly occupied a portion of the 43 acres that are wholly owned by FPL. FPL is in the process of modernizing the existing Cape Canaveral Plant, to be renamed the Cape Canaveral Next Generation Clean Energy Center (CCEC), by replacing the previous two steam generating units with a single modern, highly efficient, lower-emission next-generation clean energy center using advanced CC technology. The old units have been taken out of service and dismantled. The demolition of the Cape Canaveral Plant began in mid-2010 and was completed during the first quarter of 2011. Construction for the new CC unit began in March 2011 and is expected to be completed by June 2013.

a. Geological Survey (USGS) Map

A USGS map of the CCEC site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the general layout of the CCEC generating facilities at the site is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

The existing and future land uses on the site are primarily dedicated to electrical generation; i.e., FPL's former Cape Canaveral Units 1 & 2 and the future CCEC unit. The existing land uses that are adjacent to the site consist of single- and multi-family residences to the south and southwest, commercial property to the northwest, utility systems to the west, and a private medical/office facility to the north.

e. **General Environment Features On and In the Site Vicinity**

1. **Natural Environment**

The natural environment surrounding the site includes the Indian River Lagoon to the east and upland scrub, pine and hardwoods to the north and south. Vegetation within the approximately 45-acre offsite construction laydown and parking area (located west of U.S. Highway 1) consists of open land, upland scrub, pine, hardwoods along with exotic plant species.

2. **Listed Species**

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction of the CCEC at the site, due to the existing developed nature of the site and lack of suitable habitat for listed species. Federal- or state-listed terrestrial plants and animals inhabiting the offsite construction laydown and parking area are limited to the state-listed gopher tortoise and the state- and federally-listed scrub jay. The warm water discharges from the plant attract manatees, an endangered species. FPL continues to work closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process. In 2010, FPL installed a temporary heating system to warm the water for the manatees as required during manatee season. FPL has complied, and will continue to comply, with several other manatee-related conditions of certification to ensure the protection of the manatees during the modernization work and during subsequent operation of the new generating facility.

3. Natural Resources of Regional Significance Status

The construction and operation of the CCEC at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option is to replace the previous steam generating units (Units 1 & 2) with one new 1,210 MW (Summer) CC unit consisting of three new combustion turbines (CTs), three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit is projected to be in-service in mid-2013. Natural gas delivered via pipeline is the primary fuel type for this unit with ultra-low sulfur light fuel oil serving as a backup fuel.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is "Public Utilities" and the area has been rezoned to GML-U. Designations for the surrounding area are primarily "Community Commercial" and "Residential". A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Cape Canaveral Plant site was selected for a site modernization due to consideration of various factors including system load and economics. Environmental issues were not a significant factor since this site was the site of a previous power plant and does not exhibit significant environmental sensitivity or other environmental issues. However, the significant reduction in cooling water withdrawal and thermal component of cooling water discharges are environmental benefits of replacing the previous steam units with a new CC unit. Other environmental benefits include a significant reduction in system fuel use, a significant reduction in system air emissions, improved aesthetics at the site, and continued warm water discharge for the manatees as required during manatee season. Further, modernizing this existing facility reduces the impact on natural resources by not requiring new land, new water sources, or additional off-site transmission siting.

i. Water Resources

Condenser cooling for the steam cycle portion of the new plant and auxiliary cooling will come from the existing cooling water intake system. Process, potable, and reclaimed water for the new plant will come from the existing City of Cocoa's potable water supply.

j. Geological Features of Site and Adjacent Areas

The site is located on the Atlantic Coastal Ridge and is at an approximate elevation of 12 feet above mean sea level (msl). The land consists primarily of fine to medium sand that parallels the coast. There is a lack of shell as it was deposited during a time of transgression. The base of the sedimentary rocks is made up of a thick, primarily carbonate sequence deposited during the Jurassic age through the Pleistocene age. Starting in the Miocene age and continuing through the Holocene age, siliciclastic sedimentation became more predominant. The basement rocks in this area consist of low-grade metamorphic and igneous intrusives, which occur several thousand feet below land surface and are Precambrian, Paleozoic, and Mesozoic in age.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing is approximately 0.232 million gallons per day (mgd) for uses such as process water and service water. Potable water demand is expected to average .001 mgd. Approximately 600 mgd of cooling water would be cycled through the once-through cooling water system.

l. Water Supply Sources by Type

The modernized plant will continue to use the Indian River Lagoon water as the source of once-through cooling water. Such needs for cooling water will comply with the St. John's River Water Management District (SJRWMD) conditions in the site certification. Process and potable water for the new plant will come from the existing City of Cocoa's potable water supply. Reclaimed water may be used for irrigation.

m. Water Conservation Strategies Under Consideration

No additional water resources will be required as a result of the modernization project. CC technology uses less water by design than traditional steam generation units.

n. Water Discharges and Pollution Control

The modernized site will utilize portions of the existing once-through cooling water systems for heat dissipation. The heat recovery steam generator blowdown (wastewater discharge required to maintain process water quality) will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system. Storm water runoff will be collected and routed to storm water ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit will be transported to the site via a pipeline. New off-site gas compressors will be used to raise the gas pressure of the existing pipeline for the new unit. Ultra-low sulfur light fuel oil will be received by truck or barge from Port Canaveral and stored in an above-ground storage tank.

p. Air Emissions and Control Systems

The emission rates of CCEC would decrease by over 90% from the former Cape Canaveral Plant, resulting in substantial annual emission reductions and increased air quality benefits per unit of energy produced. The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize air emissions from the CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. CC facility emissions of greenhouse gases (GHGs) from combustion of natural gas achieve an emission rate substantially lower than the EPA proposed new source performance standards for GHGs. In total, the design of the new CCEC plant will incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida.

q. **Noise Emissions and Control Systems**

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site. Noise from the operation of the new unit will be within allowable levels.

r. **Status of Applications**

The FPSC voted to approve the need for the modernization project and the need order was issued in September 2008. The project received final state certification on October 9, 2009, through the issuance of a final order signed by the Secretary of the Department of Environmental Protection (DEP).

Preferred Site # 3: Riviera Beach Plant, Palm Beach County

This site is located on the former FPL Riviera Beach Plant property primarily within Riviera Beach, Palm Beach County (with a small portion of the Site in West Palm Beach). The site is bound to the east by the Lake Worth Lagoon (Intracoastal Waterway) and on the west by a four-lane highway (U.S. Highway 1). The site has barge access via the Port of Palm Beach. A rail line is located near the plant.

The previous site generating capacity was made up of two 300 MW (approximate) steam generating units (Units 3 & 4) that were taken out of service and dismantled in 2011. Units 1 & 2 were previously retired and dismantled and are no longer on the plant site.

FPL is in the process of modernizing the former Riviera Beach Plant, to be renamed the Riviera Beach Next Generation Clean Energy Center (RBEC), by replacing the existing generating units with a modern, highly efficient, lower-emission next-generation clean energy center using advanced CC technology.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the RBEC site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A general layout of the RBEC generating facilities is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The previous Riviera Beach Plant consisted of two 300 MW (approximate) units with conventional dual-fuel fired steam boilers and steam turbine units. The plant site includes minimal vegetation and a landscape buffer area south of the power plant. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The existing FPL Riviera Beach Plant property is located on approximately 46 acres of flat, sandy soils on the west side of the Intracoastal Waterway. The majority of the site is comprised of seven acres containing transmission lines and facilities on the west side of U.S. Highway 1, and 39 acres comprised of facilities related to electric power generation on the east side of U.S. Highway 1. The site provides warm water as required for manatees pursuant to the facility's Manatee Protection Plan.

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2. Listed Species

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species. The warm water discharges from the plant attract manatees, an endangered species. FPL continues to work closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process. In 2009, FPL installed a temporary heating system to warm the water for the manatees as required pursuant to the facility's Manatee Protection Plan. FPL will also be complying with several other manatee-related conditions of certification to ensure the protection of the manatees during the modernization work and during operation of the RBEC.

3. Natural Resources of Regional Significance Status

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option is to replace the previous steam generating units (Units 3 & 4) with one new 1,212 MW (Summer) CC unit consisting of three new CTs, three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit is projected to be in service in mid-2014. Natural gas delivered via pipeline is the primary fuel type for the unit with ultra-low sulfur light fuel oil serving as a backup fuel.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is "Utility". The Port of Palm Beach is to the north of the site. Designation to the west of the site is "Commercial." To the south of the site is "Residential" and is in the City of West Palm Beach. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

This site has been selected for site modernization due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of replacing the existing steam units with a new CC unit including a significant reduction in system air emissions, improved aesthetics at the site, and continued warm water discharge for the manatees as required during manatee season. Further, modernizing this existing facility reduces the impact on natural resources by not requiring new land or new water resources.

i. Water Resources

Water from the Lake Worth Lagoon (Intracoastal Waterway) will be used for once-through cooling water. RBEC will utilize portions of the existing once-through cooling water intake and discharge structures. Water for cooling pump seals and irrigation will come from three onsite surficial aquifer wells. Process and potable water for the converted plant will come from the existing City of Riviera Beach potable water supply.

j. Geological Features of Site and Adjacent Areas

The site is underlain by the surficial aquifer system. The surficial aquifer system in eastern Palm Beach County is primarily composed of sand, sandstone, shell, silt, calcareous clay (marl), and limestone deposited during the Pleistocene and Pliocene Epochs. The sediments forming the aquifer system are the Pamlico Sand, Fort Thompson Formation (Pleistocene) and the Caloosahatchee Marl (Pleistocene and Pliocene). Permeable sediments in the upper part of the Tamiami Formation (Pliocene) are also part of the aquifer system.

The surficial aquifer is underlain by at least 600 feet of the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing is approximately 0.232 million gallons per day (mgd) for uses such as process water and service water. Approximately 600 mgd of cooling water would be cycled through the once-through cooling water system. Potable water demand is expected to average .001 mgd.

l. Water Supply Sources by Type

The modernized plant will continue to use Lake Worth Lagoon water as the source of once-through cooling water. Water for cooling pump seals and irrigation will come from on-site surficial aquifer wells currently authorized under SFWMD conditions of certification. Process and potable water for the new plant will come from the existing City of Riviera Beach's potable water supply.

m. Water Conservation Strategies Under Consideration

No additional water resources will be required as a result of the modernization project. CC technology uses less water by design than traditional steam generation units.

n. Water Discharges and Pollution Control

The modernized plant will utilize portions of the existing once-through cooling water system for heat dissipation. The heat recovery steam generator blowdown will be mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system prior to discharge. Storm water runoff will be collected and routed to storm water ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and

Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit would be transported to the site via an approximately six mile FPL-owned pipeline and a 32 mile pipeline from the Martin Plant. Together, the two pipelines are known as the RBEC Lateral. New gas compressors will be installed at the existing FPL 45th Street Terminal facility in Riviera Beach to raise the gas pressure of the pipeline to the appropriate level for the new unit. Ultra-low sulfur light fuel oil would be received by truck, pipeline, or barge and stored in a new above-ground storage tank.

p. Air Emissions and Control Systems

The regulated air emission rates at the new plant would be more than 90 percent lower than the previous Riviera Beach Plant's emission rates, resulting in significant annual emissions reductions and air quality benefits per unit of energy produced. The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA proposed new source performance standards for GHGs. Taken together, the design of RBEC would incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site. Noise from the operation of the new unit will be within allowable levels.

r. Status of Applications

The FPSC voted to approve the need for the modernization project and the need order was issued in September 2008. The project received final state certification on November 24, 2009, through the issuance of a final order signed by the Secretary of the DEP. The project received final certification for the RBEC Lateral and compressor station on March 15, 2011.

Preferred Site # 4: Port Everglades Plant, Broward County

This site is located on the existing FPL Port Everglades Plant property within the City of Hollywood, Broward County. The site is surrounded by the Port of Port Everglades. The site has barge access via the Port of Port Everglades. A rail line is located near the plant.

The previous site generating capacity was made up of two 200 MW (approximate) steam generating units (Units 1 & 2) and two 400 MW (approximate) steam generating units (Units 3 & 4). The four units will be taken out of service and dismantled by mid-2013 as part of the modernization of the plant site.

The Port Everglades Plant site has been listed as a Potential Site in previous FPL Site Plans for both CC and CT generation options. On April 9, 2012, the FPSC issued the final need order for the modernization of the existing Port Everglades Plant. As a result of the modernization of the site, the new generating unit - to be renamed the Port Everglades Next Generation Clean Energy Center (PEEC) – will replace the existing steam generating units with a modern, highly efficient, lower-emission next-generation clean energy center using advanced CC technology. The existing four steam units will first be removed from the site and will be replaced by a single new CC unit.

a. U.S. Geological Survey (USGS) Map

A USGS map of the PEEC site is found at the end of this chapter.

b. Proposed Facilities Layout

A general layout of the PEEC generating facilities is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing Port Everglades Plant consists of two 200 MW (approximate) and two 400 MW (approximate) generating units with conventional dual-fuel fired steam boilers and steam turbine units. The plant site includes minimal vegetation. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of facilities related to electric power generation for the existing Port Everglades Plant generating units. The site is located adjacent to the Intracoastal Waterway. The site provides warm water as required for manatees pursuant to the facility's Manatee Protection Plan.

2. Listed Species

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species. The warm water discharges from the plant attract manatees, an endangered species. FPL continues to work closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process and upon operation of the new plant. FPL plans to install a temporary heating system to provide warm water for manatees as required pursuant to the facility's Manatee Protection Plan. FPL also anticipates complying with other manatee-related conditions of certification to ensure the protection of the manatees during the modernization work and during future operations of PEEC.

3. Natural Resources of Regional Significance Status

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option is to replace the existing units (Units 1 through 4) with one new 1,277 MW (Summer) unit consisting of three new CTs, three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit is projected to be in service in mid-2016. Natural gas delivered via the existing pipeline is the primary fuel type for the unit with ultra-low sulfur light fuel oil serving as a backup fuel.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is a combination of "Electrical Generating Facility" and "Utilities Use". A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Port Everglades Plant has been selected for site modernization due to consideration of various factors including system load, ability to provide generation in the Miami-Dade/Broward region to help balance load and generation in the region, and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of replacing the existing steam units with a new CC unit including a significant reduction in system air emissions, improved aesthetics at the site, and continued warm water discharge for the manatees as required pursuant to the facility's Manatee Protection Plan. Further, modernizing this existing facility reduces the impact on natural resources by not requiring new land or new water resources.

i. Water Resources

Water from the Intracoastal Waterway via the Port of Port Everglades Slip No. 3 is currently used for once-through cooling water supply. The new plant will utilize portions of the existing once-through cooling water intake and discharge structures. Process and potable water for the modernized plant will come from the existing City of Ft. Lauderdale potable water supply.

j. Geological Features of Site and Adjacent Areas

FPL's Port Everglades Plant site is underlain by the surficial aquifer system. The surficial aquifer system in eastern Broward County is primarily composed of sand, sandstone, shell, silt, calcareous clay (marl), and limestone deposited during the

Pleistocene and Pliocene ages. The sediments forming the aquifer system are the Pamlico Sand, Miami Oolite, Anastasia Formation, Key Largo Formation, and Fort Thompson Formation (Pleistocene) and the Tamiami Formation (Pliocene). The sediments in the eastern portion of the county are appreciably more permeable than in the west.

The surficial aquifer is underlain by at least 600 feet of the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Approximately 600 mgd of cooling water would be cycled through the once-through cooling water system which is a reduction of more than 51% from the previous fossil steam unit's capability. Potable water demand is expected to average .001 mgd.

l. Water Supply Sources by Type

The modernized plant will continue to use the Intracoastal Waterway as the source of once-through cooling water. Process and potable water for the new plant will come from the existing City of Ft. Lauderdale potable water supply.

m. Water Conservation Strategies Under Consideration

No additional water resources will be required as a result of the modernization project. CC technology uses less water by design than traditional steam generation units.

n. Water Discharges and Pollution Control

The modernized plant will utilize portions of the existing once-through cooling water system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system prior to discharge. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit would be transported to the site via an existing natural gas pipeline to the site. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit will be installed either at the existing site or off-site. Ultra-low sulfur light fuel oil would be received by truck, pipeline, or barge and stored in a new above-ground storage tank.

p. Air Emissions and Control Systems

The regulated air emission rates at the new plant would be approximately 90 percent lower than the previous Port Everglades Plant's emission rates, resulting in significant annual emissions reductions and air quality benefits per unit of energy produced. The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of PEEC would incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. Status of Applications

FPL filed a need determination with the FPSC on November 21, 2011. The FPSC's final need order was issued on April 9, 2012. The Site Certification Application (SCA) was submitted January 24, 2012 resulting in the issuance of Final Order PA 12-57 on

October 9, 2012. Concurrent with the SCA filing, FPL submitted applications for a Greenhouse Gas permit, a Prevention of Significant Deterioration permit and an Industrial Wastewater Facility permit revision. The revised Industrial Wastewater Facility permit was issued December 16, 2012.

Preferred Site # 5: Hendry County, Hendry County

FPL has acquired an approximately 3,120-acre site in southeast Hendry County, off CR 833. The Hendry County site has been listed as a Potential Site in previous FPL Site Plans as a possibility for a future PV facility and/or natural gas-fired CC generation. FPL currently views the Hendry site as one of the most likely sites to be used for large-scale generation additions at some future date after the last of the three modernization projects are completed in 2016.

a. Geological Survey (USGS) Map

A USGS map of the site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the property owned by FPL is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing and future land uses on the site are zoned Utility. The existing land uses that are adjacent to the site are predominately agricultural. The property to the south is the Seminole Big Cypress Reservation.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The natural environment adjacent to the north, east, and west of the site are used predominately for agricultural activities such as improved, unimproved, and woodland pasture. The majority of the pasture lands includes upland scrub, pine, and hardwoods. The Seminole Big Cypress Reservation lies to the south.

2. **Listed Species**

FPL strives to have no adverse impacts on federal- or state-listed terrestrial plants and animals. Much of southwest Florida is considered habitat for the endangered Florida Panther. Although few or no impacts are expected in association with future construction at the site, FPL anticipates minimizing or mitigating for unavoidable wildlife or wetland impacts.

3. **Natural Resources of Regional Significance Status**

Future construction and operation of a solar and/or a natural gas-fired CC generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

Options include construction of CC and/or solar power generation technologies. Mitigation for unavoidable impacts may occur through a combination of on- and off-site mitigation.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the site is Utility. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. **Site Selection Criteria Process**

The Hendry County site has been selected as "Preferred" due to consideration of various factors including system load, transmission interconnection, and economics.

i. **Water Resources**

Groundwater is anticipated to supply water to the Hendry County site.

j. **Geological Features of Site and Adjacent Areas**

The site is at an approximate elevation of 10 to 12 feet above mean sea level (msl) and is located on the Immokalee Rise and the Big Cypress Spur considered terraces created by high sea level events. The terraces are composed of fine quartz sands that lie discontinuously upon the surficial aquifer system whose sediments are the Fort Thompson (Pleistocene), Caloosahatchee Marl (Pleistocene and Pliocene), and

Tamiami Formations (Pliocene). Other soil types in the area include limestone rock, calcareous muds, sands, organic materials, and mixed solids.

The surficial aquifer is underlain by the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing at a CC unit is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Potable water demand is expected to average .001 mgd. Minimal amounts of water would be required for a PV facility. Approximately 7.5 mgd of cooling water would be used in cooling towers for one CC unit.

l. Water Supply Sources by Type

Potential water supply source is groundwater. Additional evaluations are necessary to determine the exact source.

m. Water Conservation Strategies Under Consideration

CC and cooling tower technologies withdraw less water by design than traditional steam generation units. Some solar technologies do not require water for process or cooling purposes. Specific water conservation strategies will be evaluated and selected during the detailed design phase of any development project.

n. Water Discharges and Pollution Control

A CC unit at the site will utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's cooling water flow prior to discharge. Wastewater disposal is anticipated via discharge to an Underground Injection Control well system. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral to the site. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary Ultra-low sulfur light fuel oil will be received by truck or pipeline and stored in an above-ground storage tank.

p. Air Emissions and Control Systems

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize regulated air emissions from a CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of SO_2, PM, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of NO_x and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra low sulfur fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida. PV generation does not produce air emissions.

q. Noise Emissions and Control Systems

Noise anticipated to be caused by unit construction at the site is expected to be minimal.

r. Status of Applications

FPL has not submitted any application associated with the Hendry County site.

Preferred Site # 6: NE Okeechobee County, Okeechobee County

FPL has purchased a site of approximately 2,800 acres in Northeast Okeechobee County. The site is in an unincorporated, rural area and is predominantly used for agricultural production. FPL's transmission lines intersect the property. The Northeast Okeechobee County site has been listed as a Potential Site in previous FPL Site Plans as a possibility for a future PV facility or natural gas-fired CC generation. FPL currently views the Okeechobee site as one of the most likely sites to be used for large-scale generation additions at some future date after the last of the three modernization projects are completed in 2016.

a) **U.S. Geological Survey (USGS) Map**

A USGS map of the Northeast Okeechobee site is found at the end of this chapter.

b) **Proposed Facilities Layout**

A map of the property owned by FPL is found at the end of this chapter.

c) **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d) **Existing Land Uses of Site and Adjacent Areas**

The Northeast Okeechobee County site is predominantly used for agricultural production (cattle and citrus). Adjacent land uses include primarily agriculture and conservation.

e) **General Environment Features On and In the Site Vicinity**

1. **Natural Environment**

The majority of the site is comprised of lands dedicated to agricultural production.

2. **Listed Species**

Minimal impacts to federal- or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species.

3. **Natural Resources of Regional Significance Status**

The construction and operation of a power generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f) **Design Features and Mitigation Options**

Options include construction of PV or CC technologies. Mitigation for unavoidable impacts may occur through a combination of on- and off-site mitigation.

g) **Local Government Future Land Use Designations**

Local government future land use designation for the site is predominantly unimproved pasture. A land use map of the site and adjacent areas is also found at the end of this chapter.

h) **Site Selection Criteria Process**

The Northeast Okeechobee County site has been selected as a Preferred Site due to consideration of various factors including system load, transmission interconnection, and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity.

i) **Water Resources**

Groundwater and/or surface water resources are anticipated to supply water to the Northeast Okeechobee County site.

j) **Geological Features of Site and Adjacent Areas**

The hydrostratigraphy of the Northeast Okeechobee County site is similar to that of most of South Florida. In general, the groundwater system underlying Okeechobee County consists of the Surficial Aquifer System (SAS), the Intermediate Confining Unit (ICU), and the Floridan Aquifer System (FAS). The SAS consists of approximately 100 to 250 feet of undifferentiated deposits of sand, shell, clay and silt. The ICU consists of approximately 200 feet of carbonate rocks interbedded with sandy and silty clay. The multiple layers of the FAS extend thousands of feet below the ICU.

k) **Projected Water Quantities for Various Uses**

Potable water demand is expected to average .001 mgd. The estimated quantity of water required for processing at a CC unit is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Approximately 7.5 mgd of cooling water would be used in cooling towers for a CC unit. Minimal amounts of water would be required for a PV facility.

l) Water Supply Sources by Type

Potential water supply sources are groundwater and surface water. Additional evaluations are necessary to determine which source(s) may be used.

m) Water Conservation Strategies Under Consideration

CC technology withdraws less water by design than traditional steam generation units. PV facilities have minimal water demands. Specific water conservation strategies will be evaluated and selected during the detailed design phase of any development project.

n) Water Discharges and Pollution Control

A CC plant is anticipated to utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's cooling water flow prior to discharge. Wastewater disposal is anticipated via discharge to an Underground Injection Control well system. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ Best Management Practices (BMP) and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o) Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary. Back-up fuel supplies of ultra-low sulfur light fuel oil will be received by truck or pipeline and stored in an above-ground storage tank to ensure reliability of operations.

p) Air Emissions and Control Systems

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize regulated air emissions from a CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of SO_2, PM, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of NO_x and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra- low sulfur light fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida. PV generation does not produce air emissions.

q) Noise Emissions and Control Systems

Noise anticipated to be caused by unit construction at the site is expected to be minimal.

r) Status of Applications

FPL has not filed any applications associated with the Northeast Okeechobee County site.

Preferred Site # 7: Palatka Site, Putnam County

FPL is currently evaluating the former FPL Palatka Plant site, which was dismantled in the 1990s, for future natural gas-fired generation. This 170 acre site is located on the west side of Highway 100 opposite the FPL Putnam Plant in East Palatka. The Palatka site has been listed as a Potential Site in previous FPL Site Plans as a possibility for future natural gas-fired CC generation. FPL currently views the Palatka site as one of the most likely sites to be used for large-scale generation additions at some future date after the last of the three modernization projects are completed in 2016.

a) U.S. Geological Survey (USGS) Map

A USGS map of the Palatka site is found at the end of this chapter.

b) Proposed Facilities Layout

A map of the property owned by FPL is found at the end of this chapter.

c) Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d) Existing Land Uses of Site and Adjacent Areas

The Palatka site is designated as Industrial land use. Adjacent land uses include power generation and associated facilities (the existing FPL Putnam Plant) as well as Mixed Wetland Hardwoods, Residential and Hardwood-Coniferous Mixed.

e) General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of site has been previously impacted by past power plant operations. No significant environmental features have been identified at this time.

2. Listed Species

Minimal impacts to federal- or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species.

3. Natural Resources of Regional Significance Status

The construction and operation of a power generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f) Design Features and Mitigation Options

Options include construction of CC technologies. Mitigation for unavoidable impacts may occur through a combination of on- and off-site mitigation.

g) Local Government Future Land Use Designations

Local government future land use designation for the site is Industrial. A land use map of the site and adjacent areas is also found at the end of this chapter.

h) Site Selection Criteria Process

The Palatka site has been selected as a Preferred Site due to consideration of various factors including system load, transmission interconnection, and economics.

i) Water Resources

The St John's River, ground water, and/or regional water supply initiatives are potential water sources.

j) Geological Features of Site and Adjacent Areas

The hydrostratigraphy of the Palatka site is similar to that of most of North Florida. In general, the groundwater system underlying Palatka consists of the Surficial Aquifer System (SAS), and the Floridan Aquifer System (FAS).

k) Projected Water Quantities for Various Uses

Potable water demand is expected to average .001 mgd. The estimated quantity of water required at a CC unit is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Approximately 7.5 mgd of cooling water would be used in cooling towers for a CC unit.

l) Water Supply Sources by Type

Potential water supply sources are surface and ground water. Additional evaluations are necessary to determine which source(s) may be used.

m) Water Conservation Strategies Under Consideration

CC and cooling tower technologies withdraw less water by design than traditional steam generation units. Specific water conservation strategies will be evaluated and selected during the detailed design phase of the project development.

n) Water Discharges and Pollution Control

A CC plant is anticipated to utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's cooling water flow prior to discharge. Wastewater disposal is anticipated via discharge to surface and/or ground water as with the existing Putnam Plant. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ Best Management Practices (BMP) and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o) Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary. Back-up fuel supplies of ultra-low sulfur light fuel oil will be received by water-borne delivery, truck or pipeline and stored in an above-ground storage tank to ensure reliability of operations.

p) Air Emissions and Control Systems

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize regulated air emissions from a CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of SO_2, PM, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of NO_x and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra- low sulfur light fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q) Noise Emissions and Control Systems

Noise anticipated to be caused by unit construction at the site is expected to be minimal.

r) Status of Applications

FPL has not submitted any applications associated with the Palatka site.

IV.F.2 Potential Sites for Generating Options

Five (5) sites are currently identified as Potential Sites for future generation additions to meet FPL's projected capacity and energy needs.[8] These sites have been identified as Potential Sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies, including both renewable energy and non-renewable energy technologies for various sites.

Each of these Potential Sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that will require further definition and attention. Solely for the purpose of estimating water requirements for sites more suited for non-renewable energy technologies, it was assumed that either one dual-fuel (natural gas and light oil) simple cycle CT, or a natural gas-fired CC unit, would be constructed at these Potential Sites unless otherwise noted.

A simple cycle CT would require approximately 50 gallons per minute (gpm) for both process and cooling water (assuming a cooling tower was utilized). A CC unit would require approximately up to 150 gpm for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized). If an existing power plant site is ultimately selected for modernization (as is the case with FPL's CCEC, RBEC, and PEEC sites), the water requirements discussed above for a CC unit would be approximately correct for the modernized site. If a renewable energy generating technology is ultimately selected for one of these sites, the water requirements would be significantly less than those for simple cycle CT or CC facilities.

Permits are presently considered to be obtainable for each of these sites. No significant environmental constraints are currently known for any of these sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time, FPL considers each site to be equally viable.

[8] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other Greenfield sites. Greenfield sites that FPL currently does not own, or for which FPL has not currently secured the necessary rights to, are not specifically identified as Potential Sites in order to protect the economic interests of FPL and its customers.

Potential Site # 1: Babcock Ranch, Charlotte County

This site is located within the proposed Babcock Ranch Community on the north side of Tuckers Grade, approximately 10.5 miles north of the intersection of SR-80 and SR-31 and 1.1 miles east of SR-31. The project is bordered on the north by the Babcock Ranch Preserve owned by the State of Florida. This site is a possibility for an FPL PV facility. FPL has received all permits necessary to construct a 74 MW PV facility at this location.

a. U.S. Geological Survey (USGS) Map

A map of this site is found at the end of this chapter.

b. Land Uses

Existing land use on the site is the Babcock Ranch Overlay District, and it is zoned as the Babcock Ranch Overlay Zoning District. This land use and zoning allows for solar facilities.

c. Environmental Features

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

d. Water Quantities

Minimal amounts of water, if any, would be required for a PV facility.

e. Supply Sources

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water may be brought to the site by truck.

Potential Site # 2: DeSoto Solar Expansion, DeSoto County

The DeSoto site is located at 4051 Northeast Karson Street which is approximately 0.3 miles east of U.S. Highway 17 and immediately north of Bobay Road in Arcadia, Florida. The site is located in Sections 26, 27, & 35, Township 36 South, and Range 25 East. FPL owns an approximate 13,000 acre parcel in DeSoto County. FPL has designated approximately 5,177 acres for development of a PV facility.

The DeSoto site is home to a 25 MW PV facility that has been operational since 2009. Up to an additional 275 MW of PV generation could be constructed in phases on the remaining undeveloped land. FPL has initiated permitting for the additional PV facilities.

a. **U.S. Geological Survey (USGS) Map**

A map of this site is found at the end of this chapter.

b. **Land Uses**

Existing land use on the site is agricultural. The future land use is Electric Generating Facility.

c. **Environmental Features**

There are no significant environmental features on the site.

d. **Water Quantities**

Minimal amounts of water would be required for a future expansion of the existing PV facility.

e. **Supply Sources**

Minimal water would be required for an expanded PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall. Potable water will be required in the administration building and maintenance building. FPL would propose to utilize existing wells onsite to accommodate water needs.

Potential Site # 3: Manatee Plant Site, Manatee County

The existing FPL Manatee Plant 9,500-acre site is located in unincorporated north-central Manatee County. The existing power generating facilities are located in all or portions of Sections 18 and 19 of Township 33S, Range 20-E. The plant site lies approximately 5 miles east of Parrish, Florida. It is approximately 5 miles east of U.S. Highway 301 and 9.5 miles east of Interstate Highway 75 (I-75). The existing plant is approximately 2.5 miles south of the Hillsborough-Manatee County line; a portion of the north property boundary of the plant site abuts the county line. State Road 62 (SR 62) is about 0.7 mile south of the plant, with the plant entrance road going north from that highway. This site is a possible location for an FPL PV facility. FPL has received the federal and state permits required to construct approximately 50 MW of PV at this location.

a. **U.S. Geological Survey (USGS) Map**

A map of the site is found at the end of this chapter.

b. **Land Uses**

Existing land use on the site is agricultural. The property is zoned Planned Development / Public Interest (PD-PI), which will allow for electrical generation.

c. **Environmental Features**

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall. Panel cleaning water source may be existing potable water or water tank trucked to the site.

Potential Site # 4: Martin County, Martin County

FPL is currently evaluating potential sites in Martin County for a future PV facility. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

This information is not available because a specific site has not been selected at this time.

c. **Environmental Features**

This information is not available because a specific site has not been selected at this time.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall.

Potential Site # 5: Putnam County

FPL is currently evaluating potential sites in Putnam County for a future PV facility or natural gas power generation. Sites currently under investigation are approximately 2,800 acres. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

This information is not available because a specific site has not been selected at this time.

c. **Environmental Features**

This information is not available because a specific site has not been selected at this time.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility. Natural gas power generation would require approximately up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized).

e. **Supply Sources**

The St John's River, existing groundwater, and/or regional water supply initiatives are potential water sources.

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Environmental and Land Use Information: Supplemental Information

Preferred Site #1: Turkey Point Plant

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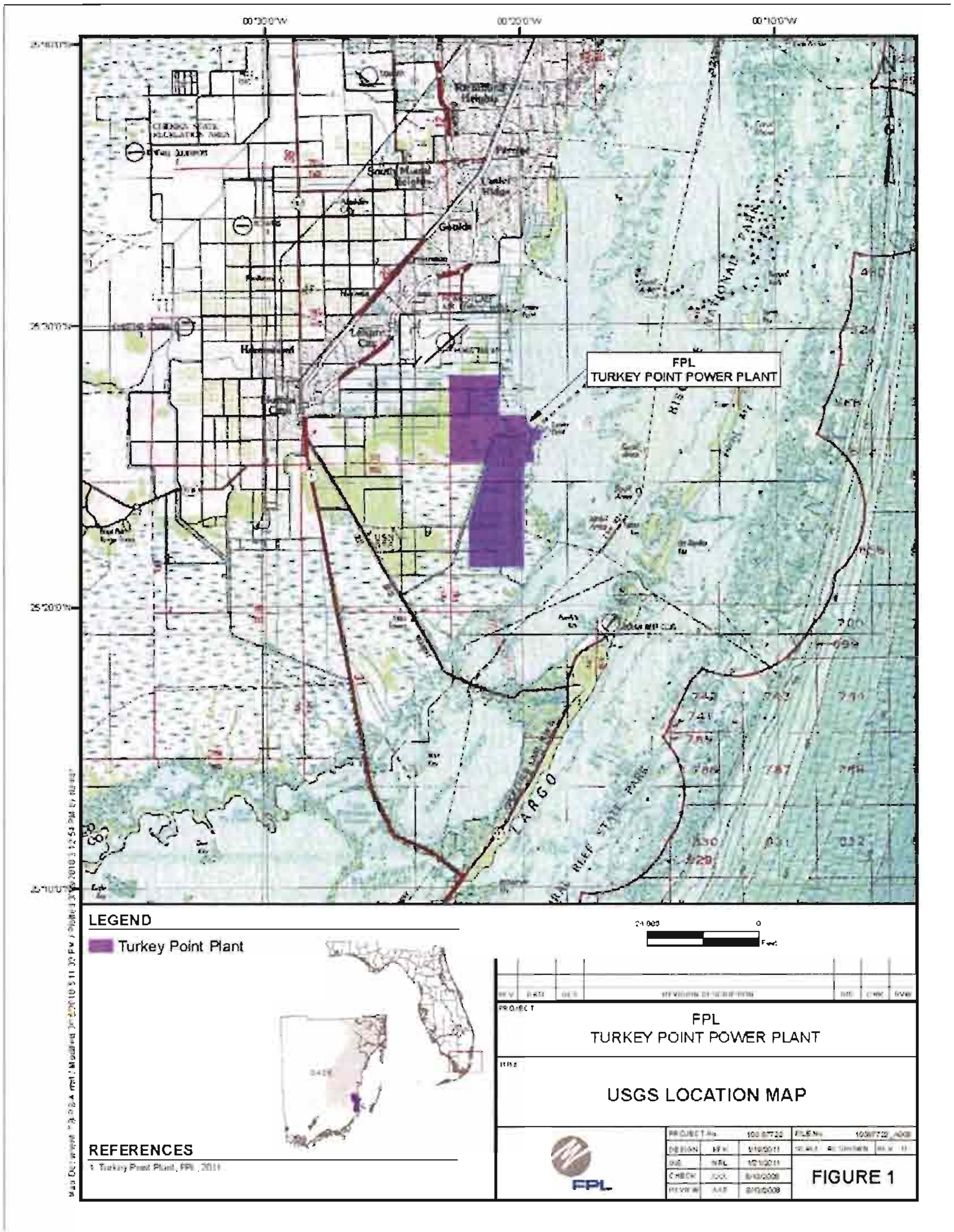
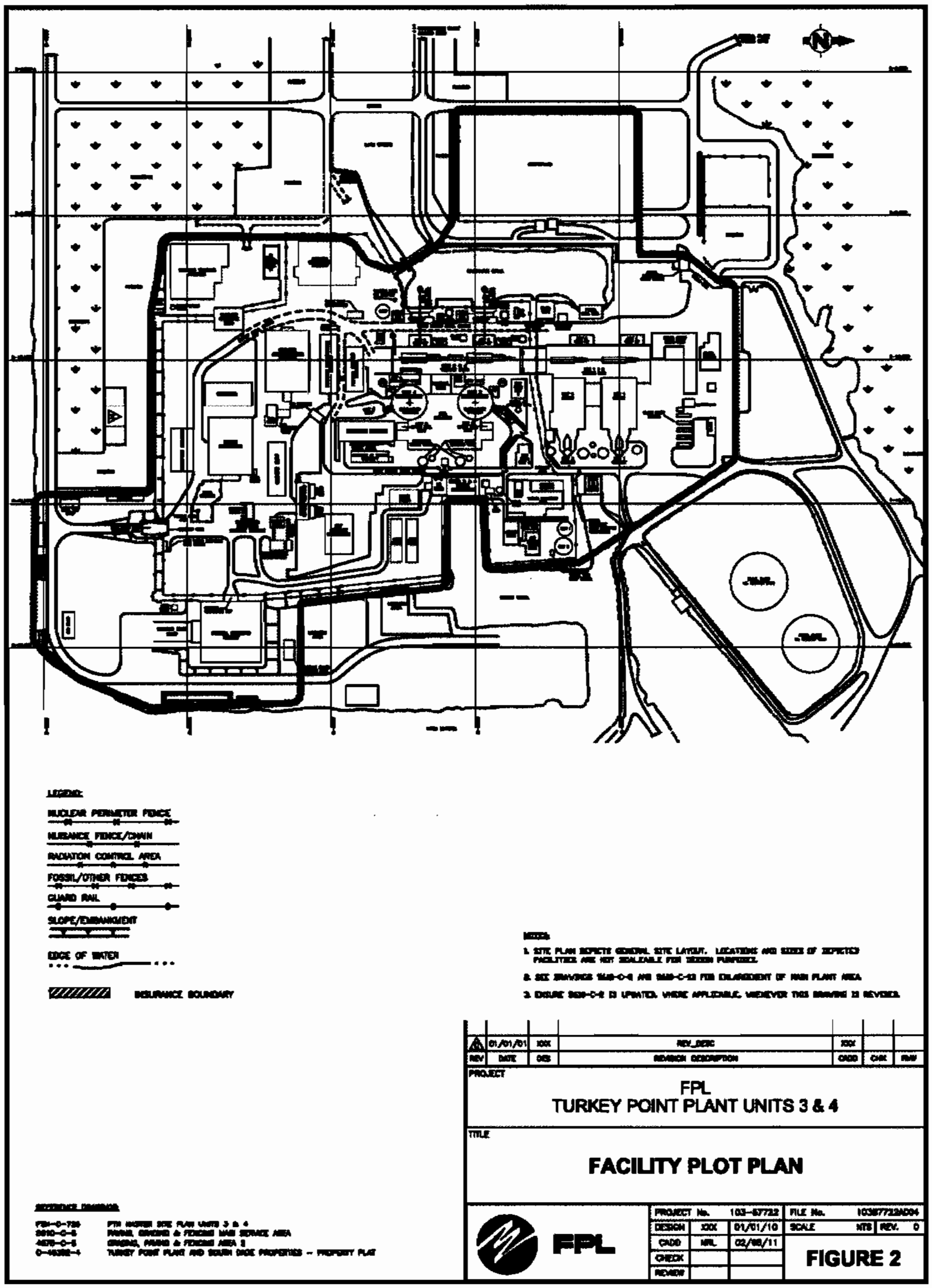
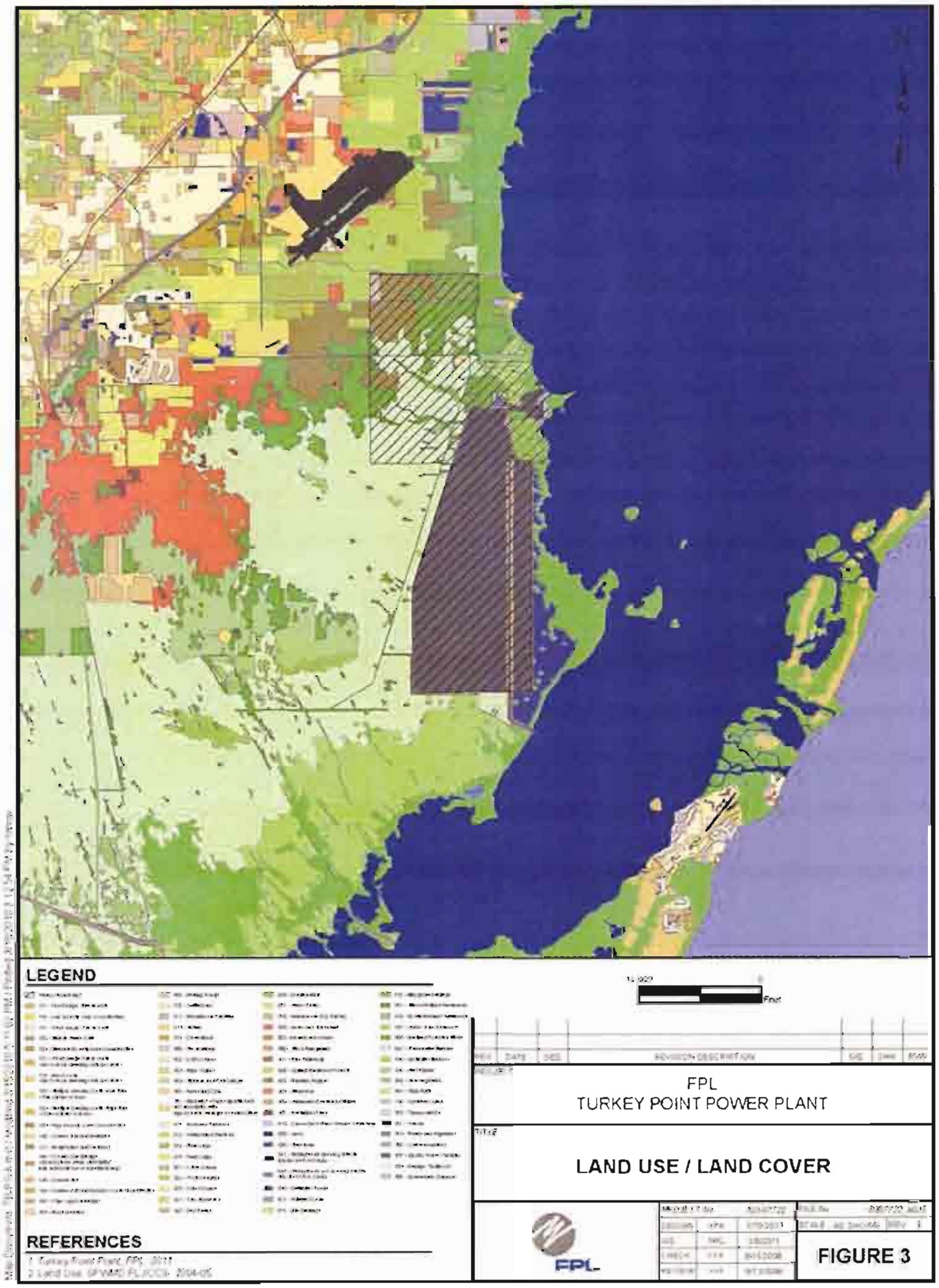

FPL
TURKEY POINT POWER PLANT
LEGEND
Turkey Point Plant
REFERENCES
FPL
TURKEY POINT POWER PLANT
USGS LOCATION MAP
FIGURE 1


LEGEND:
NUCLEAR PERIMETER FENCE
NUISANCE FENCE/CHAIN
RADIATION CONTROL AREA
FOSSIL/OTHER FENCES
GUARD RAIL
SLOPE/EMBANKMENT
EDGE OF WATER
INSURANCE BOUNDARY
NOTES:
1. SITE PLAN DEPICTS GENERAL SITE LAYOUT. LOCATIONS AND SIZES OF DEPICTED FACILITIES ARE NOT SCALEABLE FOR DESIGN PURPOSES.
PROJECT
FPL
TURKEY POINT PLANT UNITS 3 & 4
TITLE
FACILITY PLOT PLAN
FPL
FIGURE 2


LEGEND
REFERENCES
FPL
TURKEY POINT POWER PLANT
LAND USE / LAND COVER
FPL
FIGURE 3

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Environmental and Land Use Information:
Supplemental Information

Preferred Site #2: Cape Canaveral Plant

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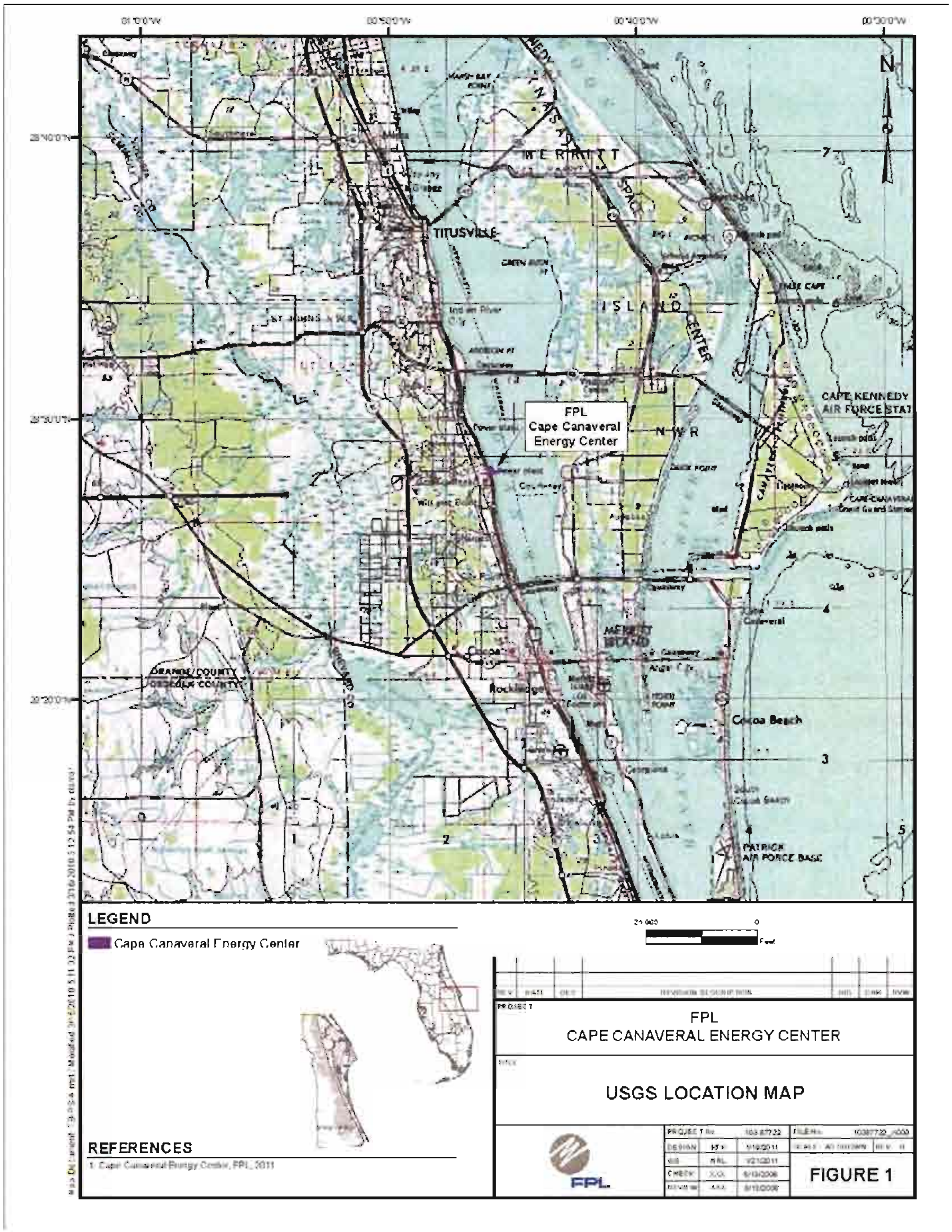
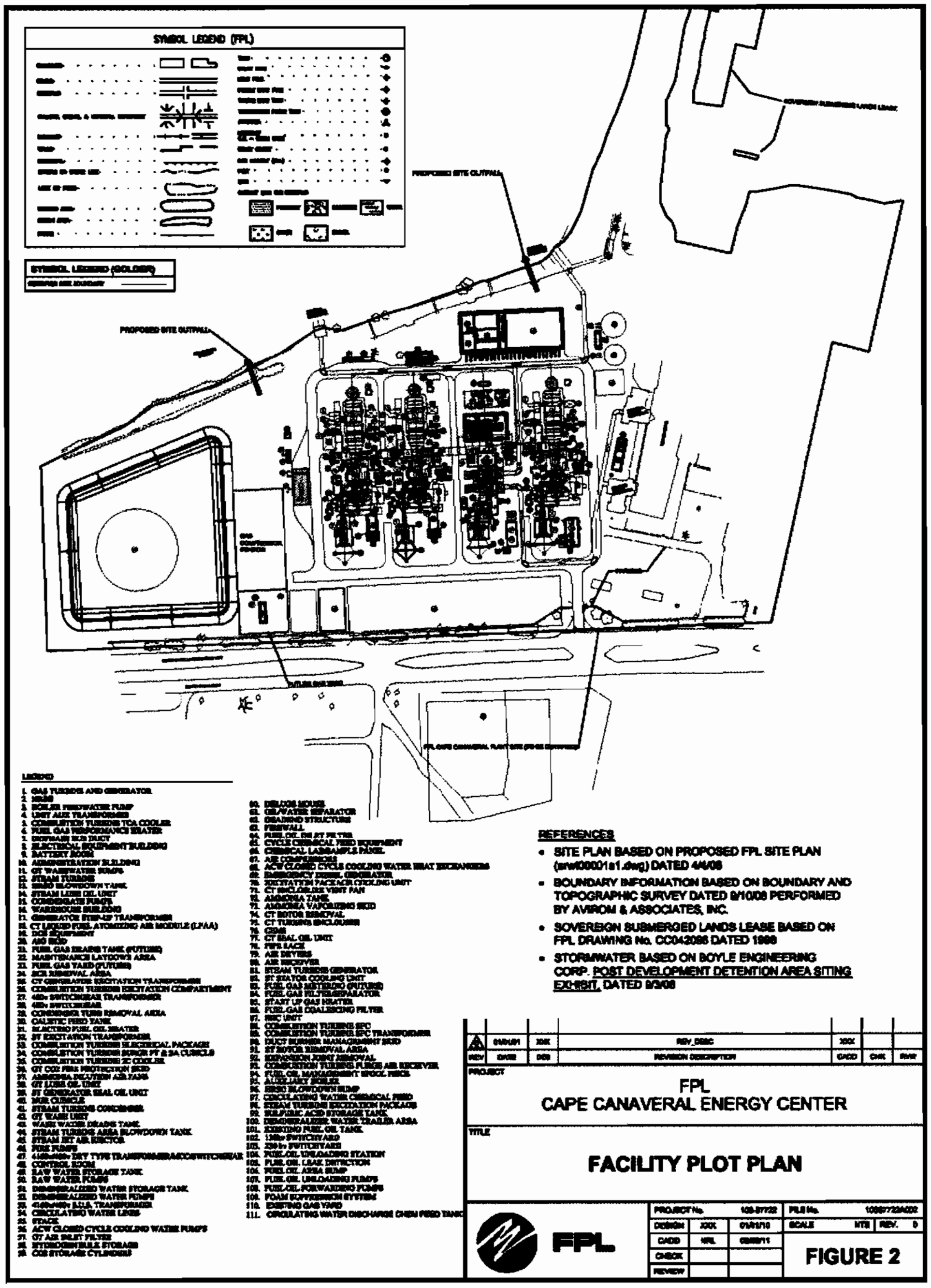

N
TITUSVILLE
MERRITT
ISLAND
SPACE CENTER
N W R
FPL
Cape Canaveral
Energy Center
CAPE KENNEDY
AIR FORCE STAT
Cocoa Beach
Rockledge
PATRICK
AIR FORCE BASE
LEGEND
Cape Canaveral Energy Center
REFERENCES
FPL
CAPE CANAVERAL ENERGY CENTER
USGS LOCATION MAP
FIGURE 1


SYMBOL LEGEND (FPL)
PROPOSED SITE OUTFALL
PROPOSED SITE OUTFALL
LEGEND
REFERENCES
• SITE PLAN BASED ON PROPOSED FPL SITE PLAN (srw00001s1.dwg) DATED 4/4/08
• BOUNDARY INFORMATION BASED ON BOUNDARY AND TOPOGRAPHIC SURVEY DATED 9/10/08 PERFORMED BY AVIROM & ASSOCIATES, INC.
• SOVEREIGN SUBMERGED LANDS LEASE BASED ON FPL DRAWING No. CC042086 DATED 1986
• STORMWATER BASED ON BOYLE ENGINEERING CORP. POST DEVELOPMENT DETENTION AREA SITING EXHIBIT, DATED 9/3/08
REV
DATE
REV_DESC
REVISION DESCRIPTION
CADD
CHK
PROJECT
FPL
CAPE CANAVERAL ENERGY CENTER
TITLE
FACILITY PLOT PLAN
FPL
PROJECT No.
FILE No.
DESIGN
SCALE
NTS
REV.
CADD
CHECK
REVIEW
FIGURE 2


LEGEND
REFERENCES
FPL
CAPE CANAVERAL ENERGY CENTER
LAND USE / LAND COVER
FPL
FIGURE 3

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Environmental and Land Use Information:
Supplemental Information
Preferred Site #3: Riviera Beach Plant

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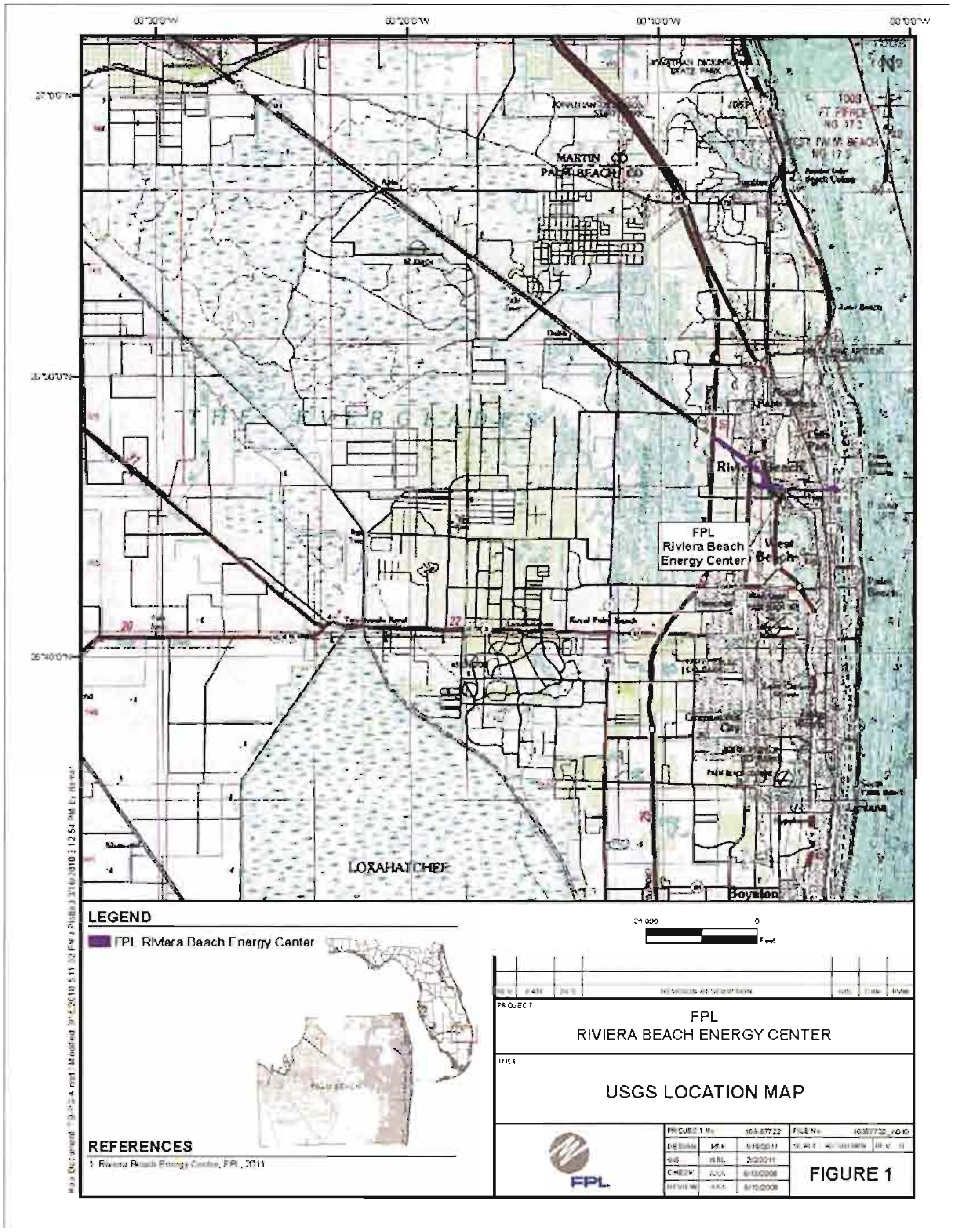

FPL
Riviera Beach
Energy Center
LOXAHATCHEE
MARTIN CO
PALM BEACH CO
LEGEND
FPL Riviera Beach Energy Center
REFERENCES
PROJECT
FPL
RIVIERA BEACH ENERGY CENTER
USGS LOCATION MAP
FPL
FIGURE 1

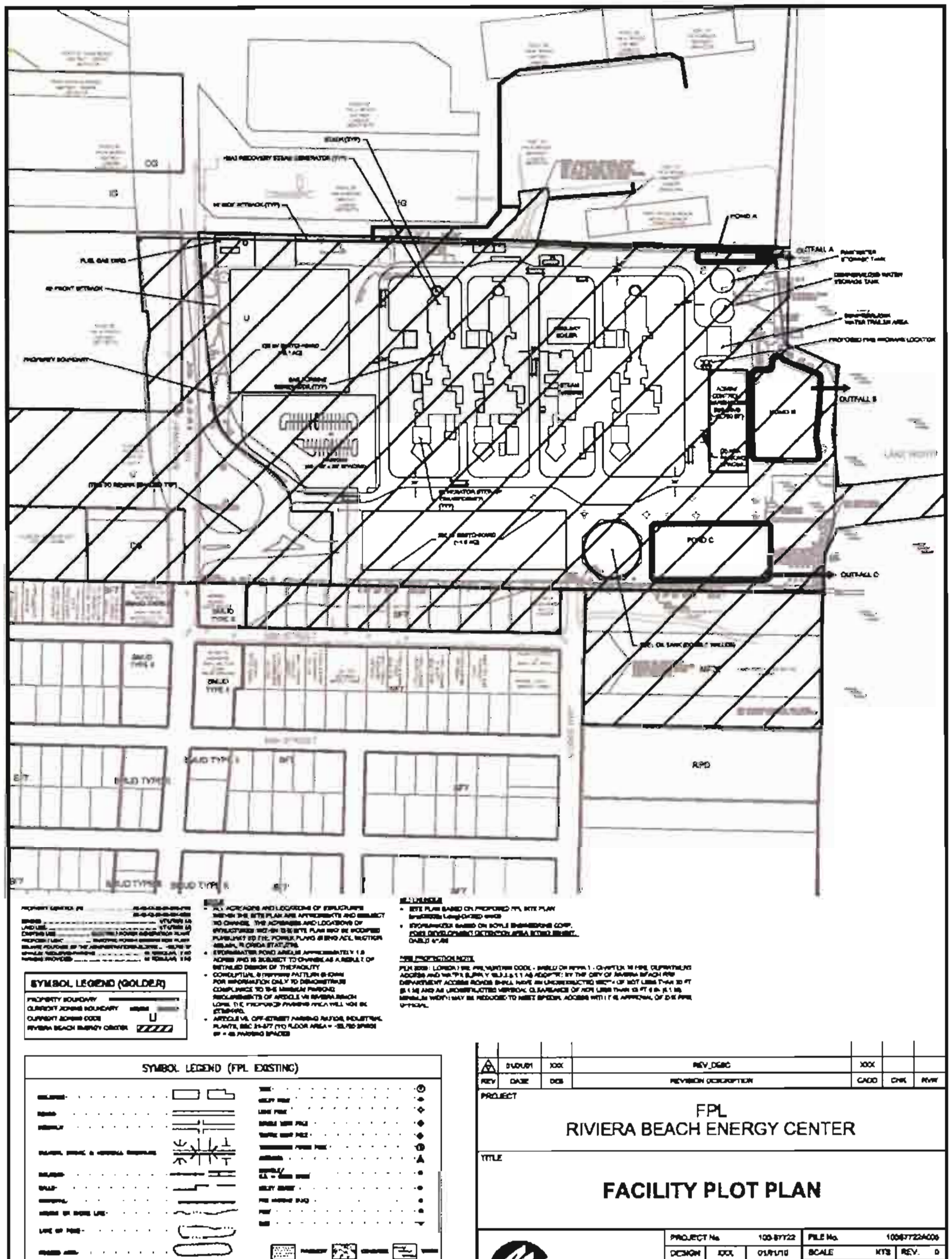
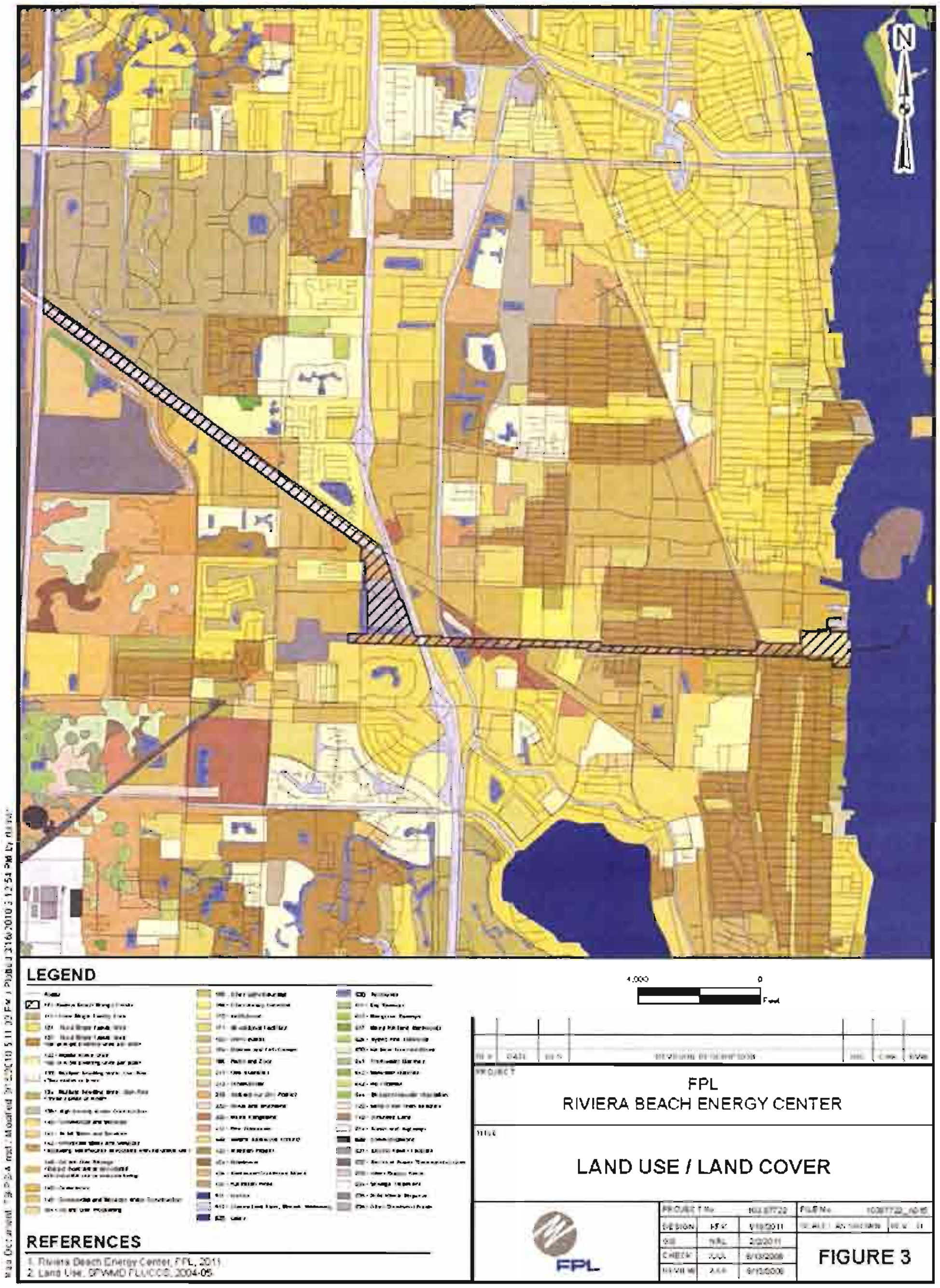

FPL
RIVIERA BEACH ENERGY CENTER
FACILITY PLOT PLAN
SYMBOL LEGEND (FPL EXISTING)
SYMBOL LEGEND (GOLDER)
POND A
POND B
POND C
OUTFALL A
OUTFALL B
OUTFALL C
FPL

FIGURE 2


N
LEGEND
REFERENCES
1. Riviera Beach Energy Center, FPL, 2011
2. Land Use, SFWMD FLUCCS, 2004-05
4,000
0
FPL
RIVIERA BEACH ENERGY CENTER
LAND USE / LAND COVER
FPL
FIGURE 3

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Environmental and Land Use Information:
Supplemental Information
Preferred Site #4: Port Everglades Plant

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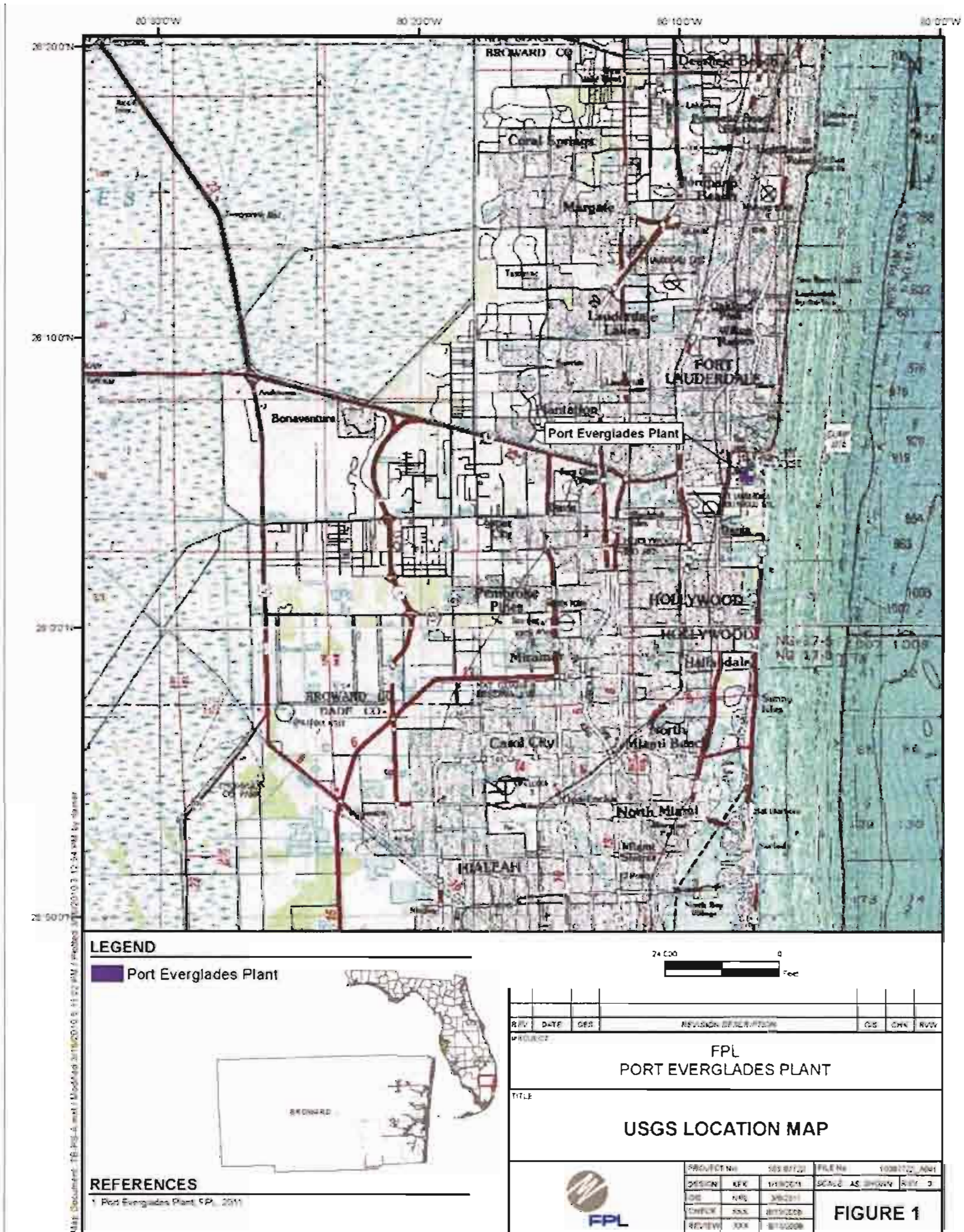
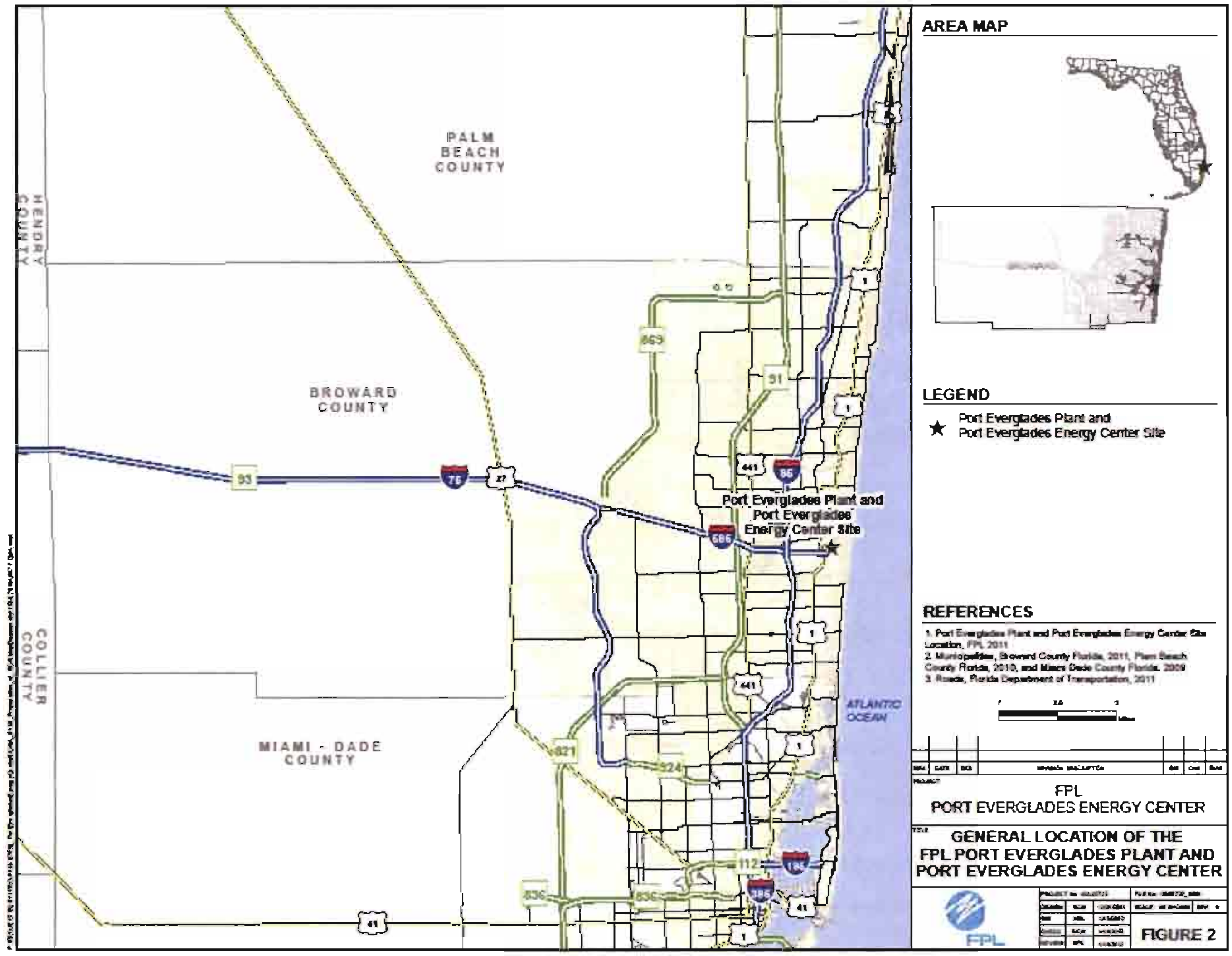
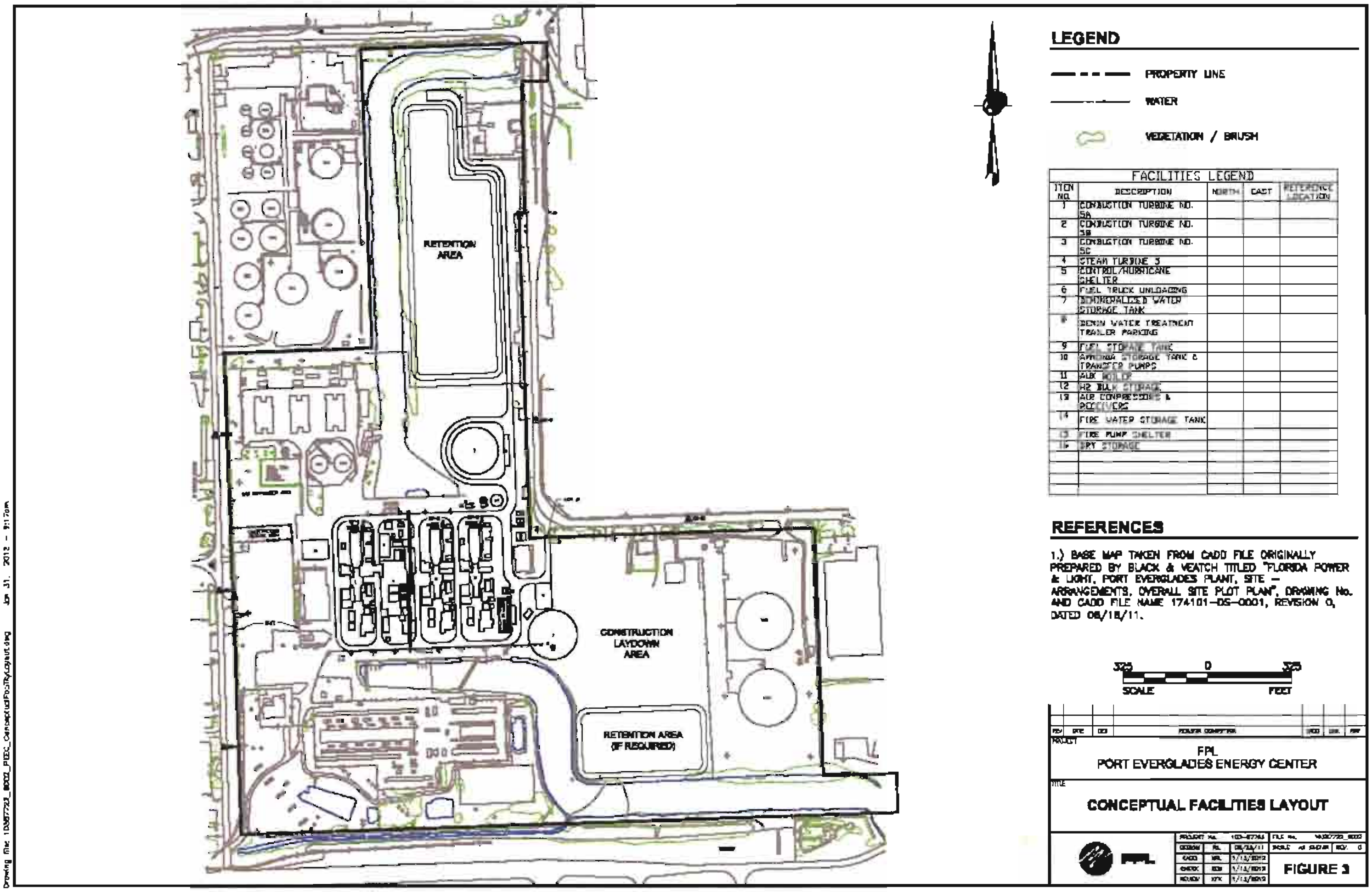
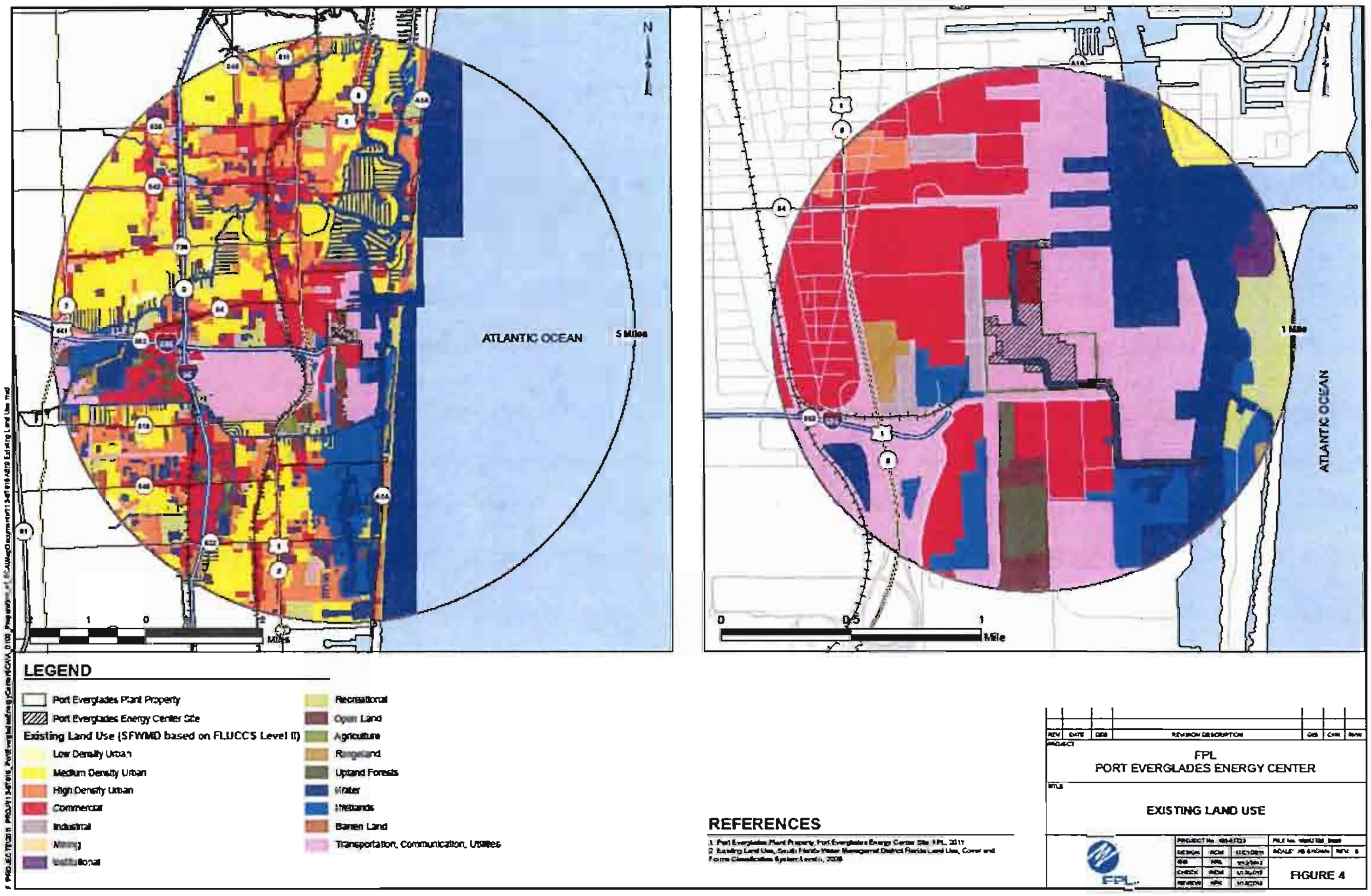

Port Everglades Plant
Coral Springs
Margate
Lauderdale Lakes
FORT LAUDERDALE
Plantation
Bonaventure
Pembroke Pines
HOLLYWOOD
Hallandale
North Miami Beach
North Miami
HIALEAH
LEGEND
Port Everglades Plant
REFERENCES
FPL
PORT EVERGLADES PLANT
USGS LOCATION MAP
FIGURE 1


AREA MAP
LEGEND
Port Everglades Plant and Port Everglades Energy Center Site
REFERENCES
PALM BEACH COUNTY
BROWARD COUNTY
MIAMI - DADE COUNTY
HENDRY COUNTY
COLLIER COUNTY
Port Everglades Plant and Port Everglades Energy Center Site
ATLANTIC OCEAN
FPL
PORT EVERGLADES ENERGY CENTER
GENERAL LOCATION OF THE FPL PORT EVERGLADES PLANT AND PORT EVERGLADES ENERGY CENTER
FIGURE 2


LEGEND
PROPERTY LINE
WATER
VEGETATION / BRUSH
FACILITIES LEGEND
ITEM NO.
DESCRIPTION
NORTH
EAST
REFERENCE LOCATION
1 COMBUSTION TURBINE NO. 5A
2 COMBUSTION TURBINE NO. 5B
3 COMBUSTION TURBINE NO. 5C
4 STEAM TURBINE 5
5 CONTROL/HURRICANE SHELTER
6 FUEL TRUCK UNLOADING
7 DEMINERALIZED WATER STORAGE TANK
8 DEMIN WATER TREATMENT TRAILER PARKING
9 FUEL STORAGE TANK
10 AMMONIA STORAGE TANK & TRANSFER PUMPS
11 AUX BOILER
12 H2 BULK STORAGE
13 AIR COMPRESSORS & RECEIVERS
14 FIRE WATER STORAGE TANK
15 FIRE PUMP SHELTER
16 DRY STORAGE
RETENTION AREA
CONSTRUCTION LAYDOWN AREA
RETENTION AREA (IF REQUIRED)
REFERENCES
1.) BASE MAP TAKEN FROM CADD FILE ORIGINALLY PREPARED BY BLACK & VEATCH TITLED "FLORIDA POWER & LIGHT, PORT EVERGLADES PLANT, SITE – ARRANGEMENTS, OVERALL SITE PLOT PLAN", DRAWING No. AND CADD FILE NAME 174101–DS–0001, REVISION 0, DATED 06/16/11.
0
SCALE
FEET
PROJECT
FPL
PORT EVERGLADES ENERGY CENTER
TITLE
CONCEPTUAL FACILITIES LAYOUT
FPL
FIGURE 3


ATLANTIC OCEAN
5 Miles
Miles
1 Mile
Mile
LEGEND
Port Everglades Plant Property
Port Everglades Energy Center Site
Existing Land Use (SFWMD based on FLUCCS Level II)
Low Density Urban
Medium Density Urban
High Density Urban
Commercial
Industrial
Mining
Institutional
Recreational
Open Land
Agriculture
Rangeland
Upland Forests
Water
Wetlands
Barren Land
Transportation, Communication, Utilities
REFERENCES
FPL
PORT EVERGLADES ENERGY CENTER
EXISTING LAND USE
FIGURE 4

Environmental and Land Use Information: Supplemental Information Preferred Site #5: Hendry County

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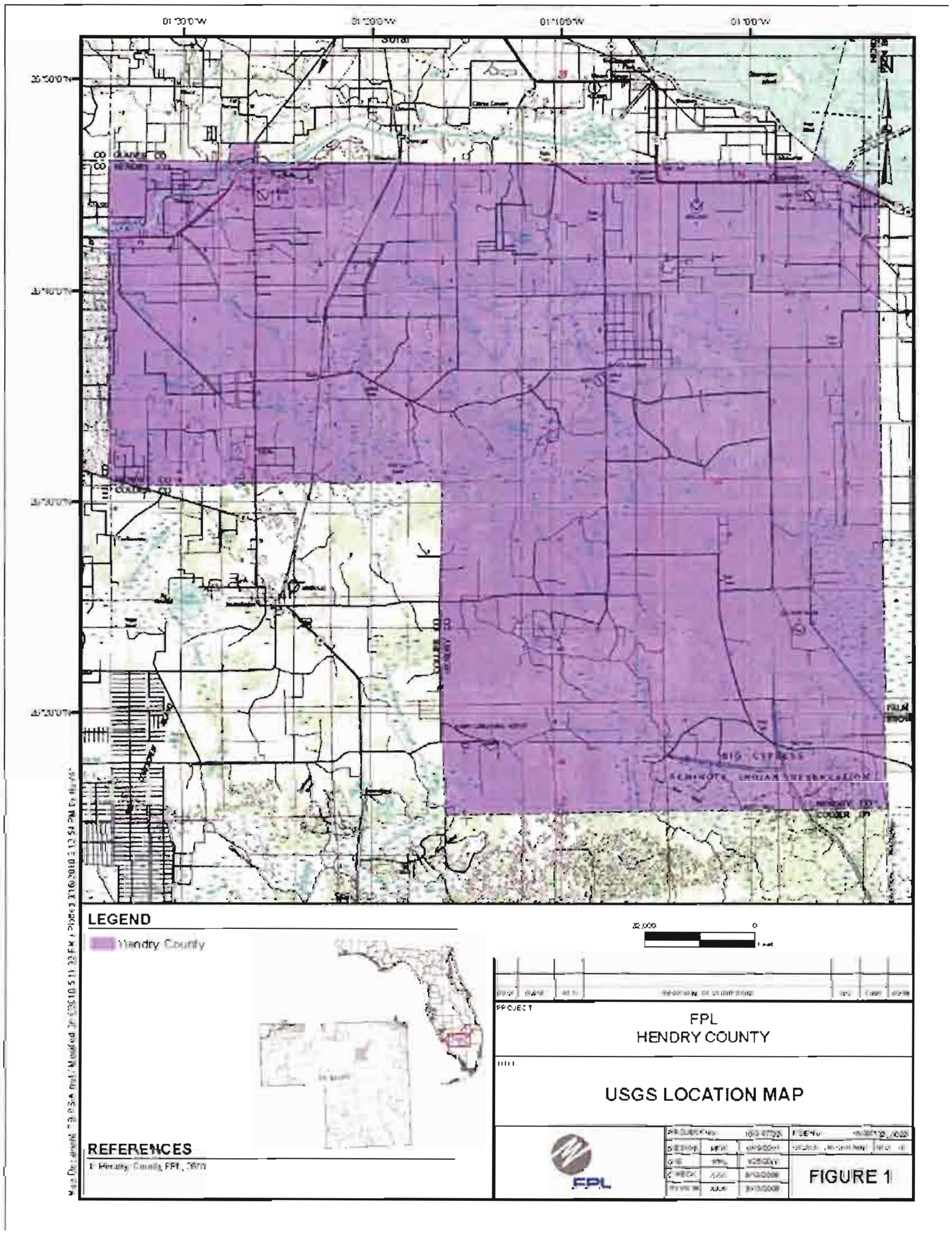
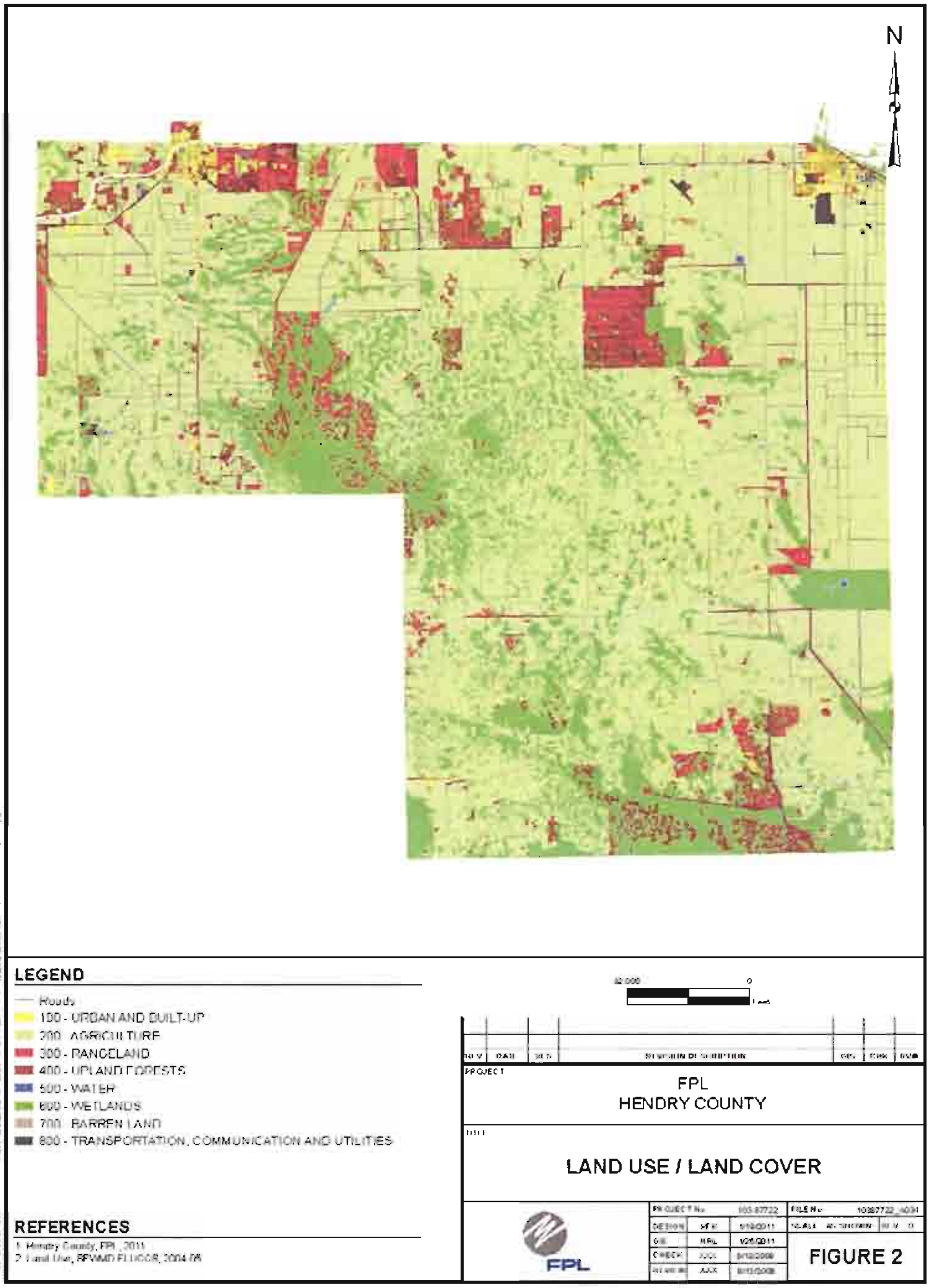

LEGEND
Hendry County
REFERENCES
FPL
HENDRY COUNTY
USGS LOCATION MAP
FPL
FIGURE 1
BIG CYPRESS
SEMINOLE INDIAN RESERVATION


N
LEGEND
Roads
100 - URBAN AND BUILT-UP
200 - AGRICULTURE
300 - RANGELAND
400 - UPLAND FORESTS
500 - WATER
600 - WETLANDS
700 - BARREN LAND
800 - TRANSPORTATION, COMMUNICATION AND UTILITIES
REFERENCES
1. Hendry County, FPL, 2011
2. Land Use, SFWMD FLUCCS, 2004-05
PROJECT
FPL
HENDRY COUNTY
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information:

Supplemental Information

Preferred Site #6: Northeast Okeechobee County

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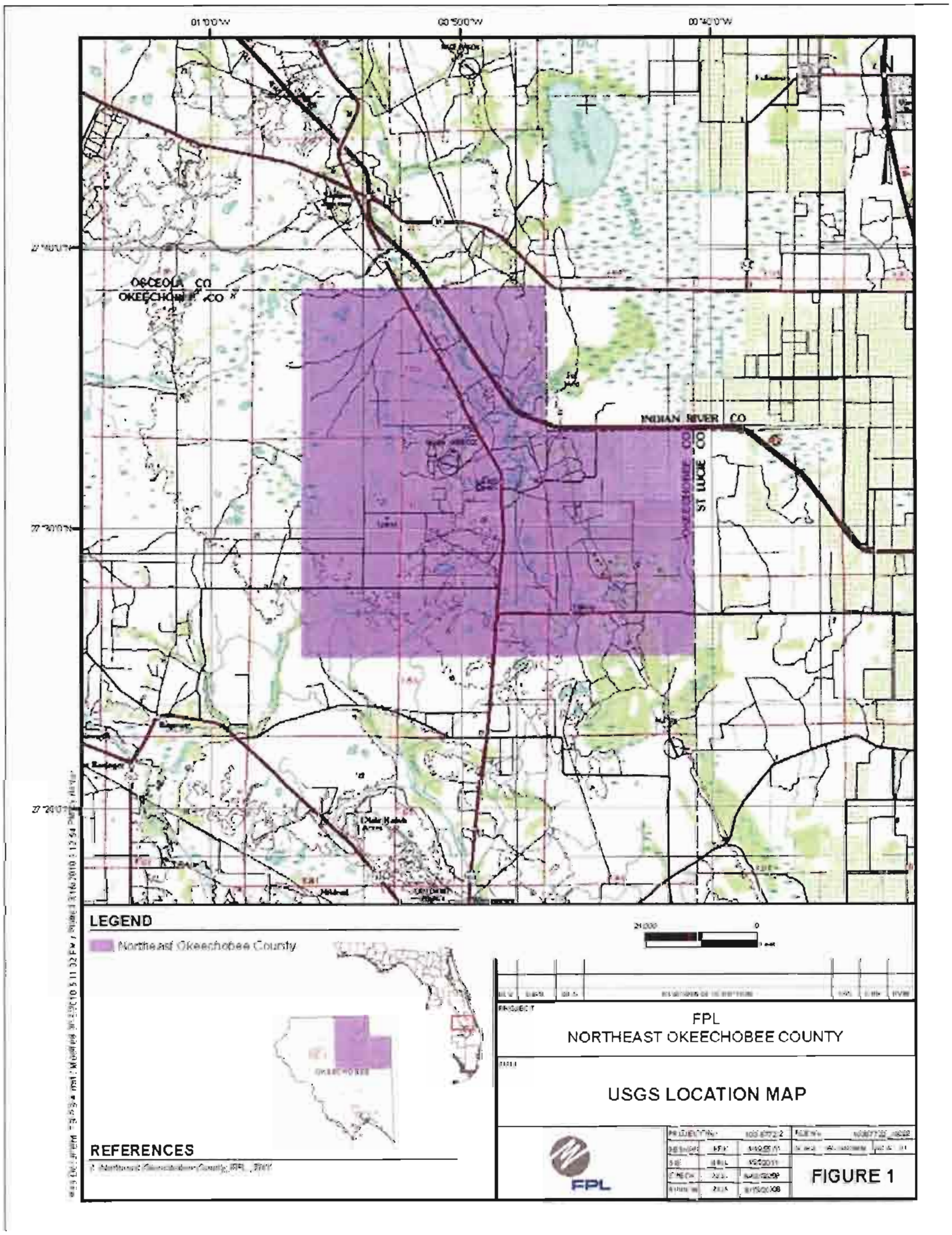
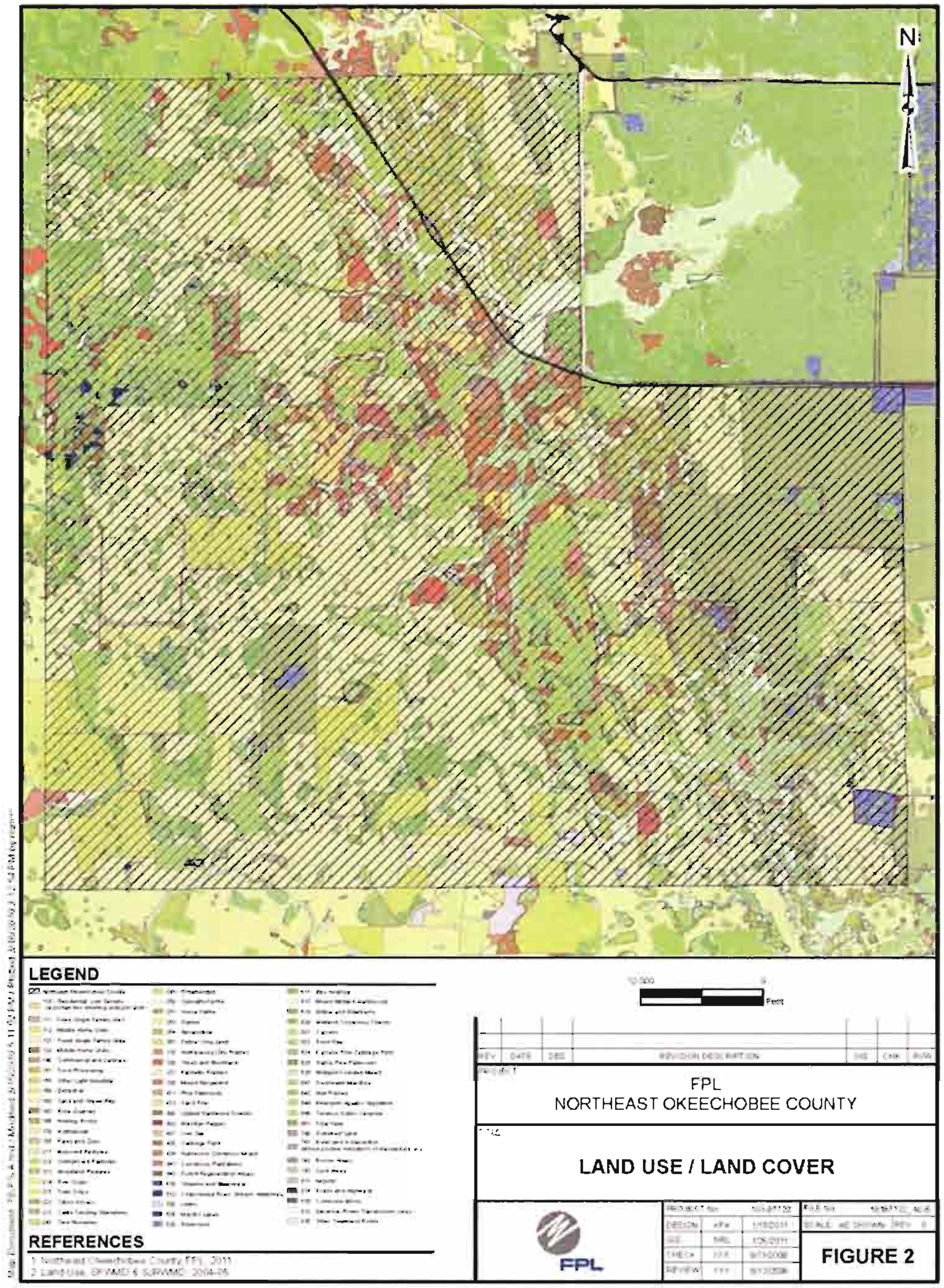

OSCEOLA CO
OKEECHOBEE CO
INDIAN RIVER CO
ST LUCIE CO
LEGEND
Northeast Okeechobee County
REFERENCES
FPL
NORTHEAST OKEECHOBEE COUNTY
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
REFERENCES
FPL
NORTHEAST OKEECHOBEE COUNTY
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information:

Supplemental Information

Preferred Site #7: Palatka Site

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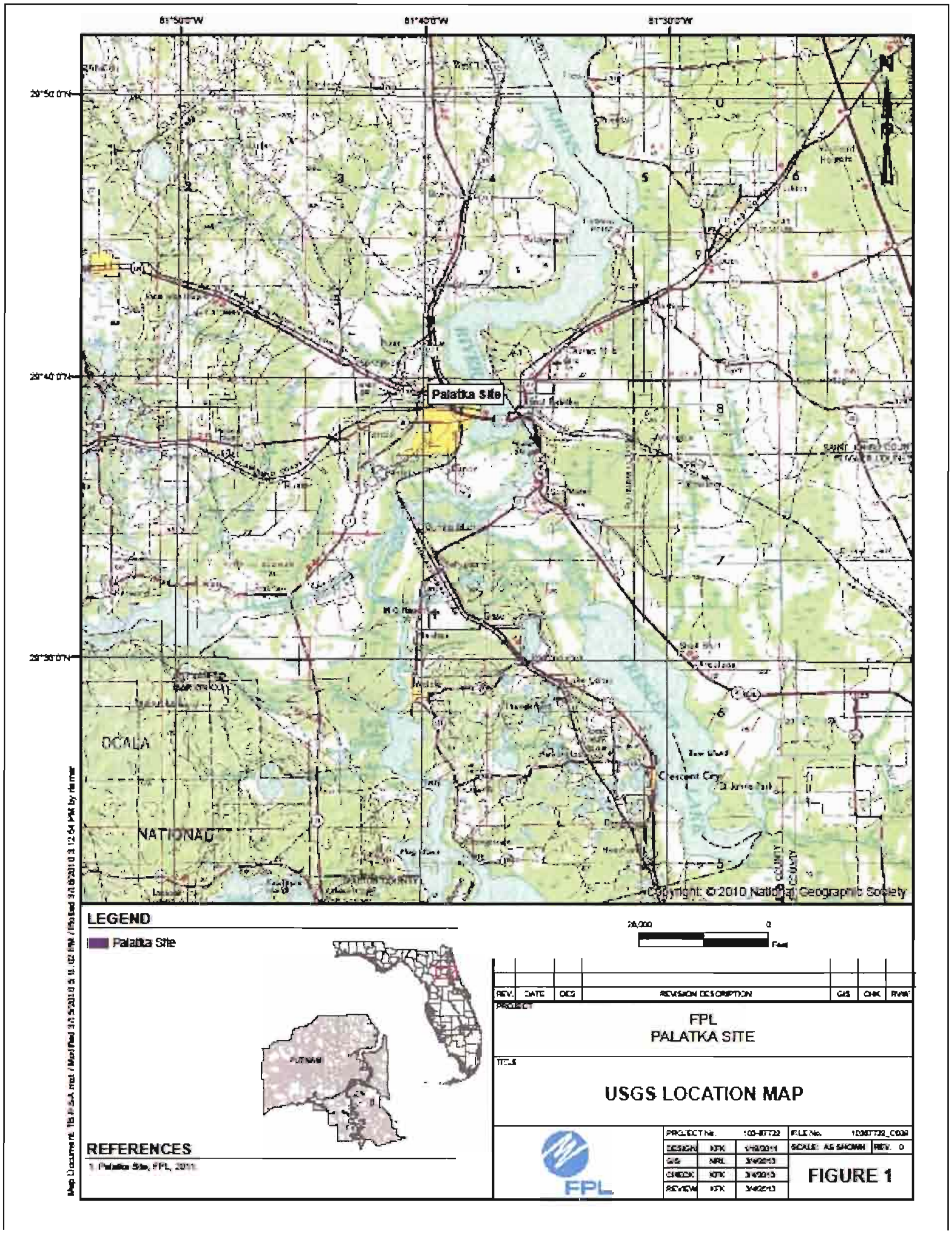
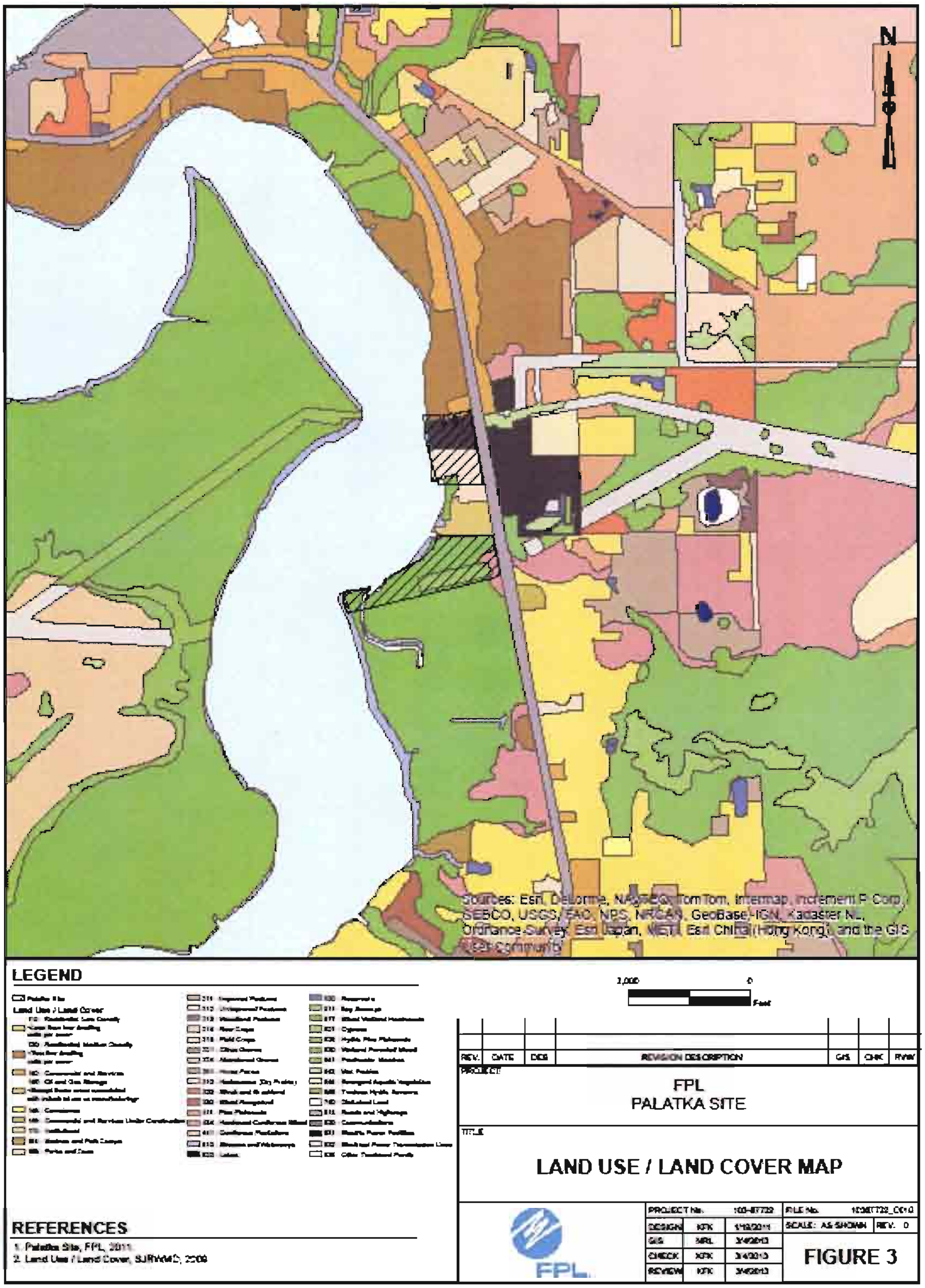

Palatka Site
Copyright: © 2010 National Geographic Society
LEGEND
Palatka Site
REFERENCES
FPL
PALATKA SITE
USGS LOCATION MAP
FIGURE 1
FPL


N
Sources: Esri, DeLorme, NAVTEQ, TomTom, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), and the GIS User Community
LEGEND
Feet
REV.
DATE
DES
REVISION DESCRIPTION
GIS
CHK
RVW
PROJECT
FPL
PALATKA SITE
TITLE
LAND USE / LAND COVER MAP
SCALE: AS SHOWN
REV. 0
DESIGN
KFK
GIS
MRL
CHECK
KFK
REVIEW
KFK
FIGURE 3
FPL
REFERENCES
1. Palatka Site, FPL, 2011
2. Land Use / Land Cover, SJRWMD, 2009
Document Path

Environmental and Land Use Information: Supplemental Information

Potential Site #1: Babcock Ranch

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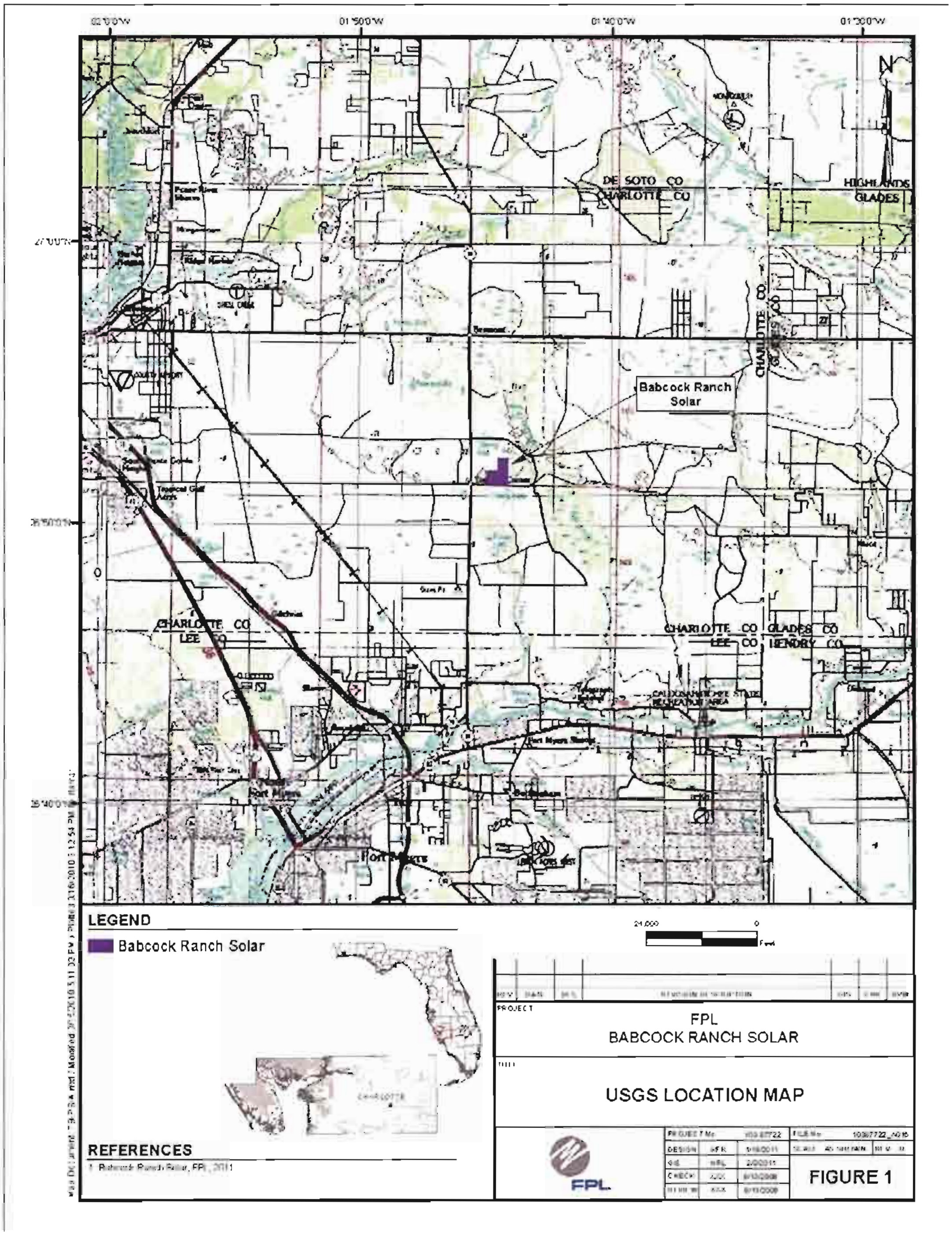
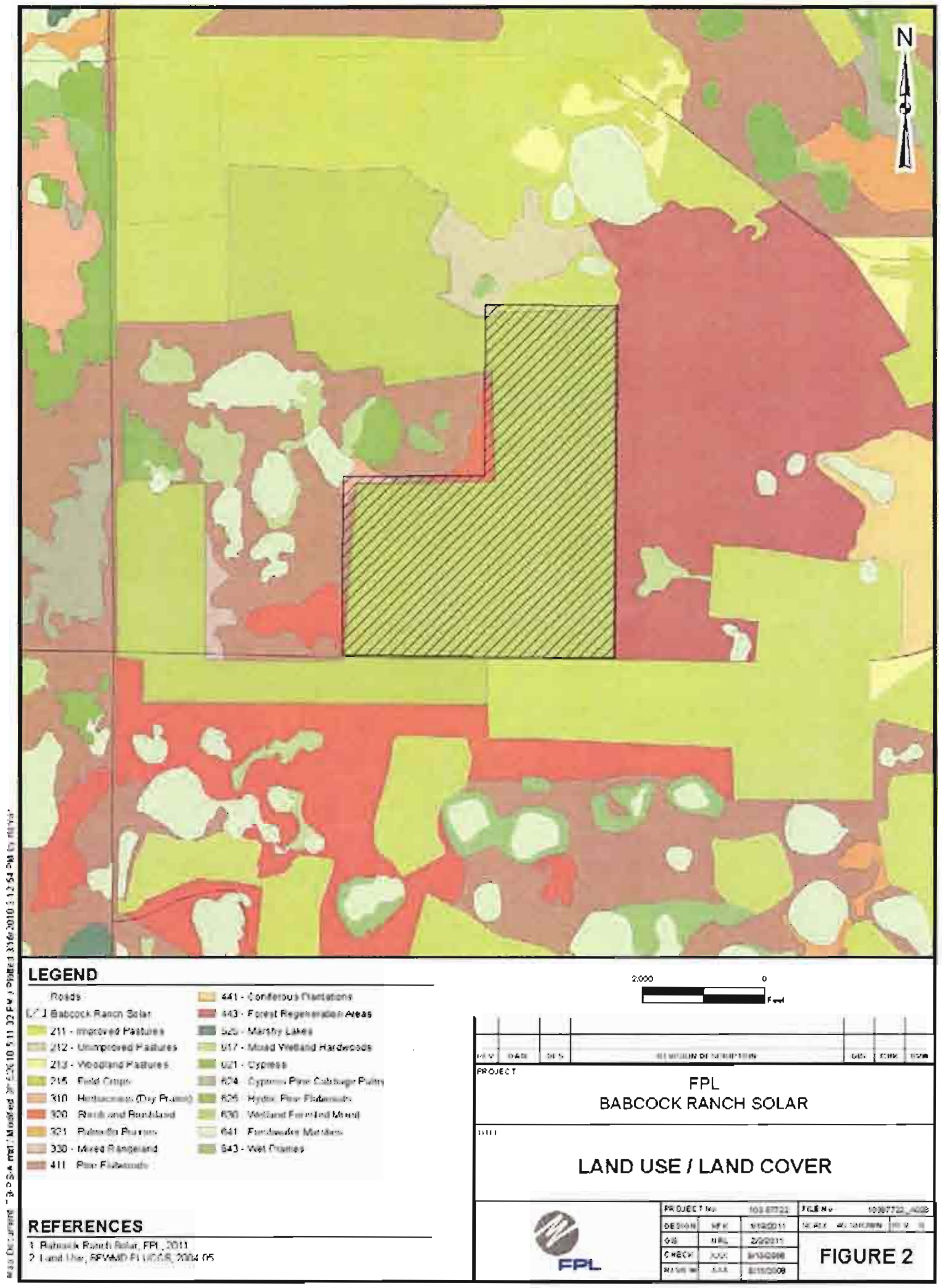

DE SOTO CO
CHARLOTTE CO
HIGHLANDS
GLADES
CHARLOTTE CO
GLADES CO
Babcock Ranch Solar
CHARLOTTE CO
LEE CO
CHARLOTTE CO
LEE CO
GLADES CO
HENDRY CO
Fort Myers
LEGEND
Babcock Ranch Solar
REFERENCES
PROJECT
FPL
BABCOCK RANCH SOLAR
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
Roads
Babcock Ranch Solar
211 - Improved Pastures
212 - Unimproved Pastures
213 - Woodland Pastures
215 Field Crops
310 Herbaceous (Dry Prairie)
330 - Mixed Rangeland
411 Pine Flatwoods
441 - Coniferous Plantations
443 - Forest Regeneration Areas
520 - Marshy Lakes
617 - Mixed Wetland Hardwoods
621 - Cypress
643 - Wet Prairies
REFERENCES
1 Babcock Ranch Solar, FPL, 2011
2,000
0
Feet
PROJECT
FPL
BABCOCK RANCH SOLAR
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #2: Desoto Solar Expansion

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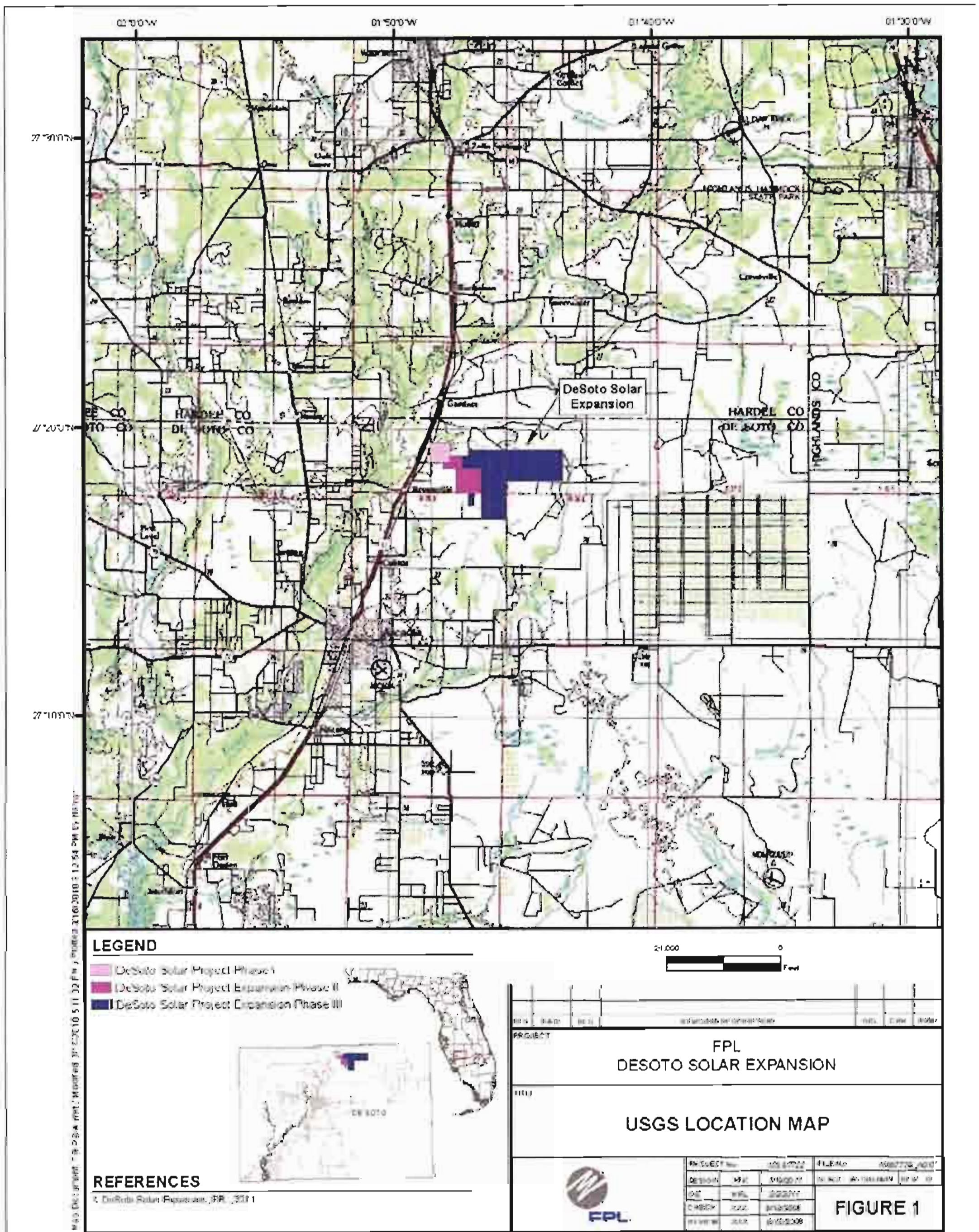
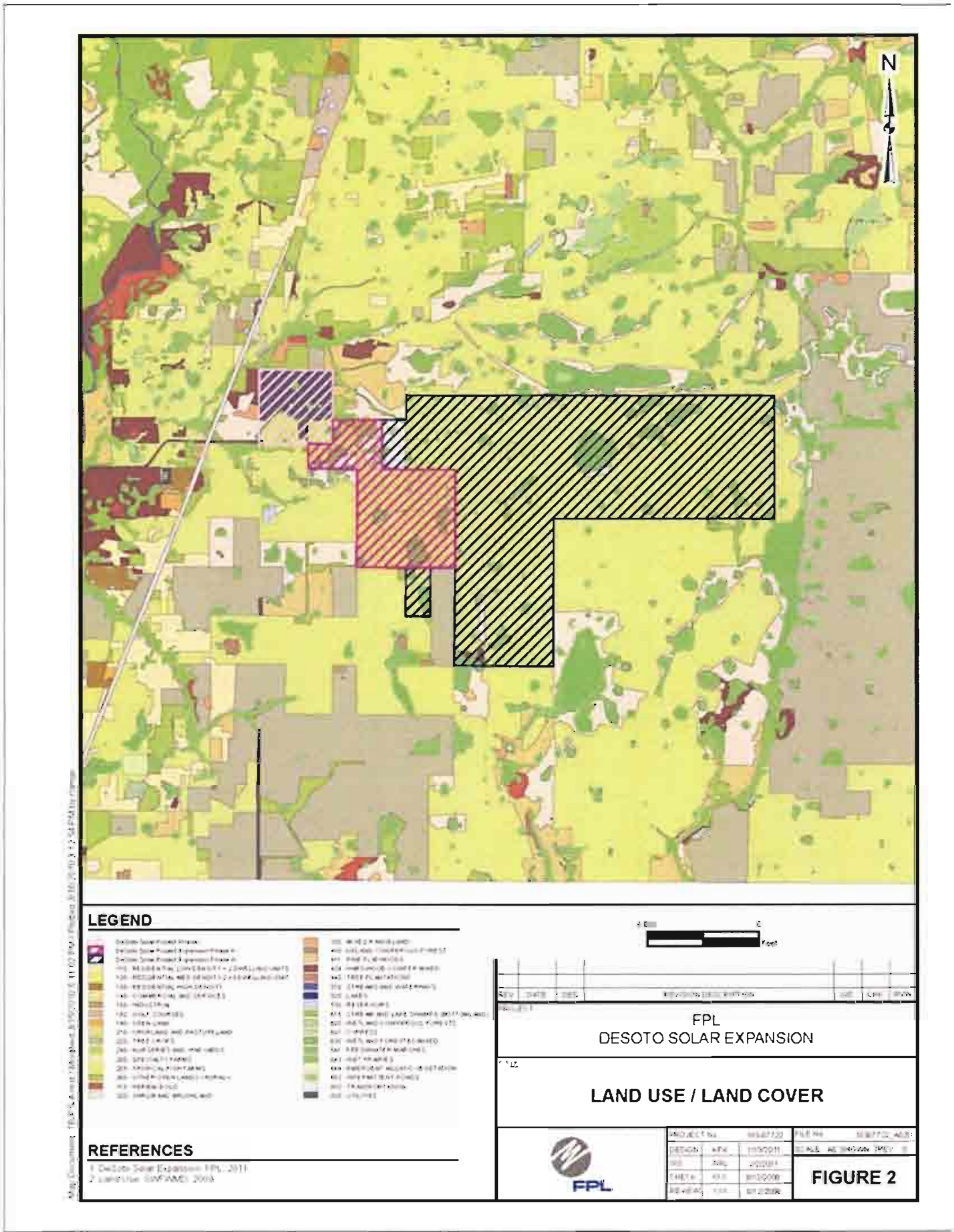

DeSoto Solar Expansion
HARDEE CO
DE SOTO CO
HIGHLANDS CO
LEGEND
DeSoto Solar Project Phase I
DeSoto Solar Project Expansion Phase II
DeSoto Solar Project Expansion Phase III
REFERENCES
PROJECT
FPL
DESOTO SOLAR EXPANSION
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
REFERENCES
FPL
DESOTO SOLAR EXPANSION
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #3: Manatee Plant Site

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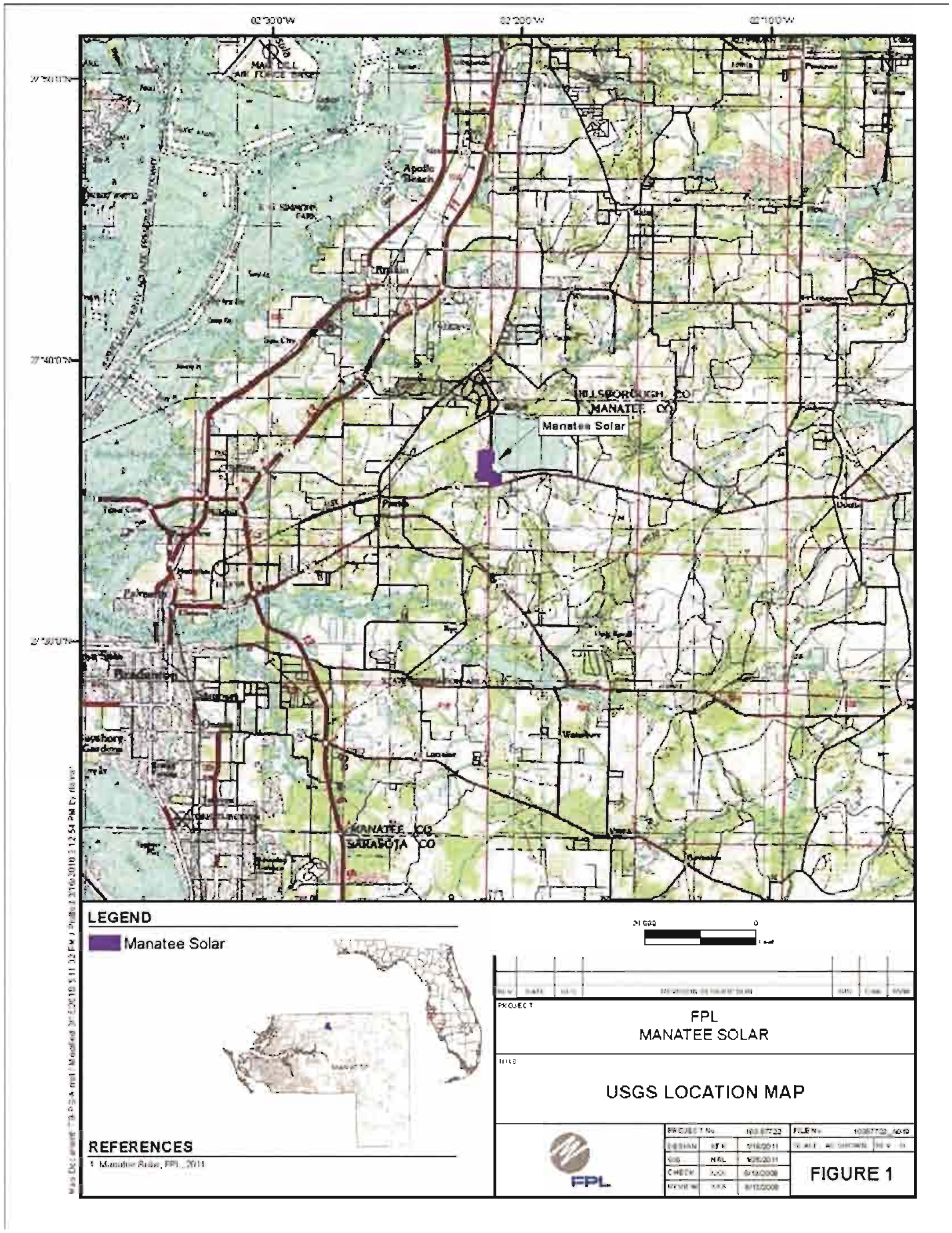
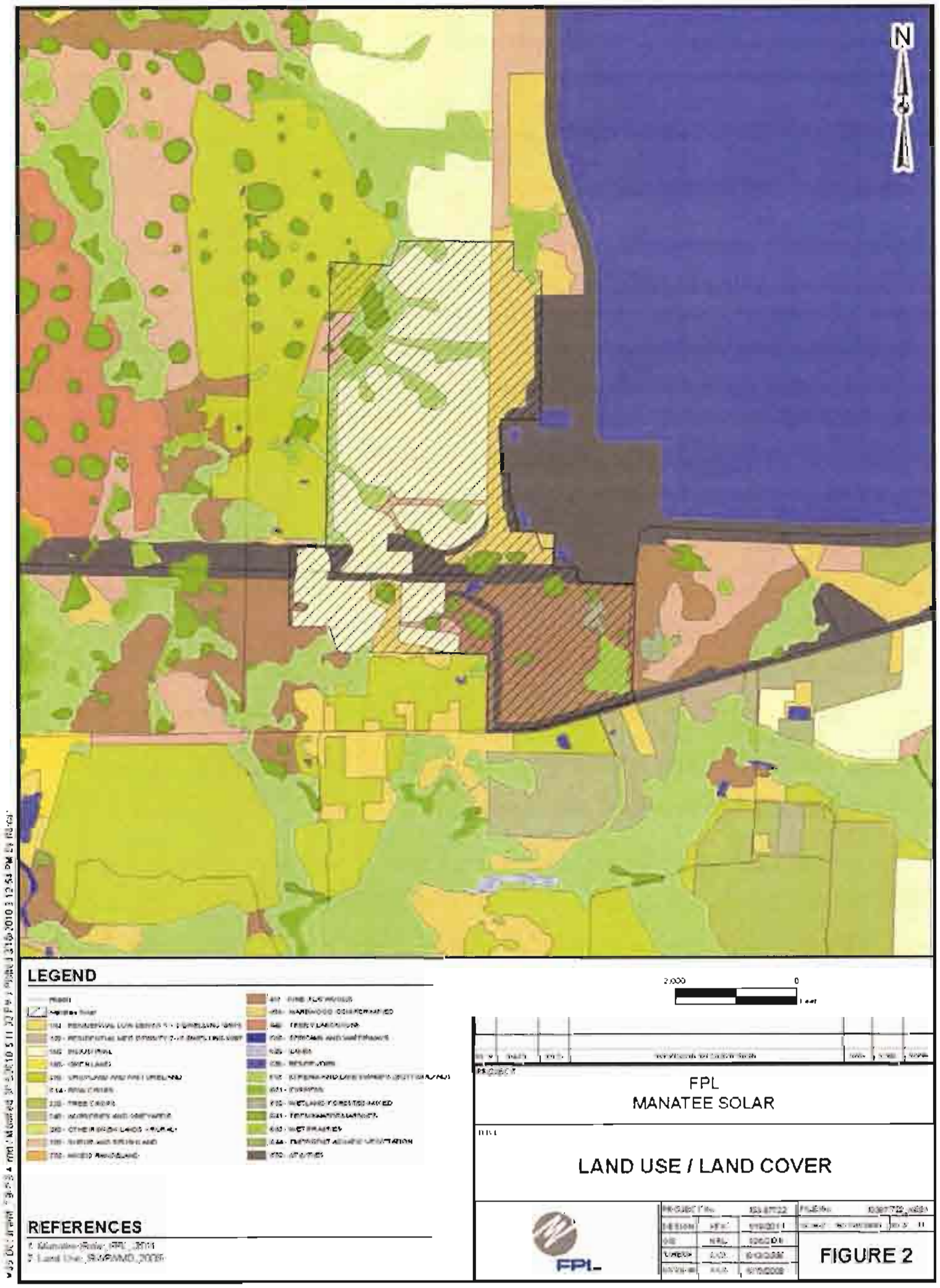

Manatee Solar
HILLSBOROUGH CO
MANATEE CO
MANATEE CO
SARASOTA CO
Bradenton
LEGEND
Manatee Solar
REFERENCES
PROJECT
FPL
MANATEE SOLAR
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
REFERENCES
FPL
MANATEE SOLAR
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #4: Martin County

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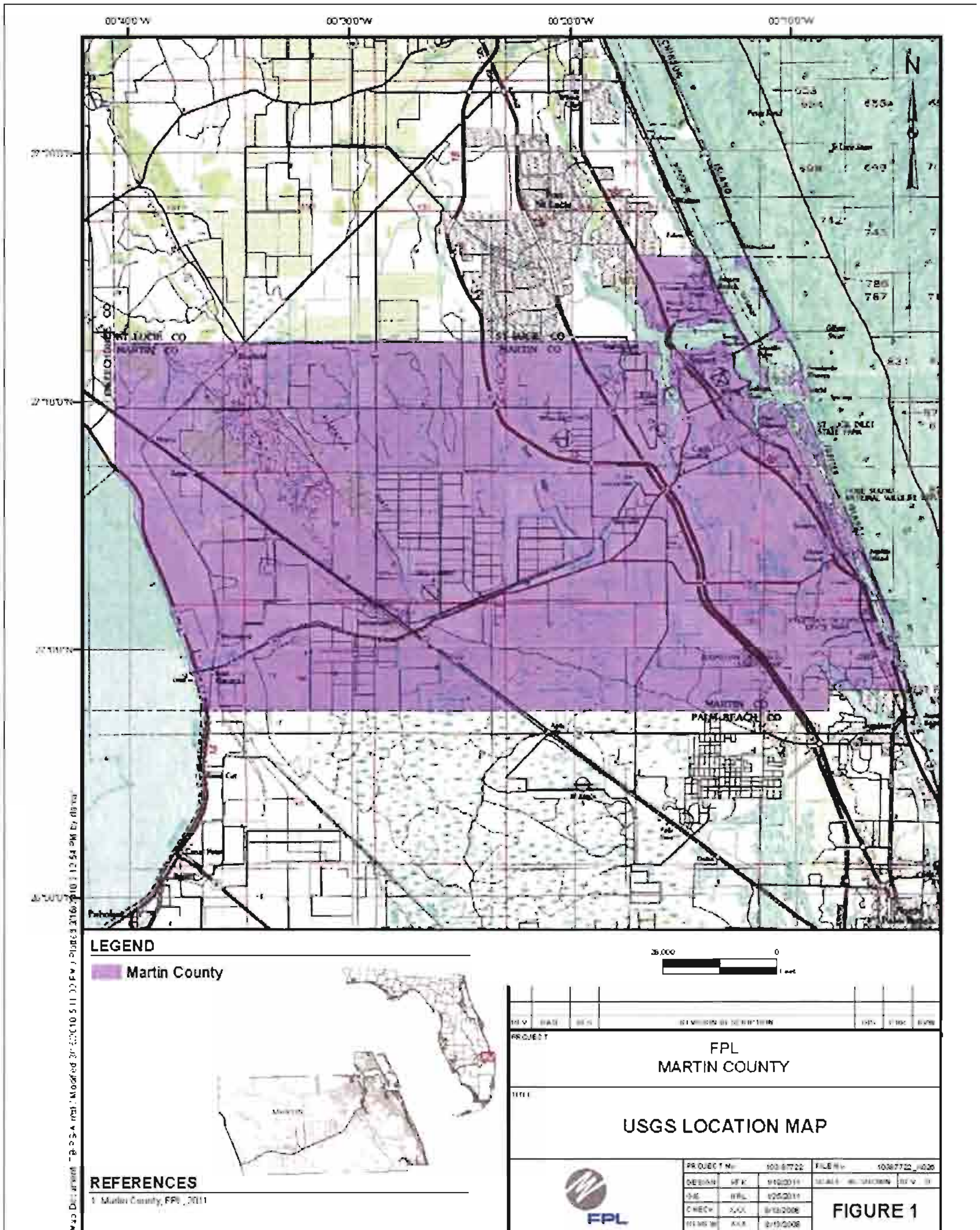
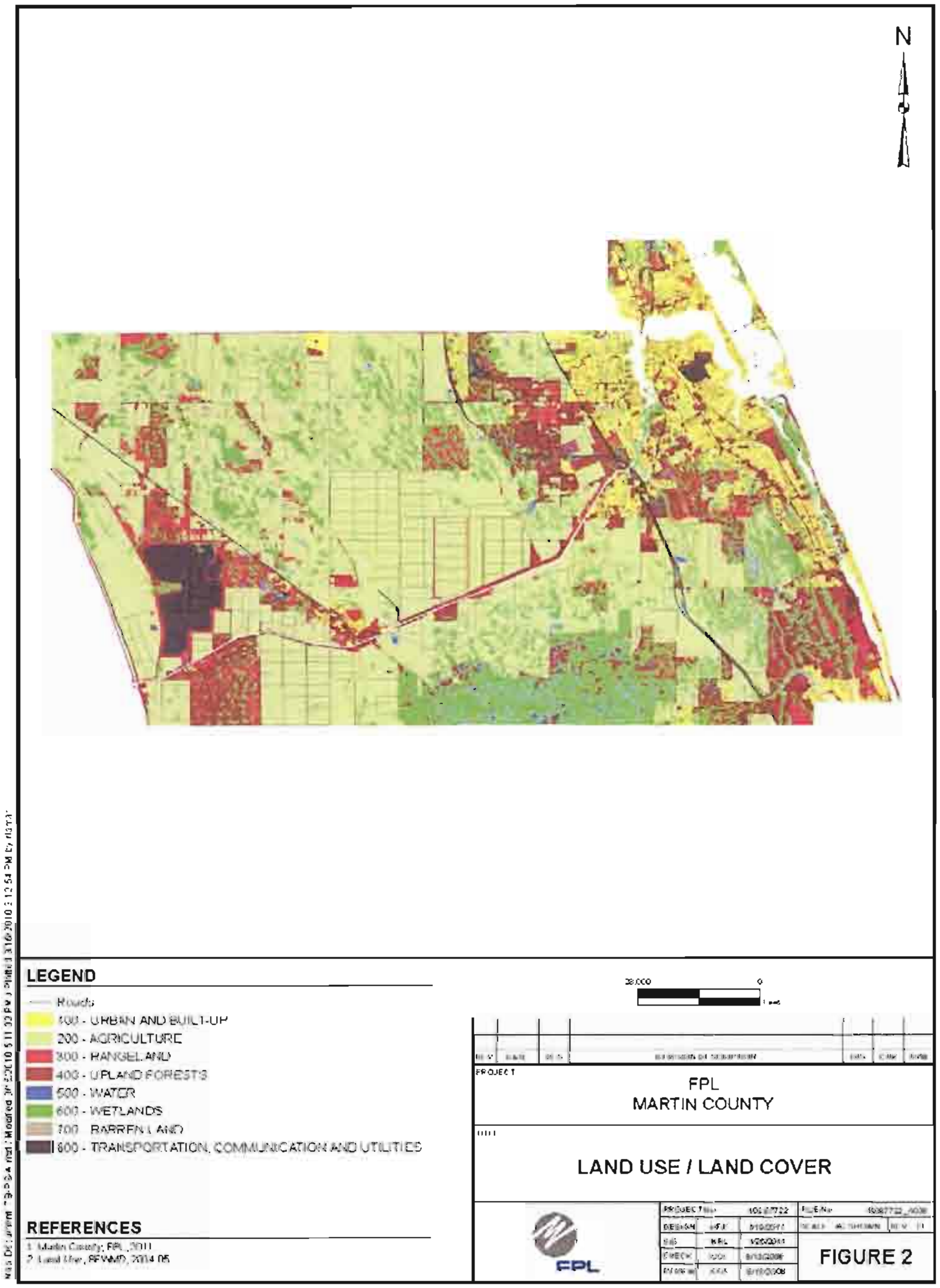

LEGEND
Martin County
REFERENCES
FPL
MARTIN COUNTY
USGS LOCATION MAP
FIGURE 1
FPL


N
LEGEND
Roads
100 - URBAN AND BUILT-UP
200 - AGRICULTURE
300 - RANGELAND
400 - UPLAND FORESTS
500 - WATER
600 - WETLANDS
700 - BARREN LAND
800 - TRANSPORTATION, COMMUNICATION AND UTILITIES
REFERENCES
PROJECT
FPL
MARTIN COUNTY
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #5: Putnam County

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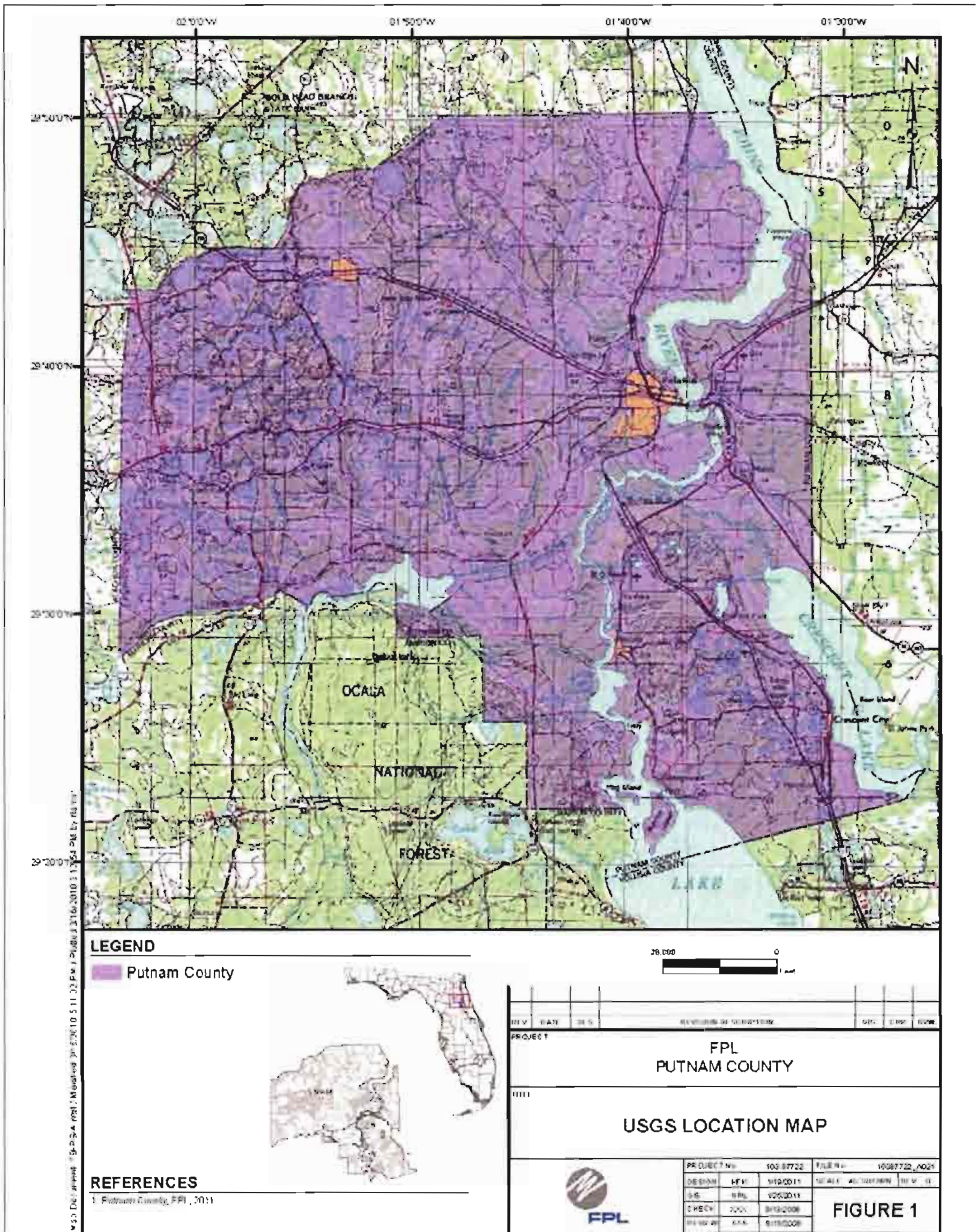
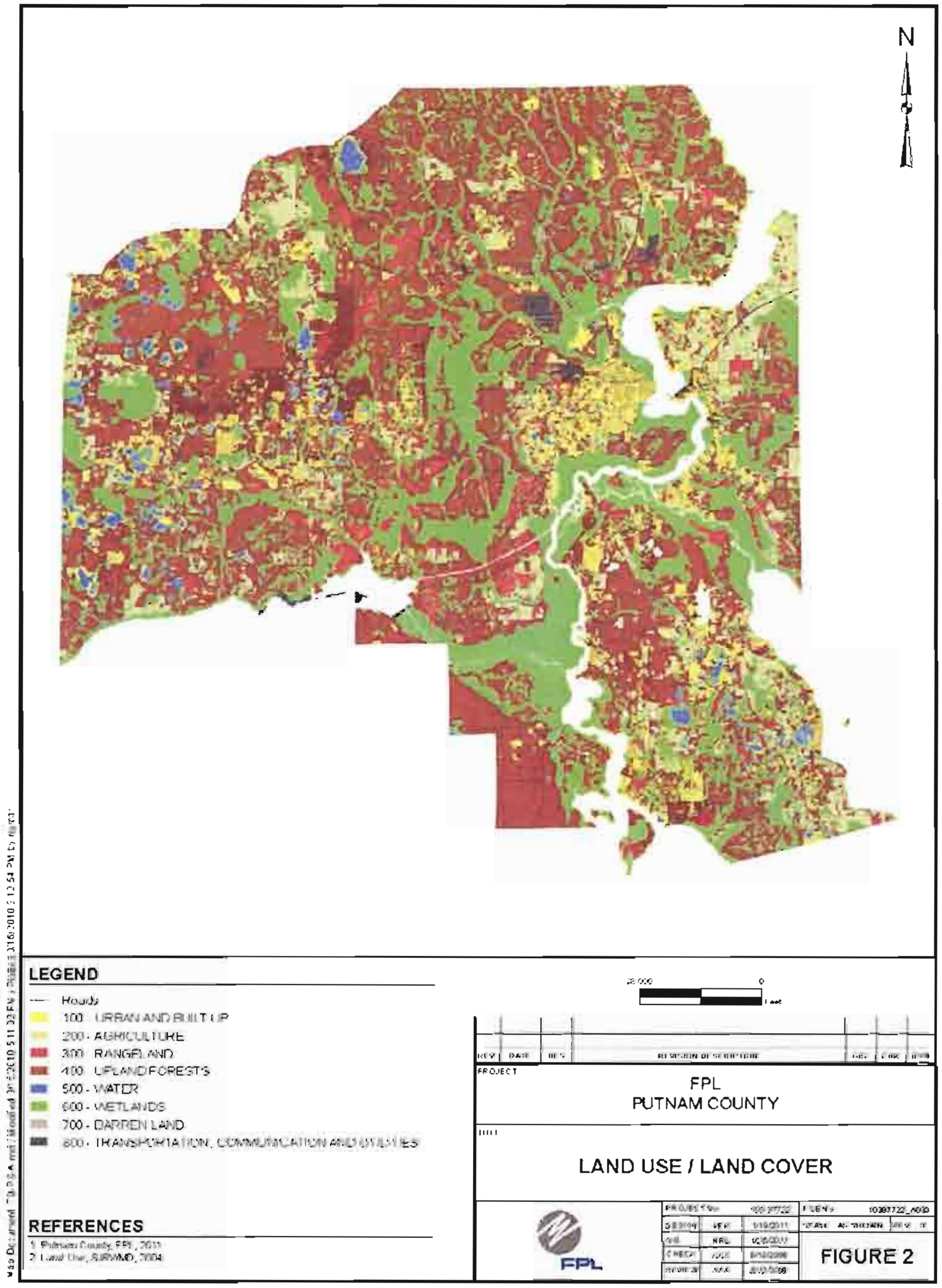

LEGEND
Putnam County
REFERENCES
FPL
PUTNAM COUNTY
USGS LOCATION MAP
FIGURE 1
OCALA
NATIONAL
FOREST
LAKE


N
LEGEND
Roads
100 - URBAN AND BUILT UP
200 - AGRICULTURE
300 - RANGELAND
400 - UPLAND FORESTS
500 - WATER
600 - WETLANDS
700 - BARREN LAND
800 - TRANSPORTATION, COMMUNICATION AND UTILITIES
REFERENCES
1. Putnam County, FPL, 2011
2. Land Use, SJRWMD, 2004
PROJECT
FPL
PUTNAM COUNTY
LAND USE / LAND COVER
FPL
FIGURE 2

CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information." These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints: external limitations and internal limitations. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important since they affect the development of assumptions for the amount of external assistance that is available to the FPL system as well as the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In the loss of load probability (LOLP) portion of its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new generating units that minimize adverse impacts to the flow of electricity within FPL's system. The internal transmission limitations are also addressed by developing the direct costs for siting new units at different locations, by evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system, and/or by evaluating the costs of transmission additions that may be needed to address regional concerns regarding an imbalance between load and generation in a given region. Both of these site- and system-related transmission costs are developed for each different unit/unit location option or groups of options. In addition, transfer limits for capacity and energy that can be imported into the Southeastern Florida region (Miami-Dade and Broward Counties) of FPL's system are also developed for use in FPL's production costing analyses. (A further discussion of the Southeastern Florida region of FPL's system, and the need to maintain a regional balance between generation and transmission contributions to meet regional load, is found in Chapter III.)

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's planned transmission facilities to interconnect and integrate generating units in FPL's resource plans, including those transmission facilities that must be certified under the Transmission Line Siting Act, are presented in Chapter III.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements for the FPL system.[9]

The load forecast that is presented in FPL's 2013 Site Plan was developed in February 2013. The only load forecast sensitivities analyzed during 2012/early 2013 were high load forecast sensitivities developed solely to analyze the quality of FPL's future reserves and the projected frequency at which load control might be implemented. These analyses are on-going.

[9] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis (i.e., when only new generating options are considered), the lowest electric rate basis approach and the lowest system cumulative present value of revenue requirements basis approach, yield identical results in terms of which resource options are more economic. In such cases FPL evaluates resource options on the simpler-to-calculate (but equivalent) lowest cumulative present value system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its fuel price forecasts are discussed in Chapter III of this document. FPL used three fuel cost, and three environmental compliance cost, forecasts in analyses supporting its 2012 nuclear cost recovery filing.

The high and low fuel cost forecasts are derived from a calculation of the historical volatility of the 12-month forward price for one year ahead. From this range of volatility, a reasonable value from the high end of the range is applied to the medium fuel cost forecast to develop a high fuel cost forecast. Similarly, a reasonable value from the low end of the range is applied to the medium fuel cost forecast to develop a low fuel cost forecast.

The resource plan presented in this Site Plan is based, in part, on those prior analyses. For that reason, this resource plan has not been further tested for different fuel cost forecasts.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item # 3, FPL used up to three fuel cost forecasts in its 2012/early 2013 resource planning analyses. While these forecasts did not represent a constant cost differential between oil/gas and coal, a variety of fuel cost differentials were represented in these forecasts.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 in Chapter I and Schedule 8 in Chapter III present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options in its resource planning work. A summary of this information for the new capacity options FPL currently projects to add over the reporting horizon for this document is presented on the Schedule 9 forms in Chapter III.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

During much of its 2012 resource planning work, FPL's financial assumptions were: i) a capital structure of 40.88% debt and 59.12% equity; (ii) a 5.50% cost of debt; (iii) a 10.0% return on equity; and (iv) an after-tax discount rate of 7.29%. Starting in late 2012, and continuing in 2013, FPL's financial assumptions have been based on the outcome of FPL's most recent base rate case and include: i) a capital structure of 40.38% debt and 59.62% equity; (ii) a 4.79% cost of debt; (iii) a 10.5% return on equity; and (iv) an after-tax discount rate of 7.45%. No sensitivities of these financial assumptions were used in FPL's 2012/early 2013 resource planning work.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item # 2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective are identical yield identical results in terms of which resource options are more economic when DSM levels are unchanged between competing resource plans. Therefore, in planning work in which DSM levels were unchanged, the equivalent, but simpler-to-calculate, cumulative present value of revenue requirements perspective was utilized.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses two system reliability criteria in its resource planning work that addresses generation, purchase, and DSM options. One of these is a minimum 20% Summer and Winter reserve margin. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These two reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability analysis work, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the Reliability Standards established by the North American Electric Reliability Council (NERC). The *NERC Reliability Standards* are available on the internet site (http://www.nerc.com/).

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Facility Rating Methodology* document that are also available on the internet under the FPL OATT Documents directory at https://www.oatioasis.com/FPL/index.html.

Generally, FPL limits its transmission facilities to 100% of the applicable thermal rating. The normal and contingency voltage criteria for FPL stations are provided below:

	Normal/Contingency	
Voltage Level (kV)	**Vmin (p.u.)**	**Vmax (p.u.)**
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09
Turkey Point (*)	1.01/1.01	1.06/1.06
St. Lucie (*)	1.00/1.00	1.06/1.06

(*) Voltage range criteria for FPL's Nuclear Power Plants

There may be isolated cases for which FPL may have determined that it is acceptable to deviate from the general criteria stated above. There are several factors that could influence these criteria, such as the overall number of potential customers that may be impacted, the probability of an outage actually occurring, or transmission system performance, as well as others.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The projected impacts of FPL's DSM programs on demand and energy consumption are revised periodically. Engineering models, calibrated with current field-metered data, are updated at regular intervals. Participation trends are tracked for all of FPL's DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants. For its load management programs, FPL conducts periodic tests of the load control equipment to ensure that the equipment is functioning correctly. These tests, plus actual, non-test load management events, also allows FPL to gauge the MW reduction capabilities of its load management programs on an on-going basis.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The Executive Summary and Chapter III provide a discussion of a variety of system concerns/issues that influence FPL's resource planning process. Please see those chapters for a discussion of those concerns/issues.

In addition to these system concerns/issues, there are other strategic factors FPL typically considers when choosing between resource options. These include the following: (1) technology risk; (2) environmental risk, and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology, which has not achieved general commercial acceptance, has a higher risk than a technology in wide use and, therefore, assuming all else equal, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the FPL system, including environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for FPL's resource plan are those which minimize environmental impacts for the FPL system as a whole through highly efficient fuel use, state of the art environmental controls, generating technologies that do not utilize fossil fuels (such as nuclear and photovoltaics), etc.

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decision-making, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As shown in this 2013 Site Plan, FPL's resource plan currently projects the following major supply-side resource additions: the completion of the nuclear uprates project, the modernizations at Cape Canaveral, Riviera, and Port Everglades, the upgrading of CTs in numerous CCs throughout FPL's system, the EcoGen PPA, and Turkey Point Unit 6.

In regard to these capacity additions for which a need determination has already been approved, the nuclear uprates and Turkey Point Unit 6, do not lend themselves to a request for proposal (RFP) approach involving bids from third parties who would build new nuclear generation capacity. In addition, nuclear capacity additions are exempted from the Commission's Bid Rule by section 403.519 (4) (c). For these nuclear projects, FPL's procurement activities are conducted to ensure the best combination of quality and cost for the delivered products. Furthermore, the modernization projects at Cape Canaveral, Riviera, and Port Everglades received Commission waivers from the Bid Rule due to attributes specific to modernization projects (such as use of existing land, water, transmission, etc.) plus other economic benefits to FPL's customers. These waivers from the Bid Rule were granted in Order No. PSC-08-0591-FOF-EI for Cape Canaveral and Riviera and in Order No. PSC-11-0360-PAA-EI for Port Everglades.

CT upgrades are currently taking place at various CC units throughout the FPL system. FPL was approached by the original equipment manufacturer (OEM) of the CTs regarding the possibility of upgrading these units. Following negotiations with the OEM, and economic analyses that showed that upgrading was cost-effective for FPL's customers, the decision was made to proceed with the CT upgrades. That process is underway and is scheduled to be completed in 2015.

The EcoGen PPA was the result of negotiations between EcoGen and FPL.

Identification of self-build options, beyond those units already approved by the FPSC and Governor and Siting Board or units for which FPL may be then seeking approval, in future FPL Site Plans will not be an indication that FPL has pre-judged any capacity solicitation it may conduct. The identification of future generating units is required of FPL in its Site Plan filings and represents those alternatives that appear to be FPL's best, most cost-effective self-build options at the time. FPL reserves the right to refine its planning analyses and to identify other self-build options. Such refined analyses have the potential to yield a variety of self-build options, some of which might not require an RFP. If an RFP is issued for Supply options, FPL reserves the right to choose the best alternative for its customers, even if that option is not an FPL self-build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

---

(1) FPL has identified the need for a new 230 kV transmission line that required certification under the Transmission Line Siting Act which was issued in April 2006. The new line is to be completed in two phases connecting FPL's St. Johns Substation to FPL's Pringle Substation (shown on Table III.E.1 in Chapter III). Phase 1 was completed in May 2009 and consisted of a new line connecting Pringle to a new Pellicer Substation. Phase 2 is planned to connect St. Johns to Pellicer and is scheduled to be completed by December 2017. The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

(2) FPL has identified the need for a new 230 kV transmission line (by December 2014) that required certification under the Transmission Line Siting Act which was issued on November 2008. The new line will connect FPL's Manatee Substation to FPL's proposed Bob White Substation (also shown on Table III.E.1 in Chapter III). The construction of this

line, scheduled to be completed in 2014, is necessary to serve existing and future customers in the Manatee and Sarasota areas in a reliable and effective manner.

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FPL

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April 1, 2014

-VIA THE WEB-BASED ELECTRONIC FILING PORTAL-

Carlotta Stauffer, Director
Division of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 140000-EI

RE: Florida Power & Light Company's 2014 Ten Year Power Plant Site Plan

Dear Ms. Stauffer:

Please find enclosed for electronic filing Florida Power & Light Company's 2014-2023 Ten Year Power Plant Site Plan. Per Commission Staff's request, five (5) hard copies also will be provided to your office.

Sincerely,

s/ Jessica A. Cano
Jessica A. Cano
Fla. Bar No. 37372

Enclosure

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 49
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-3-N

Ten Year Power Plant Site Plan
2014 – 2023

FPL

FPL

Ten Year Power Plant Site Plan

2014-2023

Submitted To:

Florida Public
Service Commission

Miami, Florida
April 2014

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Table of Contents

List of Figures and Tables

List of Schedules

Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan (Site Plan). This Site Plan should include an estimate of the utility's future electric power generating needs, a projection of how these estimated generating needs could be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The information contained in this Site Plan is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains uncertain forecasts and tentative planning information. Forecasts evolve, and all planning information is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This Site Plan document is based on Florida Power & Light Company's (FPL) integrated resource planning (IRP) analyses that were carried out in 2013 and that were on-going in the first Quarter of 2014. The forecasted information presented in this plan addresses the years 2014 through 2023.
This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, based on FPL's IRP work in 2013 and early 2014. This chapter also discusses a number of issues that may change the resource plan presented in this Site Plan. Furthermore, this chapter briefly discusses the status of FPL's DSM planning efforts, as well as FPL's, renewable energy efforts, transmission planning additions, and fuel cost forecasts.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as Preferred and Potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional information that is included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	*Abbreviation*	*Definition*
Unit Type	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	ST	Stean Unit (Fossil or Nuclear)
	PV	Photovoltaic
Fuel Type	NUC	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	Solar	Solar Energy
	SUB	Sub Bituminous Coal
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	L	Regulatory approval pending. Not under construction
	P	Planned Unit
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	ESP	Electrostatic Precipitators

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Executive Summary

Florida Power & Light Company's (FPL) 2014 Ten Year Power Plant Site Plan (Site Plan) presents FPL's current plans to augment and enhance its electric generation capability (owned or purchased) as part of its efforts to meet its projected incremental resource needs for the 2014 - 2023 time period. By design, the primary focus of this document is on supply side additions; i.e., electric generation capability and the sites for these additions. The supply side additions discussed in this document are resources projected to be needed, based on FPL's load forecast, after accounting for FPL's demand side management (DSM) resource additions. In 2014, new DSM Goals for FPL for the time period 2015 through 2024 will be set by the Florida Public Service Commission (FPSC). At almost the same time FPL is filing this 2014 Site Plan, FPL will also be filing its proposed DSM Goals with the FPSC. Consequently, the level of DSM additions reflected in the 2014 Site Plan is consistent with FPL's proposed DSM Goals. The proposed level of DSM is discussed further below and in Chapter III.

FPL's load forecast accounts for a significant amount of efficiency that results from federal and state energy efficiency codes and standards. The projected impacts of these codes and standards are directly accounted for in FPL's load forecast as discussed below and in Chapter II.

The resource plan that is presented in FPL's 2014 Site Plan contains four key similarities to the resource plan presented in FPL's 2013 Site Plan. However, there are several factors that have contributed to differences between the resource plan presented in the 2014 Site Plan and the resource plan that was previously presented in FPL's 2013 Site Plan. Additional factors will continue to influence FPL's on-going resource planning work and could result in changes in the resource plan presented in this document. A brief discussion of these similarities and factors is provided below. Additional information regarding these topics is presented in Chapter III.

I. Similarities Between the Current Resource Plan and the Resource Plan Previously Presented in FPL's 2013 Site Plan:

There are four key similarities between the current resource plan presented in this document and the resource plan presented in the 2013 Site Plan.

Similarity # 1: Modernizations of Existing Power Plant Sites.

The modernization of FPL's Cape Canaveral plant site was completed on time in 2013 and the modernization of FPL's existing Riviera Beach plant site is scheduled to be completed on/near the April 1, 2014 date this 2014 Site Plan is to be filed. In addition, the modernization of FPL's existing Port Everglades plant site is underway and is projected to be completed in 2016.

Similarity # 2: FPL continues to pursue additional nuclear energy generation to significantly (i) reduce its use of fossil fuels, (ii) lower system fuel costs, (iii) lower system air emissions, and (iv) provide a valuable hedge against future increases in fuel costs and environmental compliance costs.

In 2013 FPL successfully completed its capacity uprate projects at its four existing nuclear units ; Turkey Point Units 3 & 4 and St. Lucie Units 1 & 2. The nuclear uprate project added about 520 MW of additional nuclear capacity to FPL's system which was about 30% more additional nuclear capacity than was originally projected when the project began. FPL's customers are already benefiting from lower fuel costs and reduced system air emissions provided by this additional nuclear capacity.

FPL is also continuing its work to obtain all of the licenses, permits, and approvals that will be necessary to construct and operate two new nuclear units at its Turkey Point site in the future. The earliest deployment dates for these two new units remain 2022 and 2023, respectively, and this Site Plan projects the two new nuclear units going in-service in those years.

Similarity #3: FPL is projected to serve Vero Beach's electrical load.

An agreement to this effect was reached between Vero Beach and FPL on February 19, 2013, and a referendum was held on March 12, 2013 that resulted in a majority of Vero Beach voters approving the agreement. FPL's current load forecast projects that FPL will begin serving Vero Beach's load in January 2015.

Similarity #4: Specific generating units are projected to be retired and/or converted to synchronous condenser operation.

In the last two years, FPL has retired a number of older, less efficient generating units including: Sanford Unit 3, Cutler Units 5 & 6, Cape Canaveral Units 1 & 2, Riviera Beach Units 3 & 4, and Port Everglades Units 1 – 4. In addition, Turkey Point Unit 2 has been converted to operate in synchronous condenser mode to provide voltage support for the transmission system in Southeastern Florida.

This trend is projected to continue. Putnam Units 1 & 2 are now projected to be retired by the end of 2014. And, similar to the earlier conversion of Turkey Point Unit 2, FPL projects that Turkey Point Unit 1 will be converted to run in synchronous condenser mode starting in 2016. In addition, for planning purposes, FPL is projecting that all of its existing gas turbines (GTs) at its two Broward County sites will be retired by the end of 2018 and that 5 new combustion turbines (CTs) will be installed at FPL's Lauderdale plant site also by the end of 2018. This projection is further discussed later in this executive summary and in Chapter III.

II. Factors Influencing FPL's Resource Planning Work Which Have Impacted, or Which Could Impact, FPL's Resource Plan:

There are a number of factors that influence FPL's resource planning work. Eight (8) of these are briefly discussed below and are discussed again in Chapters II and/or III.

Two of these factors are on-going system concerns that FPL has considered in its resource planning work for a number of years. These two on-going system concerns are: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward Counties.

The third and fourth factors that will be discussed are factors that directly impacted the resource plan presented in this document because they affect FPL's forecast of its future load and its future firm load. The third factor is the impact of federal and state energy efficiency codes and standards on FPL's future loads. The impact of these codes and standards has been incorporated into FPL's current load forecast. The magnitude of efficiency that is being delivered to FPL's customers through these codes and standards is significant. For example, by the year 2023 (the last year addressed in this Site Plan), FPL's Summer peak is projected to be lower by approximately 3,477 MW compared to what the projected load would have been without the codes and standards based on cumulative savings beginning in 2005. This represents a decrease of approximately 12% in what the forecasted Summer peak load for 2023 would have been without the codes and standards. Likewise, FPL's forecasted net energy for load (NEL) in the year 2023 is projected to be approximately 9,991 GWh lower compared to what the projected NEL would have been without the efficiency codes and standards based on cumulative savings beginning in 2005. This represents a decrease of approximately 7% from what the forecasted NEL for 2023 would have been without the codes and standards.

There are two significant impacts from these codes and standards. The first impact is to substantially lower FPL's forecasted peak load and NEL. The second impact is that the codes and standards lower the potential for future MW and GWh reductions from FPL's DSM programs that address the specific appliances and equipment impacted by the codes and standards. Thus, significant energy efficiency regarding this equipment will be delivered to FPL's customers through codes and standards, thus precluding the potential for FPL to pursue these same efficiency gains through utility DSM programs.

The fourth factor is a projected decline in the cost-effectiveness of a number of utility DSM measures due to reasons that are beneficial overall for FPL's customers. Compared to 2009 (when DSM Goals were last set): (i) forecasted fuel costs have dropped by 50%, thus lowering the potential benefits from DSM kwh reductions; (ii) projected compliance costs for carbon dioxide (CO_2), have not only been significantly lowered, but their forecasted start date has been delayed by almost a decade, thus again lowering the potential benefits from DSM kwh reductions; and, (iii) FPL's generating system, due to the retirement of older, less efficient generators and replacement with highly efficient generators, plus additional nuclear capacity, has gotten more fuel-efficient, thus lowering fuel-related costs that would otherwise represent potential benefits for DSM kwh reductions. These factors are benefitting FPL's customers through lower electric rates, but they also lower the potential economic benefits that otherwise could be offered by DSM. When combined with the previously discussed fact that codes and standards have reduced the potential for efficiency gains in regard to appliance and equipment addressed by these codes and standards, the result is that FPL is logically projecting a lower contribution from utility DSM in the near-term. That lower contribution is accounted for in the 2014 Site Plan. These factors are discussed in detail in the filing FPL is making in its DSM Goals proceeding.

The fifth factor is the need to take measures to limit FPL's projected increasing dependence upon DSM resources to maintain system reliability. This factor has been previously discussed in FPL's 2011, 2012, and 2013 Site Plans. In these previous Site Plans, FPL has discussed this projection of increasing dependence upon DSM resources using a new type of reserve margin projection as an indicator: a "generation-only reserve margin" or "GRM".

The GRM projections from the 2011, 2012, and 2013 Site Plans consistently showed that these values were projected to significantly decrease over the 10-year reporting period of the Site Plans, declining to single-digit values in the latter years of the reporting periods. These projections indicated a steadily growing dependence on DSM resources to maintain system reliability. FPL's analyses show that system reliability risk increases, particularly from a system operations perspective, as dependence on DSM resources increases to a point where DSM resources account for more than half of FPL's 20% total reserve margin criterion value. Therefore, FPL is implementing a new reliability criterion of a 10% GRM in its resource planning work to complement its other two reliability criteria: a 20% total reserve margin criterion for Summer and Winter, and an annual 0.1 day/year loss-of-load-probability (LOLP) criterion. FPL is implementing the GRM criterion so that FPL's resource plans will begin to meet this criterion in the year 2019. A further discussion of the GRM criterion is presented in Chapter III.

There are additional factors that did not impact FPL's resource plan presented in this document, but which could result in future changes to this resource plan. For example, a sixth factor is the project schedule for the Turkey Point Units 6 & 7 nuclear units. At the time the 2014 Site Plan is being finalized, the Nuclear Regulatory Commission (NRC) has not provided a schedule for its review of FPL's Combined Operating License Application (COLA). Once the NRC's COLA review schedule is available, FPL will review the overall schedule for the Turkey Point Units 6 & 7 project. FPL's review will also consider the impacts of the recently amended nuclear cost recovery clause (NCRC) statute and the ongoing feasibility analyses that are part of Florida Nuclear Cost Recovery process.

The seventh factor is environmental regulation. As developments occur in regard to either new environmental regulations, and/or in how environmental regulations are interpreted and applied, the potential exists for such developments to affect FPL's resource plan that is presented in this document. For example, FPL is aware of potential impacts to generating units of recent EPA changes to the National Ambient Air Quality Standards that include shorter duration 1-hour standards for nitrogen dioxide (NO_2) and sulfur dioxide (SO_2). As a consequence, FPL filed in mid-2013 for FPSC approval to recover costs through the environmental cost recovery clause for removing all of its existing gas turbines (GTs) and partially replacing that peaking unit capacity with new combustion turbines (CTs). Although FPL withdrew its filing in December 2013 pending further analyses including on-site monitoring, FPL believes that the results of the monitoring and analyses will require that the Broward GTs be replaced. Therefore, FPL is currently projecting the retirement of all GTs in Broward County; i.e., at its existing Lauderdale and Port Everglades plant sites (a decrease in generating capacity of 1,260 MW Summer), and the installation of 5 new 201 MW CTs at its existing Lauderdale plant site (an increase of 1,005 MW Summer).

The eighth factor that will be discussed is the possibility of the establishment of a Florida standard for renewable energy or clean energy. Although no such legislation has been enacted to-date, Renewable Portfolio Standards, or Clean Energy Portfolio Standards legislation, or other legislative initiatives regarding renewable or clean energy contributions, may occur in the future at either the state or national level. If such legislation is enacted, FPL would then determine what steps need to be taken to address the legislation.

Each of these factors will continue to be examined in FPL's on-going resource planning work during the rest of 2014 and in future years.

Table ES-1 presents a current projection of major changes to specific generating units and firm capacity purchases for 2014 – 2023. (Although this table does not specifically identify the impacts of projected DSM additions on FPL's resource needs and resource plan, FPL's projected DSM additions have been fully accounted for in the resource plan presented in this Site Plan.)

Table ES-1: Projected Capacity & Firm Purchase Power Changes

Year *	Projected Capacity & Firm Purchase Power Changes	Summer MW	Date	Summer Reserve Margin **
2014	Martin Unit 1 ESP - Return from ESP outage	823	March-14	
	Martin Unit 2 ESP - Temporary Outage to install ESPs	(826)	March-14	
	Turkey Point Unit 5 CT Upgrade	30	March-14	
	Sanford 5 CT Upgrade	9	September-13	
	Riviera Beach Next Generation Clean Energy Center	1,212	April-14	
	Total of MW changes to Summer firm capacity:	**1,247**		**28.0%**
2015	Manatee Unit 3 CT Upgrade	32	October-14	
	Martin Unit 2 ESP - Returned from ESP Outage	823	December-14	
	Putnam 1&2 Retirement	(498)	December-14	
	OUC - Stanton PPAs	37	January-15	
	Vero Beach Combined Cycle 1/	46	January-15	
	Palm Beach SWA - additional capacity	70	January-15	
	Fort Myers Unit 2 CT Upgrades	18	June-15	
	Fort Myers Unit 2 CT Upgrades	18	March-15	
	Fort Myers Unit 2 CT Upgrades	18	May-15	
	Total of MW changes to Summer firm capacity:	**563**		**27.5%**
2016	UPS Replacement	(928)	December-15	
	Port Everglades Next Generation Clean Energy Center	1,237	June-16	
	Total of MW changes to Summer firm capacity:	**309**		**28.6%**
2017	Turkey Point Unit 1 synchronous condenser	(396)	October-16	
	Total of MW changes to Summer firm capacity:	**(396)**		**22.6%**
2018	OUC - Stanton PPAs	(37)	December-17	
	Vero Beach Combined Cycle 1/	(46)	January-18	
	Total of MW changes to Summer firm capacity:	**(83)**		**20.5%**
2019	Port Everglades GT retirement	(420)	December-18	
	Lauderdale GT retirement	(840)	December-18	
	Lauderdale CT	1,005	January-19	
	SJRPP suspension of energy	(381)	April-19	
	Unsited CC	1,269	June-19	
	Total of MW changes to Summer firm capacity:	**633**		**21.6%**
2020	Unspecified Purchase	129	June-20	
	Total of MW changes to Summer firm capacity:	**129**		**20.5%**
2021	Eco-Gen PPA	180	January-21	
	Unspecified Purchase	168	June-21	
	Total of MW changes to Summer firm capacity:	**348**		**20.8%**
2022	Cape Next Generation Clean Energy Center	87	June-22	
	Turkey Point Nuclear Unit 6	1,100	June-22	
	Total of MW changes to Summer firm capacity:	**1,187**		**22.6%**
2023	Riviera Beach Next Generation Clean Energy Center	55	June-23	
	Turkey Point Nuclear Unit 7	1,100	June-23	
	Total of MW changes to Summer firm capacity:	**1,155**		**24.4%**

* Year shown reflects when the MW change begins to be accounted for in Summer reserve margin calculations. (Note that addition of MW values for each year will not yield a current cumulative value.)

** Winter Reserve Margins are typically high than Summer Reserve Margin. Winter Reserve Margin are shown on Schedule 7.2 in Chapter III.

1/ This unit will be added as part of the agreement that FPL will serve Vero Beach's electric load starting January, 2015. This unit is expected to be retired within 3 years.

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 9.0 million people. FPL served an average of 4,626,934 customer accounts in thirty-five counties during 2013. These customers were served by a variety of resources including: FPL-owned fossil-fueled, renewable, and nuclear generating units, non-utility owned generation, demand side management (DSM), and interchange/purchased power.

I.A. FPL-Owned Resources

The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory, plus one site in Georgia (partial FPL ownership of one unit) and one site in Jacksonville, Florida (partial FPL ownership of two units). The current electrical generating facilities consist of four nuclear units, three coal units, sixteen combined cycle (CC) units, five fossil steam units, forty-eight combustion gas turbines, two simple cycle combustion turbines, and two photovoltaic facilities[1]. The locations of these eighty generating units are shown on Figure I.A.1 and in Table I.A.1.

FPL's bulk transmission system is comprised of 6,734 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 589 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2.

1 FPL also has one 75 MW solar thermal facility at its Martin plant site. This facility does not generate electricity as the other units mentioned above do. Instead, it produces steam that reduces the use of fossil fuel to produce steam for electricity generation.

FPL Generating Resources by Location

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	4	3,176
B	St. Lucie [1/]	2	1,821
C	Manatee	3	2,729
D	Fort Myers	3	1,748
E	Lauderdale	2	884
F	Everglades [2/]	0	0
G	Riviera [2/]	0	0
H	Martin	5	3,731
I	Cape Canaveral	1	1,210
J	Sanford	2	1,980
K	Putnam	2	498
L	St. John's River Power Park [1/]	2	254
M	West County	3	3,657
N	DeSoto [3/]	1	25
O	Space Coast [3/]	1	10
	Scherer [4/]	1	643
	Gas Turbines	48	1,908
	Total System Generation =	**80**	**24,274**
	System Firm Generation =	**78**	**24,239**

1/ Represents FPL's ownership share: St Lucie nuclear: 100% Unit 1, 85% Unit 2. St. Johns River: 20% of two units.
2/ Will be site of new Modernization Plants.
3/ The 25 MW of PV at DeSoto and the 10 MW of PV at Space Coast are considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generation" row at the end of the table.
4/ The Scherer unit is located in Georgia and is not shown on this map.

Figure I.A.1: Capacity Resources by Location (as of December 31, 2013)

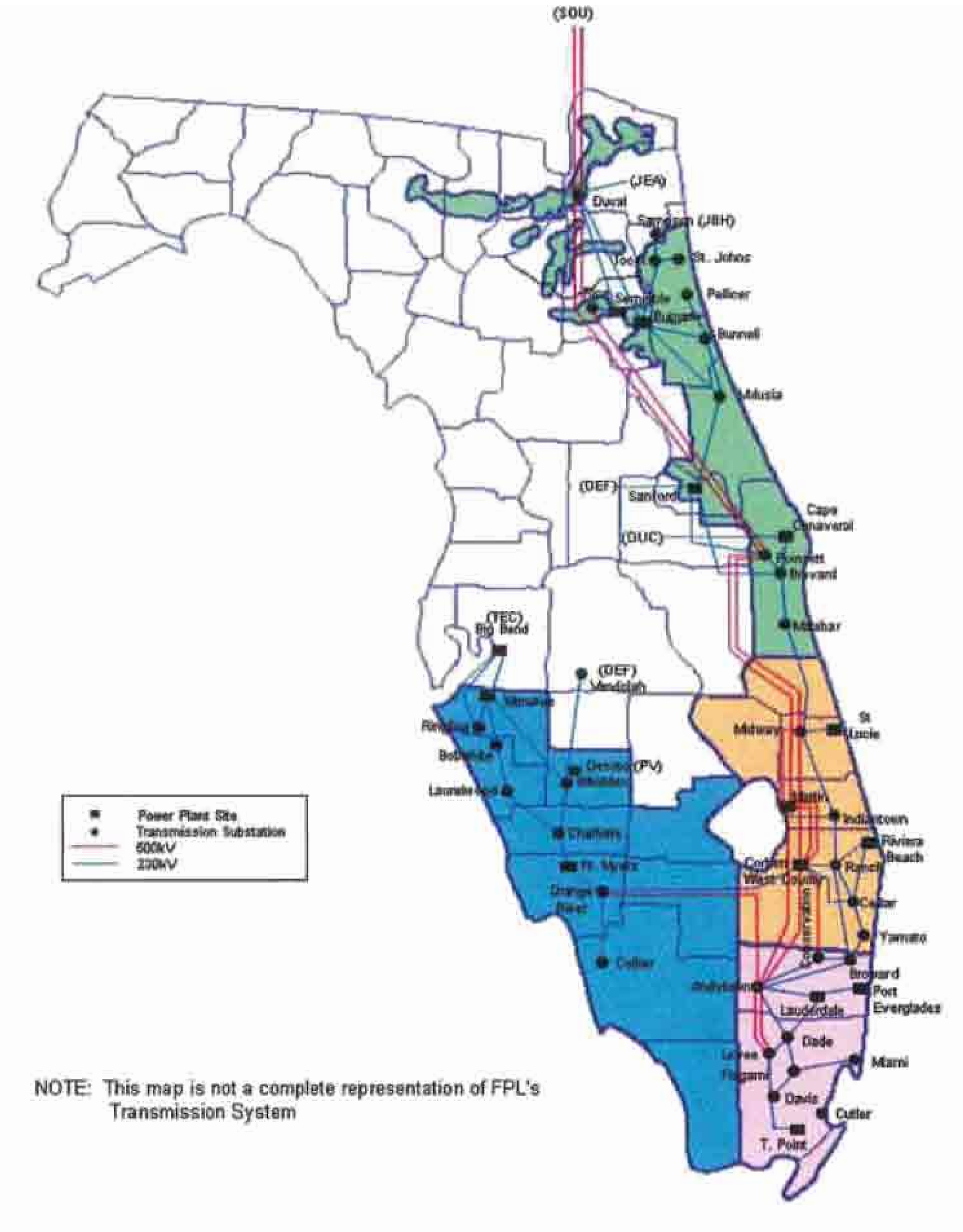
Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2013)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Nuclear				
St. Lucie 1/	Hutchinson Island, FL	2	Nuclear	1,821
Turkey Point	Florida City, FL	2	Nuclear	1,632
Total Nuclear:		**4**		**3,453**
Coal Steam				
Scherer	Monroe County, Ga	1	Coal	643
St. John's River Power Park 2/	Jacksonville, FL	2	Coal	254
Total Coal Steam:		**3**		**897**
Combined-Cycle				
Fort Myers	Fort Myers, FL	1	Gas	1,432
Manatee	Parrish, FL	1	Gas	1,111
Martin	Indiantown, FL	3	Gas	2,078
Sanford	Lake Monroe, FL	2	Gas	1,980
Cape Canaveral	Cocoa, FL	1	Gas/Oil	1,210
Lauderdale	Dania, FL	2	Gas/Oil	884
Putnam	Palatka, FL	2	Gas/Oil	498
Turkey Point	Florida City, FL	1	Gas/Oil	1,148
West County	Palm Beach County, FL	3	Gas/Oil	3,657
Total Combined Cycle:		**16**		**13,999**
Oil/Gas Steam				
Manatee	Parrish, FL	2	Oil/Gas	1,618
Martin	Indiantown, FL	2	Oil/Gas	1,652
Turkey Point	Florida City, FL	1	Oil/Gas	396
Total Oil/Gas Steam:		**5**		**3,666**
Gas Turbines(GT)				
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Total Gas Turbines/Diesels:		**48**		**1,908**
Combustion Turbines				
Fort Myers	Fort Myers, FL	2	Gas/Oil	316
Total Combustion Turbines:		**2**		**316**
PV				
DeSoto 3/	DeSoto, FL	1	Solar Energy	25
Space Coast 3/	Brevard County, FL	1	Solar Energy	10
Total PV:		**2**		**35**
Total System Generation as of December 31, 2013 =		**80**		**24,274**
System Firm Generation as of December 31, 2013 =		**78**		**24,239**

1/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/860. FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively.

2/ Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit. Represents FPL's ownership share: SJRPP coal: 20% of two units).

3/ The 25 MW of PV at DeSoto and the 10 MW of PV at Space Coast are considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generation" row at the end of the table.



NOTE: This map is not a complete representation of FPL's Transmission System

Figure I.A.2: FPL Substation and Transmission System Configuration

Description of Existing Resources

I.B Capacity and Energy Power Purchases

Firm Capacity Purchases from Qualifying Facilities (QF)

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has contracts with eight qualifying facilities; i.e., cogeneration/small power production facilities, to purchase firm capacity and energy during the 10-year reporting period of this Site Plan as shown in Table I.A.3, Table I.B.1, and Table I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source solar, wind, waste, geothermal, or other renewable resources.

Firm Capacity Purchases from Utilities

FPL has a Unit Power Sales (UPS) contract to purchase 928 MW from the Southern Company (Southern) through the end of December 2015. This capacity is being supplied by Southern from a mix of gas-fired and coal-fired units.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 375 MW (Summer) and 383 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. However, due to Internal Revenue Service (IRS) regulations, the total amount of energy that FPL may receive from this purchase is limited. FPL currently assumes, for planning purposes, that this limit will be reached in April 2019. Once this limit is reached, FPL will be unable to receive firm capacity and energy from these purchases. (However, FPL will continue to receive firm capacity and energy from its ownership portion of the SJRPP units.)

As part of the agreement that FPL will begin serving Vero Beach's electrical needs beginning in January 2015, FPL has acquired two existing power purchase agreements totaling approximately 37 MW of coal-fired capacity. These agreements will run through the end of 2017.

These purchases are shown in Table I.A.3, Table I.B.1, and Table I.B.2. FPL also has ownership interest in the SJRPP units. The ownership amount is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.

Firm Capacity Other Purchases

FPL has two other firm capacity purchase contracts with non-QF, non-utility suppliers. These contracts with the Palm Beach Solid Waste Authority were previously listed as QFs. However, the addition of a second unit will cause both units to no longer meet the statutory definition of a QF. These contracts are therefore listed as "Other Purchases" after the current estimated in-service date of the new unit. Table I.B.1 and I.B.2 present the Summer and Winter MW, respectively, resulting from these contracts under the category heading of Other Purchases.

Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. Table I.A.3 shows the amount of energy purchased in 2013 from these facilities.

Table 1.A.3: Purchase Power Resources by Contract (as of December 31, 2013)

Firm Capacity Purchases (MW)	Location (City or County)	Fuel	Summer MW
I. Purchases from QF's: Cogeneration/Small Power Production Facilities			
Cedar Bay Generating Co.	Duval	Coal (Cogen)	250
Indiantown Cogen., LP	Martin	Coal (Cogen)	330
Broward South	Broward	Solid Waste	4
Broward North	Broward	Solid Waste	11
Palm Beach SWA - extension			40
		Total:	635
II. Purchases from Utilities:			
UPS from Southern Company	Various in Georgia	Coal	928
SJRPP	Jacksonville, FL	Coal	381
		Total:	1,309
		Total Net Firm Generating Capability:	1,944

Non-Firm Energy Purchases (MWH)

Project	County	Fuel	In-Service Date	Energy (MWH) Delivered to FPL in 2013
Okeelanta (known as Florida Crystals and New Hope Power Partners) *	Palm Beach	Bagasse/Wood	11/95	87,723
Broward South *	Broward	Solid Waste	9/09	90,116
Broward North *	Broward	Solid Waste	1/12	81,316
Waste Management - Renewable Energy *	Broward	Landfill Gas	1/10	47,249
Waste Management - Collier County Landfill *	Broward	Landfill Gas	5/11	25,578
Tropicana	Manatee	Natural Gas	2/90	8,900
Georgia Pacific	Putnam	Paper by-product	2/94	5,294
Rothenbach Park (known as MMA Bee Ridge)	Sarasota	PV	10/07	289
First Solar	Miami	PV	4/11	210
Customer - Owned PV & Wind	Various	PV/Wind	9/12	1,018
INEOS Bio *	Indian River	Wood	Various	922
Miami Dade Resource Recovery*	Dade	Solid Waste	12/13	28,759

* These Non-Firm Energy Purchases are Renewable and are reflected on Schedule 11.1 row 9 column 6.

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA -extension 1/	01/01/12	04/01/32	40	0	0	0	0	0	0	0	0	0
U.S. EcoGen - Clay 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
U.S. EcoGen -Okeechobee 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
U.S. EcoGen - Martin 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
		QF Purchases Sub Total:	**635**	**595**	**595**	**595**	**595**	**595**	**595**	**775**	**775**	**775**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
UPS Replacement	06/01/10	12/31/15	928	928	0	0	0	0	0	0	0	0
SJRPP 3/	04/02/82	04/01/19	375	375	375	375	375	0	0	0	0	0
OUC - Stanton 1 4/	01/01/15	12/31/17	0	21	21	21	0	0	0	0	0	0
OUC - Stanton 2 4/	01/01/15	12/31/17	0	16	16	16	0	0	0	0	0	0
		Utility Purchases Sub Total:	**1,303**	**1,340**	**412**	**412**	**375**	**0**	**0**	**0**	**0**	**0**

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total of QF and Utility Purchases =	**1,938**	**1,934**	**1,006**	**1,006**	**970**	**595**	**595**	**775**	**775**	**775**

III. Other Purchases:

	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Palm Beach SWA -extension 1/	01/01/12	04/01/32	0	40	40	40	40	40	40	40	40	40
Palm Beach SWA - additional	01/01/15	04/01/32	0	70	70	70	70	70	70	70	70	70
Unspecified Purchases 5/	01/01/20	12/31/20	0	0	0	0	0	0	129	0	0	0
Unspecified Purchases 5/	01/01/21	12/31/21	0	0	0	0	0	0	0	168	0	0
		Other Purchases Sub Total:	**0**	**110**	**110**	**110**	**110**	**110**	**239**	**278**	**110**	**110**

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total "Non-QF" Purchase =	**1,303**	**1,450**	**522**	**522**	**485**	**110**	**239**	**278**	**110**	**110**

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Summer Firm Capacity Purchases Total MW:	**1,938**	**2,044**	**1,116**	**1,116**	**1,080**	**705**	**834**	**1,053**	**885**	**885**

1/ When the second unit comes into service at the Palm Beach SWA, neither unit will meet the standards to be a small power producers, and both units then will be accounted for under "Other Purchases".

2/ The EcoGen units will enter service in 2016, and initially provide non-firm energy. Firm capacity delivery will commence in 2021.

3/ Contract End Date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.

4/ These units are part of the purchase of the Vero Beach Electric System.

5/ These unspecified purchases are short-term purchases that are included for resource planning purposes. No decision regarding such purchases is needed at this time.

Table I.B.2: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA -extension [1/]	01/01/12	04/01/32	40	0	0	0	0	0	0	0	0	0
U.S. EcoGen - Clay [2/]	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
U.S. EcoGen -Okeechobee [2/]	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
U.S. EcoGen - Martin [2/]	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
		QF Purchases Sub Total:	**635**	**595**	**595**	**595**	**595**	**595**	**595**	**775**	**776**	**776**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
UPS Replacement	06/01/10	12/31/15	928	928	0	0	0	0	0	0	0	0
SJRPP [3/]	04/02/82	04/01/19	383	383	383	383	383	383	0	0	0	0
OUC - Stanton 1 [4/]	01/01/15	12/31/17	0	21	21	21	0	0	0	0	0	0
OUC - Stanton 2 [4/]	01/01/15	12/31/17	0	16	16	16	0	0	0	0	0	0
		Utility Purchases Sub Total:	**1,311**	**1,348**	**420**	**420**	**383**	**383**	**0**	**0**	**0**	**0**
		Total of QF and Utility Purchases =	**1,946**	**1,942**	**1,014**	**1,014**	**978**	**978**	**595**	**775**	**775**	**776**

III. Other Purchases:

	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Palm Beach SWA -extension [1/]	01/01/12	04/01/32	0	40	40	40	40	40	40	40	40	40
Palm Beach SWA - additional	01/01/15	04/01/32	0	70	70	70	70	70	70	70	70	70
Unspecified Purchases [5/]	01/01/20	12/31/20	0	0	0	0	0	0	129	0	0	0
Unspecified Purchases [5/]	01/01/21	12/31/21	0	0	0	0	0	0	0	168	0	0
		Other Purchases Sub Total:	**0**	**110**	**110**	**110**	**110**	**110**	**239**	**278**	**110**	**110**
		"Non-QF" Purchase =	**1,311**	**1,458**	**530**	**530**	**493**	**493**	**239**	**278**	**110**	**110**

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Winter Firm Capacity Purchases Total MW:	**1,946**	**2,052**	**1,124**	**1,124**	**1,088**	**1,088**	**834**	**1,053**	**885**	**885**

1/ When the second unit comes into service at the Palm Beach SWA, neither unit will meet the standards to be a small power producers, and both units then will be accounted for under "Other Purchases".
2/ The EcoGen units will enter service in 2019, and initially provide non-firm energy. Firm capacity delivery will commence in 2021.
3/ Contract End Date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.
4/ These units are part of the purchase of the Vero Beach Electric System.
5/ These unspecified purchases are short-term purchases that are included for resource planning purposes. No decision regarding such purchases is needed at this time.

I.C Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include a number of conservation/energy efficiency and load management initiatives. FPL's DSM efforts through 2013 have resulted in a cumulative Summer peak reduction of approximately 4,753 MW at the generator and an estimated cumulative energy saving of approximately 66,782 Gigawatt-hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2013 have eliminated the need to construct the equivalent of approximately 14 new 400 MW generating units. New DSM Goals for FPL for the 2015 through 2024 time period will be set by the FPSC in the second half of 2014. DSM is discussed further in Chapter III.

Schedule 1

Existing Generating Facilities
As of December 31, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Plant Name	Unit No.	Location	Unit Type	Fuel Pri.	Fuel Alt.	Fuel Transport Pri.	Fuel Transport Alt.	Alt. Fuel Days Use	Commercial In-Service Month/Year	Actual/ Expected Retirement Month/Year	Gen Max Nameplate KW	Net Capability 1/ Winter MW	Net Capability 1/ Summer MW
Cape Modernization		Brevard County											
		19/24S/36E									1,295,400	1,355	1,210
	1		CC	NG	FO2	PL	TK	Unknown	Apr-13	Unknown	1,295,400	1,355	1,210
DeSoto 2/		DeSoto County											
		27/36S/25E									27,000	25	25
	1		PV	Solar	Solar	N/A	N/A	Unknown	Oct-09	Unknown	27,000	25	25
Fort Myers		Lee County											
		35/43S/25E									2,841,990	2,552	2,396
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,721,490	1,490	1,432
	3A		CT	NG	FO2	PL	TK	Unknown	Jun-03	Unknown	188,190	176	158
	3B		CT	NG	FO2	PL	TK	Unknown	Jun-03	Unknown	188,190	176	158
	1-12		GT	FO2	No	TK	No	Unknown	May-74	Unknown	744,120	710	648
Lauderdale		Broward County											
		30/50S/42E									1,873,968	1,884	1,724
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	483	442
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	483	442
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
Manatee		Manatee County											
		18/33S/20E									2,951,110	2,806	2,729
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	819	809
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	819	809
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,168	1,111
Martin		Martin County											
		29/39S/38E									4,317,510	3,870	3,731
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	832	826
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	832	826
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	489	469
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	489	469
	8 3/		CC	NG	FO2	PL	TK	Unknown	Jun-05	Unknown	1,224,510	1,228	1,141
Port Everglades		City of Hollywood											
		23/50S/42E									410,734	459	420
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	459	420
Putnam		Putnam County											
		16/10S/27E									580,008	530	498
	1		CC	NG	FO2	PL	TK	Unknown	Apr-78	Unknown	290,004	265	249
	2		CC	NG	FO2	PL	TK	Unknown	Aug-77	Unknown	290,004	265	249

1/ These ratings are peak capability.

2/ The capacity shown for the PV facility at DeSoto is considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generating Capacity as of December 31, 2013" row at the end of the table.

3/ Martin Unit 8 is also partially fueled by a 75 MW solar thermal facility that supplies steam when adequate sunlight is available, thus reducing fossil fuel use.

Schedule 1

Existing Generating Facilities
As of December 31, 2013

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability [1] Winter MW	(14) Net Capability [1] Summer MW
Sanford		Volusia County 16/19S/30E									2,377,720	2,158	1,980
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,860	1,078	989
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	1,080	991
Scherer [2]		Monroe, GA									680,368	651	643
	4		ST	SUB	No	RR	No	Unknown	Jul-89	Unknown	680,368	651	643
Space Coast [3]		Brevard County 13/23S/36E									10,000	10	10
	1		PV	Solar	Solar	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10
St. Johns River Power Park [4]		Duval County 12/15/28E (RPC4)									271,836	260	254
	1		ST	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	130	127
	2		ST	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	130	127
St. Lucie [5]		St. Lucie County 16/36S/41E									1,743,775	1,883	1,821
	1		ST	Nuc	No	TK	No	Unknown	May-76	Unknown	1,020,000	1,003	981
	2		ST	Nuc	No	TK	No	Unknown	Jun-83	Unknown	723,775	880	840
Turkey Point		Miami Dade County 27/57S/40E									3,380,960	3,263	3,176
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	398	396
	3		ST	Nuc	No	TK	No	Unknown	Nov-72	Unknown	877,200	839	811
	4		ST	Nuc	No	TK	No	Unknown	Jun-73	Unknown	877,200	848	821
	5		CC	NG	FO2	PL	TK	Unknown	May-07	Unknown	1,224,510	1,178	1,148
West County		Palm Beach County 29&32/43S/40E									2,733,600	4,005	3,657
	1		CC	NG	FO2	PL	TK	Unknown	Aug-09	Unknown	1,244,800	1,335	1,219
	2		CC	NG	FO2	PL	TK	Unknown	Nov-09	Unknown	1,244,800	1,335	1,219
	3		CC	NG	FO2	PL	TK	Unknown	May-11	Unknown	1,244,800	1,335	1,219
Total System Generating Capacity as of December 31, 2013 [6] =												25,691	24,274
System Firm Generating Capacity as of December 31, 2013 [7] =												25,656	24,229

1/ These ratings are peak capability.
2/ These ratings represent Florida Power & Light Company's share of Scherer Unit 4, adjusted for transmission losses.
3/ The capacity shown for the PV facility at Space Coast is considered as non-firm generating capacity due to the intermittent nature of the solar resource.
4/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Units 1 and 2, excluding the Jacksonville Electric Authority (JEA) share of 80%.
5/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/880 FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively, as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.
6/ The Total System Generating Capacity value shown includes FPL-owned firm and non-firm generating capacity.
7/ The System Firm Generating Capacity value shown includes only firm generating capacity.

CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

II. A. Overview of the Load Forecasting Process

Long-term forecasts of sales, net energy for load (NEL), and peak loads are typically developed on an annual basis for resource planning work at FPL. New long-term forecasts were developed by FPL in late 2013 that replaced the previous long-term load forecasts that were used by FPL during 2013 in much of its resource planning work and which were presented in FPL's 2013 Site Plan. These new load forecasts are utilized throughout FPL's 2014 Site Plan. These forecasts are a key input to the models used to develop FPL's integrated resource plan.

The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads. Consistent with past forecasts, the primary drivers to develop these forecasts include economic conditions and weather.

The projections for the national and Florida economies are obtained from the consulting firm IHS Global Insight. Population projections are obtained from the Florida Legislature's Office of Economic and Demographic Research (EDR). These projections are developed in conjunction with the Bureau of Economic and Business Research (BEBR) of the University of Florida. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects FPL's energy sales and peak demand. Three sets of weather variables are developed and used in FPL's forecasting models:

1. Cooling degree-hours based on 72° F, winter heating degree-days based on 66° F, and heating degree-days based on 45° F are used to forecast energy sales.
2. The maximum temperature on the peak day, along with the build-up of cooling degree-hours prior to the peak, is used to forecast Summer peaks.
3. The minimum and average temperatures on the peak day, along with the build-up of heating degree-hours based on 66° F, one and two days prior to the peak, are used to forecast Winter peaks.

The cooling degree-hours and winter heating degree-days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. Heating degree-days based on 45° F are used to capture heating load resulting from sustained periods of unusually cold weather not fully captured by heating degree-days based on 66° F. A composite hourly temperature profile is derived using hourly temperatures across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained. In developing the composite hourly profile, these regional temperatures are weighted by regional energy sales. The resulting composite temperature is used to derive projected cooling and heating degree-hours and heating degree-days. Similarly, composite temperature and hourly profiles of temperatures are used to calculate the weather variables used in the Summer and Winter peak models.

II. B. Comparison of FPL's Current and Previous Load Forecasts

While reflecting some fluctuations by year, FPL's current load forecast is generally in line with the load forecast presented in its 2013 Site Plan. There are four primary factors that are driving the current load forecast: projected population growth, the continued recovery of the Florida economy, energy efficiency codes and standards, and the additional load expected as a result of the acquisition of the City of Vero Beach electric utility.

In early 2013, FPL came to an agreement with the City of Vero Beach to purchase the City's electric system. This agreement was approved by the City voters on March 12, 2013. Beginning in January 2015, NEL, customers, and peaks for Vero Beach are included in FPL's forecasts and are reflected in FPL's 2014 Site Plan.

The customer forecast is based on recent population projections as well as the actual levels of customer growth experienced historically and the additional customers expected as a result of the acquisition of Vero Beach. Population projections are derived from the EDR's July 2013 Demographic Estimating Conference. This forecast is generally consistent with previous forecasts indicating a gradual rebound in Florida's population growth. Net migration into Florida fell to a record low in 2009 during the height of the recession. Florida has since experienced an improvement in net migration which now accounts for a majority of the population growth. However, population growth rates have remained modest by historical standards. Moderately higher rates of population growth are projected from 2014 until 2018 when the projected rate of population growth gradually begins to decelerate. Consistent with past population projections, the rates of population growth in the later years of the forecast are below the rates historically experienced in Florida.

Effective January 2015, FPL is expected to begin providing electric service to more than 34,000 customers formerly served by the City of Vero Beach. Reflecting this increase, the current forecast shows an increase in customer growth in 2015. Thereafter, customer growth is expected to mirror the overall level of population growth in the state. By 2019, the total number of customers served by FPL is expected to exceed five million. Between 2013 and 2023 the total number of customers is projected to increase at an annual rate of 1.4%, the same increase projected in the 2013 Site Plan.

The economic projections incorporated into FPL's load forecast are provided by IHS Global Insight, a leading economic forecasting firm. IHS Global Insight projects a continued recovery in the Florida economy with relatively healthy increases in employment and income levels between 2014 and 2020. Particularly robust growth is projected for the tourism and healthcare industries. Consistent with past projections, economic growth in the later years of the forecast is expected to moderate slightly.

Estimates of savings from energy efficiency codes and standards are developed by ITRON, a leading expert in this area. Included in these estimates are savings from federal and state energy efficiency codes and standards, including the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the savings occurring from the use of compact fluorescent bulbs[2]. The impact of these savings began in 2005 and their cumulative impact on the Summer peak is expected to reach 3,477 MW by 2023, the equivalent of approximately a 12% reduction in what the forecasted Summer peak load for 2023 would have been without these codes and standards. The cumulative impact from these savings on NEL is expected to reach 9,991 GWH over the same period while the cumulative impact on the Winter peak is expected to be 1,689 MW by 2023. This represents a decrease of approximately 7% in the forecasted NEL for 2023 and a 4% reduction in forecasted Winter peak load for 2023.

Consistent with the forecast presented in FPL's 2013 Site Plan, the total growth projected for the ten-year reporting period of this document is significant. The Summer peak is projected to increase to 26,528 MW by 2023, an increase of 4,952 MW over the 2013 actual Summer peak. Likewise, NEL is projected to reach 132,357 GWH in 2023, an increase of 20,702 GWH from the actual 2013 value.

II.C. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for the major revenue classes and are adjusted to match the NEL forecast. The results of these sales forecasts for the years 2014 - 2023 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and NEL forecast are outlined below.

[2] Note that in addition to the fact that these energy efficiency codes and standards lower the forecasted load (as described later in this chapter), these standards also lower the potential for efficiency gains that would otherwise be available through utility DSM programs.

1. Residential Sales

Residential electric usage per customer is estimated by using an econometric model. Residential sales are a function of the following variables: cooling degree-hours, winter heating degree-days, lagged cooling degree-hours, lagged winter heating degree-days, retail gasoline prices, and Florida real per capita income weighted by the percent of the population employed. The impact of weather is captured by the cooling degree-hours, heating degree-days, and the one month lag of these variables. The impact energy prices have on electricity consumption is captured through retail gasoline prices. As energy prices rise, less disposable income is available for all goods and services, electricity included. To capture economic conditions, the model includes a composite variable based on Florida real per capita income and the percent of the state's population that is employed. Residential energy sales are forecasted by multiplying the forecasted residential use per customer by the number of residential customers forecasted.

2. Commercial Sales

The commercial sales forecast is also developed using an econometric model. Commercial sales are a function of the following variables: Florida real per capita income weighted by the percent of the population employed, cooling degree-hours, heating degree-hours, lagged cooling degree-hours, a variable designed to reflect the impact of empty homes, dummy variables for the month of December and for the specific months of January 2007, November 2005, and March 2013, and an autoregressive term. Cooling degree-hours, heating degree-hours, and the one month lag of cooling degree-hours are used to capture weather-sensitive load in the commercial sector.

3. Industrial Sales

The industrial class is comprised of three distinct groups: very small accounts (those with less than 20 kW of demand), medium accounts (those with 21 kW to 499 kW of demand), and large accounts (those with demands of 500 kW or higher). As such, the forecast is developed using a separate econometric model for each group of industrial customers. The small industrial sales model utilizes the following variables: cooling degree-hours, heating degree-hours, dummy variables for the specific months of November 2005 and August 2004, and two autoregressive terms. The medium industrial sales model utilizes the following variables: cooling degree-hours, Florida real per capita income weighted by the percent of the population employed, dummy variables for the specific months of February 2005 and 2006 and November 2005, and three autoregressive terms,. The large industrial sales model utilizes the following variables: cooling degree-hours, Florida real per capita income weighted by the percent of the population employed, the Consumer Price Index, and dummy variables for the specific months of October 2004 and 2005, November 2004, and September 2005.

4. **Railroad and Railways Sales and Street and Highway Sales**

This class consists solely of Miami-Dade County's Metrorail system. The projections for railroad and railways sales are based on a historical moving average.

The forecast for street and highway sales is developed by first developing a trended use per customer value, then multiplying this value by the number of forecasted customers.

5. **Other Public Authority Sales**

This class consists of a sports field rate schedule, which is closed to new customers, and one government account. The forecast for this class is based on its historical usage characteristics.

6. **Total Sales to Ultimate Customer**

Sales forecasts by revenue class are summed to produce a total sales forecast.

7. **Sales for Resale**

Sales for resale (wholesale) customers are composed of municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers. Currently there are five customers in this class: the Florida Keys Electric Cooperative; Lee County Electric Cooperative; Wauchula; Winter Park; and Blountstown. In addition, FPL will begin making sales to Seminole Electric Cooperative in June 2014 under a long term agreement[3].

Beginning in May 2011, FPL began providing service to the Florida Keys Electric Cooperative under a long-term full requirements contract. Previously FPL was serving the Florida Keys under a partial requirements contract. The sales to Florida Keys Electric Cooperative are based on customer-supplied information and historical coincidence factors.

Lee County has contracted with FPL for FPL to supply a portion of their load through 2013, then to begin serving their entire load beginning in 2014. This contract began in January 2010. Lee County provides a forecast of their sales by delivery point which is used to derive their sales forecast.

FPL's sales to Wauchula began in October 2011 and will continue through December 2016.

[3] FPL continues to evaluate the possibility of serving the electrical loads of other entities at the time the 2014 Site Plan is being prepared. Because these possibilities are still being evaluated, the load forecast presented in this Site Plan does not include these potential loads.

Sales to Winter Park began in January 2014 and will continue through December 2016.

Blountstown became an FPL wholesale customer in May 2012. FPL's contract with Blountstown expires in April 2017.

A new contract with Seminole Electric Cooperative is included in the forecast which includes delivery of 200 MW beginning in June 2014 and continuing through May 2021.

II.D. Net Energy for Load (NEL)

An econometric model is developed to produce a NEL per customer forecast. The inputs to the model include Florida real per capita income weighted by the percent of the population employed, and a proxy for energy prices. The model also includes several weather variables including cooling degree-hours and heating degree-days by calendar month, and heating degree-days based on 45° F. In addition, the model also includes variables for energy efficiency codes and standards and a variable designed to capture the impact of empty homes. Dummy variables are included for the specific months of May 2004, and November 2005. There is also an autoregressive term in the model.

The energy efficiency variable is included to capture the impacts from major codes and standards, including those associated with the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the savings occurring from the use of compact fluorescent bulbs. The estimated impact from these codes and standards is inclusive of engineering estimates and any resulting behavioral changes. The impact of these savings began in 2005 and their cumulative impact on NEL is expected to reach 9,991 GWH by 2023. This represents a 7.0% reduction in what the forecasted NEL for 2023 would have been absence these codes and standards. On an incremental basis, net of the reduction already experienced through 2013, the reduction in 2023 is expected to reach 6,075 GWH.

The decline in the number of empty homes resulting from the current housing recovery has affected use per customer and is captured in a separate variable. The forecast was also adjusted for additional load estimated from hybrid vehicles, beginning in 2013, which resulted in an increase of approximately 1,587 GWH by the end of the ten-year reporting period. The forecast was also adjusted for the incremental load resulting from FPL's economic development riders which began in 2013, and this incremental load is projected to grow to 537 GWH before leveling off in 2018. An additional adjustment to the NEL forecast was made to reflect the acquisition of the Vero Beach electric system. The Vero Beach acquisition is projected to add 793 GWH by 2023.

The NEL forecast is developed by first multiplying the NEL per customer forecast by the total number of customers forecasted (excluding the customers formerly served by Vero Beach) and then adjusting the forecasted results for the expected incremental load resulting from hybrid vehicles, new wholesale contracts, the Vero Beach acquisition, and FPL's economic development riders. Once the NEL forecast is obtained, total billed sales are computed using a historical ratio of sales to NEL. The sales by class forecasts previously discussed are then adjusted to match the total billed sales. The forecasted NEL values for 2014 - 2023 are presented in Schedule 3.3 that appears at the end of this chapter.

II.E. System Peak Forecasts

The rate of absolute growth in FPL system peak load has been a function of the size of the customer base, varying weather conditions, projected economic conditions, changing patterns of customer behavior, and more efficient appliances and lighting. FPL developed the peak forecast models to capture these behavioral relationships. In addition, FPL's peak forecast also reflects changes in load expected as a result of the acquisition of Vero Beach, changes in wholesale contracts, and the expected number of hybrid vehicles.

The savings from energy efficiency codes and standards incorporated into the peak forecast include the impacts from the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the use of compact fluorescent light bulbs. The impact from these energy efficiency standards began in 2005 and their cumulative impact on the Summer peak is expected to reach 3,477 MW by 2023. This reduction is inclusive of engineering estimates and any resulting behavioral changes. The cumulative 2023 impact from these energy efficiency codes and standards effectively reduces FPL's Summer peak for that year by 11.6%. On an incremental basis, net of the reduction already experienced through 2013, the impact on the Summer peak from these energy efficiency codes and standards is expected to reach 1,997 MW in 2023. By 2023, the Winter peak is expected to be reduced by 1,689 MW as result of the cumulative impact from these energy efficiency standards since 2005. On an incremental basis, net of the reduction already experienced through 2013, the impact on the Winter peak from these energy efficiency standards is expected to reach 1,065 MW in 2023.

The forecast was also adjusted for additional load estimated from hybrid vehicles which results in an expected increase of approximately 443 MW in the Summer and 221 MW in the Winter by the end of the ten-year reporting period and for the acquisition of the Vero Beach electric system. The Vero Beach acquisition will add 169 MW to the Summer peak, and 179 MW to the Winter peak, forecast by the end of the ten-year reporting period.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2014 – 2023 are presented at the end of this chapter in Schedules 3.1 and 3.2, and in Chapter III in Schedules 7.1 and 7.2.

1. **System Summer Peak**

   The Summer peak forecast is developed using an econometric model. The variables included in the model are the price of gasoline, lagged one month, Florida real household disposable income, cooling degree-hours two days prior to the peak day, the maximum temperature on the day of the peak, a variable for energy efficiency standards, and a moving average term. The model is based on the Summer peak contribution per customer which is multiplied by total customers (excluding the customers that have been served by Vero Beach), and adjusted to account for incremental loads resulting from hybrid vehicles, new wholesale contracts, the Vero Beach acquisition, and FPL's economic development riders to derive FPL's system Summer peak.

2. **System Winter Peak**

   Like the system Summer peak model, this model is also an econometric model. The model consists of three weather-related variables: the average temperature on the peak day, heating degree-hours for the prior day squared, and heating degree-hours two days prior to the peak day. The model also includes two dummy variables; one for Winter peaks occurring on weekends and one for winter peaks with minimum temperature below 40.5 degrees. Also included in the model are a variable for housing starts per capita, and an autoregressive term. The forecasted results are adjusted for the impact of energy efficiency standards. The model is based on the Winter peak contribution per customer which is multiplied by total customers (excluding the customers that have been served by Vero Beach), and then adjusted for the expected incremental loads resulting from hybrid vehicles, new wholesale contracts, the Vero Beach acquisition, and FPL's economic development riders.

3. **Monthly Peak Forecasts**

   The forecasting process for monthly peaks consists of the following steps:

   a. The forecasted annual summer peak is assumed to occur in the month of August. The month of August has historically accounted for more annual summer peaks than any other month.

b. The forecasted annual winter peak is assumed to occur in the month of January. The month of January has historically accounted for more annual winter peaks than any other month.

c. The remaining monthly peaks are forecasted based on the historical relationship between the monthly peaks and the annual summer peak.

II.F. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2014 - 2023 are produced using a System Load Forecasting "shaper" program. This model uses years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model generates a projection of hourly load values based on these load shapes and the forecast of monthly peaks and energy.

II.G. Uncertainty

In order to address uncertainty in the forecasts of aggregate peak demand and NEL, FPL first evaluates the assumptions underlying the forecasts. FPL takes a series of steps in evaluating the input variables, including comparing projections from different sources, identifying outliers in the series, and assessing the series' consistency with past forecasts. As needed, FPL reviews additional factors which may affect the input variables.

Uncertainty is also addressed in the modeling process. Generally, econometric models are used to forecast the aggregate peak demand and NEL. During the modeling process, the relevant statistics (goodness of fit, F-statistic, P-values, mean absolute deviation (MAD), mean absolute percentage error (MAPE), etc.) are scrutinized to ensure that the models adequately explain historical variation. Once a forecast is developed, it is compared with past forecasts. Deviations from past forecasts are examined in light of changes in input assumptions to ensure that the drivers underlying the forecast are well understood. Finally, forecasts of aggregate peak demand and NEL are compared with the actual values as these become available. An ongoing process of variance analyses is performed. To the extent that the variance analysis identifies large unexplained deviations between the forecast and actual values, revisions to the econometric model may be considered.

The inherent uncertainty in load forecasting is addressed in different ways in regard to FPL's overall resource planning and operational planning work. In regard to FPL's resource planning work, FPL's utilization of a 20% total reserve margin criterion, and a 10% generation-only reserve margin criterion, are designed to maintain reliable electric service to FPL's customers in light of forecasting (and other) uncertainty. In addition, banded forecasts of the projected Summer peak and net energy for load are produced based on an analysis of past forecasting variances. In regard to operational planning, a banded forecast for the projected Summer and Winter peak days is developed based on the historical weather variations. These bands are then used to develop similar bands for the monthly peaks.

II.H. DSM

The effects of FPL's DSM energy efficiency programs implementation through August 2013 are assumed to be imbedded in the actual usage data for forecasting purposes. The impacts of incremental energy efficiency that FPL plans to implement in the future, plus the cumulative and projected incremental impacts of FPL's load management programs, are accounted for as "line item reductions" to the forecasts as part of the IRP process as shown in Chapter III in Schedules 7.1 and 7.2. After making these adjustments to the load forecasts, the resulting "firm" load forecast is then used in FPL's IRP work.

Schedule 2.1
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,620,855	2.21	54,570	3,906,267	13,970	44,487	478,867	92,901
2007	8,729,806	2.19	55,138	3,981,451	13,849	45,921	493,130	93,121
2008	8,771,694	2.20	53,229	3,992,257	13,333	45,561	500,748	90,987
2009	8,732,591	2.19	53,950	3,984,490	13,540	45,025	501,055	89,860
2010	8,762,399	2.19	56,343	4,004,366	14,070	44,544	503,529	88,464
2011	8,860,158	2.20	54,642	4,028,760	13,570	45,052	508,005	88,685
2012	8,948,850	2.21	53,434	4,052,174	13,187	45,220	511,887	88,340
2013	9,025,275	2.20	53,930	4,097,172	13,163	45,341	516,500	87,786

Historical Values (2004 - 2013):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent actual energy sales <u>including</u> the impacts of existing conservation. These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.1
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2014	9,111,384	2.20	55,739	4,141,538	13,458	47,155	524,494	89,905
2015	9,302,665	2.20	57,047	4,228,484	13,491	48,634	536,771	90,267
2016	9,437,042	2.20	58,097	4,289,564	13,544	49,793	547,300	90,969
2017	9,571,922	2.20	58,893	4,350,874	13,490	50,418	555,714	90,726
2018	9,705,104	2.20	59,404	4,411,411	13,466	51,110	563,753	90,661
2019	9,835,541	2.20	60,038	4,470,700	13,429	51,667	571,672	90,379
2020	9,961,263	2.20	60,791	4,527,847	13,426	52,337	579,453	90,322
2021	10,079,425	2.20	61,219	4,581,557	13,362	52,675	587,147	89,713
2022	10,198,067	2.20	61,929	4,635,494	13,360	53,264	594,906	89,534
2023	10,318,293	2.20	62,870	4,690,133	13,405	54,043	602,612	89,681

Projected Values (2014 - 2023):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent forecasted energy sales that do <u>not</u> include the impact of incremental conservation. These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.2
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads	Street &	Sales to	Sales to
		Average	Average kWh	&	Highway	Public	Ultimate
		No. of	Consumption	Railways	Lighting	Authorities	Consumers
Year	GWh	Customers	Per Customer	GWh	GWh	GWh	GWh
2004	3,964	18,512	214,139	93	413	58	99,085
2005	3,913	20,392	191,873	95	424	49	102,296
2006	4,036	21,211	190,277	94	422	49	103,659
2007	3,774	18,732	201,499	91	437	53	105,416
2008	3,587	13,377	268,168	81	423	37	102,919
2009	3,245	10,084	321,796	80	422	34	102,755
2010	3,130	8,910	351,318	81	431	28	104,557
2011	3,086	8,691	355,104	82	437	27	103,327
2012	3,024	8,743	345,871	81	441	25	102,226
2013	2,956	9,541	309,772	88	442	28	102,784

Historical Values (2004 - 2013):

Col. (10) and Col.(15) represent actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.2
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads	Street &	Sales to	Sales to
		Average	Average kWh	&	Highway	Public	Ultimate
		No. of	Consumption	Railways	Lighting	Authorities	Consumers
Year	GWh	Customers	Per Customer	GWh	GWh	GWh	GWh
2014	2,990	10,242	291,973	82	442	24	106,432
2015	3,009	10,890	276,263	83	453	23	109,248
2016	3,008	11,520	261,101	82	460	23	111,463
2017	3,001	11,893	252,369	83	466	23	112,684
2018	2,970	12,003	247,426	83	473	23	114,063
2019	2,931	12,030	243,618	83	478	23	115,218
2020	2,875	12,017	239,258	83	484	23	116,593
2021	2,814	11,991	234,676	83	489	23	117,303
2022	2,754	11,971	230,057	83	494	23	118,548
2023	2,692	11,907	226,087	83	499	23	120,210

Projected Values (2014 - 2023):

Col. (10) and Col.(15) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2004	1,531	7,467	108,093	3,029	4,224,509
2005	1,506	7,498	111,301	3,156	4,321,895
2006	1,569	7,909	113,137	3,218	4,409,563
2007	1,499	7,401	114,315	3,276	4,496,589
2008	993	7,092	111,004	3,348	4,509,730
2009	1,155	7,394	111,303	3,439	4,499,067
2010	2,049	7,870	114,475	3,523	4,520,326
2011	2,176	6,950	112,454	3,596	4,547,051
2012	2,237	6,403	110,866	3,645	4,576,449
2013	2,158	6,713	111,655	3,722	4,626,934

Historical Values (2004 - 2013):

Col. (19) represents actual energy sales including the impacts of existing conservation.

Col. (19) = Col. (16) + Col. (17) + Col. (18). Historical NEL includes the impacts of existing conservation and agrees to Col. (5) on schedule 3.3. Historical GWH, prior to 2011, are based on a fiscal year beginning 12/29 and ending 12/28. The 2011 value is based on 12/29/10 to 12/31/11. The 2012-2013 values are based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 2.3
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2014	4,907	6,662	118,001	3,780	4,680,054
2015	5,654	6,703	121,606	4,323	4,782,469
2016	5,706	6,775	123,943	4,383	4,852,827
2017	5,418	6,811	124,914	4,437	4,922,918
2018	5,440	6,896	126,399	4,491	4,991,659
2019	5,496	6,959	127,673	4,543	5,058,945
2020	5,559	7,035	129,187	4,592	5,123,909
2021	5,133	7,018	129,454	4,638	5,185,333
2022	4,846	7,124	130,517	4,681	5,247,054
2023	4,906	7,239	132,357	4,724	5,309,376

Projected Values (2014 - 2023):

Col. (19) represents forecasted energy sales that do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

Col. (19) = Col. (16) + Col. (17) + Col. (18). These values are based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 3.1
History of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2004	20,545	258	20,287	0	894	840	588	577	19,063
2005	22,361	264	22,097	0	902	895	600	611	20,858
2006	21,819	256	21,563	0	928	948	635	640	20,256
2007	21,962	261	21,701	0	952	982	716	683	20,295
2008	21,060	181	20,879	0	966	1,042	760	706	19,334
2009	22,351	249	22,102	0	981	1,097	811	732	20,558
2010	22,256	419	21,837	0	990	1,181	815	758	20,451
2011	21,619	427	21,192	0	1,000	1,281	821	781	19,798
2012	21,440	431	21,009	0	1,013	1,351	833	810	19,594
2013	21,576	396	21,180	0	1,025	1,394	833	827	19,718

Historical Values (2004 - 2013):

Col. (2) - Col. (4) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on those peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) represent actual DSM capabilities starting from January 1988 and are annual (12-month) values except for 2013 values which are through August.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.1
Forecast of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
August of Year	Total	Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2014	22,768	1,173	21,595	0	1,077	65	816	33	20,777
2015	23,356	1,206	22,149	0	1,093	88	830	46	21,298
2016	23,778	1,212	22,565	0	1,103	89	841	49	21,695
2017	24,190	1,159	23,031	0	1,113	91	853	52	22,081
2018	24,544	1,166	23,378	0	1,124	92	865	56	22,407
2019	24,895	1,172	23,723	0	1,134	94	877	62	22,729
2020	25,239	1,179	24,061	0	1,144	97	889	67	23,042
2021	25,439	985	24,454	0	1,154	100	901	73	23,211
2022	25,908	992	24,916	0	1,165	104	912	79	23,648
2023	26,528	998	25,530	0	1,175	109	924	85	24,235

Projected Values (2014 - 2023):

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected August values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC.

Schedule 3.2
History of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2004	14,752	211	14,541	0	813	567	534	227	13,405
2005	18,108	225	17,883	0	816	583	542	233	16,751
2006	19,683	225	19,458	0	823	600	550	240	18,311
2007	16,815	223	16,592	0	846	620	577	249	15,392
2008	18,055	163	17,892	0	868	644	636	279	16,551
2009	20,061	207	19,874	0	881	666	676	285	18,524
2010	24,346	500	23,846	0	895	687	721	291	22,730
2011	21,126	383	20,743	0	903	717	723	303	19,501
2012	17,934	382	17,552	0	856	755	722	314	16,356
2013	15,031	348	15,583	0	843	781	567	326	14,521

Historical Values (2004 - 2013):

Col. (2) - Col. (4) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand. For year 2011, the actual peaked occurred in December of 2010.

Col. (5) - Col. (9) for 2003 through 2012 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.2
Forecast of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
January of Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2014	19,875	992	18,883	0	883	13	601	5	18,373
2015	20,971	1,235	19,736	0	905	52	557	16	19,442
2016	21,490	1,238	20,252	0	913	52	562	17	19,947
2017	21,731	1,164	20,567	0	921	55	568	17	20,173
2018	21,968	1,159	20,809	0	929	53	573	18	20,396
2019	22,180	1,162	21,018	0	937	53	579	19	20,592
2020	22,383	1,165	21,218	0	945	54	584	20	20,780
2021	22,584	1,168	21,416	0	953	54	590	22	20,965
2022	22,601	971	21,630	0	961	55	595	23	20,966
2023	22,891	974	21,918	0	970	56	601	24	21,240

Projected Values (2014 - 2023):

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected January values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC.

Schedule 3.3
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1) Year	(2) Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Actual Net Energy For Load GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Total Billed Retail Energy Sales (GWh)	(9) Load Factor(%)
2004	111,659	1,872	1,693	108,093	1,531	7,467	99,095	59.9%
2005	115,065	1,970	1,793	111,301	1,506	7,498	102,296	58.8%
2006	117,116	2,078	1,901	113,137	1,569	7,909	103,659	59.2%
2007	118,518	2,136	2,068	114,315	1,499	7,401	105,415	59.4%
2008	115,379	2,249	2,126	111,004	993	7,092	102,919	60.0%
2009	115,844	2,345	2,196	111,303	1,155	7,394	102,755	56.5%
2010	119,220	2,487	2,259	114,475	2,049	7,870	104,557	58.7%
2011	117,460	2,683	2,324	112,454	2,176	6,950	103,327	59.4%
2012	116,083	2,823	2,394	110,866	2,237	6,403	102,226	58.9%
2013	117,087	2,962	2,469	111,655	2,158	6,713	102,784	59.1%

Historical Values (2004 - 2013):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5).

Col. (3) & Col. (4) are DSM values starting in January 1988 and are annual (12-month) values. Col. (3) and Col. (4) for 2013 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWh reductions experienced each year.

Col. (5) is the actual Net Energy for Load (NEL) for years 2003 - 2013.

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760) Adjustments are made for leap years.

Schedule 3.3
Forecast of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1) Year	(2) Forecasted Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Net Energy For Load Adjusted for DSM GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Forecasted Total Billed Retail Energy Sales w/o DSM GWh	(9) Load Factor(%)
2014	118,001	91	53	117,856	4,907	6,662	106,432	59.2%
2015	121,606	142	80	121,383	5,854	6,703	109,248	59.4%
2016	123,943	144	81	123,718	5,708	6,775	111,463	59.3%
2017	124,914	147	81	124,686	5,419	6,811	112,684	58.9%
2018	126,399	150	81	126,168	5,440	6,896	114,063	58.8%
2019	127,673	155	80	127,438	5,496	6,959	115,218	58.5%
2020	129,187	159	81	128,948	5,559	7,035	116,593	58.3%
2021	129,454	164	82	129,208	5,133	7,018	117,303	58.1%
2022	130,517	170	82	130,264	4,846	7,124	118,548	57.5%
2023	132,357	179	83	132,095	4,908	7,239	120,210	57.0%

Projected Values (2014 - 2023):

Col. (2) represents Forecasted Net Energy for Load and does not include incremental DSM from 2013 - on. The Col. (2) values are extracted from Schedule 2.3, Col(19). The effects of conservation implemented prior to September 2012 are incorporated into the load forecast values in Col. (2).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation from Jan 2014 - on and are mid-year (6-month) values reflecting DSM signups occurring evenly thoughout each year.

Col. (5) is the forecasted Net Energy for Load (NEL) after adjusting for impacts of incremental DSM for years 2014 - 2023 using the formula: Col. (5) = Col. (2) - Col. (3) - Col. (4)

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760) Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2013 Actual		2014 FORECAST		2015 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	15,135	8,089	19,875	8,719	20,971	9,093
FEB	15,627	7,468	17,441	7,781	18,050	8,126
MAR	15,931	7,936	17,273	8,753	17,875	9,103
APR	18,419	8,967	18,149	9,047	18,782	9,386
MAY	19,579	9,494	20,331	10,369	21,040	10,701
JUN	21,147	10,460	21,852	10,865	22,416	11,127
JUL	20,261	10,649	22,413	11,625	22,991	11,884
AUG	21,576	11,392	22,768	11,840	23,356	12,096
SEP	20,297	10,229	21,959	10,997	22,525	11,256
OCT	19,313	9,969	20,458	10,354	20,986	10,617
NOV	18,028	8,506	17,994	8,686	18,458	8,960
DEC	16,161	8,497	17,563	8,965	18,016	9,257
Annual Values:		**111,655**		**118,001**		**121,606**

Col. (3) annual value shown is consistent with value shown in Col.(5) of Schedule 3.3.

Cols. (4) - (7) do not include the impacts of cumulative load management, incremental conservation, and incremental load management.

Cols. (5) and Col. (7) annual values shown are consistent with values shown in Col.(2) of Schedule 3.3.

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CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL utilizes its well established integrated resource planning (IRP) process in whole or in part as analysis needs are warranted, to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of new power plants, the primary subjects of this document, are determined as part of the IRP process work.

This section describes FPL's basic IRP process. Some of the key assumptions, in addition to a new load forecast, that were used in developing the resource plan presented in this Site Plan are also discussed.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental steps to FPL's resource planning. These steps can be generally described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Evaluate the competing options and resource plans in regard to system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process

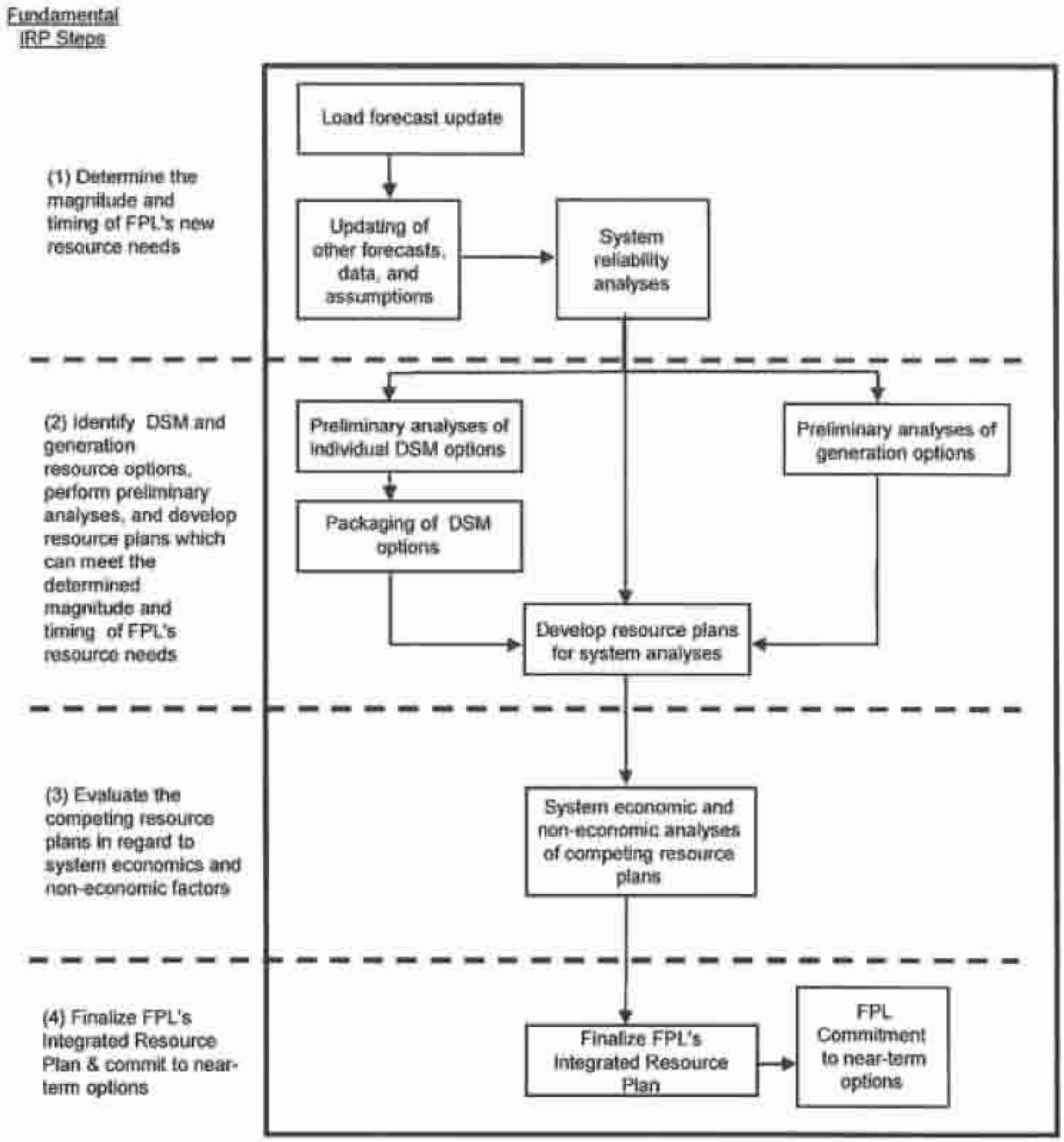

Figure III.A.1: Overview of FPL's IRP Process

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of the four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed to maintain system reliability. Also determined in this step is when the MW additions are needed to meet FPL's reliability criteria. This step is often referred to as a reliability assessment, or resource adequacy, analysis for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include, but are not limited to: delivered fuel price projections, current financial and economic assumptions, and power plant capability and operating assumptions. FPL also includes key sets of assumptions regarding three specific types of resources: (1) FPL unit capacity changes, (2) firm capacity power purchases, and (3) demand side management (DSM) implementation.

<u>Key Assumptions Regarding the Three Types of Resources:</u>

The first set of assumptions, FPL unit capacity changes, is based on the current projection of new generating capacity additions and planned retirements of existing generating units. In FPL's 2014 Site Plan, there are five such projected capacity changes. These are listed below in chronological order:

1) <u>Planned retirement of existing Putnam Units 1 & 2:</u>

   Analyses conducted during 2013 and early 2014 showed that it would be cost-effective to retire the two existing units, Putnam Units 1 & 2, and replace the capacity with new combined cycle (CC) capacity at a later date and at a site to be determined. The new CC capacity would have a significantly better heat rate, thus reducing FPL's system fuel usage and system emissions. Consequently, FPL currently projects that the two existing units will be retired by the end of 2014.

2) <u>CT upgrades at existing CC plant sites:</u>

   In the fourth quarter of 2011, FPL started upgrading the 7FA combustion turbines (CT) that are components at a number of its existing CC units. These upgrades will economically benefit FPL's customers by increasing the MW output of these CC units by approximately 209 MW (Summer peak value) in total. As reflected in Schedule 1 in Chapter I, 133 MW of the increased capacity from these CT upgrades is already in service. The work for the remaining upgrades is continuing and the project is projected to be completed in 2015.

3) Modernization of the Port Everglades plant site:
The work to modernize the existing Port Everglades site by adding new combined cycle (CC) capacity continues. The new generating unit, called the Port Everglades Next Generation Clean Energy Center (PEEC), is projected to be in-service in mid-2016 and is projected to have a peak Summer output of 1,237 MW. The FPSC issued the final need order for this modernization project in April 2012 in Order No. PSC-12-0187-FOF-EI. The site certification order for the project, DOAH Case No. 12-0422EPP, was received for the Port Everglades project in October 2012. (Note that a similar modernization of the FPL's existing Riviera Beach plant site is scheduled to be completed on/near the April 1, 2014 filing date of this 2014 Site Plan.)

4) Retirement of existing gas turbines (GTs) in Broward County and partial capacity replacement with new combustion turbines (CTs) at FPL's Lauderdale plant site:
Due to new nitrogen dioxide (NO_2) environmental regulations, FPL filed in June 2013 for FPSC approval to recover costs for removing all of its existing GTs and replacing a portion of the GT capacity with new CTs. In December 2013, FPL withdrew this request pending additional environmental monitoring and analyses. Computer modeling of the emissions from the GTs projected that the GTs would exceed the new NO_2 limit. FPL believes this monitoring and analyses will confirm that the operation of its existing GTs in Broward County will not comply with the new NO_2 regulations. Therefore, for planning purposes, FPL has assumed that all of its existing Broward County GTs will be removed (a loss of 1,260 MW Summer) and that this capacity will be partially replaced by 5 new CTs that would be sited in Broward County (an increase of 1,005 MW Summer). This GT removal and CT partial replacement is assumed to occur by the end of 2018.

5) Turkey Point Nuclear Units 6 & 7:
FPL is continuing its work to obtain all of the licenses, permits, and approvals that will be necessary to construct and operate two new nuclear units at its Turkey Point site. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. FPL received need determination approval from the FPSC for the two nuclear units in April 2008 in Order No. PSC-08-0237-FOF-EI. The earliest deployment dates for these two new units, Turkey Point Units 6 & 7, remain 2022 and 2023, respectively. Each new nuclear unit is projected to have a peak Summer output of 1,100 MW.

Also in regard to FPL unit capacity changes, as part of FPL's planned acquisition of Vero Beach's electric utility system, FPL is projected to take ownership of Vero Beach's five existing generating units starting January 2015. The current plan, based on the units' poor economics, is to immediately retire three of these older generating units and operate the remaining two, which supply approximately 46 MW (Summer) of combined cycle capacity, for a maximum of three years.

The second set of assumptions involves firm capacity power purchases. FPL's current projection of firm capacity purchases has changed from the projection in the 2013 Site Plan in regard to only two purchases. As part of the projected agreement that FPL will begin serving Vero Beach's electrical needs beginning in January 2015, FPL has acquired two existing power purchase agreements totaling approximately 37 MW of coal-fired capacity. These agreements are now projected to run through the end of 2017 instead of 2016 as projected in FPL's 2013 Site Plan. In addition, FPL now projects that Internal Revenue Service (IRS) regulations regarding the amount of energy that FPL can receive under its purchase agreement with Jacksonville Electric Authority (JEA) for St. Johns Regional Power Park (SJRPP)-based capacity and energy will not result in the suspension of the delivery of capacity and energy receipts to FPL until April 2019. [4]

None of the other purchase projections has changed from those in the 2013 Site Plan. FPL's current projection includes an additional 70 MW from the Palm Beach Solid Waste Authority (SWA) starting in year 2015. In addition, FPL projects that it will begin receiving a total of 180 MW of firm capacity in 2021 from biomass-based power purchase agreements with EcoGen.

In total, the projected firm capacity purchases are from a combination of utility and independent power producers. Details, including the annual total capacity values for these purchases, are presented in Chapter I in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's resource planning work.

The third set of assumptions involves a projection of the amount of additional DSM that is anticipated to be implemented annually over the ten-year period. A key aspect of FPL's IRP process is the evaluation of DSM resources. Since 1994, FPL's resource planning work has assumed that, at a minimum, the DSM MW called for in FPL's FPSC-approved DSM Plan will be achieved. In 2014, FPL is required to propose new DSM Goals for the 2015 through 2024 time period. Those proposed goals will be filed with the FPSC on April 2, 2014; i.e., one day after this 2014 Site Plan is filed with the FPSC. FPL's filing to support its proposed DSM goals provides extensive detail regarding how DSM resources were evaluated in FPL's most current IRP planning

[4] FPL's projected suspension date for the SJRPP purchase is based on a system reliability perspective and represents the earliest projected date at which the suspension of capacity and energy could occur.

analyses. The DSM assumptions presented in this 2014 Site Plan, and which are assumed in the analyses whose results are reflected in the Site Plan, are consistent with FPL's proposed goals. The FPSC is expected to make a decision regarding FPL's 2015 – 2024 DSM Goals later in 2014.

The Three Reliability Criteria Used to Determine FPL's Projected Resource Needs:

These key assumptions, plus the other updated information described above, are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's future resource needs. This determination is accomplished by system reliability analyses which for FPL have traditionally been based on dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry. Beginning this year, FPL is also using a third reliability criterion: a 10% generation-only reserve margin (GRM) criterion.

Historically, two types of methodologies, deterministic and probabilistic, have been utilized in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Among the most widely used is loss-of-load probability (LOLP) which FPL utilizes. Simply stated, LOLP is an index of how well a generating system may be able to meet its firm demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in terms of the projected probability that a utility will be unable to meet its entire firm load at some point during a year. The probability of not being able to meet the entire firm load is calculated for each day of the year using the daily peak hourly load. These daily probabilities are then summed to develop an annual probability value. This annual probability value is commonly expressed as "the number of days per year" that the entire system firm load could not be met. FPL's standard for LOLP, commonly accepted throughout the industry, is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

FPL's recent integrated resource planning work has resulted in FPL's resource plans showing a significant shift in the mix of generation and DSM resources over the next 10 years in regard to the relative contribution of these resources to system reliability. In order to gauge the extent of this shift and its potential implications for FPL's system reliability, FPL developed a new metric: a generation-only reserve margin (GRM). This GRM metric reflects reserves that would be provided only by actual generating resources. The GRM value is calculated by setting to zero all incremental energy efficiency (EE) and load management (LM), plus all existing LM, in a reserve margin calculation. The resulting GRM value provides an indication of how large a role generation is projected to play in each year as FPL maintains its 20% Summer and Winter "total" reserve margins (which account for both generation and DSM resources).

FPL has been reporting the GRM metric in its Site Plans since 2011 when it presented projections of its Summer GRM for the years 2011-2020. The 2011 projection showed a steady decrease in GRM values from a "balanced" 11.5% in 2011 to much reduced 7.2% by 2020. In its 2012 Site Plan, FPL's projected GRM values steadily decreased over the 10-year period from 16.2% in 2012 to 5.5% in 2021. The projected pattern in the 2013 Site Plan was similar: a steady decrease from 16.3% in 2013 to 6.9% in 2021. (The projected GRM value for 2022 presented in the 2013 Site Plan increased to 8.9% due to the planned addition of the new Turkey Point 6 nuclear unit in 2022.) Thus FPL's resource planning projections over the last 3 years have each shown a general downwards trend in projected GRM in the latter portion of this decade. This indicates increasing reliance on DSM resources, particularly EE resource additions, and decreasing reliance on generation resources, to maintain system reliability. As a result, FPL has analyzed what impact(s) this trend could have on system reliability. Two types of evaluations were conducted. One of these evaluations is from the perspective of FPL's system operators who are responsible for operating the bulk electric system. The other evaluation is from a resource planning perspective.

The first evaluation examined what impact an increasing reliance on EE resource additions was projected to have on the amount and type of reserves that operators would have at their disposal to meet load on a system peak hour. FPL first used a "looking back" perspective at a recent actual peak load day of January 11, 2010 to see how the system actually operated. Then, assuming a "what if" situation in which the system was assumed to have been designed to have an identical total reserve margin, but higher and lower GRM respectively, FPL analyzed what the impact would have been on FPL's ability to serve its customers on that peak day with these alternative assumed systems.

FPL also performed analyses taking a "looking forward" perspective at the projected year of 2021. Three scenarios were analyzed: (i) the system with its projected GRM and total reserve margin values consistent with the 2013 Site Plan; (ii) a system with an identical total reserve margin, but a higher GRM; and (iii) a system with an identical total reserve margin, but a lower GRM. Recognizing that the impacts from EE resource additions will already have been accounted for in the peak load that system operators must react to on an actual peak day, the analyses assumed an adverse peak day situation which consisted of significantly higher load and significantly less available generation than projected. The results from both the "looking back" and "looking forward" analyses were similar. For resource plans with identical total reserve margins, but different GRM levels, system operators were projected to have significantly higher levels (MW) of reserves, either generation and/or load management reserves, available on the peak days with a resource plan that had a higher GRM level than with a resource plan that had a lower GRM level. Thus a resource plan with a higher GRM, compared with a lower GRM, results in better system reliability for customers due to a greater likelihood of meeting customers' firm demand on peak load days, despite unexpected conditions or events. Better system reliability to customers translates to a reduced risk of shedding firm load.

The second evaluation was from the resource planning perspective of loss-of-load-probability (LOLP). For this evaluation, FPL also analyzed resource plans with identical total reserve margins, but higher and lower GRM levels. The results of these analyses for the FPL system showed that a resource plan with a higher GRM resulted in a projection of lower LOLP values than a resource plan with a lower GRM.

Based on these operational and resource planning evaluations, FPL has concluded that resource plans for its system with identical total reserve margins, but different GRM values, are not equal in regard to system reliability. A resource plan with a higher GRM value is projected to result in more MW being available to system operators on adverse peak load days, and in lower LOLP values, than a resource plan with a lower GRM value, even though both resource plans have an identical total reserve margin. Therefore, FPL has applied a minimum GRM criterion as a third reliability criterion in its resource planning process.

Based on the expertise and experience of FPL's system operators regarding the amount of generation MW needed for reliable operations, the GRM criterion is set at a minimum of 10% for Summer and Winter. From an operational perspective, FPL believes it is necessary to have approximately 2,650 MW of generation reserves. These reserves will allow FPL to address a variety of operational considerations including: (i) unplanned generation unavailability; (ii) the deployment of real-time operating reserves to meet its 15-minute obligations as part of the Florida Reserve Sharing Group; (iii) the requirement pursuant to NERC Reliability Standards to replace with other resources within 30 minutes following the unplanned loss of a large generation unit; and (iv) higher-than-forecasted loads. The sum of the operational reserves to cover for these requirements and considerations is approximately 2,650 MW. This MW value is consistent with a 10% GRM for the foreseeable future. FPL is planning its system so that the minimum 10% GRM criterion is met beginning in the Summer of 2019.

The 10% minimum Summer and Winter GRM criterion augments the two existing reliability criteria used by FPL: a 20% total reserve margin criterion for Summer and Winter, and a 0.1 day/year LOLP criterion. The total reserve margin and LOLP criteria continue to identify the timing and magnitude of FPL's future resource needs. The GRM criterion provides direction regarding the mix of generation and DSM resources that should be added to maintain and enhance FPL's system reliability.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, preliminary economic screening analyses of new capacity options that are identical, or virtually identical, in regard to certain key characteristics may be conducted to determine which new capacity options appear to be the most competitive on FPL's system. This preliminary analysis work can also help identify capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. Similarly, preliminary economic screening analyses of new DSM options and/or evaluation of existing DSM options are often conducted in this second fundamental IRP step.

FPL typically utilizes the P-MArea production cost model and a Fixed Cost Spreadsheet, and/or an optimization models and spreadsheet analyses, to perform the preliminary economic screening of generation resource options. For the preliminary economic screening analyses of DSM resource options, FPL typically uses its DSM CPF model which is an FPL spreadsheet model utilizing the FPSC's approved methodology for performing preliminary economic screening of individual DSM measures and programs. In addition, a years-to-payback screening test based on a two-year criterion is also used in the preliminary economic screening of individual DSM measures and programs. Then, as the focus of DSM analyses progresses from analysis of individual DSM measures to the development of DSM portfolios, FPL uses two additional models. One of these models is FPL's non-linear programming model that is used for analyzing the potential for lowering system peak loads through additional load management/demand response capability. The other model that FPL typically utilizes is its linear programming model with which FPL develops DSM portfolios.

The individual new resource options, both Supply options and DSM portfolios, emerging from these preliminary economic screening analyses are then typically "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's projected new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet and/or dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans in Regard to System Economics and Non-Economic Factors:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for evaluating these resource options and resource plans in system economic analyses that aim to account for all of the impacts to the FPL system from the competing resource options/resource plans. In FPL's 2013 and early 2014 resource planning work, once the resource plans were developed, FPL utilized the P-MArea production cost model and a Fixed Cost Spreadsheet, and/or the Strategist model, to perform the system economic analyses. Other spreadsheet models may also be used to further analyze the resource plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM methodology). In analyses in which the DSM contribution has already been determined through the same IRP process and FPSC approval, and therefore the only competing options were new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and resource plans in such cases can be evaluated on a system cumulative present value revenue requirement (CPVRR) basis.

Other factors are also included in FPL's evaluation of resource options and resource plans. While these factors may have an economic component or impact, they are often discussed in quantitative, but non-economic, terms such as percentages, tons, etc. rather than in terms of dollars. These factors are often referred to by FPL as "system concerns" that include (but are not limited to) maintaining/enhancing fuel diversity in the FPL system, system emission levels, and maintaining a regional balance between load and generating capacity, particularly in the Southeastern Florida counties of Miami-Dade and Broward. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL's system, the non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan. These, and other, factors are discussed later in this chapter in section III.C.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps are typically used to develop FPL's current resource plan. The current resource plan is presented in the following section.

III.B Projected Incremental Resource Additions/Changes in the Resource Plan

FPL's projected incremental generation capacity additions/changes for 2014 through 2023 are depicted in Table III.B.1. These capacity additions/changes include the 5 generation additions/changes previously discussed. The table shows three more generation changes: a CC unit being added in 2019, a short-term PPA of 129 MW being added in 2020, and a short-term PPA of 168 MW being added in 2021. The CC unit is added in 2019 to meet the Summer total reserve margin criterion and the two PPAs are added in 2020 and 2021 to meet the GRM criterion.

Although FPL's projected DSM additions that are developed in the IRP process are not explicitly presented in this table, these DSM additions have been fully accounted for in all of FPL's resource planning work reflected in this document. The projected MW reductions from these DSM additions are also reflected in the projected total reserve margin values shown in the table below and in Schedules 7.1 and 7.2 presented later in this chapter. DSM is further addressed later in this chapter in section III.D.

III.C Discussion of the Projected Resource Plan and Issues Impacting FPL's Resource Planning Work

As indicated in the Executive Summary, FPL's resource planning efforts in 2013 and early 2014 were influenced by a number of factors. These factors are expected to continue to influence FPL's resource planning work for the foreseeable future. In addition, other factors may also influence FPL's on-going resource planning work in the future and may result in changes to the resource plan discussed in this document. Eight (8) of these factors are discussed below (in no particular order of importance).

1) Maintaining/enhancing fuel diversity in the FPL system;
2) Maintaining a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward Counties;
3) Updated projections of Federal and state energy efficiency codes and standards;
4) Decline in the projected cost-effectiveness of utility DSM measures and programs;
5) FPL's growing dependence upon DSM resources to maintain system reliability;
6) The schedule for the new Turkey Point Nuclear Units 6 & 7;
7) Environmental regulation and/or legislation; and,
8) Possible establishment of a Florida standard for renewable energy or clean energy.

These 8 factors, and their various impacts on FPL's resource planning efforts including the current resource plan that is presented in this Site Plan, are briefly discussed below.

1. Maintaining/Enhancing System Fuel Diversity:

FPL currently uses natural gas to generate approximately 2/3 of the total electricity it delivers to its customers. In the future, the percentage of FPL's electricity that is generated by natural gas is projected to remain at a high level. For this reason, and due to evolving environmental regulations, FPL is continually seeking opportunities to economically maintain and enhance the fuel diversity of its system.

In 2007, following express direction by the FPSC to do so, FPL sought approval from the FPSC to add two new advanced technology coal units to its system. These two new units would have been placed in-service in 2013 and 2014. However, in part due to concerns over potential greenhouse gas emission legislation/regulation, FPL was unable to obtain approval for these units. Several other factors are currently unfavorable to new coal units compared to new CC units. The first of these factors is a significant reduction in the fuel cost difference between coal and natural gas compared to the fuel cost difference projected in 2007 that favored coal; i.e., the projected fuel cost advantage of coal versus natural gas has been significantly reduced. Second is the continuation of significantly higher capital costs for coal units compared to capital costs for CC units. Third is the increased fuel efficiency of new CC units compared to projected CC unit efficiencies in 2007. Fourth are existing and proposed environmental regulations, including those that address greenhouse gas emissions, that are unfavorable to new coal units when compared to new CC units. Consequently, FPL does not believe that new advanced technology coal units are currently economically, politically, or environmentally viable fuel diversity enhancement options in Florida.

Therefore, FPL has turned its attention to nuclear energy and renewable energy to enhance its fuel diversity, to diversifying the sources of natural gas, to diversifying the gas transportation paths used to deliver natural gas to FPL's generating units, and to using natural gas more efficiently. In regard to nuclear energy, in 2008 the FPSC approved the need to increase capacity at FPL's four existing nuclear units and authorized FPL to recover project-related expenditures that are approved as a result of annual nuclear cost recovery filings. FPL has now successfully completed the nuclear capacity uprate project. Approximately 520 MW of additional nuclear capacity were delivered by the project which represents an increase of approximately 30% more capacity than was originally forecasted when the project began. FPL's customers are already benefitting from lower fuel costs and reduced system emissions provided by this additional nuclear capacity.

FPL is continuing its work to obtain all of the licenses, permits, and approvals that would be necessary to construct and operate two new nuclear units at its Turkey Point site in the future. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. The earliest deployment dates for the two new nuclear units, Turkey Point Units 6 & 7, remain 2022 and 2023, respectively.

FPL also has been involved in activities to investigate adding or maintaining renewable resources as a part of its generation supply. One of these activities is a variety of discussions with the owners of existing facilities aimed at maintaining or extending current agreements. In addition, FPL considers new cost-effective renewable energy projects such as the power purchase agreements with EcoGen that will result in FPL receiving 180 MW of firm capacity from biomass facilities beginning in 2021.

FPL also sought and received approval from the FPSC in 2008 to add 110 MW through three new FPL-owned solar facilities: one solar thermal facility and two photovoltaic (PV) facilities.

One 25 MW PV facility began commercial operation in 2009. The remaining two solar facilities, a 10 MW PV facility and a 75 MW solar thermal steam generating facility, began commercial operation in 2010. The addition of these renewable energy facilities was made possible due to enabling legislation from the Florida Legislature in 2008. FPL remains strongly supportive of federal and/or state legislation that enables electric utilities to add renewable energy resources and authorize the utilities to recover appropriate costs for these resources. FPL is planning to introduce two new PV-based solar programs in 2014. These are discussed further in section III.F.4 of this chapter.

In regard to using natural gas more efficiently, FPL received approvals in 2008 from the FPSC to modernize the existing Cape Canaveral and Riviera Beach plant sites with new, highly efficient CC units that replace the former steam generating units on each of those sites. The Cape Canaveral modernization was commissioned on April 24, 2013 and the Riviera Beach modernization is projected to go in-service on/near the April 1, 2014 date this 2014 Site Plan is filed with the FPSC. On April 9th, 2012, FPL received FPSC approval to proceed with a similar modernization project at the Port Everglades site which is scheduled for completion in mid-2016. The modernization of the Port Everglades site will retain the capability of receiving water-borne delivery of oil as a backup fuel.

In regard to diversity in natural gas sourcing and delivery, in 2013 FPL was granted approval from the FPSC to build a new 3rd natural gas pipeline into Florida and FPL's service territory. The process to obtain approval for the new pipeline from the Federal Energy Regulatory Commission (FERC) is underway. The new pipeline will utilize a new route that will result in a more reliable, more economic, and more diverse natural gas supply for FPL's customers and the state of Florida.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity. In this regard, FPL is maintaining the ability to utilize fuel oil at existing units that have that capability. For this purpose, FPL has installed electrostatic precipitators (ESPs) at its two 800 MW steam generating units at the Manatee site and at one of its two 800 MW steam generating units at the Martin site. FPL is in the process of installing ESPs on its remaining 800 MW steam generating unit at the Martin site. These installations will enable FPL to retain the ability to burn oil, as needed, at these sites while retaining the flexibility to use natural gas when economically attractive.

2. Maintaining a Balance Between Load and Generation in Southeastern Florida:

An imbalance has existed between regionally installed generation and regional peak load in Southeastern Florida. As a result of that imbalance, a significant amount of energy required in the Southeastern Florida region during peak periods is provided by operating less efficient generating units located in Southeastern Florida out of economic dispatch, by importing the energy through the transmission system from plants located outside the region, or by a combination of the two. FPL's prior planning work concluded that, as load inside the region grows, either additional installed generating capacity in this region, or additional installed transmission capacity capable of delivering more electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location, four recent capacity addition decisions (Turkey Point Unit 5 and WCEC Units 1, 2, & 3) were determined to be the most cost-effective options to meet FPL's capacity needs in the near-term. In addition, FPL has added increased capacity at FPL's existing two nuclear units at Turkey Point as part of the previously mentioned nuclear capacity uprates project. The Port Everglades modernization project scheduled for completion in 2016 will also assist in addressing this imbalance. Adding the additional generation capacity through the projects mentioned above contributes to addressing the imbalance between generation, transmission capacity, and load in Southeastern Florida for approximately the remainder of this decade.

The planned addition of two new nuclear units at FPL's Turkey Point site, Turkey Point Unit 6 in 2022 and Turkey Point Unit 7 in 2023, will also address the imbalance issue for an additional period of time beginning in the next decade. Due to forecasted steadily increasing load in the Southeastern region, the Southeastern Florida imbalance issue will remain an important consideration in FPL's on-going resource planning work in future years.

3. Projections of Federal and State Energy Efficiency Codes and Standards:

As discussed in Chapter II, FPL's load forecast includes projected impacts from federal and state energy efficiency codes and standards. The magnitude of energy efficiency that is now projected to be delivered to FPL's customers through these codes and standards is significant.

In FPL's 2013 Site Plan, the projected cumulative Summer peak impact for the year 2022 from the codes and standards since 2005 was 2,898 MW compared to what the projected load would have been without the codes and standards. The current projection of cumulative Summer peak impact for the year 2023 from the codes and standards since 2005 is 3,477 MW.

In addition to lowering FPL's load forecast from what it otherwise would have been, and thus serving to lower FPL's projected resource needs, this projection of efficiency from the codes and standards also affects FPL's resource planning in another way. The projected impacts from the efficiency codes and standards lower the potential for utility DSM programs to deliver energy efficiency for the appliances and equipment that are directly addressed by the codes and standards. This effect is taken into account in FPL's proposed DSM Goals for the 2015 – 2024 time period and it is one reason why FPL's resource plan shows a diminished role for utility DSM for the years addressed by this 2014 Site Plan.

4. **Decline in the Projected Cost-Effectiveness of Utility DSM Measures and Programs:** There is another important reason why FPL's resource plan currently shows a diminished role for utility DSM: a decline in the projected cost-effectiveness of utility DSM measures and programs. The supporting testimony that FPL is filing in the DSM Goals proceeding discusses in detail the reasons for the declining cost-effectiveness of DSM. One portion of that discussion is summarized here for illustrative purposes.

The cost-effectiveness of DSM is driven in large part by the potential benefits that the kw (demand) reduction and kwh (energy) reduction characteristics of DSM programs are projected to provide. This discussion focuses solely on the current projection of potential benefits that DSM's kwh reductions can provide. At least three factors are each resulting in projections of lower kwh reduction-based benefits and thus projections of lower DSM cost-effectiveness.

The first factor is lower fuel costs. For example, comparing current fuel cost forecasts with those forecasted in 2009 – the year when FPL's DSM Goals were last set by the FPSC – shows that current forecasted fuel costs are now much lower than those forecasted in 2009, particularly in the near-term. This can be seen by comparing the 2009 and current forecasted costs ($/mmBTU) for natural gas for two specific years addressed in this Site Plan and which were addressed in the 2009 DSM goals-setting: 2015 and 2019:

Year	2009 Forecast	Current Forecast
2015	$9.64	$4.26
2019	$12.63	$6.15

As shown from these values, natural gas prices are currently forecast to be less than 50% of what they were forecast to be in 2009 when DSM goals were last set. Although lower forecasted natural gas costs are a very good thing for FPL's customers, lower fuel costs also result in lower potential fuel savings benefits from the kWh reductions of DSM measures. These lowered benefit values result in DSM being less cost-effective.

A second factor contributing to the decline in the cost-effectiveness of utility DSM is the steadily increasing efficiency with which FPL generates electricity. FPL's generating system has steadily gotten more efficient in regard to its ability to generate electricity using less fossil fuel. For example, FPL used 20% less fossil fuel to generate the same number of kwh in 2012 than it did in 2001. This is a very good thing for FPL's customers because it helps to significantly lower fuel costs.

The improvements in generating system efficiency affect DSM cost-effectiveness in much the same way that lower forecasted fuel costs do: both lower the fuel costs of energy delivered to FPL's customers. Therefore, the improvements in generating system efficiency further reduce the potential fuel savings benefits from the kWh reduction impacts of DSM, thus lowering potential DSM benefits and DSM cost-effectiveness.

A third factor for declining cost-effectiveness of utility DSM is due to significant changes in projected carbon dioxide (CO_2) compliance costs. For example, comparing CO_2 compliance forecasts with those forecasted in 2009 – the year when FPL's DSM Goals were last set by the FPSC – shows that current forecasted compliance costs are much lower than those forecasted in 2009, particularly in the near-term. This can be seen by comparing the 2009 and current forecasted costs ($/ton) for two specific years addressed in this Site Plan and which were addressed in the 2009 DSM goals-setting: 2015 and 2019:

Year	2009 Forecast	Current Forecast
2015	$17.00	$0.00
2019	$25.00	$0.00

(FPL's current forecast does not project non-zero CO_2 compliance costs until the year 2023.) While lower forecasted CO_2 compliance costs are again a good thing for FPL's customers, lower compliance costs also result in lower compliance cost savings benefits from the kWh reductions of DSM measures. These lower potential DSM benefits again result in lowering DSM cost-effectiveness.

Each of these three factors discussed above – lower forecasted fuel costs, greater efficiency in FPL's electricity generation, and lower forecasted CO_2 compliance costs – are good for FPL's customers because they will result in lower electric rates. Although good for FPL's customers, these factors also contribute to lowering the cost-effectiveness of utility DSM programs. Therefore, these factors (and other factors not discussed above), plus the growing impacts of energy efficiency codes and standards, lead to FPL's resource plan showing a diminished role for utility DSM.

5. **FPL's Increasing Dependence On DSM Resources to Maintain System Reliability:**

As discussed earlier in section III.A of this chapter, FPL's 2011, 2012, and 2013 Site Plans each projected that FPL's system was becoming increasingly dependent upon DSM resources to maintain system reliability. FPL's analyses of this projected trend showed that, from an operational perspective, there can be significant differences between resources plans on the peak day even though the resource plans have identical total reserve margins. For this reason, FPL has begun using a 10% minimum generation-only reserve margin (GRM) in its resource planning work to complement its existing 20% total reserve margin and 0.1 day/year LOLP reliability criteria. FPL will begin applying the GRM criterion in the year 2019.

6. **The Schedule for the New Turkey Point Nuclear Units 6 & 7:**

At the time the 2014 Site Plan is being finalized, the schedule for the project is under review. Several items will be considered that potentially influence the project schedule, including the Nuclear Regulatory Commission's (NRC's) schedule for reviewing the Combined Operating License Application (COLA), the impacts of the recently amended nuclear cost recovery clause (NCRC) statute, and the ongoing feasibility analyses that are part of the NCRC process.

7. **Environmental Regulation and/or Legislation:**

The seventh factor is environmental regulation. As developments occur in regard to either new environmental regulations, and/or in how environmental regulations are interpreted and applied, the potential exists for such developments to affect FPL's resource plan that is presented in this document. For example, FPL is aware of potential impacts to generating units of recent EPA changes to the National Ambient Air Quality Standards that include shorter duration 1-hour standards for nitrogen dioxide (NO_2) and sulfur dioxide (SO_2). As a consequence, FPL filed in mid-2013 for FPSC approval to recover costs through the environmental cost recovery clause for removing all of its existing gas turbines (GTs) and partially replacing that peaking unit capacity with new combustion turbines (CTs). Although FPL withdrew its filing in December 2014 pending further analyses including on-site monitoring, FPL believes that the results of the monitoring and analyses will require that the Broward GTs be replaced. Therefore, FPL is currently projecting the retirement of all GTs in Broward County; i.e., at its existing Lauderdale and Port Everglades plant sites (a decrease in generating capacity of 1,260 MW Summer), and the installation of 5 new 201 MW CTs at its existing Lauderdale plant site (an increase of 1,005 MW Summer), both by the end of 2018.

8. **Possible establishment of a Florida standard for renewable energy or clean energy:** Although no such legislation has been enacted to-date, Renewable Portfolio Standards (RPS) or Clean Energy Portfolio Standard (CPS) legislation, or other legislative initiatives regarding renewable or clean energy contributions, may occur in the future at either the state or national level. If such legislation is enacted, FPL would then determine what steps need to be taken to address the legislation.

Each of these 8 factors will continue to be examined in FPL's on-going resource planning work during the rest of 2014 and in future years.

III.D Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978 and DSM has been a key focus of FPL's IRP process for decades. During that time FPL's DSM programs have included numerous energy efficiency and load management initiatives. FPL's DSM efforts through 2013 have resulted in a cumulative Summer peak reduction of approximately 4,753 MW (Summer) at the generator and an estimated cumulative energy saving of approximately 66,782 Gigawatt Hour (GWh) at the generator. After accounting for the 20% total reserve margin requirement, FPL's DSM efforts through 2013 have eliminated the need to construct the equivalent of approximately 14 new 400 MW power plants.

FPL has consistently been among the leading utilities nationally in DSM achievement. For example, according to the U.S. Department of Energy's 2012 data (the last year for which the DOE data was available at the time this Site Plan is being developed), FPL ranked # 2 nationally in cumulative DSM demand reduction. And, importantly, FPL has achieved these significant DSM accomplishments while minimizing the DSM-based impact on electric rates for all of its customers.

In 2014, new DSM Goals for the years 2015 through 2024 will be set for FPL by the FPSC. As part of this goals-setting process, FPL must propose new DSM Goals for this time period based on its most recent resource planning analyses. The results of those analyses are reflected in this 2014 Site Plan and FPL is filing its proposed new DSM Goals on April 2, 2014 (i.e., one day after the 2014 Site Plan is filed). As discussed in the previous section of this chapter, two factors have influenced the analyses that led to the amount of DSM that FPL is proposing as its new DSM Goals: (i) increased energy efficiency that will be delivered to FPL's customers through Federal and state energy efficiency codes and standards; and (ii) a decline in the projected cost-effectiveness of DSM measures.

Based on these factors and FPL's most recent resource planning analyses, FPL is proposing that its DSM Goals be set at 337 MW of Summer MW reduction. After accounting for the 20% total reserve margin requirements, this represents the elimination of the need to construct the equivalent of another 400 MW power plant. The resource plan presented in this 2014 Site Plan accounts for the proposed amount of annual DSM implementation through the year 2023 and the DSM contribution is shown in Schedules 7.1 and 7.2 that appear later in this chapter. The FPSC is expected to make its decision regarding what FPL's DSM Goals will be for 2015 through 2024 later this year.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy to FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV bulk transmission lines that must be certified under the Transmission Line Siting Act.

Table III.E.1: List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	St. Johns [1/]	Pringle	25	Dec – 18	230	759
FPL	Manatee [2/]	Bob White	30	Dec – 14	230	1195

1/ Final order certifying the corridor was issued on April 21, 2006. This project is to be completed in two phases. Phase I consisted of 4 miles of new 230 kV line (Pringle to Pellicer) and was completed in May-2009. Phase II consists of 21 miles of new 230 kV line (St. Johns to Pellicer) and is scheduled to be completed by Dec-2018.

2/ Final order certifying the corridor was issued on November 6, 2008. This project consists of 30 miles of new 230 kV line (Manatee to Bob White) and is scheduled to be completed by Dec-2014

In addition, there will be transmission facilities needed to connect several of FPL's projected generating capacity additions to the system transmission grid. These transmission facilities (described on the following pages) are for the Port Everglades modernization, the planned Lauderdale gas turbine replacements, and the planned new nuclear capacity addition at the Turkey Point site from Turkey Point Units 6 & 7.[5] Please see discussion in the Turkey Point Preferred Site section, subsection r, of the possibility of a transmission corridor/land swap between FPL and the National Park Service. At the time the 2014 Site Plan is being prepared, no

[5] Please see discussion in the Turkey Point Preferred Site section, subsection r of the possibility of a transmission corridor/land sway between FPL and National Park Service.

site has been selected for the planned addition of a CC unit in 2019. Therefore, no transmission information for this new unit is presented.

II.E.1 Transmission Facilities for Port Everglades Next Generation Clean Energy Center (Modernization)

The work required to connect the Port Everglades Next Generation Clean Energy Center in 2016 to the FPL grid is projected to be:

I. Substation:

1. Construct two string busses to connect two combustion turbines (CT) to the Port Everglades 138 kV Substation.
2. Construct two string busses to connect one CT, and one steam turbine (ST) to the Port Everglades 230 kV Substation.
3. Add four main step-up transformers (3-450 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. Replace ten (10) 138 kV breakers.
5. Replace eight (8) 230 kV breakers.
6. At Port Everglades Switchyard replace twenty-two 138 kV disconnect switches. Also upgrade associated jumpers, bus work, and equipment connections.
7. Expand switchyard relay vault and add relays and other protective equipment.

II. Transmission:

1. Upgrade of existing transmission facilities:
   - An ampacity upgrade up to 1905 amps on the Port Everglades-Port Everglades Tap 138kV line section.
   - An ampacity upgrade up to 1905 amps on the Port Everglades Tap-Port Everglades Tap 2 138 kV line section.
   - An ampacity upgrade up to 1695 amps on the Port Everglades Tap 1-Dania 138 kV line section.
   - An ampacity upgrade up to 1695 amps on the Dania-Hollywood 138 kV line section.

III.E.2 Transmission Facilities for the Lauderdale GT Replacement Project

The work required to connect the five Lauderdale combustion turbines (CT) in 2018 to the FPL grid is projected to be:

I. Substation:

1. Construct a collector switchyard for the five (5) CTs at Lauderdale Plant.
2. Install five (5) main step-up transformers (5 - 320 MVA), one for each CT.
3. Construct one 230 kV collector buss to connect two (2) CT step-up transformers to collector switchyard.
4. Construct one 138 kV collector buss to connect two (2) CT step-up transformers to collector switchyard.
5. Construct Cable Termination Structures (CTS) in the collector switchyard and the Lauderdale 138 kV Substation to connect the 138 kV collector buss for the two CTs to the Lauderdale 138 kV Substation Outside Bus.
6. Construct CTS in the collector switchyard and the Lauderdale 138 kV Substation to connect the fifth CT to the Lauderdale 138 kV Substation Inside Bus.
7. Add relays and other protective equipment.

II. Transmission:

1. Construct overhead 230 kV string bus to connect the 230 kV collector buss to the Lauderdale 230 kV Substation Inside Bus.
2. Construct two (2) underground 138 kV cables connecting the collector switchyard to the Lauderdale Substation Inside and Outside Busses.

III.E.3 Transmission Facilities for Turkey Point Nuclear Unit 6

The work required to connect the Turkey Point Nuclear Unit 6 by Summer 2022 to the FPL grid is projected to be:

I. Substation:

1. Build new Clear Sky 500/230kV Switchyard with six (6) bays on the 230 kV section for generator main step-up transformer connection, reserve auxiliary transformer connections, four (4) 230 kV line terminals, two (2) autotransformers and two (2) 500 kV line terminals.
2. At Turkey Point Switchyard add a new bay to accommodate the Turkey Point-Clear Sky 230 kV line terminal.
3. At Pennsuco Substation install a fourth line terminal to accommodate the Pennsuco-Clear Sky 230 kV line by converting the ring bus to a breaker and a half scheme and adding four (4) 230 kV breakers.
4. At Davis Substation construct two (2) new 230kV line terminals for the Clear Sky-Davis 230 kV line and the Davis-Miami 230 kV line.
5. At Levee Substation expand 500 kV section to accommodate the two (2) Levee-Clear Sky 500 kV lines.
6. At Andytown Substation install two (2) 5-Ohm inductors combined with external shunt capacitors on the 230kV side of the 500/230 autotransformers (one per auto).
7. At Miami Substation expand the 230kV section to a double bus configuration and add a new 230kV line terminal for Davis line and replace one (1) autotransformer.
8. Breaker replacements:
   Flagami Substation – Replace five (5) 230 kV breakers and three (3) 138 kV breakers
   Miami Substation – Replace one (1) 230 kV breaker and four (4) 138 kV breakers
   Davis Substation - Replace two (2) 230 kV breakers

II. Transmission:

1. FPL will design and construct two (2) 500kV transmission lines from the new Clear Sky Substation to the existing FPL Levee 500kV Substation switchyard. The lines will be approximately 43 miles long.
2. Construct a new Clear Sky-Davis 230kV line (approximately 19 miles) with a rating of 2990 Amperes.
3. Construct a new Clear Sky-Pennsuco 230kV line (approximately 52 miles) with a rating of 2990 Amperes.
4. Construct a new Davis-Miami 230kV line (approximately 18 miles) with a rating of 2297 Amperes.
5. Construct a new Clear Sky-Turkey Point 230kV line (approximately 0.5 miles) with a rating of 2990 Amperes.

III.E.4 Transmission Facilities for Turkey Point Nuclear Unit 7

The work required to connect the Turkey Point Nuclear Unit 7 by Summer 2023 to the FPL grid is projected to be:

I. Substation:

1. At Gratigny Substation install a second 230/138 kV autotransformer with one (1) 230 kV breaker and one (1) 138 kV breaker.
2. At Davis Substation construct a switch-able inductor to be installed on the Davis-Miami 230 kV line.
3. At Flagami Substation install a small inductor on one end of the Flagami-Miami 230kV #2 circuit.
4. Breaker replacements:
   Dade Substation - Replace seven (7) 230 kV breakers
   Court Substation – Replace one (1) 138 kV breaker.

II. Transmission:

1. The transmission line facilities required for Turkey Point Unit 7 will be constructed with the transmission line facilities needed for Turkey Point Unit 6, as described above in section III. E.3.

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to effectively utilize renewable energy technologies to serve its customers. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. For purposes of discussing FPL's renewable energy efforts in this document, those efforts will be placed into five categories.

Two of these categories are Supply-Side Efforts – Power Purchases, and Supply-Side Efforts – FPL Facilities. Since 2011, the energy (MWh) total output from these renewable energy sources has been greater than the energy produced from oil-fired generation. The renewable energy information is presented in Schedule 11.1, and the oil-based energy information is presented in Schedule 6.1 and in Schedule 11.1. Both of these schedules are presented at the end of this chapter.

1) <u>Early Research & Development Efforts:</u>

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970s in demonstrating the first residential photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-kilowatt (kW) system was placed into operation in 1984. (The system was removed in 1990 at the conclusion of the PV testing to make room for substation expansion.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. This FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site became the home for PV capacity which was installed as a result of other FPL renewable energy initiatives.

2) <u>Demand Side & Customer Efforts:</u>

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers who chose solar water heaters. Before the program ended (due to the fact that it was no longer projected to be cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for six passive home designs with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code was one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the FPSC to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test were deemed to be solvable, particularly when new pools are constructed. However, challenges included the significant percentage of sites with unacceptable shading and various customer satisfaction issues.

FPL has since continued to analyze and promote the utilization of PV. These efforts have included PV research, development, and education, as well as development and implementation of the FPL Next Generation Solar Station Program. This initiative also delivers teacher training and curriculum that is tied to the Sunshine Teacher Standards in Florida. The program provides teacher grants to promote and fund projects in the classrooms.

In addition, FPL assists customers who are interested in installing PV equipment at their facilities. Consistent with Florida Administrative Code Rule 25-6.065, Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned PV systems. Through December 2013, approximately 2,565 customer systems (predominantly residential) have been interconnected.

As part of its 2009 DSM Goals decision, the FPSC imposed a requirement for Florida's investor-owned utilities to spend up to a set, not-to-exceed amount of money annually to facilitate demand side solar water heater and PV applications. FPL's not-to-exceed amount of money for these applications is approximately $15.5 million per year through 2014. In regard to this direction, FPL received approval from the FPSC in 2011 to initiate a solar pilot portfolio that consists of three PV-based programs and three solar water heating-based programs, plus Conservation Research and Development. These programs are currently projected to be offered through 2014. FPL's analyses of the results to-date from these programs shows that none of these programs are projected to be cost-effective using any of the three cost-effectiveness screening tests used by the State of Florida. The fate of these solar programs, including their potential replacement with new solar initiatives, will be determined later in 2014 as part of the FPSC's 2014 DSM Goals docket.

FPL has also been investigating fuel cell technologies through monitoring of industry trends, discussions with manufacturers, and direct field trials. From 2002 through the end of 2005, FPL conducted field trials and demonstration projects of Proton Exchange Membrane (PEM) fuel cells with the objectives of serving customer end-uses while evaluating the technical performance, reliability, economics, and relative readiness of the PEM technology. The demonstration projects were conducted in partnership with customers and included five locations. The research projects were useful to FPL in identifying specific issues that can occur in field applications and the current commercial viability of this technology. FPL will continue to monitor the progress of these technologies and conduct additional field evaluations as significant developments in fuel cell technologies occur.

3) <u>Supply Side Efforts – Power Purchases:</u>

FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy, and as-available energy, have been purchased by FPL from these types of facilities. (Please refer to Tables I.B.1, I.B.2, and I.C.1 in Chapter I).

FPL issued Renewable Requests for Proposals (RFPs) in 2007 and 2008 soliciting proposals to provide firm capacity and energy, and energy only, at or below avoided costs, from renewable generators. FPL also promptly responds to inquiries for information from prospective renewable energy suppliers either by e-mail or phone.

On April 22, 2013 in Order No. PSC-13-1064-PAA-EQ, the FPSC approved three 60 MW power purchase agreements with affiliates of U.S. EcoGen for biomass-fired renewable energy facilities. These facilities are expected to begin service in 2019, and to begin providing firm renewable energy and capacity to FPL's customers in 2021.

With regard to existing contracts that have recently ended, FPL and the Solid Waste Authority of Palm Beach (SWA) agreed to extend their contract that expired March 31, 2010 for a 20-

year term beginning in April 1, 2012 through April 1, 2032. However, the SWA refurbished their generating unit ahead of schedule and, as of January 2012, this unit began delivering firm capacity to FPL. In 2011, the FPSC approved a contract for an additional 70 MW between FPL and SWA for a new unit to be constructed and to begin delivering firm capacity and energy beginning on January 1, 2015. At the end of December 2011, the contract between FPL and Okeelanta (New Hope) expired. However, Okeelanta continues to deliver energy to FPL as an as-available, non-firm supplier of renewable energy.

4) **Supply Side Efforts – FPL Facilities:**

With regard to solar generating facilities, FPL has three such facilities: (i) a 75 MW steam generation solar thermal facility in Martin County (the Martin Next Generation Solar Energy Center); (ii) a 25 MW PV electric generation facility in DeSoto County (the DeSoto Next Generation Solar Energy Center); and (iii) a 10 MW PV electric generation facility in Brevard County at NASA's Kennedy Space Center (the Space Coast Next Generation Solar Energy Center). The DeSoto County project was completed in 2009 and the other two projects were completed in 2010. These three solar facilities were constructed in response to the Florida Legislature's House Bill 7135 which was signed into law by the Governor in June 2008.

House Bill 7135 was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in the State of Florida. Specifically, the bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land, zoning, and transmission rights in place. FPL's three solar projects met the specified criteria, and were granted approval for cost recovery in 2008. Each of the three solar facilities is discussed below.

a. **The Martin Next Generation Solar Energy Center:**

This facility began commercial operation in 2010 and provides 75 MW of solar thermal capacity in an innovative way that directly displaces fossil fuel usage on the FPL system. This facility consists of solar thermal technology which generates steam that is integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired CC plant. This project is the first "hybrid" solar plant in the world, and, at the time the facility came in-service, was the second largest solar facility in the world and the largest solar plant of any kind in the U.S. outside of California.

b. **The DeSoto Next Generation Solar Energy Center:**

This PV facility began commercial operation in 2009 and provides 25 MW of non-firm capacity and energy, making it one of the largest PV facilities in the U.S. The facility utilizes a tracking PV array that is designed to follow the sun as it traverses across the sky.

c. **The Space Coast Next Generation Solar Energy Center:**

Located at the Kennedy Space Center, this facility is part of an innovative public/private partnership with NASA. This non-tracking PV facility began commercial operation in 2010 and provides 10 MW of non-firm capacity and energy.

At the time the 2014 Site Plan is being prepared, FPL considers the output from these renewable facilities to be "as available," non-firm energy only. This is due to several factors. First, the Martin solar thermal facility is a "fuel-substitute" facility, not a facility that provides additional capacity and energy. The solar thermal facility displaces the use of fossil fuel to produce steam on the FPL system when the solar thermal facility is operating. Second, in regard to the two PV facilities, the intermittent nature of the solar resource has made it difficult to-date to accurately determine what contribution the PV facilities at these specific locations can consistently make at FPL's late Summer afternoon and early Winter morning peak load hours. This is, in part, due to the fact that at least several years worth of Summer and Winter peak load periods are needed to accurately gauge the actual output of these PV facilities during system peak hours. FPL is now evaluating what portion, if any, of the PV facilities' output can be projected as firm capacity at the projected peak hours in FPL's resource planning work.

In addition to these three solar facilities, FPL is currently in the process of identifying other potential sites in the state for central station PV facilities. FPL is evaluating existing FPL generation sites along with potential Greenfield sites within FPL's service territory. These sites are discussed further in Chapter IV.

In regard to PV distributed generation (DG), FPL is planning to implement two PV DG solar programs in 2014. The first program is a voluntary customer participation program that will be pursued on a pilot basis. FPL will file for FPSC approval of this program near the April filing date of the 2014 Site Plan. The second program is designed to research the effects of increasing PV DG on the FPL system. This program will be introduced later in 2014. A brief description of the two programs follows.

d. **Voluntary, Community-based Solar Partnership Pilot Program**

FPL will be filing for FPSC approval of a tariff that provides customers an opportunity to make voluntary contributions toward the construction of PV facilities on a local level throughout FPL's service territory. The pilot program will provide all customers the opportunity to support the use of solar energy at a community scale, and is designed to be especially attractive for customers who do not wish, or are not able, to place solar equipment on their roof.

d. **C&I Solar Partnership Program:**

This is also a PV-focused research program that will be conducted in partnership with interested commercial and industrial (C&I) customers. Limited investments will be made in rooftop PV facilities in selected geographic areas in order to examine the effect of PV DG on FPL's distribution system. FPL will attempt to site these PV facilities in areas where PV DG already exists to better study feeder loading impacts. The PV facilities will be located on C&I customer property near the targeted feeders. The objective of the program is to gather data that will result in a better understanding of the effects of high PV DG penetrations on FPL's system.

5) **Ongoing Research & Development Efforts:**

FPL has developed alliances with several Florida universities to promote development of emerging technologies. For example, FPL has an alliance has been established with the newly formed Southeast National Marine Renewable Energy Center (SNMREC) at Florida Atlantic University (FAU), which will focus on the commercialization of ocean current, ocean thermal (i.e., energy conversion as well as cold water air conditioning), and hydrogen technologies. FPL has been supporting FAU with the discussions being held with the U.S. Department of the Interior's Minerals Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE). BOEMRE is working to establish the permitting process for ocean energy development on the outer continental shelf.

FPL has also developed a "Living Lab" to demonstrate FPL's solar energy commitment to employees and visitors at its Juno Beach office facility. To-date, FPL has installed five different PV arrays (different technologies) of rooftop PV totaling 24 kW at the Living Lab. In addition, two PV-covered parking structures with a total of approximately 90 kW of PV are in use at the FPL Juno office parking lot. Through these Living Lab projects, FPL is able to evaluate multiple solar technologies and applications for the purpose of developing a renewable business model resulting in the most cost-effective and reliable uses of solar energy for FPL's customers. FPL plans to continue to expand the Living Lab as new solar products come to market.

FPL has also been in discussions with several private companies on multiple emerging technology initiatives including ocean current, ocean thermal, hydrogen, fuel cell technology, biomass, biofuels, and energy storage

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fired generation. In the early 1980s, FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership (20%) and additional purchases (30%) from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit 4 which began serving FPL's customers in 1991.

The trend since the early 1990s has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective CC generating units and the ready availability of natural gas. Most recently, FPL placed into commercial operation two new gas-fired CC units at the West County Energy Center (WCEC) site in 2009. A third new CC unit was added to the WCEC site in 2011. In addition, FPL finished modernization of its Cape Canaveral and Riviera Beach plant sites and is currently modernizing its existing Port Everglades plant site by removing the steam generating units previously on the site and replacing them with one highly efficient new CC unit. The new CC units at each of these three sites will provide highly efficient generation that will dramatically improve the efficiency of FPL's generation system in general and, more specifically, the efficiency at which natural gas is utilized.

In addition, FPL increased its utilization of nuclear energy through capacity uprates of its four existing nuclear units. With these uprates, more than 520 MW of additional nuclear capacity have been added to the FPL system. FPL is also pursuing plans to obtain licenses, permits, and approvals to construct and operate two new nuclear units at its existing Turkey Point site that, in total, would add approximately 2,200 MW of new nuclear generating capacity. The earliest dates by which these two new nuclear units could practically be deployed remain 2022 and 2023, respectively.

In regard to utilizing renewable energy, FPL has a 110 MW of solar generating capacity through a 75 MW solar thermal steam generating facility at FPL's existing Martin site, a 25 MW PV facility in DeSoto County, and a 10 MW PV facility in Brevard County. The DeSoto facility was placed into commercial operation in 2009. The other two solar facilities were placed into commercial operation in 2010.

FPL's future resource planning work will continue to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance FPL's long-term fuel diversity. These fuel diverse alternatives may include: the purchase of power from renewable energy facilities, additional FPL-owned renewable energy facilities, obtaining additional access to diversified sources of natural gas such as liquefied natural gas (LNG) and natural gas from the Mid-Continent unconventional reserves, preserving FPL's ability to utilize fuel oil at its existing units, and increased utilization of nuclear energy. (As previously discussed, new advanced technology coal generating units are not currently considered as viable options in Florida in the ten-year reporting period of this document due, in part, to current projections of relatively small differences in fuel costs between coal and natural gas, significantly higher capital costs for coal units compared to CC units, greater efficiencies of CC units, and concerns over environmental regulations that would impact coal units more negatively than CC units.) The evaluation of the feasibility and cost-effectiveness of these, and other possible fuel diversity alternatives, will be part of FPL's on-going resource planning efforts.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2023 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

FPL's Fossil Fuel Cost Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future resource needs. FPL's forecasts are generally consistent with other published contemporary forecasts. An October 2013 fuel cost forecast was used in the analyses whose results led to the resource plan presented in this 2014 Site Plan.

Future oil and natural gas prices, and to a lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, coal, and petroleum coke. These drivers include U.S. and worldwide demand, production capacity, economic growth, environmental legislation, and politics.

The inherent uncertainty and unpredictability in these factors today and tomorrow clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal and petroleum coke) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed and utilized Low, Medium, and High price forecasts for fossil fuels in some of its 2013 and early 2014 resource planning work, particularly in regard to analyses conducted as part of the nuclear cost recovery filing work.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

a. For 2014 through 2015, the methodology used the October 7, 2013 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil, ultra low sulfur diesel fuel oil, and Henry Hub natural gas commodity prices;

b. For the next two years (2016 and 2017), FPL used a 50/50 blend of the October 7, 2013 forward curve and the most current projections at the time from The PIRA Energy Group;

c. For the 2018 through 2030 period, FPL used the annual projections from The PIRA Energy Group; and,

d. For the period beyond 2030, FPL used the real rate of escalation from the Energy Information Administration (EIA). In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach:

a. Delivered price forecasts for Central Appalachian (CAPP), Illinois Basin (IB), Powder River Basin (PRB), and South American coal and petroleum coke were provided by JD Energy; and,

b. The coal price forecast for SJRPP and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for oil, natural gas, coal, and petroleum coke prices were based on the historical volatility of the 12-month forward price, one year ahead. FPL developed these forecasts to account for the uncertainty which exists within each commodity as well as across commodities. These forecasts reflect a range of reasonable forecast outcomes.

3. Natural Gas Storage

FPL was under contract through March 2013 for 2 billion cubic feet (Bcf) of firm natural gas storage capacity in the Bay Gas storage facility located in Alabama. The Bay Gas storage facility is interconnected with the Florida Gas Transmission (FGT) pipeline. Starting on April 1, 2013, FPL entered into a new deal with Bay Gas Storage for one year for 2.5 billion cubic feet (Bcf) of firm natural gas storage capacity. In December 2013, FPL elected to extend this transaction for an additional three years which resulted in a lower annual cost for Bay Gas. FPL has predominately utilized natural gas storage to help mitigate gas supply problems caused by severe weather and/or infrastructure problems. Over the past several years, FPL has acquired upstream transportation capacity on several pipelines to help mitigate the risk of off-shore supply problems caused by severe weather in the Gulf of Mexico. While this transportation capacity has reduced FPL's off-shore exposure, a portion of FPL's supply portfolio remains tied to off-shore natural gas sources. Therefore, natural gas storage remains an important tool to help mitigate the risk of supply disruptions. For these reasons, FPL has typically maintained nearly full natural gas inventory during normal operations from June through November (hurricane season). From December through March, FPL typically maintains lower levels of natural gas inventory compared to Summer peak months.

As FPL's reliance on natural gas has increased, its ability to manage the daily "swings" that can occur on its system due to weather and unit availability changes has become more challenging, particularly from oversupply situations. Natural gas storage is a valuable tool to help manage the daily balancing of supply and demand. From a balancing perspective, injection and withdrawal rights associated with gas storage have become an increasingly important part of the evaluation of overall gas storage requirements.

As FPL's system grows to meet customer needs, it must maintain adequate gas storage capacity to continue to help mitigate supply and/or infrastructure problems and to provide FPL the ability to manage its supply and demand on a daily basis. FPL continues to evaluate its gas storage portfolio and is likely to subscribe for additional gas storage capacity to help increase reliability, provide the necessary flexibility to respond to demand changes, and diversify the overall portfolio.

4. **Securing Additional Natural Gas:**

The recent trend of increasing reliance upon natural gas to produce electricity for FPL's customers is projected to continue due to FPL's growing load. The addition of highly fuel-efficient CC units at Cape Canaveral and Riviera Beach due to completed modernization projects, and the on-going Port Everglades modernization project, will serve to reduce the growth in natural gas use from what it otherwise might have been due to the high fuel-efficiency levels of these new CC units. However, these efficiency gains do not fully offset the effects of FPL's growing load. Therefore, FPL will need to secure more natural gas supply and more firm gas transportation capacity in the future as fuel requirements dictate. The issue is how to secure these additional natural gas resources in a manner that is economical for FPL's customers and which maintains and/or enhances the reliability of natural gas supply and deliverability to FPL's generating units.

FPL has historically purchased the gas transportation capacity required for new natural gas supply from two existing natural gas pipeline companies. As more natural gas is delivered through these two pipelines, the impact of a supply disruption on either pipeline becomes more problematic. Therefore, FPL issued a Request for Proposals (RFP) in December 2012 for gas transportation capacity to meet FPL's system natural gas requirements beginning in 2017. The RFP encouraged bidders to propose new gas transportation infrastructure to meet Florida's growing need for natural gas. A third pipeline would have benefits for FPL and its customers by increasing the diversity of FPL's fuel supply sources, increasing the physical reliability of the pipeline delivery system, and enhancing competition among pipelines. The RFP process was completed in June 2013 and the winning bidders, Sabal Trail Transmission, LLC (Sabal Trail) and Florida Southeast Connection, LLC (FSC), have begun the Federal Energy Regulatory Commission approval process with a planned in-service date of May 2017. The contracts with Sabal Trail and FSC were reviewed by the FPSC and were approved for cost recovery in late 2013. The order approving this cost recovery became final in January 2014.

5. Nuclear Fuel Cost Forecast

This section reviews the various steps needed to fabricate nuclear fuel for delivery to the nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

a) Steps Required for Nuclear Fuel to be delivered to FPL's Plants

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

(1) Mining: Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U3O8 (sometimes referred to as yellowcake).

(2) Conversion: During the second step, the U3O8 is chemically converted into UF6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

(3) Enrichment: The third step is called enrichment. Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to almost five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 2.2% to as high as 4.95%). The output of this enrichment process is enriched uranium in the form of UF6.

(4) Fabrication: During the last step, fuel fabrication, the enriched UF6 is changed to a UO2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) Mining: The impact of the earthquake and tsunami that struck the Fukushima nuclear complex in Japan in March 2011 is still being felt in the uranium market. Current demand has declined and several of the production facilities have announced delays. Factors of importance are:

- Hedge funds are still very active in the market. This causes more speculative demand that is not tied to market fundamentals and causes the market price to move up or down just based on news that might affect future demand.
- Some of the uranium inventory from the U.S. Department of Energy (DOE) is finding its way into the market periodically to fund cleanup of certain Department of Energy facilities.
- Although a limited number of new nuclear units are scheduled to start production in the U.S. during the next 5 to 10 years, other countries, more specifically China, have announced an increase in construction of new units which may cause uranium prices to trend up in the near future.

Over a 10-year horizon, FPL expects the market to be more consistent with market fundamentals. The supply picture is more stable, with laws enacted to resolve the import of Russian-enriched uranium, by allowing some imports of Russian-enriched uranium to meet about 20-25% of needs for currently operating units, but with no restriction on the first core for new units and no restrictions after 2020. New and current uranium production facilities continue to add capacity to meet demands. Actual demand tends to grow over time because of the long lead time to build nuclear units. However, FPL cannot discount the possibility of future periodic sharp increase in prices, but believes such occurrences will likely be temporary in nature.

(2) Conversion: The conversion market is also in a state of flux due to the Fukushima events. Planned production after 2016 is currently forecasted to be insufficient to meet the higher demand scenario, but it is projected to be sufficient to meet most reference case scenarios. As with additional raw uranium production, supply will expand beyond current level once more firm commitments are made including commitments to build new nuclear units. FPL expects long term price stability for conversion services to support world demand.

(3) Enrichment: As a result of the Fukushima events in March 2011, the near-term price of enrichment services has been declining for the last three years. However, plans for construction of several new facilities that were expected to come on-line in the next few years have been delayed. Also, some of the existing high operating cost diffusion plants have shut down. As with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand. Meanwhile, world supply and demand will continue to be balanced such that FPL expects adequate supply of enrichment services. The current supply/demand profile will most likely result in the price of enrichment services remaining stable or declining for the next few years before starting to increase.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the Nuclear Regulatory Commission (NRC), not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand is expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies. The calculations for the nuclear fuel cost forecasts used in FPL's 2013 and early 2014 resource planning work were performed consistent with the method then used for FPL's Fuel Clause filings, including the assumption of refueling outages every 18 months and plant operation at power uprate levels. The costs for each step to fabricate the nuclear fuels were added to come up with the total costs of the fresh fuel to be loaded at each refueling (acquisition costs). The acquisition cost for each group of fresh fuel assemblies were then amortized over the energy produced by each group of fuel assemblies. FPL also added 1 mill per kilowatt hour net to reflect payment to DOE for spent fuel disposal.

Schedule 5
Fuel Requirements
(for FPL only)

Fuel Requirements	Units	Actual 1/ 2012	Actual 1/ 2013	Forecasted 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1) Nuclear	Trillion BTU	188	273	288	300	306	303	320	306	302	300	357	455
(2) Coal	1,000 TON	2,692	3,540	3,414	3,778	2,124	3,076	3,574	3,781	3,855	3,893	3,750	3,758
(3) Residual (FO6) - Total	1,000 BBL	459	150	715	1,130	1,139	561	546	164	176	188	111	52
(4) Steam	1,000 BBL	459	150	715	1,130	1,130	561	546	164	176	188	111	52
(5) Distillate (FO2) - Total	1,000 BBL	23	152	37	35	226	61	293	247	284	282	184	126
(6) Steam	1,000 BBL	4	0	0	0	0	0	0	0	0	0	0	0
(7) CC	1,000 BBL	15	140	7	30	88	6	186	144	160	153	100	76
(8) CT	1,000 BBL	4	12	30	6	138	56	107	104	124	129	84	51
(9) Natural Gas - Total	1,000 MCF	595,356	550,350	550,762	544,653	584,056	578,902	581,638	580,361	586,151	600,152	570,633	518,693
(10) Steam	1,000 MCF	46,112	30,348	4,413	8,385	10,562	9,343	8,867	2,912	3,104	3,280	2,021	1,001
(11) CC	1,000 MCF	546,386	514,793	544,867	534,847	571,277	567,674	568,822	575,025	580,083	593,852	566,719	516,379
(12) CT	1,000 MCF	2,899	5,208	1,483	1,421	2,216	1,884	3,849	2,424	2,944	3,020	1,793	1,313

1/ Source: A Schedules
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

Schedule 6.1
Energy Sources

Energy Sources	Units	Actual[1] 2012	2013	Forecasted 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1) Annual Energy Interchange 2/	GWH	5,186	4,445	3,539	3,876	2,165	2,316	2,640	962	0	0	0	0
(2) Nuclear	GWH	18,916	25,243	27,792	27,981	28,593	28,279	27,859	28,550	28,177	27,971	33,464	42,915
(3) Coal	GWH	4,745	5,981	6,020	6,662	3,827	5,488	6,488	6,850	6,923	6,867	6,778	6,779
(4) Residual(FO6) -Total	GWH	378	75	437	722	684	333	327	104	111	118	69	32
(5) Steam	GWH	378	75	437	722	684	333	327	104	111	118	69	32
(6) Distillate(FO2) -Total	GWH	54	120	13	26	104	17	208	177	203	200	131	91
(7) Steam	GWH	2	2	0	0	0	0	0	0	0	0	0	0
(8) CC	GWH	49	114	6	25	72	5	148	115	128	122	80	60
(9) CT	GWH	4	5	7	1	32	12	60	63	75	78	51	31
(10) Natural Gas -Total	GWH	80,505	75,208	78,228	77,979	84,154	83,812	84,144	84,899	87,546	88,092	83,914	76,379
(11) Steam	GWH	5,543	2,472	381	724	932	817	789	249	267	283	172	94
(12) CC	GWH	74,668	72,308	77,722	77,131	83,029	82,833	82,978	84,412	86,994	87,519	83,567	76,167
(13) CT	GWH	295	428	125	124	194	163	377	238	285	291	176	129
(14) Solar[3]	GWH	159	155	191	176	195	194	194	194	194	188	192	192
(15) PV	GWH	71	68	72	71	71	70	70	69	69	68	68	67
(16) Solar Thermal	GWH	89	87	119	104	125	124	124	124	125	119	124	124
(17) Other[4]	GWH	2,922	428	1,782	4,185	4,220	4,475	4,435	5,936	6,032	6,015	5,987	5,988
Net Energy For Load[5]	GWH	110,806	111,656	118,002	121,606	123,942	124,914	126,395	127,670	129,184	129,451	130,515	132,356

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report.
2/ The projected figures are based on estimated energy purchases from SJRPP, the Southern Companies (UPS contract), and other utilities.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
5/ Net Energy For Load values for the years 2014- 2023 are also shown in Col. (19) on Schedule 2.3.

Schedule 6.2
Energy Sources % by Fuel Type

Energy Source	Units	Actual 1/ 2012	2013	Forecasted 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1) Annual Energy Interchange 2/	%	4.7	4.0	3.0	3.2	1.7	1.9	2.1	0.8	0.0	0.0	0.0	0.0
(2) Nuclear	%	15.3	22.6	23.6	23.0	23.1	22.6	22.1	22.4	21.8	21.6	25.6	32.4
(3) Coal	%	4.3	5.4	5.1	5.5	3.1	4.4	5.1	5.4	5.4	5.3	5.2	5.1
(4) Residual (FO6) -Total	%	0.3	0.1	0.4	0.6	0.6	0.3	0.3	0.1	0.1	0.1	0.1	0.0
(5) Steam	%	0.3	0.1	0.4	0.6	0.6	0.3	0.3	0.1	0.1	0.1	0.1	0.0
(6) Distillate (FO2) -Total	%	0.0	0.1	0.0	0.0	0.1	0.0	0.2	0.1	0.2	0.2	0.1	0.1
(7) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8) CC	%	0.0	0.1	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.0
(9) CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0
(10) Natural Gas -Total	%	72.6	67.4	66.3	64.1	67.9	67.1	66.6	66.5	67.8	68.1	64.2	57.7
(11) Steam	%	5.0	2.2	0.3	0.6	0.8	0.7	0.6	0.2	0.2	0.2	0.1	0.1
(12) CC	%	67.3	64.8	65.9	63.4	67.0	66.3	65.7	66.1	67.3	67.6	64.0	57.5
(13) CT	%	0.3	0.4	0.1	0.1	0.2	0.1	0.3	0.2	0.2	0.2	0.1	0.1
(14) Solar 3/	%	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1
(15) PV	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(16) Solar Thermal	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(17) Other 4/	%	2.6	0.4	1.5	3.4	3.4	3.6	3.5	4.6	4.7	4.6	4.6	4.5
		100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report
2/ The projected figures are based on estimated energy purchases from SJRPP, the Southern Companies (UPS contract), and other utilities.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled
Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Reserve Margin MW	Generation Reserve Margin % of Peak
2014	25,488	1,303	0	635	27,426	22,768	1,992	20,777	6,649	32.0	826	5,823	28.0	3,831	16.8
2015	25,121	1,450	0	595	27,165	23,356	2,057	21,298	5,867	27.5	0	5,867	27.5	3,810	16.3
2016	26,358	522	0	595	27,474	23,778	2,082	21,696	5,779	26.6	0	5,779	26.6	3,697	15.5
2017	25,962	522	0	595	27,078	24,190	2,108	22,082	4,996	22.6	0	4,996	22.6	2,888	11.9
2018	25,916	485	0	595	26,996	24,544	2,136	22,408	4,587	20.5	0	4,587	20.5	2,452	10.0
2019	26,930	110	0	595	27,635	24,896	2,165	22,731	4,904	21.6	0	4,904	21.6	2,739	11.0
2020	26,930	239	0	595	27,764	25,239	2,195	23,044	4,720	20.5	0	4,720	20.5	2,524	10.0
2021	26,930	278	0	775	27,983	25,439	2,227	23,212	4,770	20.6	0	4,770	20.6	2,544	10.0
2022	28,117	110	0	775	29,002	25,908	2,259	23,649	5,353	22.6	0	5,353	22.6	3,094	11.9
2023	29,272	110	0	775	30,157	26,528	2,292	24,236	5,921	24.4	0	5,921	24.4	3,628	13.7

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col (4) + Col.(5).
Col. (7) reflects the 2013 load forecast without incremental DSM or cumulative load management.
Col. (8) represents cumulative load management capability, plus incremental conservation,and load management, from 9/2013-on intended for use with the 2013 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period; i.e., Martin Unit 2's planned outage in Summer 2014 for the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)
Col. (15) =Col. (6) - Col. (7)
Col. (16) = Col.(15) / Col.(7)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled
Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
January of Year	Firm Installed Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Reserve Margin MW	Generation Reserve Margin % of Peak
2014	25,671	1,311	0	635	27,617	19,875	1,502	18,373	9,243	50.3	832	8,411	45.8	6,910	34.8
2015	26,597	1,458	0	595	28,649	20,971	1,530	19,442	9,208	47.4	0	9,208	47.4	7,678	36.6
2016	26,653	530	0	595	27,777	21,490	1,543	19,947	7,831	39.3	0	7,831	39.3	6,287	29.3
2017	27,601	530	0	595	28,725	21,731	1,558	20,173	8,552	42.4	0	8,552	42.4	6,994	32.2
2018	27,557	493	0	595	28,645	21,968	1,573	20,396	8,249	40.4	0	8,249	40.4	6,676	30.4
2019	27,295	493	0	595	28,383	22,180	1,588	20,592	7,790	37.8	0	7,790	37.8	6,203	28.0
2020	28,724	239	0	595	29,558	22,383	1,603	20,780	8,777	42.2	0	8,777	42.2	7,174	32.1
2021	28,724	278	0	775	29,777	22,584	1,619	20,966	8,811	42.0	0	8,811	42.0	7,192	31.8
2022	28,724	110	0	775	29,609	22,601	1,634	20,967	8,642	41.2	0	8,642	41.2	7,007	31.0
2023	29,910	110	0	775	30,795	22,891	1,651	21,241	9,554	45.0	0	9,554	45.0	7,903	34.5

Col. (2) represents capacity additions and changes projected to be in-service by January 1st. These MW are generally considered to be available to meet winter peak loads which are forecasted to occur during January of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2013 load forecast without incremental DSM or cumulative load management. 2013 load is an actual load value.
Col. (8) represents cumulative load management capability, plus incremental conservation and load management., from 9/2013-on intended for use with the 2013 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Winter peak period; i.e., Martin Unit 1's planned outage during the Winter of 2014 for the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)
Col. (15) =Col. (6) - Col. (7)
Col. (16) = Col.(15) / Col.(7)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes [1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability [2]		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2014														
Sanford CT Upgrade	5B	Volusia County	CC	NG	No	PL	No	Aug-13	Sep-13	Unknown	188,190	10	8	OT
Turkey Point CT Upgrade	5A	Miami Dade County	CC	NG	FO2	PL	TK	—	Mar-14	Unknown	188,190	—	7	OT
Turkey Point CT Upgrade	5B	Miami Dade County	CC	NG	FO2	PL	TK	—	Mar-14	Unknown	188,190	—	7	OT
Turkey Point CT Upgrade	5C	Miami Dade County	CC	NG	FO2	PL	TK	—	Mar-14	Unknown	188,190	—	7	OT
Turkey Point CT Upgrade	5D	Miami Dade County	CC	NG	FO2	PL	TK	—	Mar-14	Unknown	188,190	—	7	OT
Martin [3]	1	Martin County	ST	FO6	NG	PL	PL	Jun-13	Mar-14	Unknown	934,500	(832)	823	ESP
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	TK	WA	Jun-12	Apr-14	Unknown	1,295,400	—	1,212	U
Martin [3]	2	Martin County	ST	FO6	NG	PL	PL	Mar-14	Dec-14	Unknown	934,500	—	(826)	OT
										2014 Changes/Additions Total:		(822)	1,247	
2015														
Turkey Point CT Upgrade	5A	Miami Dade County	CC	NG	FO2	PL	TK	—	Mar-14	Unknown	188,190	8	—	OT
Turkey Point CT Upgrade	5B	Miami Dade County	CC	NG	FO2	PL	TK	—	Mar-14	Unknown	188,190	8	—	OT
Turkey Point CT Upgrade	5C	Miami Dade County	CC	NG	FO2	PL	TK	—	Mar-14	Unknown	188,190	8	—	OT
Turkey Point CT Upgrade	5D	Miami Dade County	CC	NG	FO2	PL	TK	—	Mar-14	Unknown	188,190	8	—	OT
Martin [3]	1	Martin County	ST	FO6	NG	PL	PL	Jun-13	Mar-14	Unknown	934,500	832	—	ESP
Manatee CT Upgrade	3A	Manatee County	CC	NG	No	PL	No	Aug-14	Oct-14	Unknown	188,190	9	8	OT
Manatee CT Upgrade	3B	Manatee County	CC	NG	No	PL	No	Aug-14	Oct-14	Unknown	188,190	9	8	OT
Manatee CT Upgrade	3C	Manatee County	CC	NG	No	PL	No	Apr-14	Oct-14	Unknown	188,190	9	8	OT
Manatee CT Upgrade	3D	Manatee County	CC	NG	No	PL	No	Apr-14	Oct-14	Unknown	188,190	9	8	OT
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	TK	WA	Jun-12	Jun-14	Unknown	188,190	1,244	—	U
Vero Beach Combined Cycle	1	Indian River	CC	NG	DFO	PL	TK	—	Jan-15	Unknown	—	44	46	OT
Martin [3]	2	Martin County	ST	FO6	NG	PL	PL	Mar-14	Dec-14	Unknown	934,500	—	823	ESP
Putnam	1	Putnam County	CC	NG	FO2	PL	TK	—	—	Jun-15	290,004	(265)	(249)	
Putnam	2	Putnam County	CC	NG	FO2	PL	TK	—	—	Jun-15	290,004	(265)	(249)	
Ft. Myers CT Upgrade	2A	Lee County	CC	NG	No	PL	No	—	Jun-15	Unknown	188,190	—	8	OT
Ft. Myers CT Upgrade	2B	Lee County	CC	NG	No	PL	No	—	Mar-15	Unknown	188,190	—	8	OT
Ft. Myers CT Upgrade	2C	Lee County	CC	NG	No	PL	No	—	Jun-15	Unknown	188,190	—	8	OT
Ft. Myers CT Upgrade	2D	Lee County	CC	NG	No	PL	No	—	May-15	Unknown	188,190	—	8	OT
Ft. Myers CT Upgrade	2E	Lee County	CC	NG	No	PL	No	—	May-15	Unknown	188,190	—	8	OT
Ft. Myers CT Upgrade	2F	Lee County	CC	NG	No	PL	No	—	Mar-15	Unknown	188,190	—	8	OT
										2015 Changes/Additions Total:		1,793	458	
2016														
Ft. Myers CT Upgrade	2B	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	188,190	9	—	OT
Ft. Myers CT Upgrade	2F	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	188,190	9	—	OT
Ft. Myers CT Upgrade	2D	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	188,190	9	—	OT
Ft. Myers CT Upgrade	2E	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	188,190	9	—	OT
Ft. Myers CT Upgrade	2A	Lee County	CC	NG	No	PL	No	Jun-15	Jul-15	Unknown	188,190	9	—	OT
Ft. Myers CT Upgrade	2C	Lee County	CC	NG	No	PL	No	Jul-15	Aug-15	Unknown	188,190	9	—	OT
Port Everglades Next Generation Clean Energy Center	1	City of Hollywood	CC	NG	FO2	TK	WA	Jun-14	Jun-16	Unknown	Unknown	—	1,237	U
										2016 Changes/Additions Total:		58	1,237	

(1) Schedule 8 shows only planned and prospective changes to generating facilities and does not reflect changes to existing purchases. These changes are reflected on Tables ES-1, I.B.1 and I.B.2.
The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after August each year will be picked up for reserve margin calculation purposes in the following year.
(2) This generating unit is currently serving as a synchronous condenser and is not included in reserve margin calculation.
(3) Outages for ESP work.

Schedule 8
Planned And Prospective Generating Facility Additions And Changes [1]

	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability [2]		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2017														
Port Everglades Next Generation Clean Energy Center	1	City of Hollywood	CC	NG	FO2	TK	WA	Jun-14	Jun-16	Unknown	Unknown	1,246	—	U
Turkey Point Synchronous Condenser	1	Miami Dade County	ST	FO6	NG	WA	PL	—	—	Jun-17	402,050	(300)	(300)	OT
										2017 Changes/Additions Total:		946	(298)	
2018														
Vero Beach Combined Cycle	1	Indian River	CC	NG	DFO	PL	TK	—	—	Jan-18	—	(44)	(45)	OT
										2018 Changes/Additions Total:		(44)	(45)	
2019														
Lauderdale GT	1-12	Broward County	GT	NG	FO2	PL	PL	—	—	Dec-18	410,734	(450)	(420)	P
Lauderdale GT	13-24	Broward County	GT	NG	FO2	PL	PL	—	—	Dec-18	410,734	(450)	(420)	P
Port Everglades GT	1-12	Broward County	GT	NG	FO2	PL	PL	—	—	Dec-18	410,734	(450)	(420)	P
Lauderdale CT	1-5	Broward County	CT	NG	FO2	PL	PL	—	Jan-19	Unknown	Unknown	1,115	1,065	P
Unified 3x1 CC unit	1	—	CC	NG	FO2	TK	WA	Jun-17	Jun-19	Unknown	Unknown	—	1,269	P
										2019 Changes/Additions Total:		(262)	1,614	
2020														
Unified 3x1 CC unit			CC	NG	FO2	TK	WA	Jun-17	Jun-18	Unknown	Unknown	1,429	—	P
										2020 Changes/Additions Total:		1,429	0	
2021														
												—	—	
										2021 Changes/Additions Total:		0	0	
2022														
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	TK	—	Jun-22	Unknown	1,295,400	—	87	P
Turkey Point	6	Miami Dade County	ST	NP	No	TK	No	2014	Jun-22	Unknown	Unknown	—	1,100	T
										2022 Changes/Additions Total:		0	1,187	
2023														
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	TK	—	Jun-22	Unknown	1,295,400	87	—	P
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	TK	WA	Jan-12	Apr-14	Unknown	1,295,400	—	55	P
Turkey Point	6	Miami Dade County	ST	NP	No	TK	No	2014	Jun-22	Unknown	Unknown	1,100	—	L
Turkey Point	7	Miami Dade County	ST	NP	No	TK	No	2015	Jun-23	Unknown	Unknown	—	1,100	L
										2022 Changes/Additions Total:		1,187	1,155	

(1) Schedule 8 shows only planned and prospective changes to generating facilities and does not reflect changes to existing purchases. These changes are reflected on Tables ES-1, I.B.1 and I.B.2
(2) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after August each year will be picked up for reserve margin calculation purposes in the following year.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Vero Beach Combined Cycle Capacity

(2) **Capacity**
a. Summer 46 MW
b. Winter 44 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: Not Applicable - See Note 1 below.
b. Commercial In-service date: 2015

(5) **Fuel**
a. Primary Fuel Gas
b. Alternate Fuel Oil

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 16 Acres

(9) **Construction Status:** See note 1 below

(10) **Certification Status:** See note 1 below

(11) **Status with Federal Agencies:** See note 1 below

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	20.5%	
Forced Outage Factor (FOF):	0.0%	
Equivalent Availability Factor (EAF):	72.5%	
Resulting Capacity Factor (%):	3.88%	
Average Net Operating Heat Rate (ANOHR):	9,397	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data**

Book Life (Years):	TBD	years
Total Installed Cost ($/kW):	Not Applicable	
Direct Construction Cost ($/kW):	Not Applicable	
AFUDC Amount ($/kW):	Not Applicable	
Escalation ($/kW):	Not Applicable	
Fixed O&M ($/kW-Yr): ($)	Not Applicable	
Variable O&M ($/MWH):($)	Not Applicable	
K Factor:	Not Applicable	

NOTE 1: The combined cycle capacity consists of two existing units. This existing unit is being acquired by FPL as part of the arrangement for FPL to serve Vero Beach's load beginning in January 2015. FPL is also taking ownership of three steam units.The three steam units will be retired as soon as they aquired. FPL plans to retire the CC unit at the end of 2017.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Port Everglades Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,237 MW
b. Winter 1,429 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2014
b. Commercial In-service date: 2016

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** Existing Site Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): 3.5%
Forced Outage Factor (FOF): 1.1%
Equivalent Availability Factor (EAF): 95.4%
Resulting Capacity Factor (%): Approx. 90% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR): 6,330 Btu/kWh
Base Operation 75F,100%

(13) **Projected Unit Financial Data *,****
Book Life (Years): 30 years
Total Installed Cost (2016 $/kW): 928
Direct Construction Cost ($/kW):
AFUDC Amount ($/kW): 87
Escalation ($/kW):
Fixed O&M ($/kW-Yr): (2016 $) 30.00
Variable O&M ($/MWH): (2016 $) 0.10
K Factor: 1.51

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing plant are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Lauderdale CT's (5 CTs will be added)

(2) **Capacity (for each CT)**
a. Summer 201 MW
b. Winter 223 MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2017
b. Commercial In-service date: 2018

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Water to Air Heat Exchangers

(8) **Total Site Area:** Existing Site Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	1.6%
Forced Outage Factor (FOF):	1.0%
Equivalent Availability Factor (EAF):	97.4%
Resulting Capacity Factor (%):	3% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	10,057 Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2018 $/kW):	547
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	56
Escalation ($/kW):	
Fixed O&M ($/kW-Yr): (2018 $)	17.63
Variable O&M ($/MWH): (2018 $)	0.07
K Factor:	1.59

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing GTs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited 3x1 CC

(2) **Capacity**

a. Summer	1,269	MW
b. Winter	1,429	MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2017
b. Commercial In-service date:	2019

(5) **Fuel**

a. Primary Fuel	Natural Gas
b. Alternate Fuel	Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:**		Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate
(7) **Cooling Method:**		Once-through cooling water
(8) **Total Site Area:**	TBD	Acres
(9) **Construction Status:**	P	(Planned Unit)
(10) **Certification Status:**	—	
(11) **Status with Federal Agencies:**	—	

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.5%
Forced Outage Factor (FOF):	1.1%
Equivalent Availability Factor (EAF):	95.4%
Resulting Capacity Factor (%):	Approx. 90% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	6,334 Btu/kWh

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2019 $/kW):	968
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	95
Escalation ($/kW):	872.79
Fixed O&M ($/kW-Yr): (2019 $)	22.25
Variable O&M ($/MWH): (2019 $)	0.72
K Factor:	1.51

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas lateral, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point Nuclear Unit 6

(2) **Capacity**
a. Summer 1,100 MW
b. Winter 1,100 MW

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2015
b. Commercial In-service date: 2022

(5) **Fuel**
a. Primary Fuel: Uranium Dioxide
b. Alternate Fuel: N/A

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** Mechanical Draft Cooling Towers

(8) **Total Site Area:** 211 Acres

(9) **Construction Status:** L (Regulatory approval pending.Not under construction)

(10) **Certification Status:** L (Regulatory approval pending.Not under construction)

(11) **Status with Federal Agencies:** L (Regulatory approval pending.Not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	TBD	
Forced Outage Factor (FOF):	TBD	
Equivalent Availability Factor (EAF):	TBD	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	TBD	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	TBD	years
Total Installed Cost ($/kW):	TBD	
Direct Construction Cost ($/kW):	TBD	
AFUDC Amount ($/kW):	TBD	
Escalation ($/kW):	TBD	
Fixed O&M ($/kW-Yr): ($)	TBD	
Variable O&M ($/MWH):($)	TBD	
K Factor:	TBD	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point Nuclear Unit 7

(2) **Capacity**
a. Summer 1,100 MW
b. Winter 1,100 MW

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2015
b. Commercial In-service date: 2023

(5) **Fuel**
a. Primary Fuel: Uranium Dioxide
b. Alternate Fuel: N/A

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** Mechanical Draft Cooling Towers

(8) **Total Site Area:** 211 Acres

(9) **Construction Status:** L (Regulatory approval pending. Not under construction)

(10) **Certification Status:** L (Regulatory approval pending. Not under construction)

(11) **Status with Federal Agencies:** L (Regulatory approval pending. Not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	TBD	
Forced Outage Factor (FOF):	TBD	
Equivalent Availability Factor (EAF):	TBD	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	TBD	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	TBD	years
Total Installed Cost ($/kW):	TBD	
Direct Construction Cost ($/kW):	TBD	
AFUDC Amount ($/kW):	TBD	
Escalation ($/kW):	TBD	
Fixed O&M ($/kW-Yr): ($)	TBD	
Variable O&M ($/MWH):($)	TBD	
K Factor:	TBD	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Vero Beach Existing Combined Cycle Capacity

The Vero Beach existing combined cycle capacity that FPL is projected to take ownership of starting January 1, 2015 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Port Everglades Next Generation Clean Energy Center

The Port Everglades Next Generation Clean Energy Center which will result from the modernization of the Port Everglades power plant site does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Lauderdale Combustion Turbine Project

The Lauderdale Combustion Turbine (CT) project, which will result in the retirement of 36 aero-derivative combustion gas turbines at the Lauderdale and Port Everglades plant sites, and their replacement with 5 simple-cycle combustion turbines at the Lauderdale site, does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Unsited Combined Cycle in 2019

No projection of a new transmission line(s) can be made until a site is selected for this unit.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 6

The Turkey Point New Nuclear Project starting with the addition of Turkey Point Unit 6 will require a new substation and five new transmission lines terminating at existing substations.

(1)	Point of Origin and Termination:	New Clear Sky Substation – Levee Substation
(2)	Number of Lines:	2
(3)	Right-of-way	FPL Owned
(4)	Line Length:	43 miles
(5)	Voltage:	500 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Levee Substation
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	New Clear Sky Substation – Pennsuco Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	52 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Pennsuco Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 6 (continued)

(1)	Point of Origin and Termination:	New Clear Sky Substation – Davis Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	19 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Davis Substation
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	Davis Substation – Miami Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	18 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	Davis Substation and Miami Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 6 (continued)

(1)	Point of Origin and Termination:	New Clear Sky Substation – Turkey Point Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	0.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Turkey Point Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 7

The transmission lines required for Turkey Point Unit 7 will be constructed with Turkey Point Unit 6 and are listed in the Schedule 10 for Turkey Point Nuclear Unit 6.

Schedule 11.1

Existing FIRM and NON-FIRM Capacity and Energy by Primary Fuel Type
Actuals for the Year 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	Summer (MW)	Summer (%)	Winter (MW)	Winter (%)	GWh (2)	%
(1)	Coal	897	3.4%	911	3.3%	5,981	5.4%
(2)	Nuclear	3,453	13.2%	3,550	12.8%	25,243	22.6%
(3)	Residual	3,666	14.0%	3,700	13.4%	75	0.1%
(4)	Distillate	648	2.5%	710	2.6%	120	0.1%
(5)	Natural Gas	15,575	59.4%	16,785	60.6%	75,208	67.4%
(6)	Solar (Non-Firm)	35	0.1%	35	0.1%	155	0.1%
(7)	***FPL Existing Units Total (1):***	***24,274***	***92.6%***	***25,691***	***92.8%***	***106,782***	***95.6%***
(8)	Renewables (Purchases)- Firm	61.0	0.2%	112.0	0.4%	43	0.0%
(9)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	362	0.3%
(10)	***Renewable Total:***	61.0	0.2%	112.0	0.4%	405	0.36%
(11)	***Purchases Other :***	1,683.0	7.2%	1,891.0	6.8%	4,468	4.0%
(12)	***Total :***	*26,218.0*	*100.0%*	*27,694.0*	*100.0%*	*111,655*	*100.0%*

Note:

(1) FPL Existing Units Total values on row (7), columns (2) and (4), match the System Firm Generating Capacity values found on Schedule 1 for Summer and Winter.

(2) Net Energy for Load GWh values on row (12), column (6), matches Schedule 6.1 value for 2013.

Schedule 11.2

Existing NON-FIRM Self-Service Renewable Generation Facilities
Actuals for the Year 2013

(1)	(2)	(3)	(4)	(5)	(6) = (3)+(4)-(5)
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh)	Annual Energy Purchased from FPL (MWh)	Annual Energy Sold to FPL (MWh)	Projected Annual Energy Used by Customers
Customer-Owned Renewable Generation (0 kW to 10 kW)	12.86	16,142	111,831	465	127,508
Customer-Owned Renewable Generation (> 10 kW to 100 kW)	6.69	8,758	197,171	376	205,553
Customer-Owned Renewable Generation (> 100 kW - 2 MW)	7.94	10,475	62,050	177	72,348
	27.49	35,375	371,052	1,018	405,409

Notes:

(1) There were 2,565 customers with renewable generation facilities interconnected with FPL on December 31, 2013.

(2) The Installed Capacity value is the sum of the nameplate ratings (DC MW) for all of the customer-owned renewable generation facilities connected as of Dec. 31,2013. One system does not have a DC rating. The AC valued of 0.75 MW was included in the (> 100 - 2 MW) row.

(3) The Projected Annual Output value is based on NREL's PV Watts 1 program and the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.

(4) The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2013.

(5) The Annual Energy Sold to FPL is an actual value from FPL's metered data for 2013.

(6) The Projected Annual Energy Used by Customers is a projected value that equals: (Renewable Projected Annual output + Annual Energy Purchased) minus the Annual Energy Sold to FPL.

CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

Florida is a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered or threatened plant and animal species. Florida's residents, wildlife, and ecosystems require the same air, land, and water resources that are necessary to meet the demand for the generation, transmission, and distribution of electricity. The general public has an expectation that a large corporation, such as FPL, will conduct their business in an environmentally responsible manner that minimizes impacts to the natural environment.

FPL has been recognized for many years as one of the leaders among electric utilities for its commitment to the environment. Being responsible stewards of the environment is ingrained in FPL's corporate culture. FPL has one of the lowest emissions profiles among U.S. utilities and in 2013 its carbon dioxide (CO_2) emission rate was 35% lower (better) than the industry average.

FPL's environmental leadership and that of its parent company, NextEra Energy, Inc., has been heralded by many outside organizations as demonstrated by a few recent examples.

FPL's responsible tree care practices across its 35-county service area have been recognized for almost a decade. FPL has been the recipient of the Tree Line USA award annually from 2003 - 2013. This award is sponsored by the Arbor Day Foundation in cooperation with the National Association of State Foresters. The recognition is given to utilities that demonstrate quality tree care practices, annual worker training, and public education programs.

In 2013, FPL continued to support the Loggerhead Marinelife Center with a $21,500 donation toward the acquisition of a larger tank to assist in sea turtle rehabilitation. Two FPL employees serve as members of the Loggerhead Marinelife Center and are committed to its success. In addition, through a "Power to Care" charity event an additional $500 was collected by FPL staff and given to the Center. In past years, FPL has won the Loggerhead Marinelife Center's "Blue Business of the Year" award, which is given to those who are leading the way in raising awareness about, and have made significant contributions to improve and protect, South Florida's oceans, beaches, and wildlife. The award recognized FPL's protection and conservation of the endangered Florida manatee and the fostering of public and employee education and support.

FPL employees serve as board members for many organizations that focus on environmental restoration, preservation, and stewardship. A partial list of these organizations includes: Audubon Florida, the Everglades Foundation, the Arthur R. Marshall Foundation, The Nature Conservancy, and the Palm Beach Zoo.

IV.B FPL's Environmental Statement

At FPL and its parent company, NextEra Energy, Inc., we are committed to being an industry leader in environmental protection and stewardship, not only because it makes business sense, but because it is the right thing to do. Our commitment to compliance, conservation, communication, and continuous improvement fosters a culture of environmental excellence and drives the sustainable management of our business planning, operations, and daily work.

In accordance with our commitments to environmental protection and stewardship, FPL and NextEra Energy, Inc. endeavor to:

Comply

- Comply with all applicable environmental laws, regulations, and permits
- Proactively identify environmental risks and take action to mitigate those risks
- Pursue opportunities to exceed environmental standards
- Participate in the legislative and regulatory process to develop environmental laws, regulations, and policies that are technically sound and economically feasible
- Design, construct, operate, and maintain our facilities in an environmentally sound and responsible manner

Conserve

- Prevent pollution, minimize waste, and conserve natural resources
- Avoid, minimize, and/or mitigate impacts to habitat and wildlife
- Promote the efficient use of energy, both within our company and in our communities

Communicate

- Communicate this policy to all employees and publish it on the corporate website
- Invest in environmental training and awareness to achieve a corporate culture of environmental excellence
- Maintain an open dialogue with stakeholders on environmental matters and performance

Continuously Improve

- Establish, monitor, and report progress toward environmental targets
- Review and update this policy on a regular basis
- Drive continuous improvement through ongoing evaluations of our environmental management system to incorporate lessons learned and best practices.

This statement was updated in 2013 by FPL's parent company, NextEra Energy, Inc. to reflect changing expectations and ensure that employees are doing the utmost to protect the environment. FPL complies with all environmental laws, regulations, and permit requirements. FPL designs, constructs, and operates its facilities in an environmentally sound and responsible manner. It also responds immediately and effectively to any known environmental hazards or non-compliance situations. FPL's commitment to the environment does not end there. It proactively pursue opportunities to exceed current environmental standards, including reducing waste and emission of pollutants, recycling materials, and conserving natural resources throughout its operations and day-to-day work activities. FPL also encourages the efficient use of energy, both within the Company and in communities served by FPL. These actions are just a few examples of how FPL is committed to the environment.

To ensure that FPL is adhering to its environmental commitment, it has developed rigorous environmental governance procedures and programs. These include its Environmental Assurance Program and Corporate Environmental Governance Council. Through these programs, FPL conducts periodic environmental self-evaluations to verify that its operations are in compliance with environmental laws, regulations, and permit requirements. Regular evaluations also help identify best practices and opportunities for improvement.

IV.C Environmental Management

In order to successfully implement the Environmental Statement, FPL has developed a robust Environmental Management System program to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program. Other components of the system include: executive management support and commitment, a dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

As part of its commitment to excellence and continuous improvement, FPL began implementing an enhanced environmental data management information system (EDMIS) in 2013. Environmental data management software systems are increasingly viewed as an industry best-management practice to ensure environmental compliance. FPL's top goals for this project are to: 1) improve the flow of environmental data between site operations and corporate services to ensure compliance, and 2) improve operating efficiencies. In addition, the EDMIS will help standardize environmental data collection, thus improving external reporting to the public.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities that are designed to evaluate environmental performance, verify compliance with corporate policy as well as legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and FPL policies. In addition to FPL facility audits, the Environmental Assurance Program performs audits of third-party vendors used for recycling and/or disposal of waste generated by FPL operations. Vendor audits provide information used for selecting candidates or incumbent vendors for disposal and recycling needs.

FPL has also implemented a Corporate Environmental Governance System, in which quarterly reviews are performed by each business unit deemed to have significant environmental exposures. Quarterly reviews evaluate operations for potential environmental risks and consistency with the company's Environmental Policy. Items tracked during the quarterly reviews include processes for the identification and management of environmental risks, metrics, and indicators and progress / changes since the most recent review.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2013 environmental outreach activities are summarized in Table IV.E.1.

Table IV.E.1: 2013 FPL Environmental Outreach Activities

Activity	Count (#)
Visitors to FPL's Energy Encounter at St. Lucie	2,900
Visitors to Manatee Park, Ft. Myers	>210,000
Number of website visits to FPL's Environmental & Corporate Responsibility Websites	245,630
Visitors to Barley Barber Swamp (Treasured Lands Partnership)	1,492
Martin Energy Center Solar Tours	~850
Solar Schools Program (# of schools actively generating)	24 schools 5 demo sites An additional 67 schools will come online by the end of 2014

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified six (6) Preferred Sites and four (4) Potential Sites for future generation additions. Preferred Sites are those locations where FPL has conducted significant reviews and has either taken action, is currently committed to take action, or is likely to take action, to site new generating capacity. Potential Sites are those sites that have attributes that support the siting of generation and are under consideration as a location for future generation. Some of these sites are currently in use as existing generation sites and some are not. The identification of a Potential Site does not indicate that FPL has made a definitive decision to pursue generation (or generation expansion or modernization in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of a generator has been determined. Analyses of any modernization candidates would include evaluation of numerous factors including: fuel delivery, transmission, permitting, etc. The Preferred Sites and Potential Sites are discussed in separate sections below.

IV.F.1 Preferred Sites

The modernization of FPL's Riviera Beach site was scheduled to be completed on/near April 1, 2014 (the filing date for this 2014 Site Plan). Therefore, the Riviera Beach modernization is not discussed further in this chapter. FPL currently has identified six (6) Preferred Sites. Four of these are existing plant sites: Port Everglades, Lauderdale, Putnam and Turkey Point; two of these would be new plant sites: Hendry County and Northeast (NE) Okeechobee County.

The Port Everglades site is a location where modernization work, to replace the former steam generating units with new combined cycle (CC) technology, is in progress. The modernization work is scheduled to be completed in mid-2016. The existing gas turbines (GTs) at the Port Everglades and the Lauderdale sites are projected to be removed by the end of 2018. Five new combustion turbines (CTs) are projected to be added at the Lauderdale site by the end of 2018 to partially replace the capacity from existing GTs at Port Everglades and at the Lauderdale sites. These actions will aid in addressing compliance with new air emissions standards. The Hendry County, NE Okeechobee County, and Putnam sites are the likely next locations for new CC units after the Port Everglades and Lauderdale projects mentioned above have been completed. In addition, the Hendry County and Okeechobee County sites are also likely sites for new photovoltaic (PV) facilities.

In regard to the Turkey Point site, the nuclear capacity uprate project was successfully completed in 2013. The new Turkey Point nuclear Units 6 & 7 are currently projected to come in-service in 2022 and 2023, respectively.

The first two Preferred Sites discussed below are in general chronological order with respect to when the capacity additions are projected to occur. The remaining four Preferred Sites are discussed in alphabetical order.

Preferred Site # 1: Port Everglades Plant, Broward County

This site is located on the existing FPL Port Everglades Plant property within the City of Hollywood, Broward County. The site is surrounded by the Port of Port Everglades. The site has barge access via the Port of Port Everglades. A rail line is located near the plant.

The previous site generating capacity was made up of two 200 MW (approximate) steam generating units (Units 1 & 2) and two 400 MW (approximate) steam generating units (Units 3 & 4). The four units have been taken out of service and dismantled as part of the modernization of the plant site.

The Port Everglades Plant site has been listed as a Preferred or Potential Site in previous FPL Site Plans for both CC and CT generation options. On April 9, 2012, the FPSC issued the final need order for the modernization of the existing Port Everglades Plant. As a result of the modernization of the site, the new generating unit - to be renamed the Port Everglades Next Generation Clean Energy Center (PEEC) – will replace the existing steam generating units with modern, highly efficient, lower-emission next-generation advanced CC technology. The existing four steam units have been removed from the site and will be replaced by a single new CC unit.

a. U.S. Geological Survey (USGS) Map

A USGS map of the PEEC site is found at the end of this chapter.

b. Proposed Facilities Layout

A general layout of the PEEC generating facilities is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing Port Everglades Plant formerly consisted of two 200 MW (approximate) and two 400 MW (approximate) generating units with conventional dual-fuel fired steam boilers and steam turbine units. These generating units have now been removed as part of the modernization project. The plant site includes minimal vegetation. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of facilities related to electric power generation for the former Port Everglades Plant generating units. The site is located adjacent to the Intracoastal Waterway. The site provides warm water as required for manatees pursuant to the facility's Manatee Protection Plan.

2. Listed Species

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species. The warm water discharges from the plant attract manatees, an endangered species. FPL continues to work closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process and upon operation of the new plant. FPL plans to install a temporary heating system to provide warm water for manatees as required pursuant to the facility's Manatee Protection Plan. FPL also anticipates complying with other manatee-related conditions of certification to ensure the protection of the manatees during the modernization work and during future operations of PEEC.

3. Natural Resources of Regional Significance Status

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

The design option is to replace the former units (Units 1 through 4) with one new approximately 1,237 MW (Summer) unit consisting of three new CTs, three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit is projected to be in service in mid-2016. Natural gas delivered via an existing pipeline is the primary fuel type for the unit with ultra-low sulfur light fuel oil serving as a backup fuel.

In addition, all of the existing GTs at the Port Everglades site are projected to be removed by the end of 2018.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the site is a combination of "Electrical Generating Facility" and "Utilities Use". A land use map of the site and adjacent areas is also found at the end of this chapter.

h. **Site Selection Criteria Process**

The Port Everglades site has been selected for modernization due to consideration of various factors including system load, ability to provide generation in the Miami-Dade/Broward region to help balance load and generation in the region, and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of replacing the former steam units with a new CC unit including a significant reduction in system air emissions, improved aesthetics at the site, and continued warm water discharge for the manatees as required pursuant to the facility's Manatee Protection Plan. Further, modernizing this existing facility reduces the impact on natural resources by not requiring new land or new water resources.

i. **Water Resources**

Water from the Intracoastal Waterway via the Port of Port Everglades Slip No. 3 is currently used for once-through cooling water supply. The new plant will utilize portions of the existing once-through cooling water intake and discharge structures. Process and potable water for the modernized plant will come from the existing City of Ft. Lauderdale potable water supply.

j. **Geological Features of Site and Adjacent Areas**

FPL's Port Everglades Plant site is underlain by the surficial aquifer system. The surficial aquifer system in eastern Broward County is primarily composed of sand, sandstone, shell, silt, calcareous clay (marl), and limestone deposited during the Pleistocene and Pliocene ages. The sediments forming the aquifer system are the Pamlico Sand, Miami Oolite, Anastasia Formation, Key Largo Formation, and Fort Thompson Formation (Pleistocene) and the Tamiami Formation (Pliocene). The sediments in the eastern portion of the county are appreciably more permeable than in the west.

The surficial aquifer is underlain by at least 600 feet of the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. **Projected Water Quantities for Various Uses**

The estimated quantity of water required for processing is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Approximately 600 mgd of cooling water would be cycled through the once-through cooling water system which is a reduction of more than 51% from the previous fossil steam unit's capability. Potable water demand is expected to average .001 mgd.

l. **Water Supply Sources by Type**

The modernized plant will continue to use the Intracoastal Waterway as the source of once-through cooling water. Process and potable water for the new plant will come from the existing City of Ft. Lauderdale potable water supply.

m. **Water Conservation Strategies Under Consideration**

No additional water resources will be required as a result of the modernization project. CC technology uses less water by design than traditional steam generation units.

n. **Water Discharges and Pollution Control**

The modernized plant will utilize portions of the existing once-through cooling water system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system prior to discharge. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit would be transported to the site via an existing natural gas pipeline to the site. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit will be installed either at the existing site or off-site. Ultra-low sulfur light fuel oil would be received by truck, pipeline, or barge and stored in a new above-ground storage tank.

p. Air Emissions and Control Systems

The regulated air emission rates at the new plant would be approximately 90 percent lower than the previous Port Everglades Plant's emission rates, resulting in significant annual emissions reductions and air quality benefits per unit of energy produced. The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. CC facility emissions of greenhouse gas emissions (GHGs) from combustion of natural gas achieve an emission rate substantially lower than the EPA proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of PEEC would incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. Status of Applications

FPL filed a need determination with the FPSC on November 21, 2011. The FPSC's final need order was issued on April 9, 2012. The Site Certification Application (SCA) was submitted January 24, 2012 resulting in the issuance of Final Order PA 12-57 on October 9, 2012. Concurrent with the SCA filing, FPL submitted applications for a Greenhouse Gas (GHG) permit, a Prevention of Significant Deterioration (PSD) permit, and an Industrial Wastewater Facility permit revision. The revised Industrial Wastewater Facility permit was issued

December 16, 2012. The GHG permit was issued December 26, 2013 and the PSD permit was issued May 1, 2012.

Preferred Site # 2: Lauderdale Plant, Broward County

This site is located at and situated within the existing FPL Lauderdale Plant property, approximately 392 acres, within the Cities of Dania Beach and Hollywood in Broward County, Florida. The jurisdiction for the City of Hollywood is a small area south of SW 42nd Street in the eastern portion of the property. The remainder of the Plant property is located in the City of Dania Beach. The Plant property is located east of U.S. Highway 441, north of Griffin Road, west of SW 30th Avenue, and south of Interstate 595. The existing accesses to the Plant are from SW 24th Avenue and SW 42nd Street. The adjacent properties include residential properties to the south, the South Broward County Resource Recovery Facility to the west, Pond Apple Slough to the north and commercial properties to the east.

The Lauderdale Plant includes two banks of 12 simple cycle gas turbines (GTs) that began operation in the early 1970s. These GTs are first generation GTs that are used to serve peak and emergency demands in a quick-start manner. Each bank of GTs has a net capacity of 420 (Summer) megawatts (MWs), and are authorized to operate on natural gas and distillate oil. Due to new nitrogen dioxide (NO_2) environmental regulations, FPL filed in June 2013 for FPSC approval to recover costs for removing all of its existing GTs and replacing a portion of the GT capacity with new CTs. In December 2013, FPL withdrew this request pending additional environmental monitoring and analyses. Computer modeling of the emissions from the GTs projected that the GTs would exceed the new NO_2 limit. FPL believes this monitoring and analyses will confirm that the operation of its existing GTs in Broward County will not comply with the new NO_2 regulations. Therefore, for planning purposes, FPL has assumed that all of its existing Broward County GTs will be removed (a loss of 1,260 MW Summer) and that this capacity will be partially replaced by 5 new CTs that would be sited in Broward County (an increase of 1,005 MW Summer). This GT removal and CT partial replacement is assumed to occur by the end of 2018.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the Lauderdale site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A general layout of the Lauderdale generating facilities is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing Lauderdale Plant includes two combined cycle units (Units 4 and 5) and two banks of 12 simple cycle gas turbines (GT1 through GT12 and GT13 through GT24). Units 4 and 5 have net capacity of 442 (Summer) MW each. Each bank of GTs has a net capacity of 420 (Summer) MW. The northern portion of the property is comprised of a forested wetland area adjacent to the Pond Apple Slough.

The adjacent properties to the Lauderdale Site include residential properties to the south, the South Broward County Resource Recovery Facility to the west, Pond Apple Slough to the north and commercial properties to the east. The Dania Cut-off Canal is located along the southern boundary and the South New River Canal is located along the western and northern boundaries.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

FPL Lauderdale Plant property consists of approximately 392 acres, within the Cities of Dania Beach and Hollywood in Broward County, Florida. The Project area comprises approximately 20 acres in the northern portion of the existing Plant site, and includes the approximately 6-acre north gas turbine site containing 12 gas turbines as well as approximately 14 acres of surrounding forested wetlands and upland spoil piles.

2. Listed Species

No negative impacts to threatened or endangered species are anticipated as a result of the CT Project.

Based upon the field assessment conducted in 2013, review of United States Fish and Wildlife (USFWS) and Florida Fish and Wildlife Conservation Commission (FWC) literature and databases, the Florida Natural Areas Inventory (FNAI) database of documented listed species occurrences, and the lack of suitable habitat, federally listed species are not anticipated to utilize the CT Project area. The potential occurrence of listed flora and fauna within the CT Project area is limited due to the surrounding land uses (industrial, commercial, and residential areas, as well as Ft. Lauderdale-Hollywood International Airport), and lack of suitable habitat within and surrounding the CT Project area to support partial or full life-cycle requirements of federally listed species known to occur within Broward County.

3. **Natural Resources of Regional Significance Status**

The construction and operation of the CT Project at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands. No named wetlands, named surface waters, Outstanding Florida Waters, or Aquatic Preserves would be impacted by the proposed Project.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

In the event monitoring confirms that emissions from operation of the existing GTs would not comply with the NO_2 regulations, the design option is to remove 24 gas turbines (GTs) at the existing Lauderdale Plant, and an additional 12 simple cycle GTs at their nearby Port Everglades Plant, and replace them with five new highly efficient simple cycle combustion turbines (CTs). The CTs operate in simple cycle mode with associated stacks and produce electrical energy by direct connection to an electric generator. The CTs will operate using natural gas and ultra-low sulfur distillate (ULSD) oil as fuel.

g. **Local Government Future Land Use Designations**

The site is zoned General Industrial by the City of Dania Beach, a designation intended to provide for light and medium intensity industrial, research, and assembly fabrication uses. Electrical power plants are permitted within a General Industrial zoning designation as a special exception use only.

A land use map of the site and adjacent areas is also found at the end of this chapter.

h. **Site Selection Criteria Process**

The Lauderdale Plant site has been selected as a "Preferred" for the location of peaking unit facilities due to consideration of various factors including maximizing opportunities to utilize existing utility infrastructure, system load, transmission interconnection, and economics.

i. **Water Resources**

The Project will require a marginal increase in demineralized water that will be obtained from the existing Lauderdale Plant's water treatment system.

j. **Geological Features of Site and Adjacent Areas**

According to the Natural Resource Conservation Service (NRCS) Soil Survey of Broward County, the Project area is dominated by Okeelanta muck, with Udorthents, shaped as a minor association.

The Okeelanta series consists of very deep, very poorly drained, rapidly permeable soils in large fresh water marshes and small depressional areas. They formed in decomposed hydrophytic non-woody organic material overlying sand. Slopes range from zero to two percent. In un-drained areas the water table is at depths of less than ten inches below the surface or the soil is covered by water 6 to 12 months during most years. Areas of Okeelanta muck within the Project area support a mixed native and exotic hardwood wetland community.

k. **Projected Water Quantities for Various Uses**

The CT Project consists of CTs that are operated in simple cycle mode and do not require a heat dissipation system. As a result, there are no associated cooling water uses, cooling water discharges, or other heat dissipation impacts.

l. **Water Supply Sources by Type**

The CT Project would continue to acquire water from existing water contracts with Broward County. Therefore, the Project will have no adverse impact to groundwater. The CT Project would not use onsite groundwater or a new groundwater source for any purpose. The CT Project would have no adverse impact to surface water.

The CT Project would continue to use municipal potable water from the City of Hollywood to provide drinking water for employees. There is no projected increase in employment at the Lauderdale Plant as a result of the CT Project and no associated potable water use increase for that purpose. Therefore, there would be no impact to drinking water sources from the CT Project.

m. **Water Conservation Strategies Under Consideration**

No additional water resources would be required as a result of the CTs project.

n. **Water Discharges and Pollution Control**

There would be no surface water discharges required for the operation of the CT Project, other than storm water discharges from non-contact areas. Operation of the CT Project would not generate leachate and the stormwater management system has been designed to prevent direct discharge to surface waters. Therefore, there would be no adverse impact to water supplies due to runoff or leachate from the CT Project.

The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. <u>Fuel Delivery, Storage, Waste Disposal, and Pollution Control</u>

The fuel to be used in the CTs is natural gas and ULSD oil. Natural gas will be transported to the facility via existing pipeline. No onsite storage is provided for natural gas. ULSD oil would be trucked or piped to the facility and stored in double walled ULSD oil tanks.

p. <u>Air Emissions and Control Systems</u>

Air emission rates for NOx with the CT Project would be approximately 90 percent lower than the existing GT emission rates, resulting in significantly lower air quality impacts. In addition to lower air emissions, the maximum total air quality impacts for the CT Project are predicted to be well below and in compliance with the National Ambient Air Quality Standards (NAAQS). For pollutants such as NO_2, the CT Project's total air quality impacts are predicted to be significantly reduced by 40 percent or more compared to the existing GTs.

The use of clean fuels (natural gas and ULSD oil) and combustion controls would minimize air emissions of SO_2, sulfuric acid mist (SAM), particulates (PM/PM10/PM2.5), and other fuel-bound contaminants and ensure compliance with applicable emission-limiting standards. Combustion controls will minimize the formation of NOx and the formation of CO and VOCs by combustor design. Further NOx reduction will be achieved by water injection during oil firing.

q. <u>Noise Emissions and Control Systems</u>

It is not expected that noise from the CT Project would exceed the maximum permissible sound levels in Section 17-86 of the City of Dania Beach noise ordinance. The operation of the CTs is not expected to exceed the City of Dania Beach maximum permissible sound levels in residential areas.

The design of the CT Project includes components that mitigate noise from being emitted to the surrounding environment. The majority of the noise sources, such as the CTs, are located within enclosures that mitigate sounds emitted by equipment.

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. **Status of Applications**

No licenses or permits have been issued for the CT Project. FPL has submitted applications to: the Florida Department of Environmental Protection (FDEP) for the Prevention of Significant Deterioration (PSD) air permit; U.S. Environmental Protection Agency (EPA) for the Greenhouse Gas air permit; and to the U. S. Army Corps of Engineers (USACE) for the 404 dredge and fill permit. These applications are currently in review with the respective agencies.

Preferred Site # 3: Hendry County, Hendry County

FPL has acquired an approximately 3,120-acre site in southeast Hendry County, off CR 833. The Hendry County site has been listed as a Preferred or Potential Site in previous FPL Site Plans as a possibility for a future PV facility and/or natural gas-fired CC generation. FPL currently views the Hendry site as one of the most likely sites to be used for future large-scale generation.

a. **Geological Survey (USGS) Map**

A USGS map of the site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the property owned by FPL is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

The existing and future land uses on the site are zoned Planned Unit Development (PUD). The PUD is currently being challenged. The existing land uses that are adjacent to the site are predominately agricultural. The property to the south is the Seminole Big Cypress Reservation.

e. **General Environment Features On and In the Site Vicinity**

1. **Natural Environment**

The natural environment adjacent to the north, east, and west of the site are used predominately for agricultural activities such as improved, unimproved, and woodland pasture. The majority of the pasture lands includes upland scrub, pine, and hardwoods. The Seminole Big Cypress Reservation lies to the south.

2. **Listed Species**

FPL strives to have no adverse impacts on federal- or state-listed terrestrial plants and animals. Much of southwest Florida is considered habitat for the endangered Florida

Panther. Although few or no impacts are expected in association with future construction at the site, FPL anticipates minimizing or mitigating for unavoidable wildlife or wetland impacts.

3. **Natural Resources of Regional Significance Status**

Future construction and operation of a solar and/or a natural gas-fired CC generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

Options include construction of CC and/or solar power generation technologies. Mitigation for unavoidable impacts may occur through a combination of on- and off-site mitigation.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the site is Utility. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. **Site Selection Criteria Process**

The Hendry County site has been selected as "Preferred" due to consideration of various factors including system load, transmission interconnection, and economics.

i. **Water Resources**

Groundwater is anticipated to supply water to the Hendry County site.

j. **Geological Features of Site and Adjacent Areas**

The site is at an approximate elevation of 10 to 12 feet above mean sea level (msl) and is located on the Immokalee Rise and the Big Cypress Spur considered terraces created by high sea level events. The terraces are composed of fine quartz sands that lie discontinuously upon the surficial aquifer system whose sediments are the Fort Thompson (Pleistocene), Caloosahatchee Marl (Pleistocene and Pliocene), and Tamiami Formations (Pliocene). Other soil types in the area include limestone rock, calcareous muds, sands, organic materials, and mixed solids.

The surficial aquifer is underlain by the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. **Projected Water Quantities for Various Uses**

The estimated quantity of water required for processing at a CC unit is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Potable water demand is expected to average .001 mgd. Minimal amounts of water would be required for a PV facility. Approximately 7.5 mgd of cooling water would be used in cooling towers for one CC unit.

l. **Water Supply Sources by Type**

Potential water supply source is groundwater. Additional evaluations are necessary to determine the exact source. Process and potable water for the new plant will come from the existing potable water supply.

m. **Water Conservation Strategies Under Consideration**

CC and cooling tower technologies utilize less water by design than traditional steam generation units. PV facilities have minimal water demands. Specific water conservation strategies will be evaluated and selected during the detailed design phase of any development project.

n. **Water Discharges and Pollution Control**

A CC unit at the site would utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's cooling water flow prior to discharge. Wastewater disposal is anticipated via discharge to an Underground Injection Control well system. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral to the site. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary Ultra-low sulfur light fuel oil will be received by truck or pipeline and stored in an above-ground storage tank.

p. **Air Emissions and Control Systems**

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize regulated air emissions from a CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of SO_2, PM, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of NO_x and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra low sulfur fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA's proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida. PV generation does not produce air emissions.

q. <u>Noise Emissions and Control Systems</u>

Noise anticipated to be caused by unit construction at the site is expected to be minimal.

r. <u>Status of Applications</u>

FPL has not submitted any application associated with the Hendry County site.

<u>Preferred Site # 4: NE Okeechobee County, Okeechobee County</u>

FPL has purchased a site of approximately 2,800 acres in Northeast Okeechobee County. The site is in an unincorporated, rural area and is predominantly used for agricultural production. FPL's transmission lines intersect the property. The Northeast Okeechobee County site has been listed as a Preferred or Potential Site in previous FPL Site Plans as a possibility for a natural gas-fired CC generation and/or future PV facility. Natural gas-fired CC generation will be made possible by the May,2017 projected commercial operating date of the Florida Southeast Connection (FSC) natural gas pipeline. FSC is within 3 miles of the NE Okeechobee County site. FPL currently views the Okeechobee site as one of the most likely sites to be used for future large-scale generation.

a. <u>U.S. Geological Survey (USGS) Map</u>

A USGS map of the Northeast Okeechobee site is found at the end of this chapter.

b. <u>Proposed Facilities Layout</u>

A map of the property owned by FPL is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The Northeast Okeechobee County site is predominantly used for agricultural production (cattle and citrus). Adjacent land uses include primarily agriculture and conservation.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of lands dedicated to agricultural production.

2. Listed Species

Minimal impacts to federal- or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species.

3. Natural Resources of Regional Significance Status

The construction and operation of a power generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

Options include construction of PV or CC technologies. Mitigation for unavoidable impacts may occur through a combination of on- and off-site mitigation.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is predominantly unimproved pasture. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Northeast Okeechobee County site has been selected as a Preferred Site due to consideration of various factors including system load, transmission interconnection, the proximity of the proposed FSC natural gas pipeline, and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity.

i. **Water Resources**

Groundwater is anticipated to supply water to the Northeast Okeechobee County site.

j. **Geological Features of Site and Adjacent Areas**

The hydrostratigraphy of the Northeast Okeechobee County site is similar to that of most of South Florida. In general, the groundwater system underlying Okeechobee County consists of the Surficial Aquifer System (SAS), the Intermediate Confining Unit (ICU), and the Floridan Aquifer System (FAS). The SAS consists of approximately 100 to 250 feet of undifferentiated deposits of sand, shell, clay and silt. The ICU consists of approximately 200 feet of carbonate rocks interbedded with sandy and silty clay. The multiple layers of the FAS extend thousands of feet below the ICU.

k. **Projected Water Quantities for Various Uses**

Potable water demand is expected to average .001 mgd. The estimated quantity of water required for processing at a CC unit is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Approximately 7.5 mgd of cooling water would be used in cooling towers for a CC unit. Minimal amounts of water would be required for a PV facility.

l. **Water Supply Sources by Type**

Potential water supply source is groundwater. Additional evaluations are necessary to determine the exact source. Process and potable water for the new plant will come from the existing a potable water supply.

m. **Water Conservation Strategies Under Consideration**

CC technology utilizes less water by design than traditional steam generation units. PV facilities have minimal water demands. Specific water conservation strategies will be evaluated and selected during the detailed design phase of any development project.

n. **Water Discharges and Pollution Control**

A CC plant is anticipated to utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's cooling water flow prior to discharge. Wastewater disposal is anticipated via discharge to an Underground Injection Control well system. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ Best

Management Practices (BMP) and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary. Back-up fuel supplies of ultra-low sulfur light fuel oil will be received by truck or pipeline and stored in an above-ground storage tank to ensure reliability of operations.

p. **Air Emissions and Control Systems**

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize regulated air emissions from a CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of SO_2, PM, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of NO_x and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA's proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida. PV generation does not produce air emissions.

q. **Noise Emissions and Control Systems**

Noise anticipated to be caused by unit construction at the site is expected to be minimal.

r. **Status of Applications**

FPL has not filed any applications associated with the Northeast Okeechobee County site.

Preferred Site # 5: Putnam Site, Putnam County

FPL is currently evaluating the existing Putnam Plant site for future natural gas-fired generation as part of a potential modernization project. This 66 acre site is located on the east side of Highway 100 opposite the former FPL Palatka Plant in East Palatka. The Putnam site has been listed as a Potential Site in previous FPL Site Plans as a possibility for future natural gas-fired CC generation.

FPL currently views the Putnam site as one of the most likely sites to be used for future large-scale generation.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the Putnam site is found at the end of this chapter.

b. **Proposed Facilities Layout**

A map of the property owned by FPL is found at the end of this chapter.

c. **Map of Site and Adjacent Areas**

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. **Existing Land Uses of Site and Adjacent Areas**

The Putnam site is designated as Industrial land use. Adjacent land uses include power generation and associated facilities (the former Palatka Plant) as well as Mixed Wetland Hardwoods, Residential, and Hardwood-Coniferous Mixed.

e. **General Environment Features On and In the Site Vicinity**

1. **Natural Environment**

The majority of the site is developed and has facilities necessary for power plant operations. No significant environmental features have been identified at this time.

2. **Listed Species**

Minimal impacts to federal- or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species.

3. **Natural Resources of Regional Significance Status**

The construction and operation of a power generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

Options include construction of CC technology. Mitigation for unavoidable impacts may occur through a combination of on- and off-site mitigation.

g. **Local Government Future Land Use Designations**

Local government future land use designation for the site is Industrial. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. **Site Selection Criteria Process**

The Putnam site has been selected as a Preferred Site due to consideration of various factors including system load, transmission interconnection, and economics.

i. **Water Resources**

The St John's River and/or regional water supply initiatives are potential water sources.

j. **Geological Features of Site and Adjacent Areas**

The hydrostratigraphy of the Putnam site is similar to that of most of North Florida. In general, the groundwater system underlying Putnam consists of the Surficial Aquifer System (SAS), and the Floridan Aquifer System (FAS).

k. **Projected Water Quantities for Various Uses**

Potable water demand is expected to average .001 million gallons per day (mgd). The estimated quantity of water required at a CC unit is approximately 0.24 mgd for uses such as process water and service water. Approximately 7.5 mgd of cooling water would be used in cooling towers for a CC unit.

l. **Water Supply Sources by Type**

Potential water supply source is the St. John's River. Additional evaluations are necessary to determine the exact source. Process and potable water for the new plant will come from the existing a potable water supply.

m. **Water Conservation Strategies Under Consideration**

CC and cooling tower technologies utilize less water by design than traditional steam generation units. Specific water conservation strategies will be evaluated and selected during the detailed design phase of the project development.

n. **Water Discharges and Pollution Control**

A CC plant is anticipated to utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's cooling water flow prior to discharge. Wastewater disposal is anticipated via discharge to surface and/or ground water as is the case with the existing Putnam Plant. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ Best Management Practices (BMP) and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary. Back-up fuel supplies of ultra-low sulfur light fuel oil will be received by water-borne delivery, truck, or pipeline and stored in an above-ground storage tank to ensure reliability of operations.

p. **Air Emissions and Control Systems**

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize regulated air emissions from a CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of SO_2, PM, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of NO_x and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra- low sulfur light fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA's proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida.

q. **Noise Emissions and Control Systems**

Noise anticipated to be caused by unit construction at the site is expected to be minimal.

r. **Status of Applications**

FPL has not submitted any applications associated with the Putnam site.

Preferred Site # 6: Turkey Point Plant, Miami-Dade County

The Turkey Point Plant (Turkey Point) is located on the west side of Biscayne Bay, 25 miles south of Miami. Turkey Point is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. The land surrounding Turkey Point is owned by FPL and acts as a buffer zone. Turkey Point is comprised of two natural gas/oil conventional steam units (Units 1 & 2), two nuclear units (Units 3 & 4), one combined cycle natural gas unit (Unit 5), nine small diesel generators, and the cooling canals. A capacity uprate project for the two nuclear units was successfully completed in 2013. The Everglades Mitigation Bank (EMB), an approximately 13,000 acre, FPL-maintained natural wildlife and wetlands area that has been set aside, is located to the south and west of the site.

In regard to Turkey Point Units 6 & 7, FPL is pursuing licensing for two new nuclear units at Turkey Point. Each of these two units would provide 1,100 MW of capacity. The current projections for the earliest in-service dates for the two new units remain 2022 (for Turkey Point Unit 6) and 2023 (for Turkey Point Unit 7). In addition to the two generating units, supporting buildings, facilities, and equipment will be located on the Turkey Point Units 6 & 7 site, along with a construction laydown area. Proposed associated facilities include: a nuclear administration building, a training building, a parking area, an FPL reclaimed water treatment facility and reclaimed water pipelines, radial collector wells and delivery pipelines, an equipment barge unloading area, transmission lines (and transmission system improvements elsewhere within Miami-Dade County), access roads and bridges, and potable water pipelines.

a. <u>U.S. Geological Survey (USGS) Map</u>

USGS maps of the Turkey Point area, with the proposed location of Turkey Point Units 6 & 7 identified, are found at the end of this chapter.

b. <u>Proposed Facilities Layout</u>

Maps of the general layout of Turkey Point Units 6 &7 are found at the end of this chapter.

c. <u>Map of Site and Adjacent Areas</u>

Land Use / Land Cover overview maps of the Turkey Point Units 6 & 7 site and adjacent areas are also found at the end of this chapter.

d. <u>Existing Land Uses of Site and Adjacent Areas</u>

Turkey Point Plant is currently home to five generating units and support facilities that occupy approximately 150 acres of the approximately 9,400-acre Turkey Point property. Prominent features beyond the power block area include the intake system, cooling canal system, switchyard, spent fuel storage facilities, and technical and administrative support facilities The cooling canal system occupies approximately 5,900 acres.

The two 400-megawatt (MW) (nominal) fossil fuel-fired steam electric generation units at Turkey Point have been in service since 1967 (Unit 1) and 1968 (Unit 2). These units have historically burned residual fuel oil and/or natural gas with a maximum equivalent sulfur content of one percent. Unit 2 is currently serving, not as a power generating unit, but as a synchronous condenser to provide voltage support to the southeastern end of FPL's transmission system. The two original 700-MW (nominal) nuclear units have been in service since 1972 (Unit 3) and 1973 (Unit 4) and were uprated to a total of approximately 1,632 (Summer) MW's in 2013. Turkey Point Units 3 and 4 are pressurized water reactor (PWR) units. Turkey Point Unit 5 is a net 1,148 (Summer) MW natural gas-fired combined cycle unit that began operation in 2007. The site for the new Units 6 & 7 is south of existing Units 3 and 4 and occupies approximately 300 acres within the existing cooling canal system.

Properties adjacent to Turkey Point property are almost exclusively undeveloped land. The FPL-owned EMB is adjacent to most of the western and southern boundaries of Turkey Point property. The South Florida Water Management District (SFWMD) Canal L-31E is also situated to the west of Turkey Point property. The eastern portions of Turkey Point property are adjacent to Biscayne Bay, the Biscayne National Park (BNP), and Biscayne Bay Aquatic Preserve. The southeastern portion of Turkey Point property is bounded by state-owned land located on Card Sound. The Homestead Bayfront Park, owned and operated by Miami-Dade County, is situated to the north of the Turkey Point property.

e. <u>General Environment Features On and In the Site Vicinity</u>

1. <u>Natural Environment</u>

Turkey Point is located directly on the northwest, west, and southwest shoreline of Biscayne Bay and the Biscayne National Park, 25 miles south of Miami. Biscayne National Park was first established in 1968 as a National Monument and was expanded in 1980 to approximately 173,000 acres of water, coastal lands, and 42 keys. A portion of Biscayne Bay Aquatic Preserve, a state-owned preserve, is adjacent to the eastern boundary of the Turkey Point plant property. The Biscayne Bay Aquatic Preserve is a shallow, subtropical lagoon consisting of approximately 69,000 acres of submerged State land that has been designated as an Outstanding Florida Water.

The approximately 300-acre Turkey Point Units 6 & 7 site consists of the plant area and adjacent areas designated for laydown and ancillary facilities. The site includes hypersaline mud flats, man-made active cooling canals, man-made remnant canals, previously filled areas/roadways, mangrove heads associated with historical tidal channels, dwarf mangroves, open water /discharge canal associated with the cooling canals on the western portion of the site, wet spoil berms associated with remnant canals, and upland spoil areas.

2. **Listed Species**

Threatened, endangered, and/or animal species of special concern known to occur at the site, transmission line corridors, or in the nearby Biscayne National Park, include the peregrine falcon *(Falco peregrinus)*, wood stork *(Mycteria americana)*, American crocodile *(Crocodylus acutus)*, roseate spoonbill (*Ajaja ajaja)*, little blue heron *(Egretta caerulea)*, snowy egret *(Egretta thula)*, American oystercatcher *(Haematopus palliates)*, least tern *(Sterna antillarum)*, the white ibis *(Eudocimus albus)*, Florida manatee (Trichechus manatus latirostris), eastern indigo snake (Drymarchon couperi), snail kite (Rostrhamus sociabilis plumbeus), white-crowned pigeon (Patagioenas leucocephala), and bald eagle *(Haliaeetus leucocephalus)*. No bald eagle nests are known to exist in the vicinity of the site. The federally listed, threatened American crocodile thrives at Turkey Point, primarily in and around the southern end of the cooling canals which lie south of the Turkey Point Unit 6 & 7 area. The majority of Turkey Point is considered American crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American Crocodile and the program is credited with survival improvement and contributing to the downlisting of the American Crocodile from endangered to threatened.

Some listed flora species likely to occur at the site or vicinity include pinepink (Bletia purpurea), Florida brickell-bush (Brickellia mosieri), Florida lantana (Lantana depressa var. depressa), mullien nightshade (Solanum donianum), and lamarck's trema (Trema lamarckianum).

The construction, and operation after construction, of Turkey Point Unit 6 & 7 project is not expected to adversely affect any rare, endangered, or threatened species.

3. **Natural Resources of Regional Significance Status**

Significant features within the vicinity of the site include Biscayne National Park, the Biscayne Bay Aquatic Preserve, Miami-Dade County Homestead Bayfront Park, and Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park. Biscayne National Park contains 180,000 acres, approximately 95 percent of which is open water interspersed with more than 40 keys. The Biscayne National Park headquarters is located approximately two miles north of Turkey Point and is adjacent to the Miami-Dade County Homestead Bayfront Park, which contains a marina and day-use recreational facilities.

4. **Other Significant Features**

FPL is not aware of any other significant features of the site.

f. **Design Features and Mitigation Options**

For Turkey Point Units 6 & 7, the technology proposed is the Westinghouse AP1000 pressurized water reactor (PWR). This design is certified by the Nuclear Regulatory Commission (NRC) under 10 CFR 52 and incorporates the latest technology and more advanced safety features than today's nuclear plants that have already achieved record safety levels. The Westinghouse AP1000 unit consists of the reactor, steam generators, pressurizer, and steam turbine/electric generator. Condenser cooling for the Units 6 & 7 steam turbines will be accomplished using six circulating water cooling towers. The makeup water reservoir is the reinforced concrete structure beneath the circulating water system cooling towers that will contain reserve reclaimed water capacity to be used for the circulating water system. The structures for the Westinghouse AP1000 are the nuclear island (containment building, shield building, and auxiliary building), turbine building, annex building, diesel generator building, and radwaste building. The plant area will also contain the Clear Sky substation (switchyard) that will connect Units 6 & 7 to FPL's transmission system.

g. **Local Government future Land Use Designations**

The Turkey Point Plant site is designated by the Miami-Dade County Comprehensive Development Management Plan as an IU-3 (Industrial, Utilities, and Communications) Unlimited Manufacturing District that carries a dual designation of MPA (Mangrove Protection Area) in portions of the property. There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. **Site Selection Criteria Process**

For Turkey Point Units 6 & 7, FPL conducted an extensive site selection analysis leading to the selection of the Turkey Point site as the site that, on balance, provided the most favorable location for developing new nuclear generation to serve FPL's customers. The Site Selection Study employed the principles of the Electric Power Research Institute (EPRI) siting guidelines and is modeled upon applicable NRC site suitability and National Environmental Policy Act (NEPA) criteria regarding the consideration of alternative sites. The study convened a group of industry and FPL subject matter experts to develop and assign weighting factors to a broad range of site selection criteria. Twenty-three candidate sites were then ranked using the siting criteria. This review allowed the list of candidates to be reduced until the best site emerged. Key factors contributing to the selection of the Turkey Point site include the existing transmission and transportation infrastructure to support new generation, the large size and seclusion of the site while being relatively close to the load center, and the long-standing record of safe and secure operation of nuclear generation at the site since the early 1970s.

i. **Water Resources**

In regard to Turkey Point Units 6 & 7, the primary source of cooling water makeup will be reclaimed water from the Miami-Dade County Water and Sewer Department (MDWASD), with potable water also from MDWASD. When reclaimed water is not available in sufficient quantity and quality of water needed for cooling, makeup water will be saltwater supplied by radial collector wells that are recharged from the marine environment of Biscayne Bay. Horizontal collector wells (radial collector wells) have become widely used for the purpose of inducing infiltration from surface water bodies into hydraulically-connected aquifer systems in order to develop moderate to high capacity water supplies. Turkey Point Units 6 & 7 wastewater will be discharged via on-site deep injection wells.

j. **Geological Features of Site and Adjacent Areas**

Turkey Point lies upon the Floridian Plateau, a partly-submerged peninsula of the continental shelf. The peninsula is underlain by approximately 4,000 to 15,000 feet of sedimentary rocks consisting of limestone and associated formations that range in age from Paleozoic to Recent. Little is known about the basement complex of Paleozoic igneous and metamorphic rocks due to their great depth.

Generally in Miami-Dade County, the surficial aquifer (Biscayne Aquifer) consists of a wedge-shaped system of porous clastic and carbonate sedimentary materials, primarily limestone and sand deposits of the Miocene to late Quaternary age. The Biscayne Aquifer is thickest along the eastern coast and varies in thickness from 80 to 200 feet thick. The surficial aquifer is typically composed of Pamlico Sand, Miami Limestone (Oolite), the Fort Thompson and Anastasia Formations (lateral equivalents), Caloosahatchee Marl, and the Tamiami formation. The lower confining layers below the surficial aquifer range in thickness from 350 to 600 feet and are composed of the Hawthorn Group. Beneath the Hawthorn Group, the Floridan Aquifer System ranges from 2,800 to 3,400 feet thick and consists of Suwannee Limestone, Avon Park Limestone, and the Oldsmar Formations.

k. **Projected Water Quantities for Various Uses**

The estimated quantity of water required for the new Turkey Point Units 6 & 7 for industrial processing is approximately 936 gallons per minute (gpm) for uses such as process water and service water. Approximately 55.3 million gallons per day (mgd) of cooling water would be cycled through the cooling towers. Water quantities needed for other uses such as potable water are estimated to be approximately 50,400 gallons per day (gpd) for Units 6 & 7.

l. **Water Supply Sources and Type**

The water for the various water needs of Turkey Point 6 & 7 will be obtained from a reclaimed water supply, a saltwater supply, and a potable water supply. Reclaimed water will be used as makeup water to the cooling water system with saltwater from radial collector wells as a back-up water source to be used when reclaimed water is not available in sufficient quantity or quality.

Potable water will be used as makeup water for the service water system. The potable water supply will also provide water to the fire protection system, demineralized water treatment system, and other miscellaneous uses.

m. **Water Conservation Strategies**

Use of reclaimed water from MDWASD Turkey Point Units 6 & 7 is a beneficial and cost-effective means of increasing the use of reclaimed water. This use of reclaimed water helps Miami-Dade County meet approximately half of its wastewater reuse goals and will provide environmental benefits by reducing the volume of wastewater discharged by the County. In the absence of reuse opportunities, this treated domestic wastewater would likely continue to be discharged to the ocean or into deep injection wells.

Miami-Dade County is required to eliminate ocean outfalls and increase the amount of water that is reclaimed for environmental benefit and other beneficial uses. Turkey Point Units 6 & 7 will use reclaimed water 24 hours per day, 365 days per year when operating and when the reclaimed water is available in sufficient quantity and quality.

n. **Water Discharges and Pollution Control**

Turkey Point Units 6 & 7 will dissipate heat from the power generation process using cooling towers. Blowdown water or discharge from the cooling towers, along with other wastestreams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Storm water runoff will be released to the closed-loop cooling canal system.

Turkey Point Units 6 & 7 will employ Best Management Practices (BMP) plans and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o. **Fuel Delivery, Storage, Waste Disposal, and Pollution Control**

The Turkey Point Units 6 & 7, reactors will contain enriched uranium fuel assemblies. A fuel assembly consists of 264 fuel rods, 24 guide thimbles, and 1 instrumentation tube in a 17-by-

17 square array. The fuel rods consist of enriched uranium, in the form of cylindrical pellets of sintered uranium dioxide contained in ZIRLO™ tubing.

New fuel assemblies will be transported to Turkey Point for use in Units 6 & 7 by truck from a fuel fabrication facility in accordance with U.S. Department of Transportation (DOT) and NRC regulations. Spent fuel assemblies being discharged will remain in the spent fuel pool while short half-life isotopes decay.

After a sufficient decay period, the fuel would be transferred to an on-site independent spent fuel storage installation facility or an off-site disposal facility. Packaging of the fuel for off-site shipment will comply with the applicable DOT and NRC regulations for transportation of radioactive material.

The U.S. Department of Energy (DOE) is responsible for spent fuel transportation from reactor sites to a repository under the Nuclear Waste Policy Act of 1982, as amended. FPL has executed a standard spent nuclear fuel disposal contract with DOE for fuel used in Units 6 & 7.

p. <u>Air Emissions and Control Systems</u>

Turkey Point Units 1, 2, and 5, and the emergency diesel generators associated with Units 3 and 4, are classified as a major source of air pollution. FDEP has issued a separate Title V Air Operating Permit for the fossil units at Turkey Point and for the emergency diesel generators associated with the nuclear units. There are no operating limits for the emergency generators or diesel engines. Emergency diesel generators are limited to use ultra-low sulfur diesel fuel (0.0015% sulfur). NO_x emissions are regulated under Reasonably Available Control Technology (RACT) requirements in Rule 62-296.570(4) (b) 7 F.A.C., which limit NO_x emissions to 4.75 lb/MMBtu. The use of 0.05 percent sulfur diesel fuel and good combustion practices serve to keep NO_x emissions under this limit.

Regarding Turkey Point Units 6 & 7, the units will also minimize FPL system air pollutant emissions by using nuclear fuel to generate electric power. This includes avoiding emissions of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), carbon dioxide (CO_2), and volatile organic compounds (VOC). The circulating water cooling towers will be equipped with high-efficiency drift or mist eliminators to minimize emissions of PM to 0.0005 percent of the circulating water, which represents 99.99-percent control of potential drift emissions based on the circulating water flow.

The diesel engines necessary to support Turkey Point Units 6 & 7 and fire pump engines will be purchased from manufacturers whose engines meet the EPA's New Source Performance Standards (NSPS) Subpart IIII emission limits.

q. **Noise Emissions and Control Systems**

Field surveys and impact assessments of noise expected to be caused by activities associated with the Turkey Point Units 6 & 7 project were conducted. Predicted noise levels associated with these projects are not expected to result in adverse noise impacts in the vicinity of the site.

r. **Status of Applications**

The Turkey Point Units 6 & 7 Site Certification Application (SCA), under the Florida Electrical Power Plant Siting Act, was filed in June 2009 and a final order is anticipated in mid-2014. The FPSC issued the final order approving the need for this additional nuclear capacity in April 2008.

A Combined License Application for Units 6 & 7 was submitted to the NRC in June 2009. There are two components to that application; one is the Environmental Assessment (EA) and the other is the Safety component. The Application is still in process.

Besides the certification and the license, additional approvals have been issued for Turkey Point Units 6 & 7 including Miami-Dade County Unusual Use approvals that were issued in 2007 and 2013 and a Land Use Consistency Determination that was issued in 2013. The Prevention of Significant Deterioration (Air permit) was issued in 2009. In addition, a permit to construct an exploratory well and a dual zone monitoring well, under the Underground Injection Control Program, was issued in 2010, and a permit to convert the exploratory well, to an injection well and to operationally test the system, was issued in 2013. Permits from the Federal Aviation Administration (FAA) for the containment structure were originally issued in 2009 and renewed in 2012.

The western transmission lines associated with Units 6 & 7 (2 500 kV New Clear Sky Substation – Levee Substation and 1 230 kV New Clear Sky Substation – Pennsuco Substation) will utilize the existing approximately 40-mile-long transmission line right-of-way acquired by FPL in the 1960s and early 1970s between the Turkey Point plant property and Levee Substation. A 7.4 mile long segment of that existing right-of-way became surrounded by the Everglades National Park in 1989 when the East Everglades Expansion Area south of Tamiami Trail (US-41) was added to the Park. The National Park Service and several other federal, state and local agencies entered into contingent agreements in 2008 to exchange

FPL's fee-owned property within the Park for an alternative right-of-way along the Park's eastern boundary (the Exchange Right-of-Way). That land exchanges was authorized by the U.S. Congress in the 2009 Omnibus Public Lands Management Act, and the National Park Service is currently engaged in a National Environmental Policy Act (NEPA) review of the proposed exchange. The Recommended Order to be considered by the Siting Board in 2014 recommends for approval FPL's West Preferred Corridor, which includes the Exchange Right-of-Way, as a back-up western transmission line corridor to another corridor. The primary western corridor recommended for approval is the West Consensus Corridor (comprising an alternate corridor proposed by the Miami-Dade Limestone Products Association and a portion of FPL's West Preferred Corridor). Both of those western transmission line corridors recommended for certification use the Exchange Right-of-Way. In the event the pending land exchange with the National Park Service and other agencies is not consummated on a timely basis, FPL will need to evaluate other potential western corridors for the western transmission lines associated with Units 6 & 7, including its existing fee-owned right-of-way in the Park, and seek necessary approvals for construction of the required transmission facilities.

IV.F.2 Potential Sites for Generating Options

Four (4) sites are currently identified as Potential Sites for future generation additions to meet FPL's projected capacity and energy needs.[6] These sites have been identified as Potential Sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies, including both renewable energy and non-renewable energy technologies for various sites.

Each of these Potential Sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that will require further definition and attention.

Permits are presently considered to be obtainable for each of these sites. No significant environmental constraints are currently known for any of these sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time, FPL considers each site to be equally viable.

[6] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other Greenfield sites. Greenfield sites that FPL currently does not own, or for which FPL has not currently secured the necessary rights to, are not specifically identified as Potential Sites in order to protect the economic interests of FPL and its customers.

Potential Site # 1: Babcock Ranch, Charlotte County

This site is located within the proposed Babcock Ranch Community on the north side of Tuckers Grade, approximately 10.5 miles north of the intersection of SR-80 and SR-31 and 1.1 miles east of SR-31. The project is bordered on the north by the Babcock Ranch Preserve owned by the State of Florida. This site is a possibility for an FPL PV facility. FPL has received all permits necessary to construct a 74 MW PV facility at this location.

a. **U.S. Geological Survey (USGS) Map**

A map of this site is found at the end of this chapter.

b. **Land Uses**

Existing land use on the site is the Babcock Ranch Overlay District, and it is zoned as the Babcock Ranch Overlay Zoning District. This land use and zoning allows for solar facilities.

c. **Environmental Features**

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

d. **Water Quantities**

Minimal amounts of water, if any, would be required for a PV facility.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water may be brought to the site by truck.

Potential Site # 2: DeSoto Solar Expansion, DeSoto County

The DeSoto site is located at 4051 Northeast Karson Street which is approximately 0.3 miles east of U.S. Highway 17 and immediately north of Bobay Road in Arcadia, Florida. The site is located in Sections 26, 27, & 35, Township 36 South, and Range 25 East. FPL owns an approximate 13,000 acre parcel in DeSoto County. FPL has designated approximately 5,177 acres for development of a PV facility.

The DeSoto site is home to a 25 MW PV facility that has been operational since 2009. Up to an additional 275 MW of PV generation could be constructed in phases on the remaining undeveloped land. FPL has initiated permitting for the additional PV facilities.

a. U.S. Geological Survey (USGS) Map

A map of this site is found at the end of this chapter.

b. Land Uses

Existing land use on the site is agricultural. The future land use is Electric Generating Facility.

c. Environmental Features

There are no significant environmental features on the site.

d. Water Quantities

Minimal amounts of water would be required for a future expansion of the existing PV facility.

e. Supply Sources

Minimal water would be required for an expanded PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall. Potable water will be required in the administration building and maintenance building. FPL would propose to utilize existing wells onsite to accommodate water needs.

Potential Site # 3: Manatee Plant Site, Manatee County

The existing FPL Manatee Plant 9,500-acre site is located in unincorporated north-central Manatee County. The existing power generating facilities are located in all or portions of Sections 18 and 19 of Township 33S, Range 20-E. The plant site lies approximately 5 miles east of Parrish, Florida. It is approximately 5 miles east of U.S. Highway 301 and 9.5 miles east of Interstate Highway 75 (I-75). The existing plant is approximately 2.5 miles south of the Hillsborough-Manatee County line. A portion of the north property boundary of the plant site abuts the county line. State Road 62 (SR 62) is about 0.7 mile south of the plant, with the plant entrance road going north from that highway. This site is a possible location for an FPL PV facility. FPL has received the federal and state permits required to construct approximately 50 MW of PV at this location.

a. U.S. Geological Survey (USGS) Map

A map of the site is found at the end of this chapter.

b. Land Uses

Existing land use on the site is agricultural. The property is zoned Planned Development / Public Interest (PD-PI), which will allow for electrical generation.

c. Environmental Features

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

d. Water Quantities

Minimal amounts of water would be required for a PV facility.

e. Supply Sources

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall. Panel cleaning water source may be existing potable water or water tank trucked to the site.

Potential Site # 4: Martin County, Martin County

FPL is currently evaluating potential sites in Martin County for a future PV facility. No specific locations have been selected at this time.

a. U.S. Geological Survey (USGS) Map

A USGS map of the county has been included at the end of this chapter.

b. Land Uses

This information is not available because a specific site has not been selected at this time.

c. Environmental Features

This information is not available because a specific site has not been selected at this time.

d. Water Quantities

Minimal amounts of water would be required for a PV facility.

e. Supply Sources

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall.

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Environmental and Land Use Information: Supplemental Information Preferred Site #1: Port Everglades Plant

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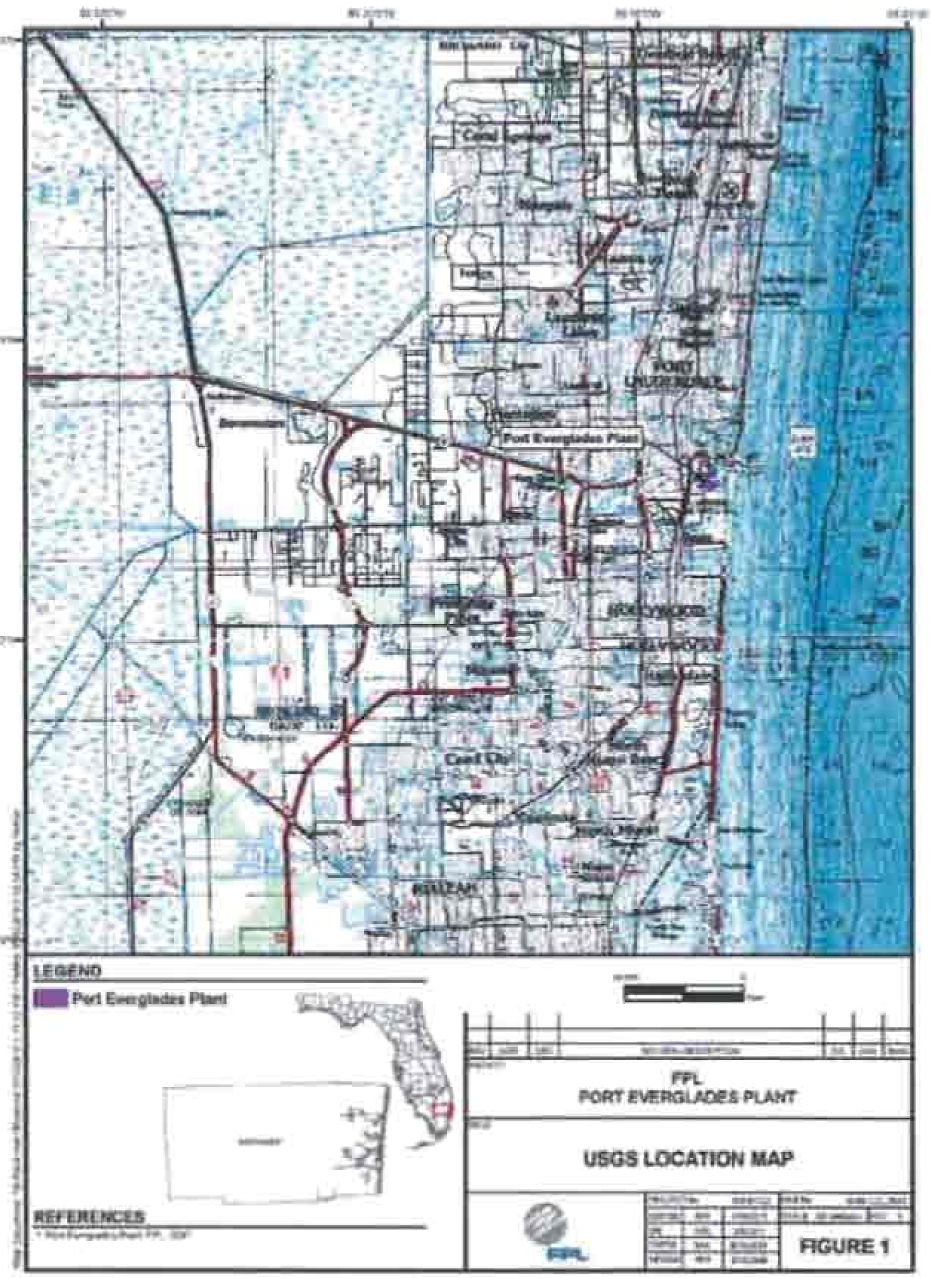
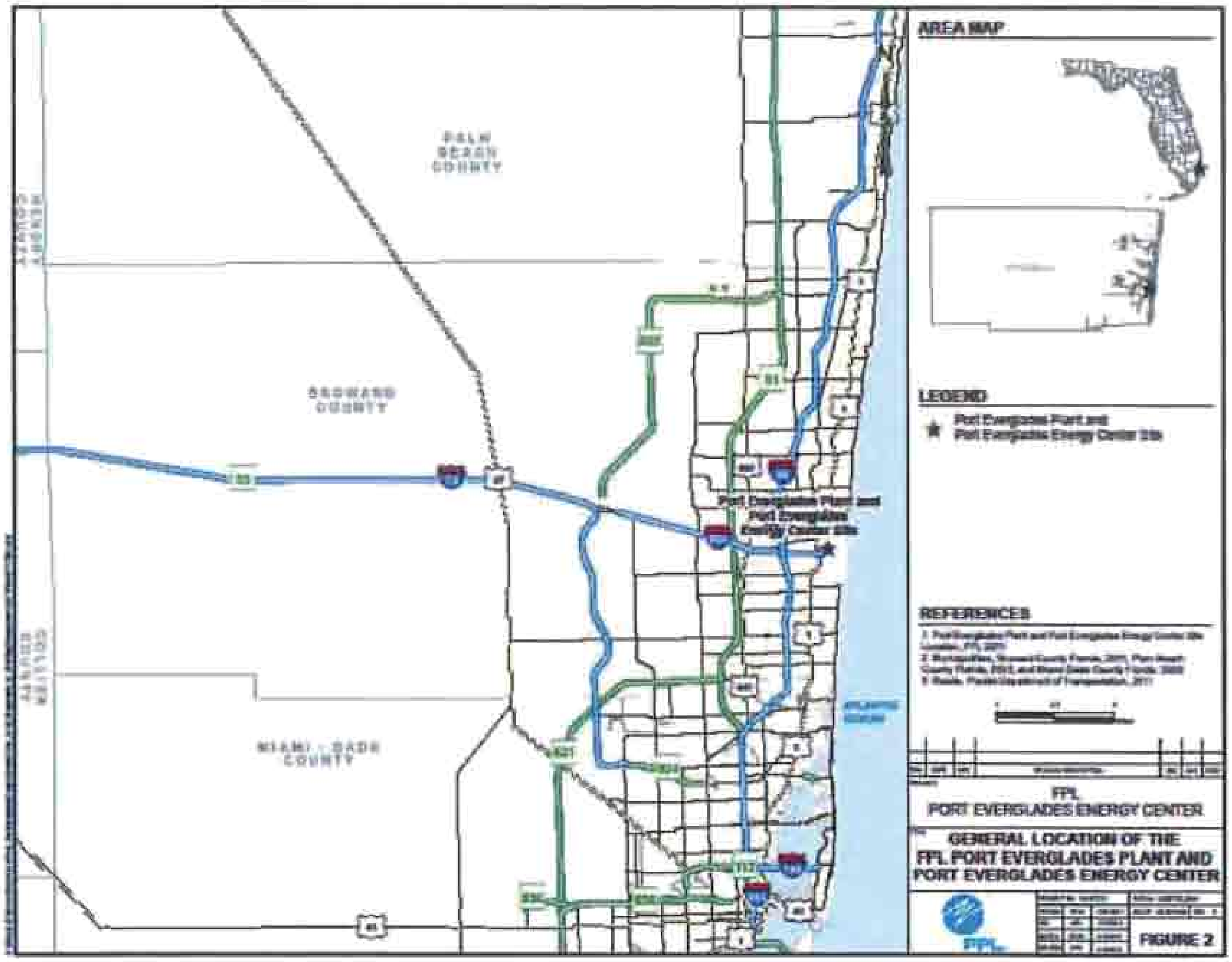
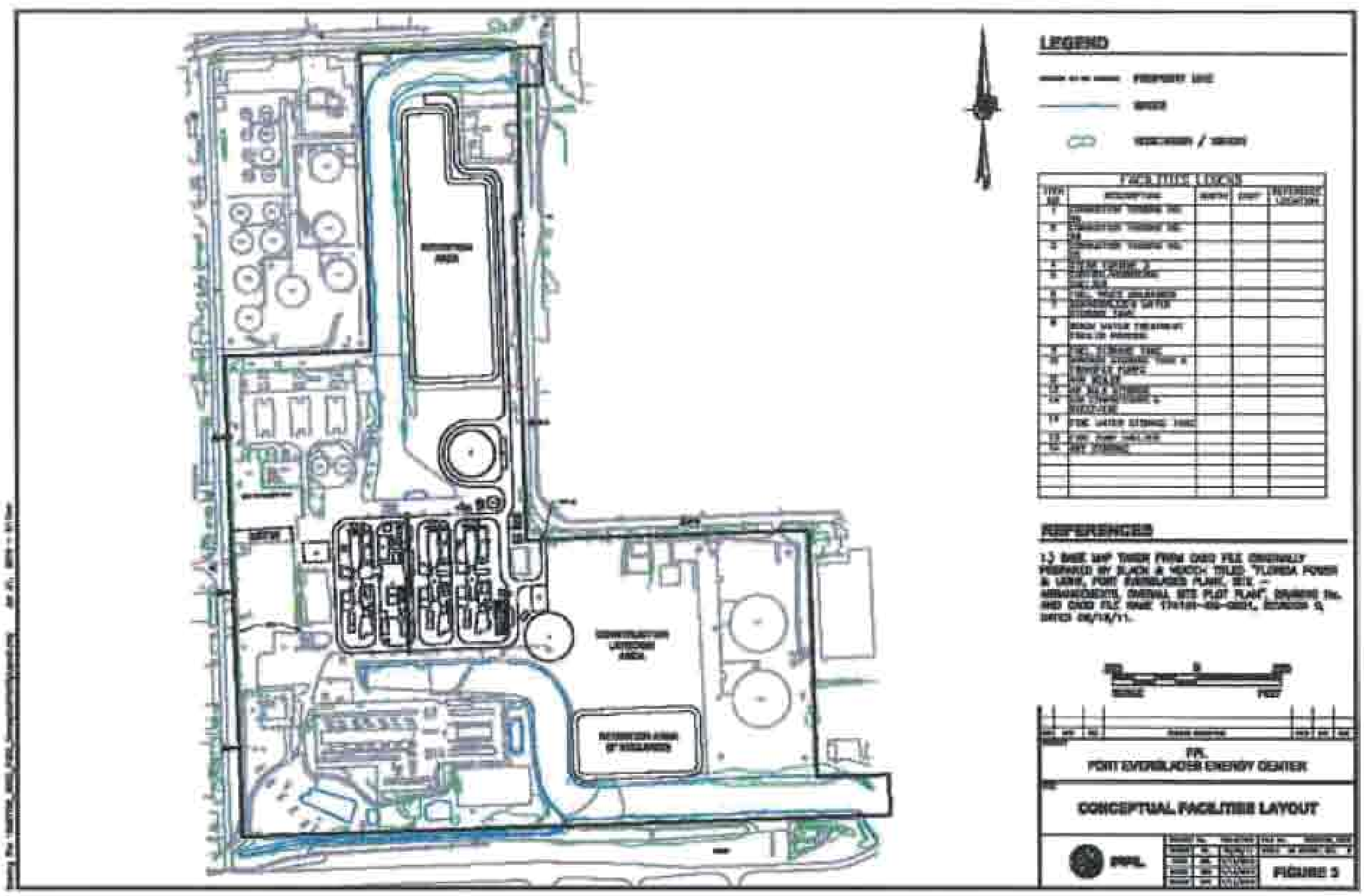
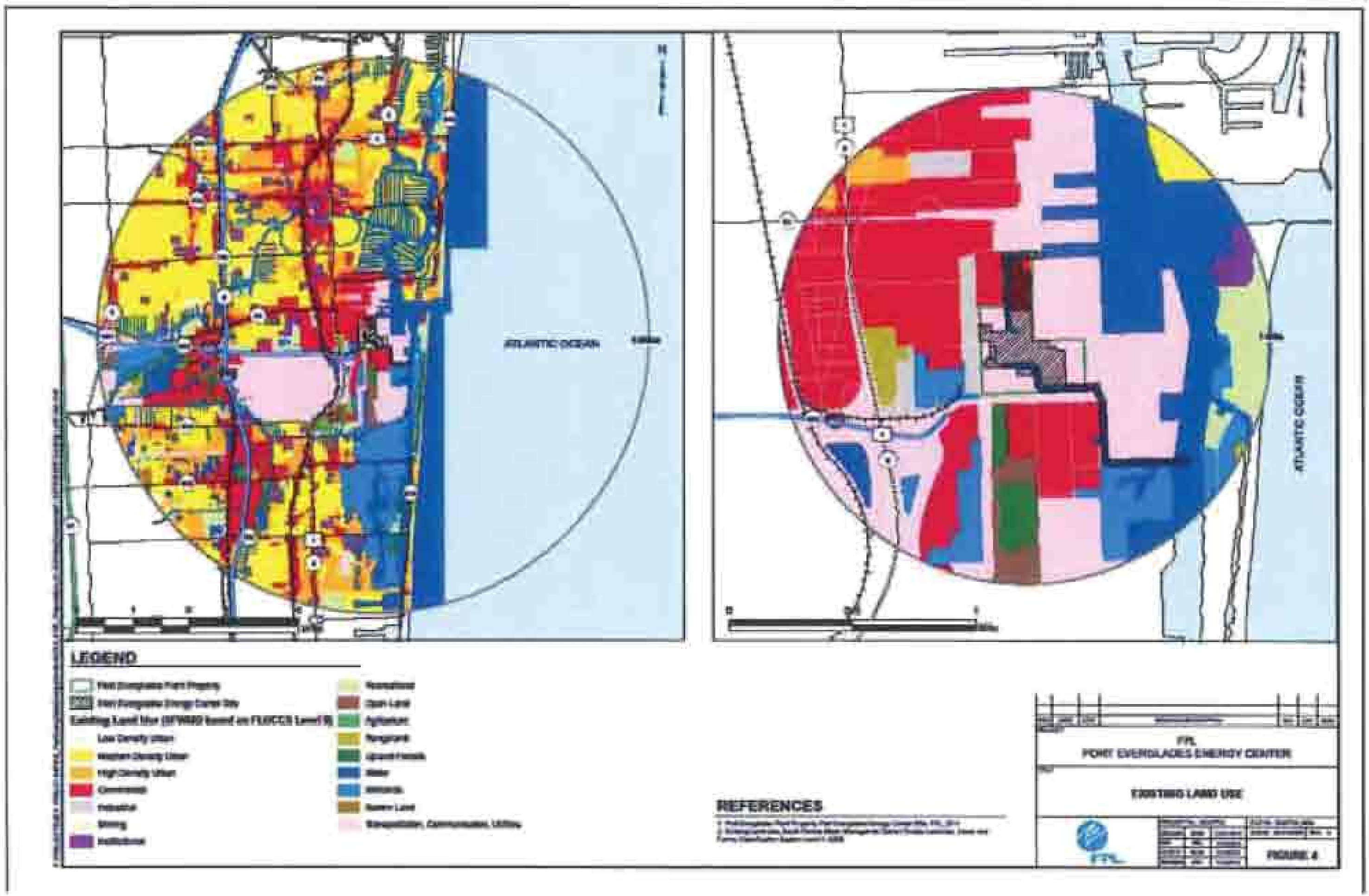

Port Everglades Plant
HOLLYWOOD
FORT LAUDERDALE
LEGEND
Port Everglades Plant
REFERENCES
FPL
PORT EVERGLADES PLANT
USGS LOCATION MAP
FIGURE 1


AREA MAP
PALM BEACH COUNTY
BROWARD COUNTY
MIAMI - DADE COUNTY
LEGEND
Port Everglades Plant and Port Everglades Energy Center Site
REFERENCES
FPL
PORT EVERGLADES ENERGY CENTER
GENERAL LOCATION OF THE FPL PORT EVERGLADES PLANT AND PORT EVERGLADES ENERGY CENTER
FIGURE 2


LEGEND
FACILITIES LEGEND
REFERENCES
FPL
PORT EVERGLADES ENERGY CENTER
CONCEPTUAL FACILITIES LAYOUT
FIGURE 3


ATLANTIC OCEAN
ATLANTIC OCEAN
LEGEND
REFERENCES
FPL
PORT EVERGLADES ENERGY CENTER
EXISTING LAND USE
FIGURE 4

Environmental and Land Use Information:

Supplemental Information

Preferred Site #2: Lauderdale Plant

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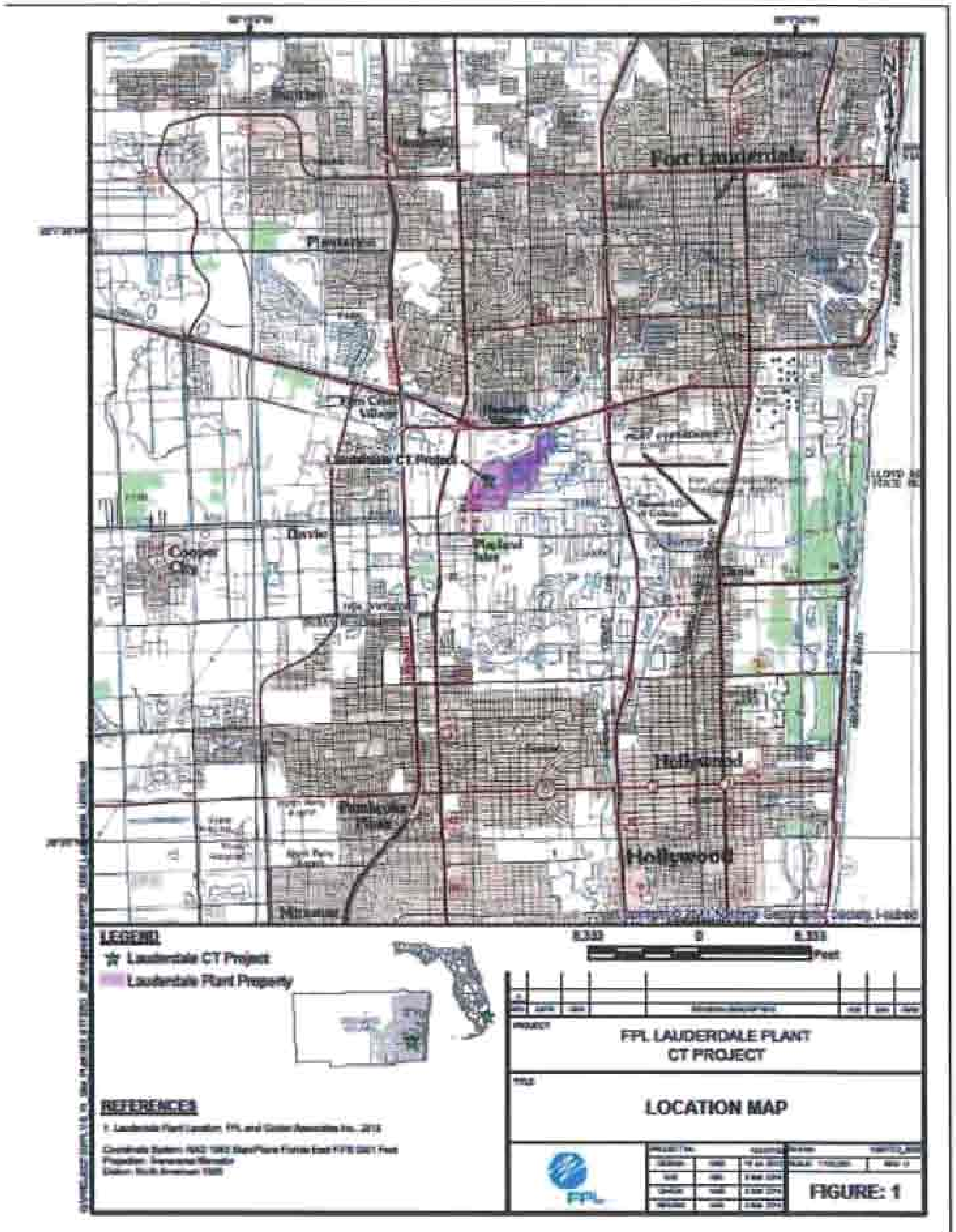
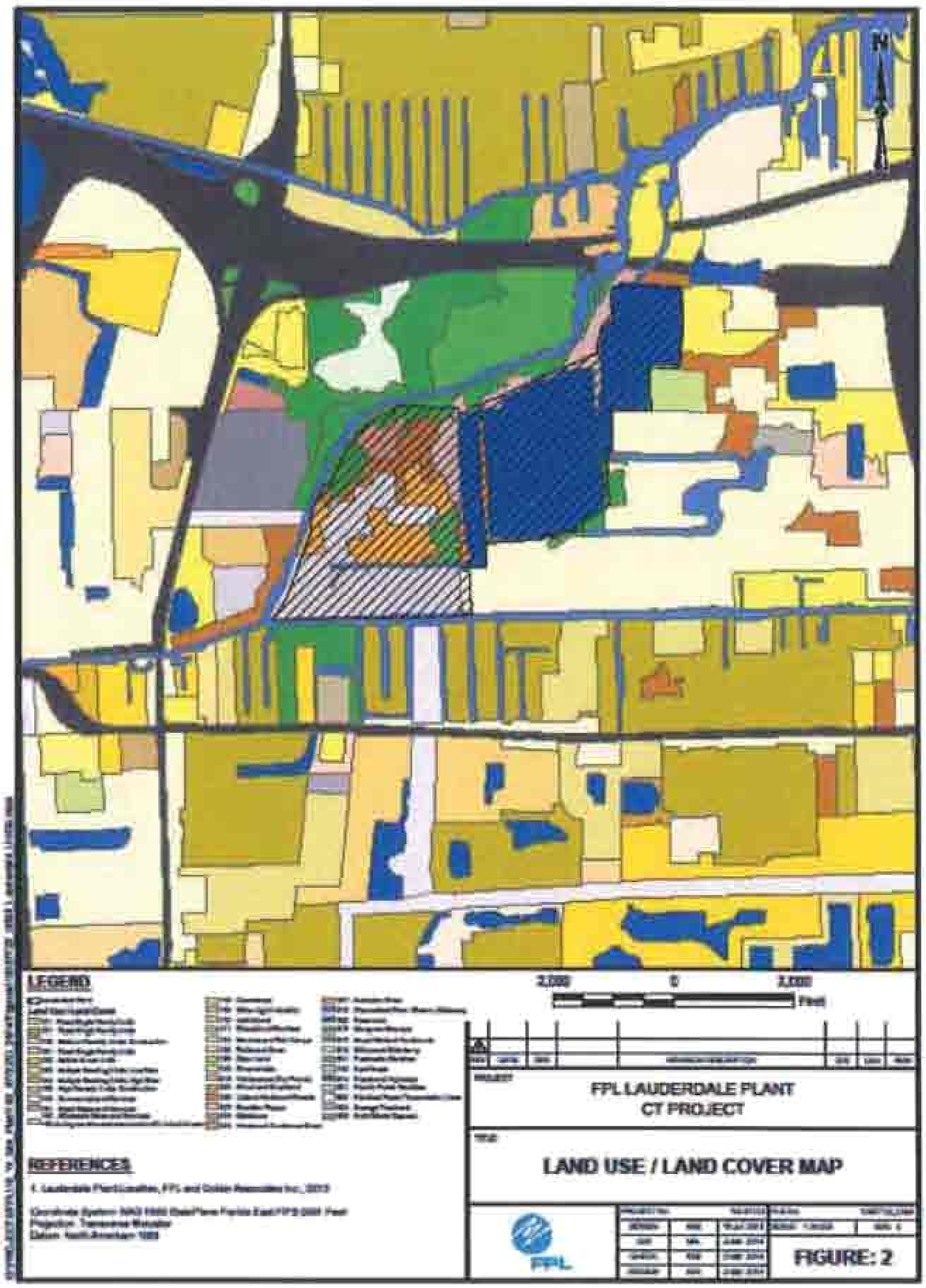

Fort Lauderdale
Plantation
Davie
Cooper City
Hollywood
Lauderdale CT Project
LEGEND
Lauderdale CT Project
Lauderdale Plant Property
REFERENCES
FPL LAUDERDALE PLANT
CT PROJECT
LOCATION MAP
FIGURE: 1
FPL


LEGEND
2,000
0
2,000
Feet
FPL LAUDERDALE PLANT
CT PROJECT
LAND USE / LAND COVER MAP
REFERENCES
FPL
FIGURE: 2

Environmental and Land Use Information: Supplemental Information Preferred Site #3: Hendry County

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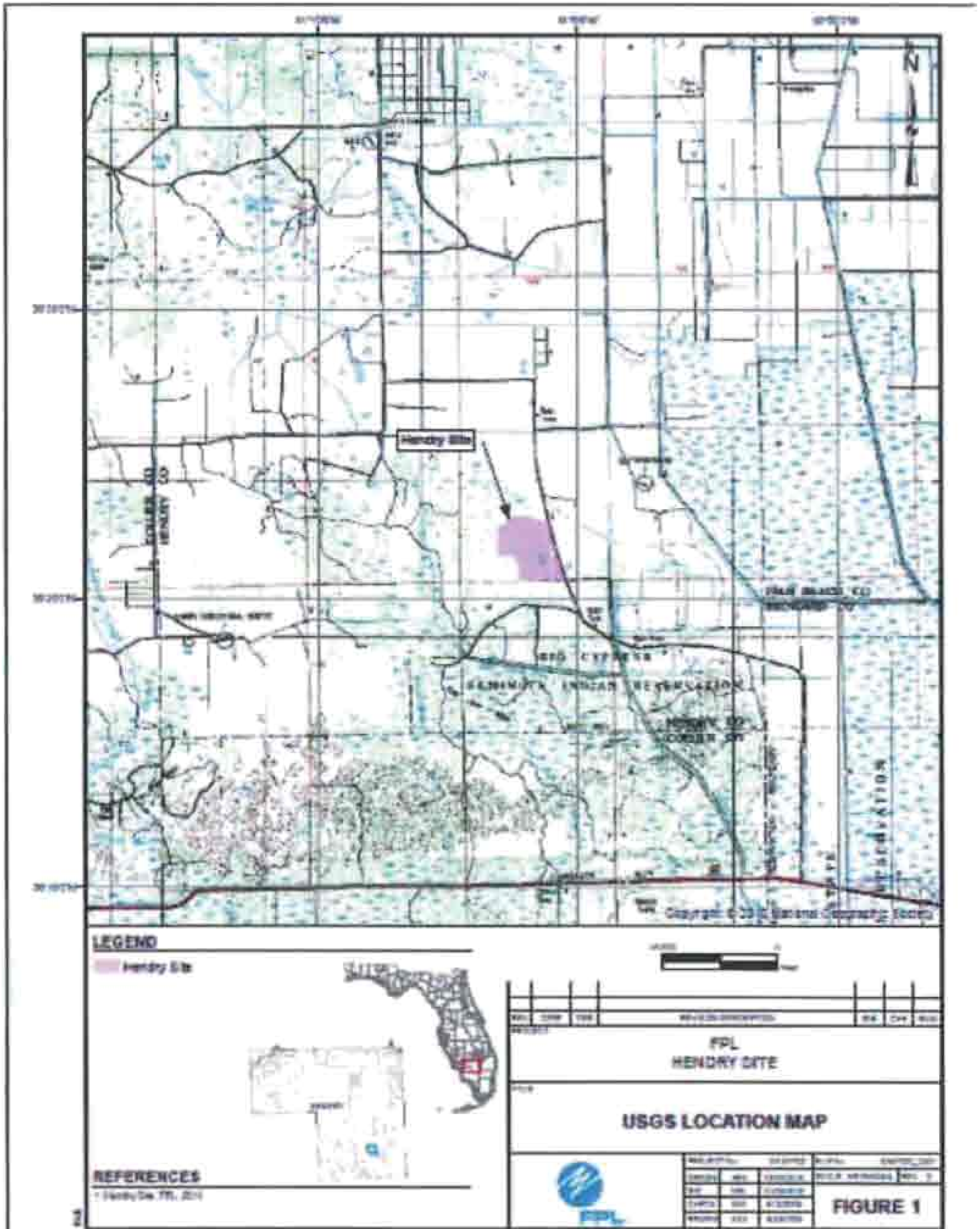
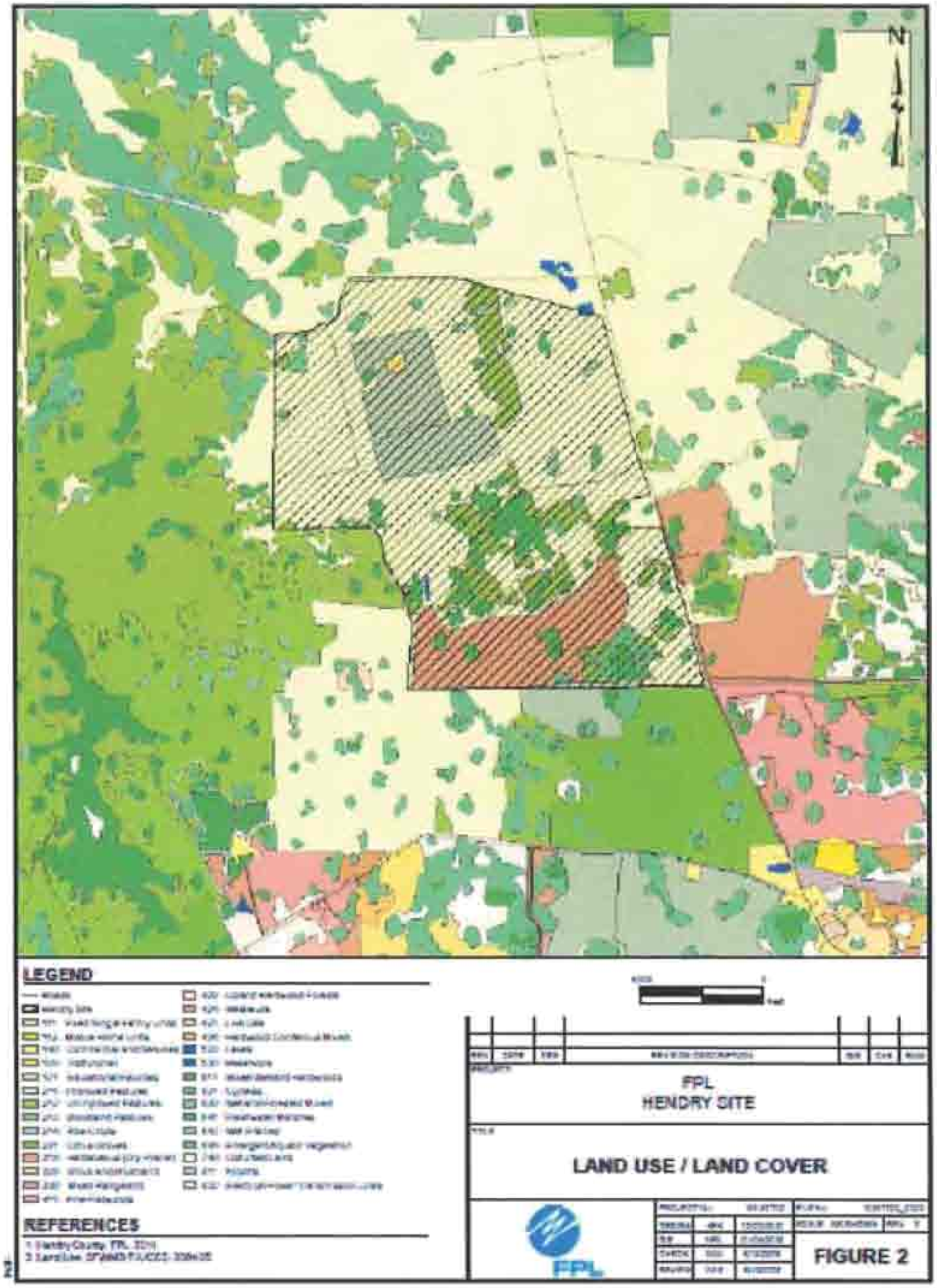

Hendry Site
LEGEND
Hendry Site
REFERENCES
FPL
HENDRY SITE
USGS LOCATION MAP
FIGURE 1


N
LEGEND
REFERENCES
FPL
HENDRY SITE
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information:
Supplemental Information
Preferred Site #4: NE Okeechobee County

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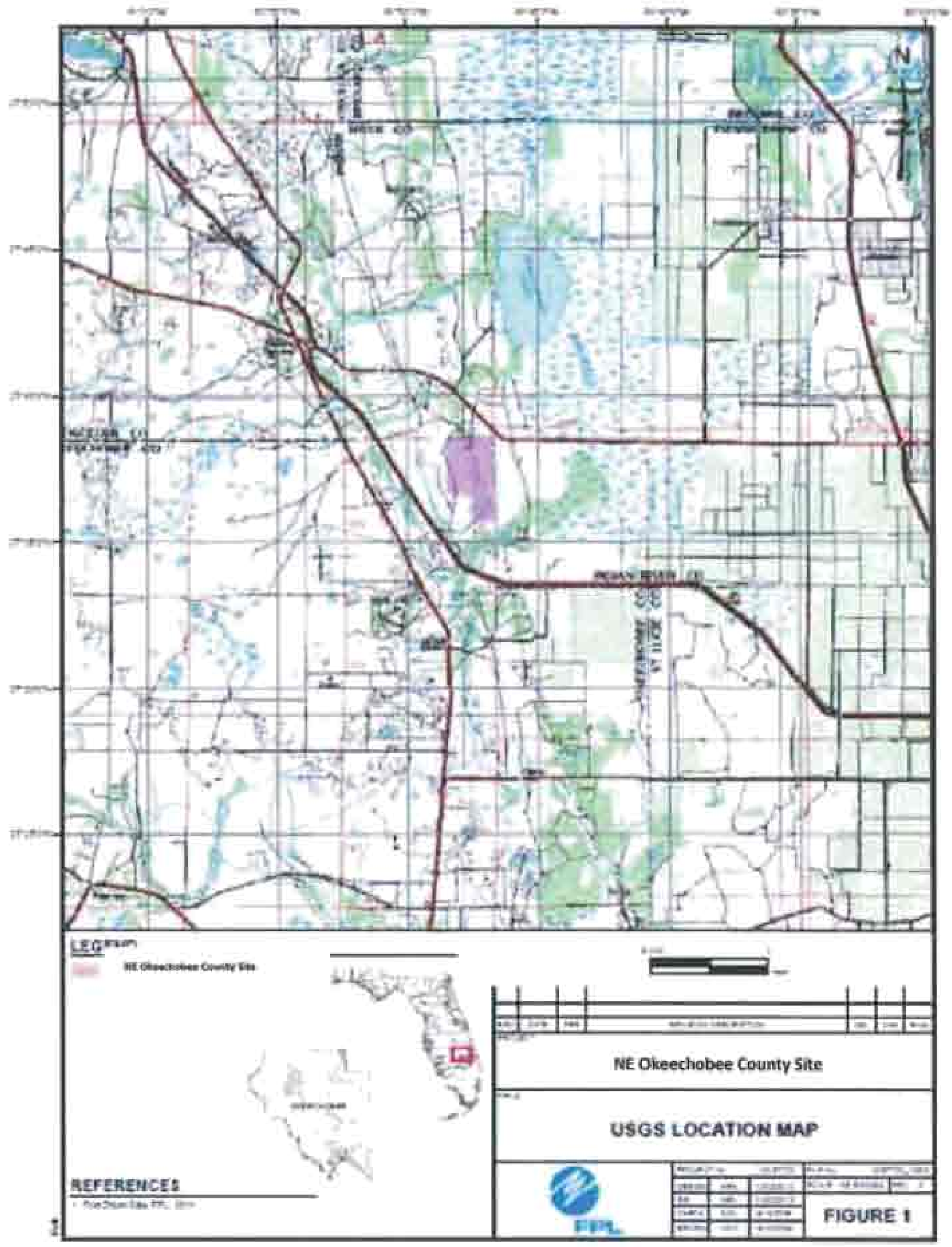
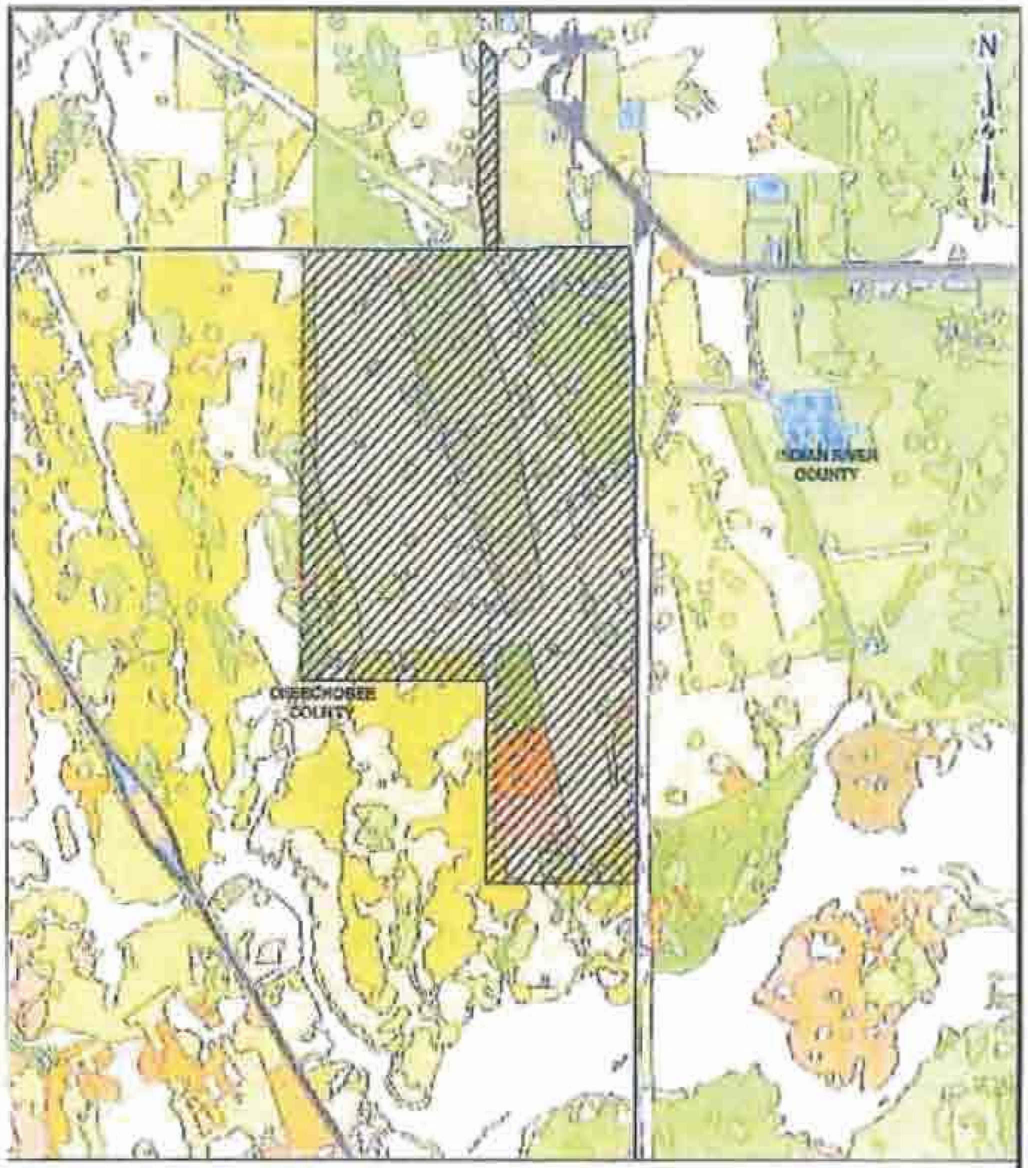

LEGEND
NE Okeechobee County Site
NE Okeechobee County Site
USGS LOCATION MAP
REFERENCES
FPL
FIGURE 1



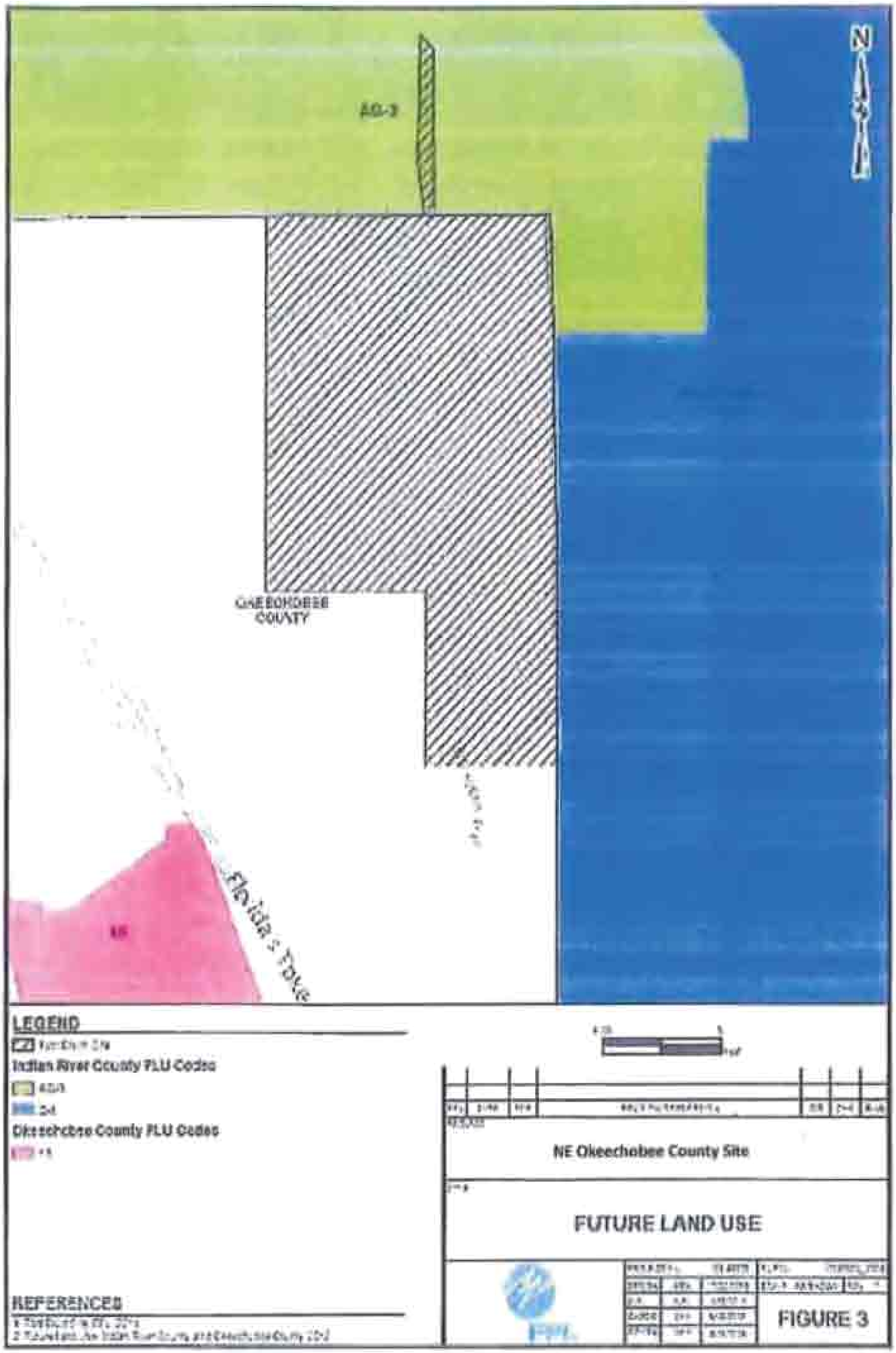
LEGEND

REFERENCES

NE Okeechobee County Site

LAND USE / LAND COVER

FIGURE 2


AG-3
OKEECHOBEE
COUNTY
Florida's Turnpike
LEGEND
Indian River County FLU Codes
Okeechobee County FLU Codes
REFERENCES
NE Okeechobee County Site
FUTURE LAND USE
FIGURE 3
FPL

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Environmental and Land Use Information:

Supplemental Information

Preferred Site #5: Putnam Site

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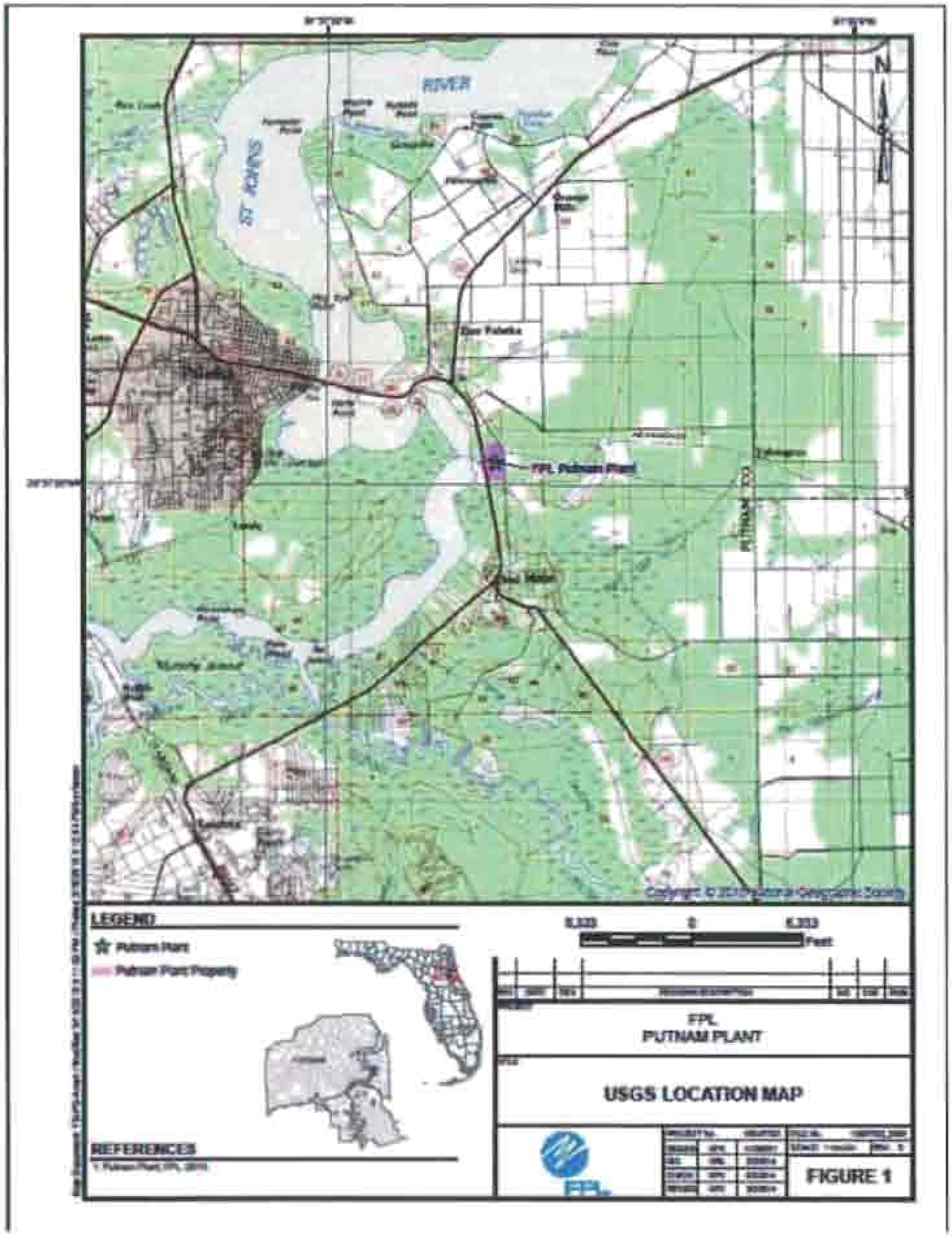
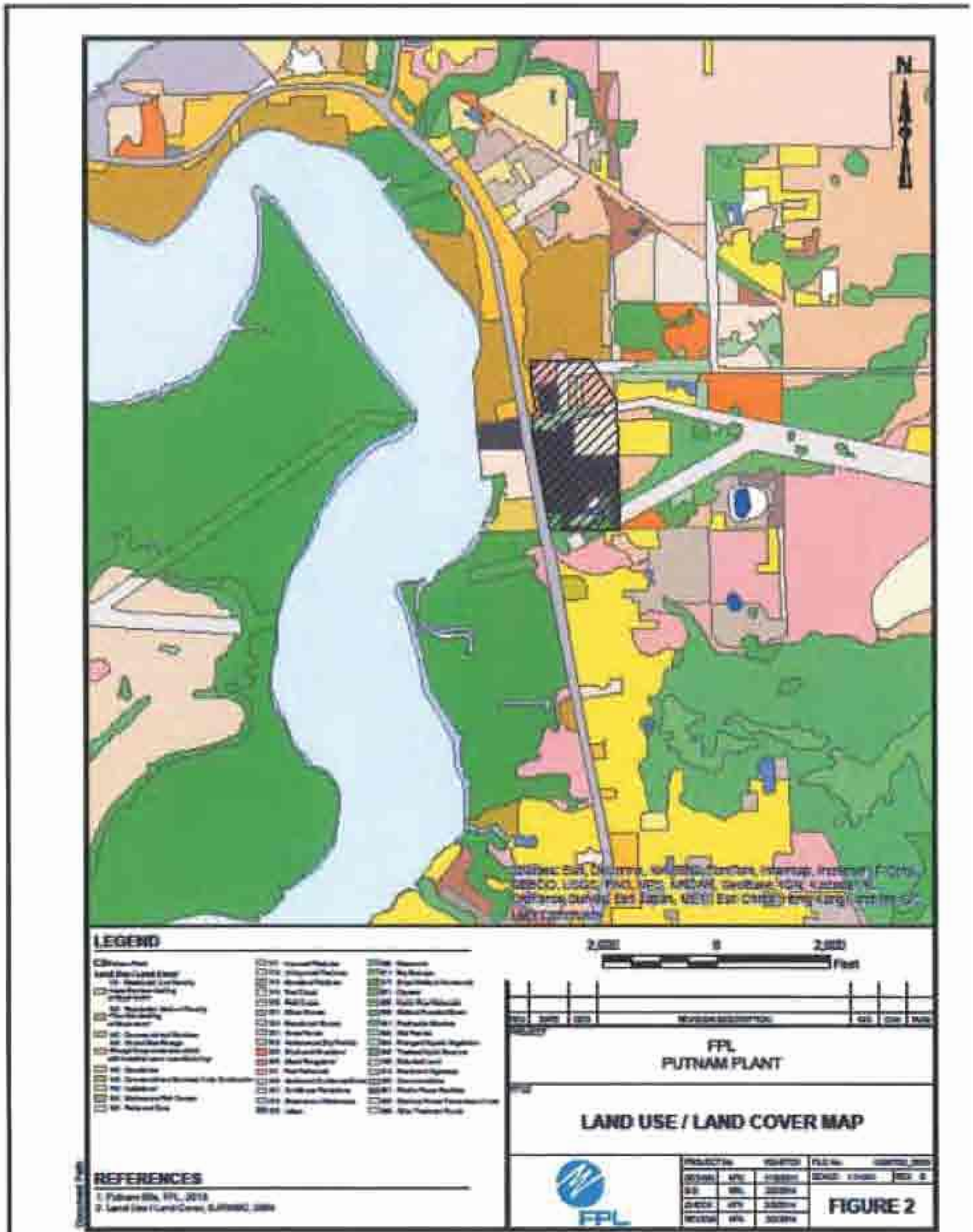

RIVER
ST JOHNS
FPL Putnam Plant
PUTNAM CO
LEGEND
Putnam Plant
Putnam Plant Property
REFERENCES
Feet
FPL
PUTNAM PLANT
USGS LOCATION MAP
FIGURE 1
FPL


N
LEGEND
2,000
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2,000
Feet
FPL
PUTNAM PLANT
LAND USE / LAND COVER MAP
REFERENCES
FIGURE 2
FPL

Environmental and Land Use Information:
Supplemental Information
Preferred Site #6: Turkey Point Plant

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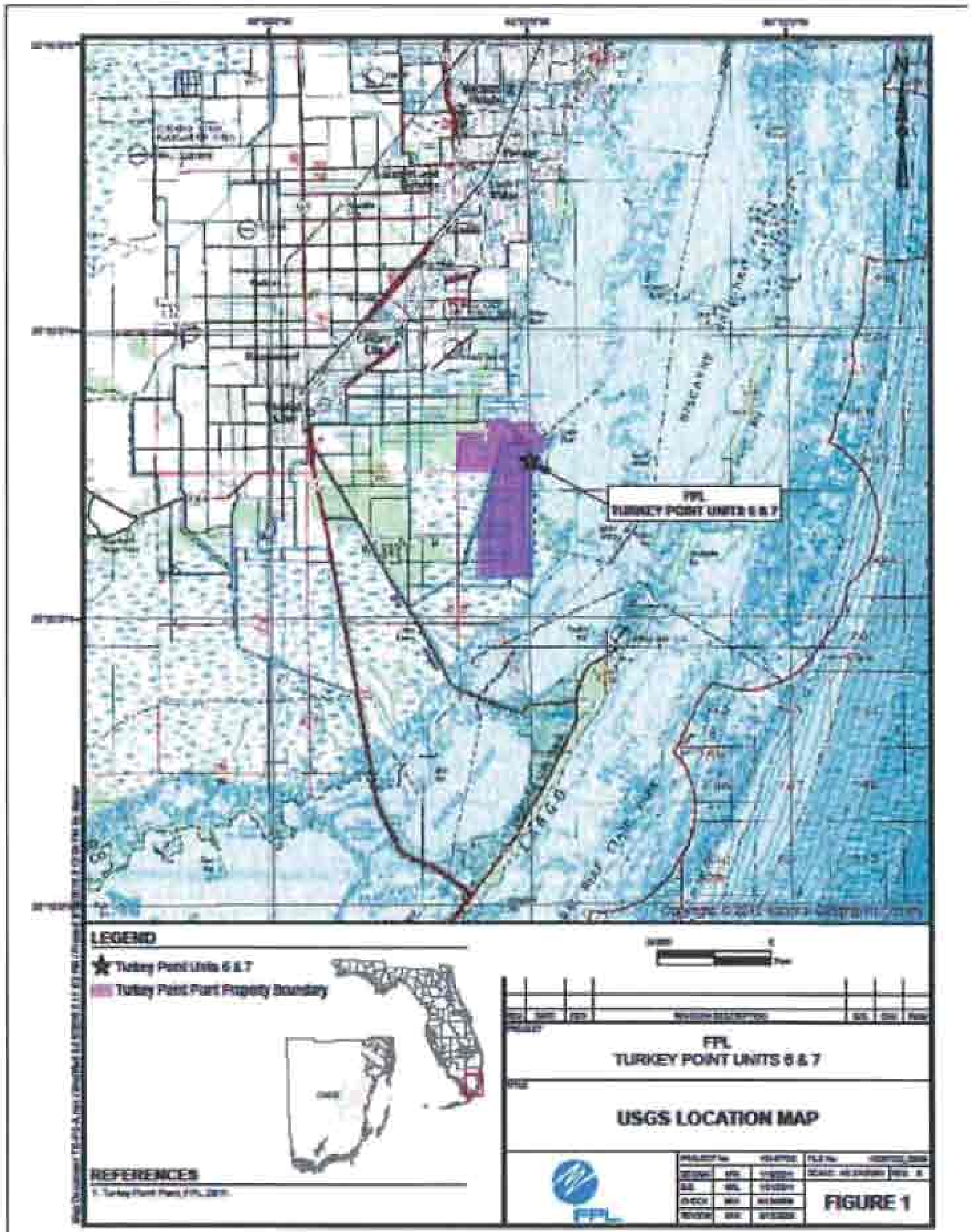
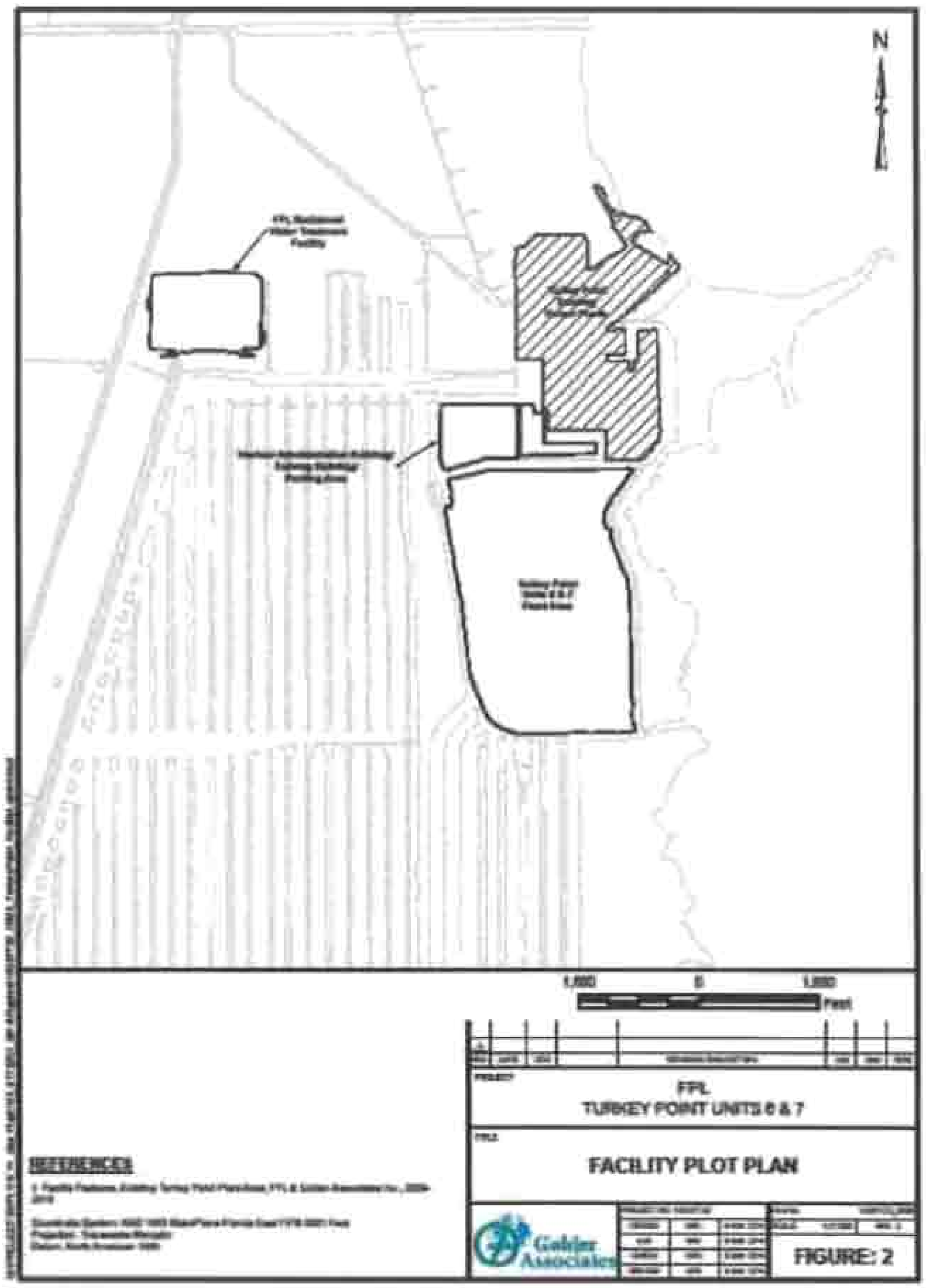
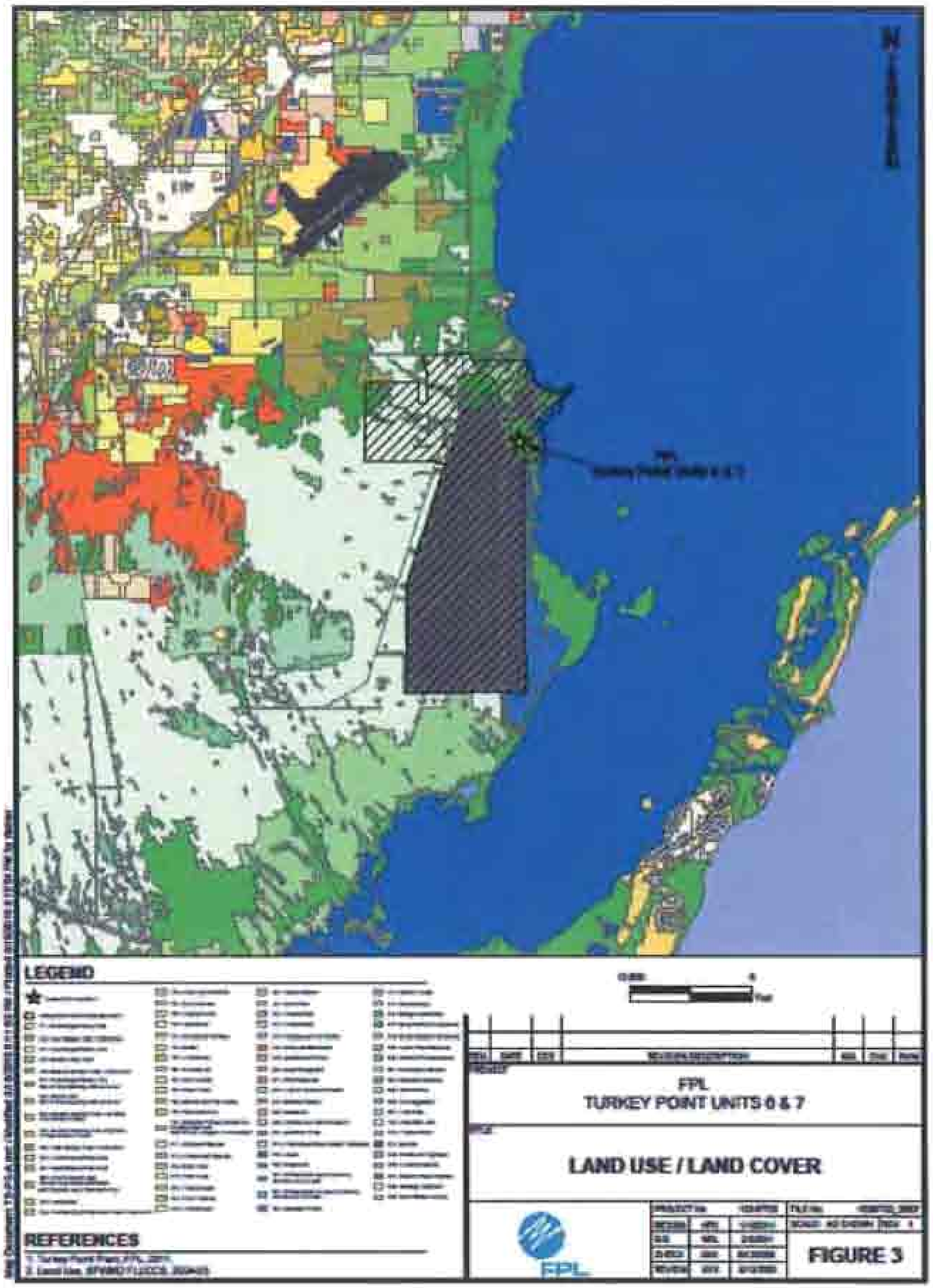

FPL
TURKEY POINT UNITS 6 & 7
LEGEND
Turkey Point Units 6 & 7
Turkey Point Plant Property Boundary
REFERENCES
FPL
TURKEY POINT UNITS 6 & 7
USGS LOCATION MAP
FIGURE 1


N
1,000
0
1,000
Feet
FPL
TURKEY POINT UNITS 6 & 7
FACILITY PLOT PLAN
REFERENCES
Golder Associates
FIGURE: 2


LEGEND
REFERENCES
FPL
TURKEY POINT UNITS 6 & 7
LAND USE / LAND COVER
FPL
FIGURE 3

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Environmental and Land Use Information: Supplemental Information

Potential Site #1: Babcock Ranch

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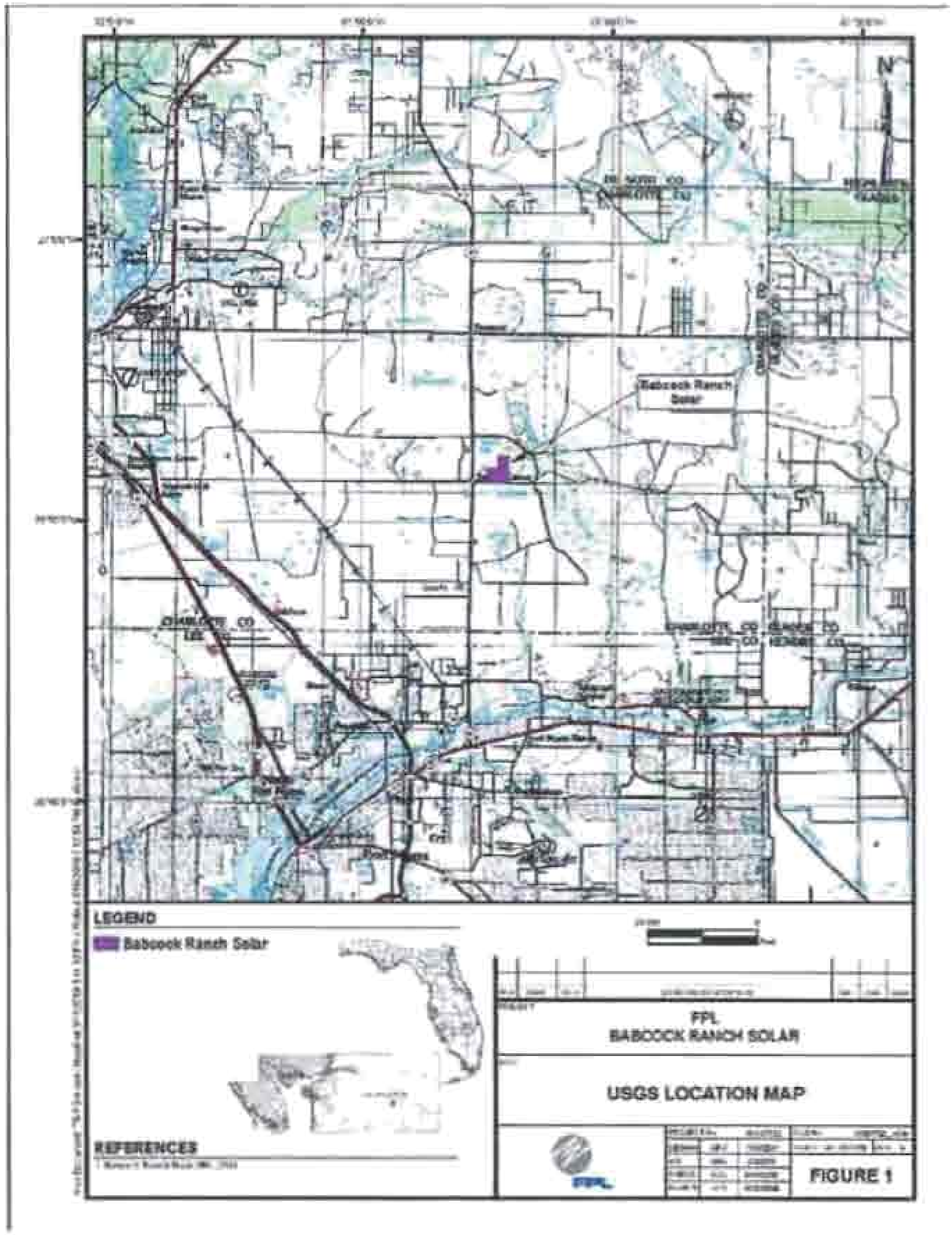
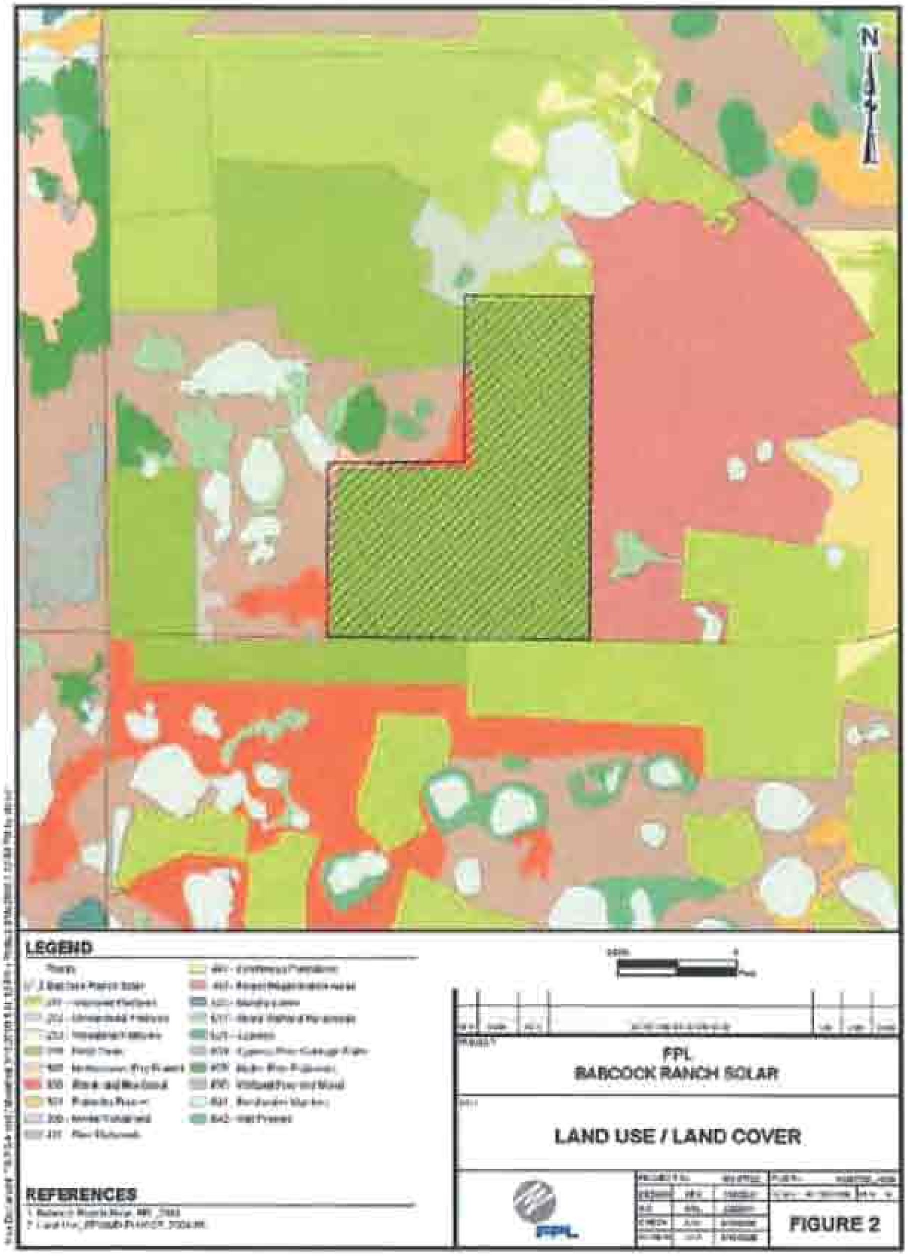

Babcock Ranch Solar
CHARLOTTE CO
LEE CO
LEGEND
Babcock Ranch Solar
REFERENCES
FPL
BABCOCK RANCH SOLAR
USGS LOCATION MAP
FIGURE 1


N
LEGEND
REFERENCES
FPL
BABCOCK RANCH SOLAR
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #2: Desoto Solar Expansion

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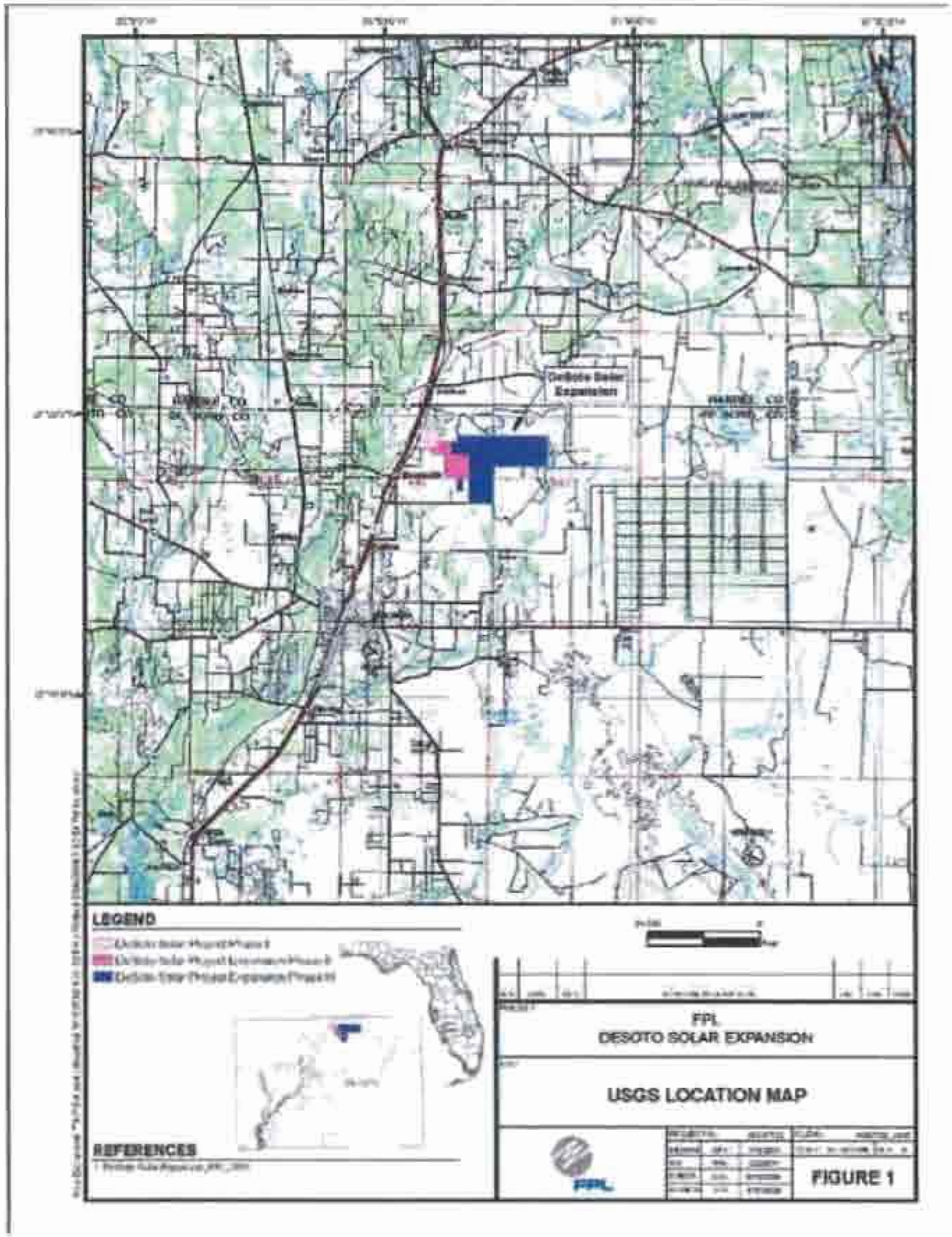
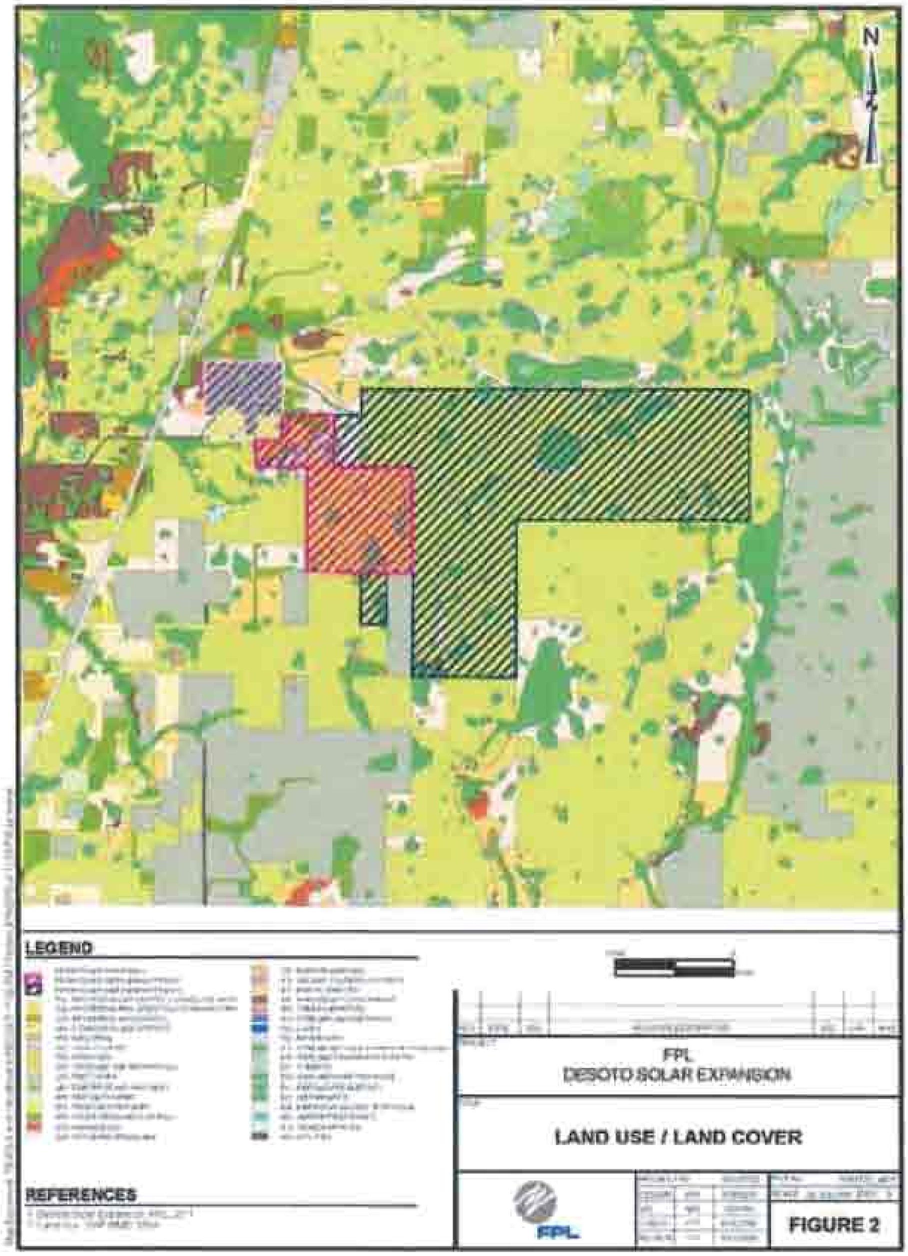

DeSoto Solar Expansion
LEGEND
REFERENCES
FPL
DESOTO SOLAR EXPANSION
USGS LOCATION MAP
FIGURE 1


N
LEGEND
REFERENCES
FPL
DESOTO SOLAR EXPANSION
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #3: Manatee Plant Site

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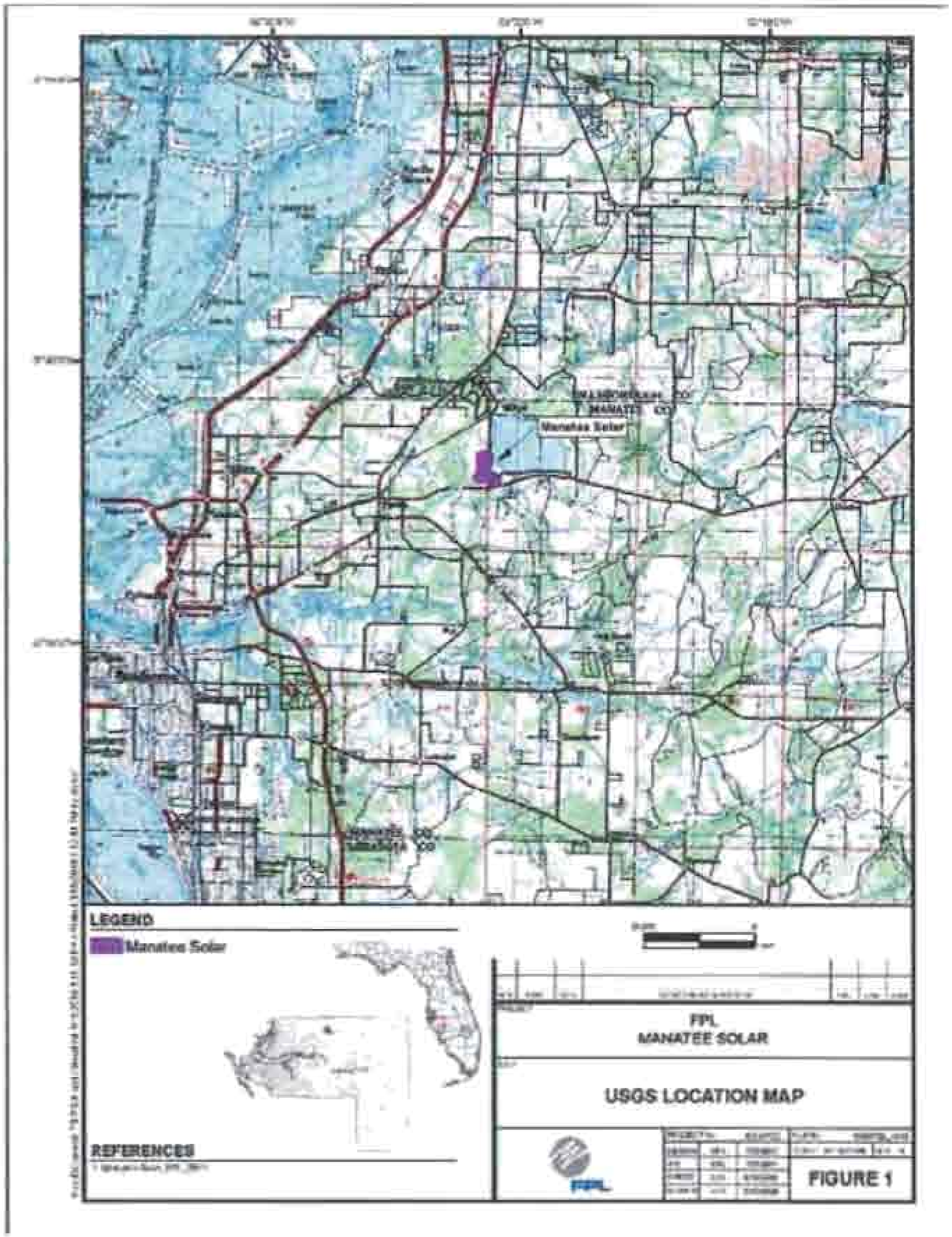
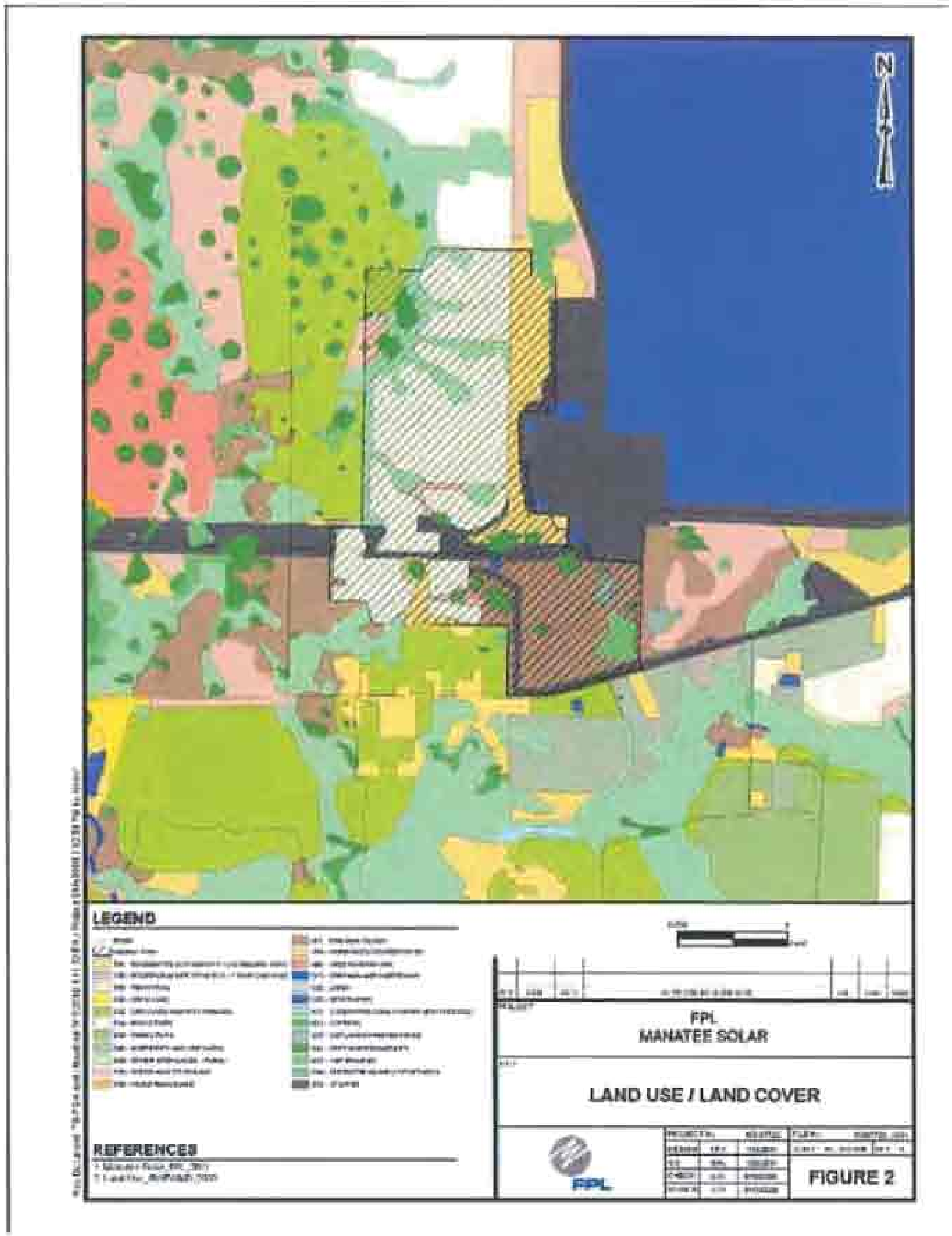

Manatee Solar
LEGEND
Manatee Solar
REFERENCES
FPL
MANATEE SOLAR
USGS LOCATION MAP
FIGURE 1


LEGEND
REFERENCES
FPL
MANATEE SOLAR
LAND USE / LAND COVER
FPL
FIGURE 2

Environmental and Land Use Information: Supplemental Information

Potential Site #4: Martin County

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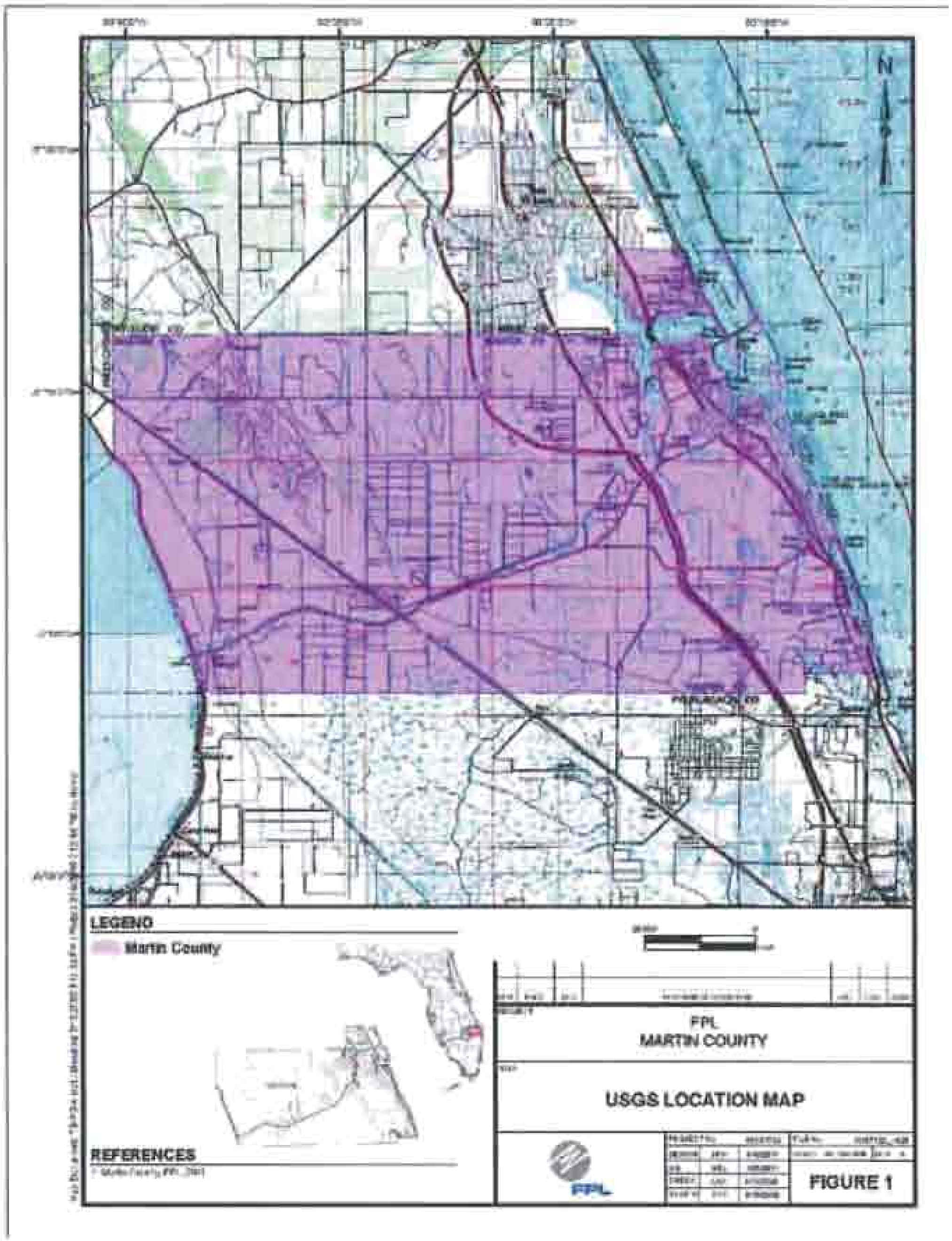
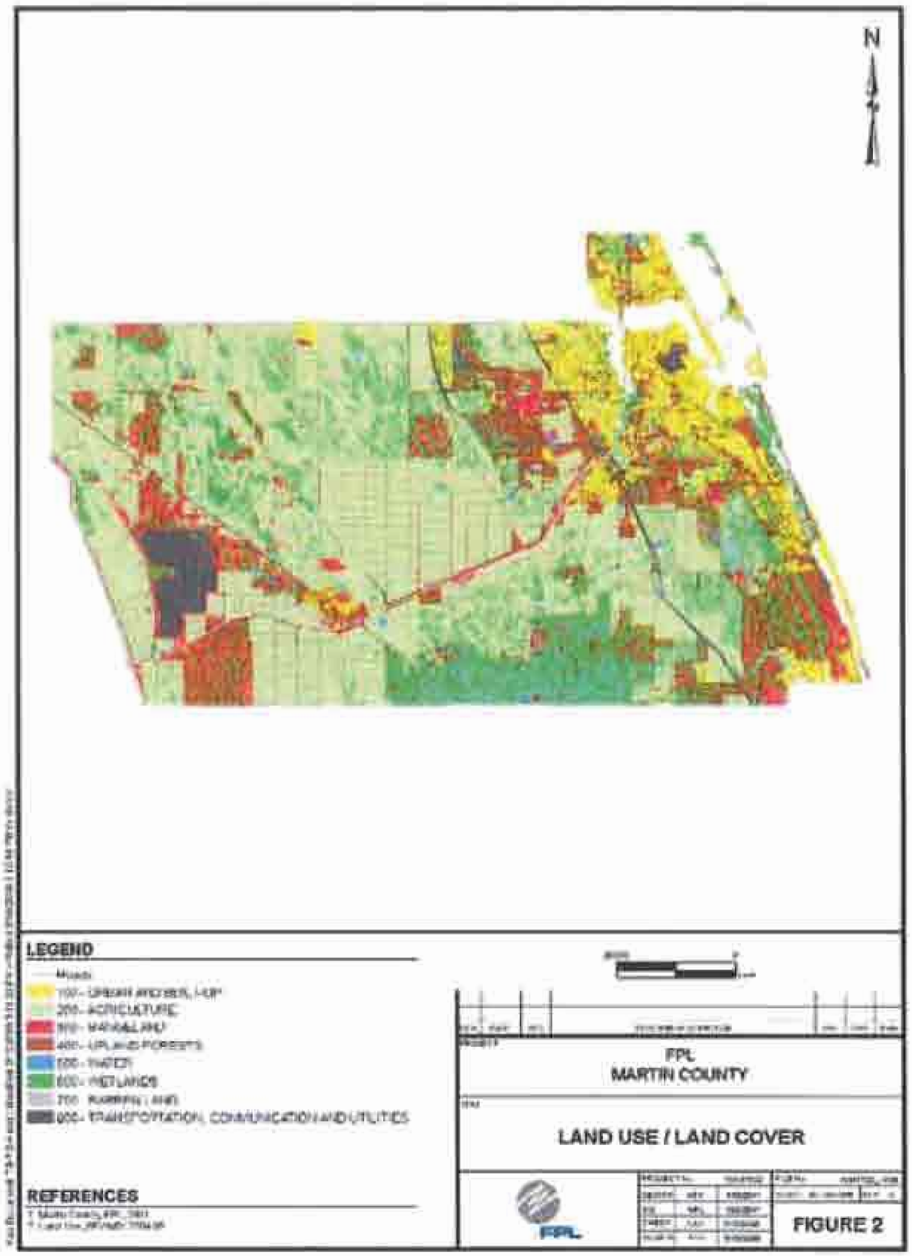

LEGEND
Martin County
REFERENCES
FPL
MARTIN COUNTY
USGS LOCATION MAP
FPL
FIGURE 1


N
LEGEND
200 - AGRICULTURE
400 - UPLAND FORESTS
500 - WATER
600 - WETLANDS
800 - TRANSPORTATION, COMMUNICATION AND UTILITIES
REFERENCES
FPL
MARTIN COUNTY
LAND USE / LAND COVER
FPL
FIGURE 2

CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information." These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints: external limitations and internal limitations. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important since they affect the development of assumptions for the amount of external assistance that is available to the FPL system as well as the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In the loss of load probability (LOLP) portion of its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new generating units that minimize adverse impacts to the flow of electricity within FPL's system. The internal transmission limitations are also addressed by developing the direct costs for siting new units at different locations, by evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system, and/or by evaluating the costs of transmission additions that may be needed to address regional concerns regarding an imbalance between load and generation in a given region. Both of these site- and system-related transmission costs are developed for each different unit/unit location option or groups of options. When analyzing DSM portfolios, such as in a DSM Goals docket, FPL also examines the potential of utility DSM energy efficiency programs to avoid/defer regional transmission expenditures that would otherwise be needed to import power into that region by lowering electrical load in Southeastern Florida. In addition, transfer limits for capacity and energy that can be

imported into the Southeastern Florida region (Miami-Dade and Broward Counties) of FPL's system are also developed for use in FPL's production costing analyses. (A further discussion of the Southeastern Florida region of FPL's system, and the need to maintain a regional balance between generation and transmission contributions to meet regional load, is found in Chapter III.)

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's planned transmission facilities to interconnect and integrate generating units in FPL's resource plans, including those transmission facilities that must be certified under the Transmission Line Siting Act, are presented in Chapter III.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements for the FPL system.[7]

The load forecast that is presented in FPL's 2014 Site Plan was developed in October 2014. The only load forecast sensitivities analyzed during 2013/early 2014 were high load forecast sensitivities developed to analyze FPL's potential future natural gas needs and to analyze the quality of FPL's future reserves.

[7] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis (i.e., when only new generating options are considered), the lowest electric rate basis approach and the lowest system cumulative present value of revenue requirements basis approach yield identical results in terms of which resource options are more economic. In such cases FPL evaluates resource options on the simpler-to-calculate (but equivalent) lowest cumulative present value system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its fuel price forecasts are discussed in Chapter III of this document. FPL used three fuel cost, and three environmental compliance cost, forecasts in analyses supporting its 2013 nuclear cost recovery filing. Also, in response to a request from the FPSC Staff, FPL used three fuel cost forecasts in sensitivity case analyses for the 2014 DSM Goals docket.

A Medium fuel cost forecast is developed first. Then the Medium fuel cost forecast is adjusted upwards (for the High fuel cost forecast), or downwards (for the Low fuel cost forecast), by multiplying the annual cost values from the Medium fuel cost forecast by a factor of (1 + the historical volatility in the 12-month forward price, one year ahead) for the High fuel cost forecast, or by a factor of (1 – the historical volatility of the 12-month forward price, one year ahead) for the Low fuel cost forecast.

The resource plan presented in this Site Plan is based, in part, on those prior analyses. For that reason, this resource plan has not been further tested for different fuel cost forecasts.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item # 3, FPL used up to three fuel cost forecasts in its 2013/early 2014 resource planning analyses. While these forecasts did not represent a constant cost differential between oil/gas and coal, a variety of fuel cost differentials were represented in these forecasts.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 in Chapter I and Schedule 8 in Chapter III present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options in its resource planning work. A summary of this information for the new capacity options FPL currently projects to add over the reporting horizon for this document is presented on the Schedule 9 forms in Chapter III.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

During 2013, FPL used the following financial assumptions: i) a capital structure of 40.38% debt and 59.62% equity; (ii) a 4.79% cost of debt; (iii) a 10.5% return on equity; and (iv) an after-tax discount rate of 7.45%. In early 2014, the cost of debt and the after-tax discount rate changed slightly to 5.14% and 7.54%, respectively. The other assumptions did not change. No sensitivities of these financial assumptions were used in FPL's 2013/early 2014 resource planning work.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item # 2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective yield identical results in terms of which resource options are more economic when DSM levels are unchanged between competing resource plans. Therefore, in planning work in which DSM levels were unchanged, the equivalent, but simpler-to-calculate, cumulative present value of revenue requirements perspective was utilized.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses three system reliability criteria in its resource planning work that addresses generation, purchase, and DSM options. One criterion is a minimum 20% Summer and Winter reserve margin. Another reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). The third criterion is a minimum 10% generation-only reserve margin (GRM) criterion. These three reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability analysis work, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the Reliability Standards established by the North American Electric Reliability Council (NERC). The *NERC Reliability Standards* are available on the internet site (http://www.nerc.com/).

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Facility Rating Methodology* document that are also available on the internet under the Interconnection Request Information, and FPL Facility Ratings Methodologies, directories respectively
at https://www.oatioasis.com/FPL/index.html.

Generally, FPL limits its transmission facilities to 100% of the applicable thermal rating. The normal and contingency voltage criteria for FPL stations are provided below:

	Normal/Contingency	
Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09
Turkey Point (*)	1.01/1.01	1.06/1.06
St. Lucie (*)	1.00/1.00	1.06/1.06

(*) Voltage range criteria for FPL's Nuclear Power Plants

There may be isolated cases for which FPL may have determined that it is acceptable to deviate from the general criteria stated above. There are several factors that could influence these criteria, such as the overall number of potential customers that may be impacted, the probability of an outage actually occurring, or transmission system performance, as well as others.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The projected impacts of FPL's DSM programs on demand and energy consumption are revised periodically. Engineering models, calibrated with current field-metered data, are updated at regular intervals. Participation trends are tracked for all of FPL's DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants. For its load management programs, FPL conducts periodic tests of the load control equipment to ensure that the equipment is functioning correctly. These tests, plus actual, non-test load management events, also allows FPL to gauge the MW reduction capabilities of its load management programs on an on-going basis.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The Executive Summary and Chapter III provide a discussion of a variety of system concerns/issues that influence FPL's resource planning process. Please see those chapters for a discussion of those concerns/issues.

In addition to these system concerns/issues, there are other strategic factors FPL typically considers when choosing between resource options. These include the following: (1) technology risk; (2) environmental risk, and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology, which has not achieved general commercial acceptance, has a higher risk than a technology in wide use and, therefore, assuming all else equal, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the FPL system, including environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for FPL's resource plan are those which minimize environmental impacts for the FPL system as a whole through highly efficient fuel use, state of the art environmental controls, generating technologies that do not utilize fossil fuels (such as nuclear and solar), etc.

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decision-making, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As shown in this 2014 Site Plan, FPL's resource plan currently reflects the following major supply-side resource additions: the on-going modernization at Port Everglades, on-going upgrading of CTs in several CCs throughout FPL's system, the projected addition of CTs at FPL's Lauderdale plant site, the implementation of the previously executed EcoGen PPA, a projected new CC unit (at a site that has not yet been selected), and the projected Turkey Point Units 6 & 7.

In regard to the above capacity additions for which a need determination has already been granted, Turkey Point Units 6 & 7, did not lend themselves to a request for proposal (RFP) approach involving bids from third parties who would build new nuclear generation capacity. In addition, nuclear capacity additions are exempted from the Commission's Bid Rule by section 403.519 (4) (c). For nuclear projects, FPL's procurement activities are conducted to ensure the best combination of quality and cost for the delivered products. In regard to the modernization project at Port Everglades, the project received a Commission waiver from the Bid Rule due to attributes specific to the Port Everglades site and to modernization projects in general (such as use of existing land, water, transmission, etc.) plus other economic benefits to FPL's customers. This waiver from the Bid Rule was granted in Order No. PSC-11-0360-PAA-EI for Port Everglades.

CT upgrades are currently taking place at several CC units throughout the FPL system. FPL was approached by the original equipment manufacturer (OEM) of the CTs regarding the possibility of upgrading these units. Following negotiations with the OEM, and economic analyses that showed that upgrading was cost-effective for FPL's customers, the decision was made to proceed with the CT upgrades. That process is underway and is scheduled to be completed in 2015.

In regard to the addition of five new CTs at FPL's Lauderdale plant site, FPL anticipates selecting the CTs through negotiations with, and/or competitive solicitation of, CT manufacturers. The EcoGen PPA, which was approved by the Commission in Order No. PSC-13-0205-CO-EQ dated 5/21/13, was the result of negotiations between EcoGen and FPL.

Identification of projected self-build options, beyond those units already approved by the FPSC and Governor and Siting Board or units, such as the 2019 CC unit presented in this Site Plan, is required of FPL in its Site Plan filings and represents FPL's current view of alternatives that appear to be FPL's best, most cost-effective self-build options at present. FPL reserves the right to refine its planning analyses and to identify and evaluate other options before making decisions regarding future capacity additions. Such refined analyses have the potential to yield a variety of self-build options, some of which might not require an RFP. If an RFP is issued for Supply options, FPL reserves the right to choose the best alternative for its customers, even if that option is not an FPL self-build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

(1) FPL has identified the need for a new 230 kV transmission line that required certification under the Transmission Line Siting Act which was issued in April 2006. The new line is to be completed in two phases connecting FPL's St. Johns Substation to FPL's Pringle Substation (shown on Table III.E.1 in Chapter III). Phase 1 was completed in May 2009 and consisted of a new line connecting Pringle to a new Pellicer Substation. Phase 2 is planned to connect St. Johns to Pellicer and is scheduled to be completed by December 2018. The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

(2) FPL has identified the need for a new 230 kV transmission line (by December 2014) that required certification under the Transmission Line Siting Act which was issued on November 2008. The new line will connect FPL's Manatee Substation to FPL's proposed Bob White Substation (also shown on Table III.E.1 in Chapter III). The construction of this line, scheduled to be completed in 2014, is necessary to serve existing and future customers in the Manatee and Sarasota areas in a reliable and effective manner.

Ten Year Power Plant Site Plan

2015-2024

Submitted To:

Florida Public Service Commission

Miami, Florida
April 2015

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List of Figures and Tables

List of Schedules

Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan (Site Plan). This Site Plan should include an estimate of the utility's future electric power generating needs, a projection of how these estimated generating needs could be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The information contained in this Site Plan is compiled and presented in accordance with Rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains uncertain forecasts and tentative planning information. Forecasts evolve, and all planning information is subject to change, at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This Site Plan document is based on Florida Power & Light Company's (FPL's) integrated resource planning (IRP) analyses that were carried out in 2014 and that were on-going in the first Quarter of 2015. The forecasted information presented in this plan addresses the years 2015 through 2024.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and the resulting forecast of seasonal peaks and annual energy usage, is presented in Chapter II. Included in this discussion is the projected significant impact of federal and state energy efficiency codes and standards.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, based on FPL's IRP work in 2014 and early 2015. This chapter also discusses a number of factors or issues that either have changed, or may change, the resource plan presented in this Site Plan. Furthermore, this chapter discusses FPL's previous and planned demand side management (DSM) efforts, the projected significant impact of the combined effects of FPL's DSM plans and state/federal energy efficiency codes and standards, FPL's previous and planned renewable energy efforts, projected transmission planning additions, and FPL's fuel cost forecasting processes.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as Preferred and Potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional information that is included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	***Abbreviation***	***Definition***
Unit Type	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	ST	Steam Unit (Fossil or Nuclear)
	PV	Photovoltaic
Fuel Type	NUC	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	Solar	Solar Energy
	SUB	Sub Bituminous Coal
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	L	Regulatory approval pending. Not under construction
	P	Planned Unit
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	ESP	Electrostatic Precipitators

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Executive Summary

Florida Power & Light Company's (FPL's) 2015 Ten Year Power Plant Site Plan (Site Plan) presents FPL's current plans to augment and enhance its electric generation capability (owned or purchased) as part of its efforts to meet FPL's projected incremental resource needs for the 2015 - 2024 time period. By design, the primary focus of this document is on projected supply side additions; *i.e.*, electric generation capability and the sites for these additions. The supply side additions discussed in this document are resources projected to be needed, based on FPL's load forecast, after accounting for FPL's demand side management (DSM) resource additions. New DSM Goals for FPL for the time period 2015 through 2024 were set in November 2014 by the Florida Public Service Commission (FPSC). Consequently, the level of DSM additions reflected in the 2015 Site Plan is consistent with these newly approved DSM Goals. DSM is discussed later in this summary and in Chapters II and III.

In addition, FPL's load forecast accounts for a significant amount of efficiency that results from federal and state energy efficiency codes and standards. The projected impacts of these codes and standards are directly accounted for in FPL's load forecast and are discussed in Chapter II.

The resource plan presented in FPL's 2015 Site Plan contains both similarities and differences when compared to the resource plan presented in FPL's 2014 Site Plan. There are a number of factors that have either contributed to the differences between the resource plan presented in this Site Plan and the resource plan that was previously presented in FPL's 2014 Site Plan, or which may influence FPL's on-going resource planning efforts. These factors could result in future changes to the resource plan presented in this document. A brief discussion of these similarities, differences, and factors is provided below. Additional information regarding these topics is presented in Chapters II and III.

I. Similarities Between the Current Resource Plan and the Resource Plan Previously Presented in FPL's 2014 Site Plan:

There are three key similarities between the current resource plan presented in this document and the resource plan that was discussed in the 2014 Site Plan.

Similarity # 1: Modernizations of Existing Power Plant Sites.

As discussed in previous Site Plans, FPL has been in the process of modernizing several existing power plant sites during the last few years. These modernizations consist of replacing old existing steam generating units with modern, highly efficient combined cycle (CC) generating units. The modernizations of FPL's existing Cape Canaveral and Riviera Beach plant sites were completed in 2013 and 2014, respectively. The last of the previously approved modernization projects, the modernization of FPL's existing Port Everglades plant site, is underway and projected to be completed in 2016.

Similarity # 2: Specific generating units are projected to be retired and/or converted to synchronous condenser operation.

In the last several years, FPL has retired a number of older, less efficient generating units including: Sanford Unit 3, Cutler Units 5 & 6, Cape Canaveral Units 1 & 2, Riviera Beach Units 3 & 4, and Port Everglades Units 1 – 4. In addition, Turkey Point Unit 2 has been converted to operate in synchronous condenser mode to provide voltage support for the transmission system in Southeastern Florida.

This trend is projected to continue. As discussed in FPL's 2014 Site Plan, Putnam Units 1 & 2 were retired at the end of 2014. In addition, similar to the earlier conversion of Turkey Point Unit 2, FPL projects that Turkey Point Unit 1 will be converted to run in synchronous condenser mode starting in 2016.

Similarity # 3: A number of older gas turbine peaking units are projected to be retired and replaced with modern combustion turbine peaking units.

In FPL's 2014 Site Plan, FPL projected that it would retire all of its existing gas turbine (GT) units in Broward County at its Lauderdale and Port Everglades sites (a decrease in peaking generating capacity of 1,260 MW) and partially replace this peaking capacity with the installation of 5 new combustion turbine (CT) units at the Lauderdale site (an increase of 1,005 MW). These changes were projected to be completed in 2019. These changes to FPL's generating system were based on concerns regarding whether the older, existing GTs would allow FPL to be able to meet the new EPA 1-hour standards for nitrogen dioxide and sulfur dioxide. Economic analyses now indicate that it is cost-effective to retire and replace a number of the existing GTs at an earlier date. Based on these analyses, FPL currently projects the retirement of a number of its existing GTs, including: 22 of 24 GTs at the Lauderdale site, all 12 GTs at the Port Everglades site, and 10 of 12 GTs at the Fort Myers plant site. Two of the existing GTs at the Lauderdale site, and two of the existing GTs at the Ft. Myers site, will be retained for black start capability. In conjunction with the retirement of these peaking units, FPL is adding a number of new, larger, and more efficient CTs: 5 at the Lauderdale site and 2 at the Fort Myers site. Also, the two existing CTs at the Fort Myers site will undergo capacity upgrades. In total, the net effect of the GT retirements, plus new/upgraded CTs, is a net reduction of approximately 40 MW in net peaking capability. All of these changes are projected to be completed by the end of 2016.

II. Differences Between the Current Resource Plan and the Resource Plan Previously Presented in FPL's 2014 Site Plan:

There are four key differences between the current resource plan presented in this document and the resource plan previously presented in the 2014 Site Plan. These differences are discussed below in chronological order as they pertain to FPL's current resource plan.

Difference # 1: FPL no longer projects that it will serve Vero Beach's electrical load.

Difficulties in the negotiations among the parties involved have led FPL to no longer project that it will serve Vero Beach's electrical load as had been assumed in FPL's most recent Site Plans and load forecasts. This factor results in a reduction of FPL's forecasted load. To the extent circumstances change and a consummation of the sale once again seems likely, FPL will reincorporate this load into its forecast.

Difference # 2: FPL's power purchase agreement with Cedar Bay will be terminated in 2015.

FPL anticipates terminating its existing power purchase agreement for 250 MW of coal-fired capacity from the Cedar Bay generating facility at the end of August 2015 as a result of a Purchase and Sale Agreement between FPL and Cedar Bay Generating Company, L.P. FPL would then own the unit starting on September 1, 2015. FPL currently anticipates that it will not need the unit for economic purposes after 2016 and, if that proves to be the case, would retire the unit at that time. FPL filed for FPSC approval of the Purchase and Sale Agreement in the first quarter of 2015.

Difference # 3: FPL will approximately triple its solar generating capacity by the end of 2016.

FPL will be adding three new photovoltaic (PV) facilities by the end of 2016. Each of the PV facilities will be approximately 74.5 MW (nameplate rating, AC). As a result, FPL's solar generation capacity will increase from its current 110 MW to approximately 333 MW. The new PV installations are projected to be sited in Manatee, Charlotte, and DeSoto counties. The economics of these specific PV projects are aided by the fact that the sites are located close to existing electric infrastructure, including tranmission lines and electric substations, and by the fact that bringing these solar facilities into service prior to the end of 2016 will allow the facilities to take advantage of the current 30% investment tax credit that is scheduled to be reduced to 10% beginning in 2017.

Difference # 4: The projected in-service dates of FPL's planned two new nuclear units, Turkey Point 6 & 7, have now been moved outside of the 10-year reporting period of this document.

In recent Site Plans, the earliest practical deployment dates for the new Turkey Point 6 & 7 nuclear unit were identified as 2022 and 2023, and these two dates were used as the projected in-service dates for these units. However, in the second half of 2014, the Nuclear Regulatory Commission (NRC) issued a new schedule for completing its review of FPL's Combined Operating License Application (COLA) for Turkey Point 6 & 7. The NRC's new schedule now projects that its review will not be completed until late 2016. As a consequence of the NRC delay, and the impacts of the recently amended Florida nuclear cost recovery (NCR) statute, FPL now projects that the earliest practical deployment dates for Turkey Point 6 & 7 will fall outside of the 10-year time period of 2015 through 2024 that is addressed in this Site Plan document. However, emissions-free, baseload capacity and energy from nuclear power remains an important part of FPL's resource plans. For that reason, Chapter IV provides detailed information regarding the Turkey Point site for these two new nuclear units.

III. Factors Which Have Impacted, or Which Could Impact, FPL's Resource Plan:

In addition to these key similarities and differences, there are a number of factors which have impacted, or which may impact, FPL's resource plan. Six (6) such factors are summarized in the text below and these are presented in no particular order. These factors, and/or their corresponding impacts on FPL's resource plan, are further discussed in Chapters II and III.

The first and second of these factors are on-going system concerns that FPL has considered in its resource planning work for a number of years. The first factor is the objective to maintain/enhance fuel diversity in the FPL system. Diversity is sought both in terms of the types of fuel utilized by FPL and how these fuels are supplied to FPL. (Related to the fuel diversity objective, FPL also seeks to enhance the efficiency with which it uses fuel to generate electricity.) The second factor is the need to maintain a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward counties. This balance has both reliability and economic implications for FPL's system.

The third factor is also a system concern that FPL has considered in its resource planning for several years. This factor addresses system reliability and focuses upon the desirability of maintaining an appropriate balance of DSM and supply resources from a system reliability perspective. FPL addresses this through the use of a 10% generation-only reserve margin (GRM) reliability criterion in its resource planning work to complement its other two reliability criteria: a 20% total reserve margin criterion for Summer and Winter, and an annual 0.1 day/year loss-of-load-probability (LOLP) criterion. Together, these three criteria allow FPL to address this specific concern regarding system reliability in a comprehensive manner.

The fourth factor is the significant and increasing impact that federal and state energy efficiency codes and standards are having on FPL's projected demand and energy load forecasts. The incremental impacts of these energy efficiency codes and standards during the 2015 through 2024 time period are projected to reduce FPL's forecasted Summer peak load by more than 2,000 MW, and reduce annual energy consumption by more than 6,800 GWh, by 2024. In addition, this mandated energy efficiency significantly reduces the potential for cost-effective energy efficiency that might otherwise have been obtained through FPL's DSM programs.

The fifth factor is the increasing cost competitiveness of utility-scale PV facilities due to the continued decline of the cost of PV modules. Utility-scale PV facilities are the most economical way to utilize PV technology and the declining costs of PV modules have resulted, for the first time, in utility scale PV now being competitive on FPL's system at specific, highly advantaged sites. As a result, FPL's current resource plan presented in this year's Site Plan includes approximately 223 MW (nameplate, AC) of new PV facilities at three specific sites that offer particular cost advantages. The projected new PV facilities are also presented in Table ES – 1 at the end of this executive summary.

The sixth factor is environmental regulation, particularly the U.S. Environmental Protection Agency's (EPA) proposed Clean Power Plan issued in June 2014. The intent of the Clean Power Plan is to set carbon dioxide (CO_2) emission limits for each state. The EPA is scheduled to issue final rules and emission limits in June 2015 (several months after this Site Plan is filed). The current draft rules call for each state to submit its compliance plan by June 2016 (although a delay of at least one year is possible). FPL's resource planning work will account for the CO_2 limits as they are finalized and FPL expects to be actively engaged in the development of Florida's statewide compliance plan.

Each of these factors will continue to be examined in FPL's on-going resource planning work during the rest of 2015 and in future years.

Table ES-1 presents a current projection of major changes to specific generating units and firm capacity purchases for 2015 – 2024. Although this table does not specifically identify the impacts of projected DSM additions on FPL's resource needs and resource plan, FPL's projected DSM additions that are consistent with its new DSM Goals have been fully accounted for in the resource plan presented in this Site Plan.

In addition, this table shows the addition of an FPL CC unit in 2019. This potential new unit represents FPL's most economic self-build generation option for 2019 and it appears in this table and this Site Plan as a placeholder for that year. In March 2015, FPL issued a capacity request for proposals (RFP) that solicited proposals from interested parties for generation that could supply firm, dispatchable capacity starting in mid-2019. Proposals are due in May 2015. At that time, FPL and an independent evaluator will conduct separate reviews of proposals received in response to the RFP and of FPL's potential self-build

CC unit. At the conclusion of the analyses, FPL will file for a determination of need, or approval of cost recovery, from the Florida Public Service Commission for the generation option(s) that was determined in these analyses to be the best selection for FPL's customers beginning in 2019.

Table ES-1: Projected Capacity & Firm Purchase Power Changes

Year *	Projected Capacity & Firm Purchase Power Changes	Summer MW	Date	Summer Reserve Margin **
2015	Turkey Point	(22)	January-15	
	Fort Myers	(5)	January-15	
	Lauderdale GT	(8)	January-15	
	Lauderdale GT	(8)	January-15	
	Port Everglades GT	(8)	January-15	
	Palm Beach SWA - additional firm capacity	70	June-15	
	Martin	(3)	June-15	
	Scherer	(9)	June-15	
	Total of MW changes to Summer firm capacity:	**6**		**26.7%**
2016	Cedar Bay -PPA retirement	(250)	October-15	
	Cedar Bay -FPL Ownership	250	October-15	
	UPS Replacement	(928)	December-15	
	Fort Myers 2	37	June-16	
	Fort Myers GTs 1 -10	(540)	June-16	
	Lauderdale GTs 1- 12	(412)	June-16	
	Martin	2	June-16	
	Port Everglades Next Generation Clean Energy Center	1,237	June-16	
	Sanford	3	June-16	
	Total of MW changes to Summer firm capacity:	**(601)**		**21.3%**
2017	Babcock Solar Energy Center (Charlotte) ***	38	September-16	
	Citrus Solar Energy Center (DeSoto) ***	38	September-16	
	Manatee Solar Energy Center ***	38	September-16	
	Lauderdale GTs 13- 22	(343)	October-16	
	Turkey Point Unit 1 synchronous condenser	(396)	October-16	
	Port Everglades GTs	(412)	December-16	
	Cedar Bay	(250)	December-16	
	Lauderdale GTs - 5 CT	1,155	December-16	
	Fort Myers GTs - 2 CT	462	December-16	
	Fort Myers 3A&B - upgraded	50	December-16	
	Martin	2	January-17	
	Sanford	1	January-17	
	Sanford	4	January-17	
	Turkey Point #5	23	June-17	
	Manatee	4	June-17	
	Total of MW changes to Summer firm capacity:	**415**		**20.9%**
2018	Unspecified Short-Term Purchase	207	May-18	
	Turkey Point Nuclear Unit #3	20	June-18	
	Turkey Point Nuclear Unit #5	3	June-18	
	Total of MW changes to Summer firm capacity:	**227**		**20.0%**
2019	Unspecified Short-Term Purchase	(207)	September-18	
	SJRPP suspension of energy	(382)	2nd Quarter	
	Turkey Point Nuclear Unit #4	20	June-19	
	Okeechobee Next Generation Clean Energy Center ****	1,622	June-19	
	Total of MW changes to Summer firm capacity:	**1,053**		**22.8%**
2020	---	---	---	
	Total of MW changes to Summer firm capacity:	**0**		**21.3%**
2021	Eco-Gen PPA firm capacity	180	January-21	
	Cape Next Generation Clean Energy Center	88	June-21	
	Total of MW changes to Summer firm capacity:	**268**		**22.0%**
2022	Riviera Beach Next Generation Clean Energy Center	86	June-22	
	Total of MW changes to Summer firm capacity:	**86**		**20.9%**
2023	Unsited CC	1,317	June-23	
	Total of MW changes to Summer firm capacity:	**1,317**		**24.4%**
2024	---	---	---	
	Total of MW changes to Summer firm capacity:	**0**		**22.2%**

* Year shown reflects when the MW change begins to be accounted for in Summer reserve margin calculations.

** Winter Reserve Margins are typically high than Summer Reserve Margin. Winter Reserve Margin are shown on Schedule 7.2 in Chapter III.

*** MW values shown represent the firm capacity assumption for each 74.5 MW nameplate (AC) PV facility.

**** The Okeechobee generating is FPL's best self-build option for 2019. During 2015 it will be evaluated versus

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CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 9.1 million people. FPL served an average of 4,708,829 customer accounts in 35 counties during 2014. These customers were served by a variety of resources including: FPL-owned fossil-fuel, renewable, and nuclear generating units, non-utility owned generation, demand side management (DSM), and interchange/purchased power.

I.A. FPL-Owned Resources

The existing FPL generating resources are located at 14 generating sites distributed geographically around its service territory, plus one site in Georgia (partial FPL ownership of one unit) and one site in Jacksonville, Florida (partial FPL ownership of two units). As of December 31, 2014, FPL's electrical generating facilities consisted of: four nuclear units, three coal units, 15 combined cycle (CC) units, five fossil steam units, 48 combustion gas turbines, two simple cycle combustion turbines, and two photovoltaic facilities[1]. The locations of these 79 generating units are shown on Figure I.A.1 and in Table I.A.1.

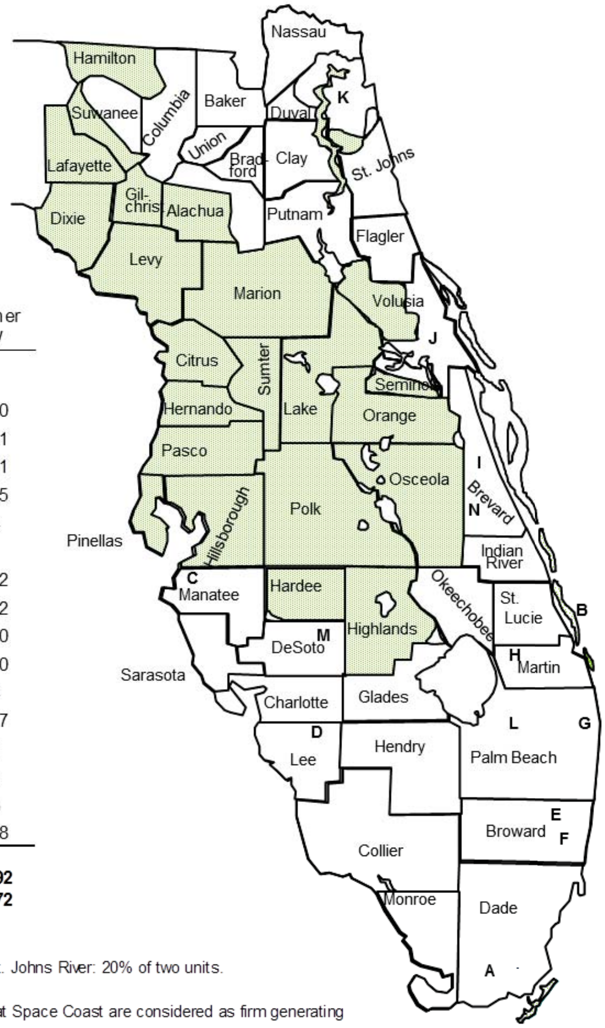
FPL's bulk transmission system, including both overhead and underground lines, is comprised of 6,888 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 596 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2.

1 FPL also has one 75 MW solar thermal facility at its Martin plant site. This facility does not generate electricity as the other units mentioned above do. Instead, it produces steam that reduces the use of fossil fuel to produce steam for electricity generation.

FPL Generating Resources by Location

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	4	3,220
B	St. Lucie [1/]	2	1,821
C	Manatee	3	2,761
D	Fort Myers	3	1,755
E	Lauderdale	2	884
F	Everglades [2/]	0	0
G	Riviera	1	1,212
H	Martin	5	3,722
I	Cape Canaveral	1	1,210
J	Sanford	2	2,010
K	St. John's River Power Park [1/]	2	254
L	West County	3	3,657
M	DeSoto [3/]	1	25
N	Space Coast [3/]	1	10
	Scherer [4/]	1	643
	Gas Turbines	48	1,908
	Total System Generation =	**79**	**25,092**
	System Firm Generation =		**25,072**



1/ Represents FPL's ownership share: St Lucie nuclear: 100% Unit 1, 85% Unit 2: St. Johns River: 20% of two units.
2/ Will be site of new Modernization Plant.
3/ Approximately 46% of the 25 MW of PV at DeSoto and 32% of the 10 MW of PV at Space Coast are considered as firm generating capacity for Summer reserve margin purposes.
4/ The Scherer unit is located in Georgia and is not shown on this map.

Non-FPL Territory

Figure I.A.1: Capacity Resources by Location (as of December 31, 2014)

Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2014)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Nuclear				
St. Lucie [1/]	Hutchinson Island, FL	2	Nuclear	1,821
Turkey Point	Florida City, FL	2	Nuclear	1,632
Total Nuclear:		**4**		**3,453**
Coal Steam				
Scherer	Monroe County, Ga	1	Coal	643
St. John's River Power Park [2/]	Jacksonville, FL	2	Coal	254
Total Coal Steam:		**3**		**897**
Combined-Cycle				
Fort Myers	Fort Myers, FL	1	Gas	1,436
Manatee	Parrish, FL	1	Gas	1,143
Martin	Indiantown, FL	3	Gas	2,073
Sanford	Lake Monroe, FL	2	Gas	2,010
Cape Canaveral	Cocoa, FL	1	Gas/Oil	1,210
Lauderdale	Dania, FL	2	Gas/Oil	884
Riviera Beach	City of Riviera Beach, FL	1	Gas/Oil	1,212
Turkey Point	Florida City, FL	1	Gas/Oil	1,192
West County	Palm Beach County, FL	3	Gas/Oil	3,657
Total Combined Cycle:		**15**		**14,817**
Oil/Gas Steam				
Manatee	Parrish, FL	2	Oil/Gas	1,618
Martin	Indiantown,FL	2	Oil/Gas	1,649
Turkey Point	Florida City, FL	1	Oil/Gas	396
Total Oil/Gas Steam:		**5**		**3,663**
Gas Turbines(GT)				
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Total Gas Turbines/Diesels:		**48**		**1,908**
Combustion Turbines				
Fort Myers	Fort Myers, FL	2	Gas/Oil	319
Total Combustion Turbines:		**2**		**319**
PV				
DeSoto [3/]	DeSoto, FL	1	Solar Energy	25
Space Coast [3/]	Brevard County, FL	1	Solar Energy	10
Total PV:		**2**		**35**
Total System Generation as of December 31, 2013 =		**79**		**25,092**
System Firm Generation as of December 31, 2013 =				**25,072**

1/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/860. FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively.

2/ Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit. Represents FPL's ownership share: SJRPP coal: 20% of two units).

3/ Approximately 46% of the 25 MW of PV at DeSoto, and 32% of the 10 MW of PV at Space Coast, are considered as firm generating capacity for Summer reserve margin purposes.

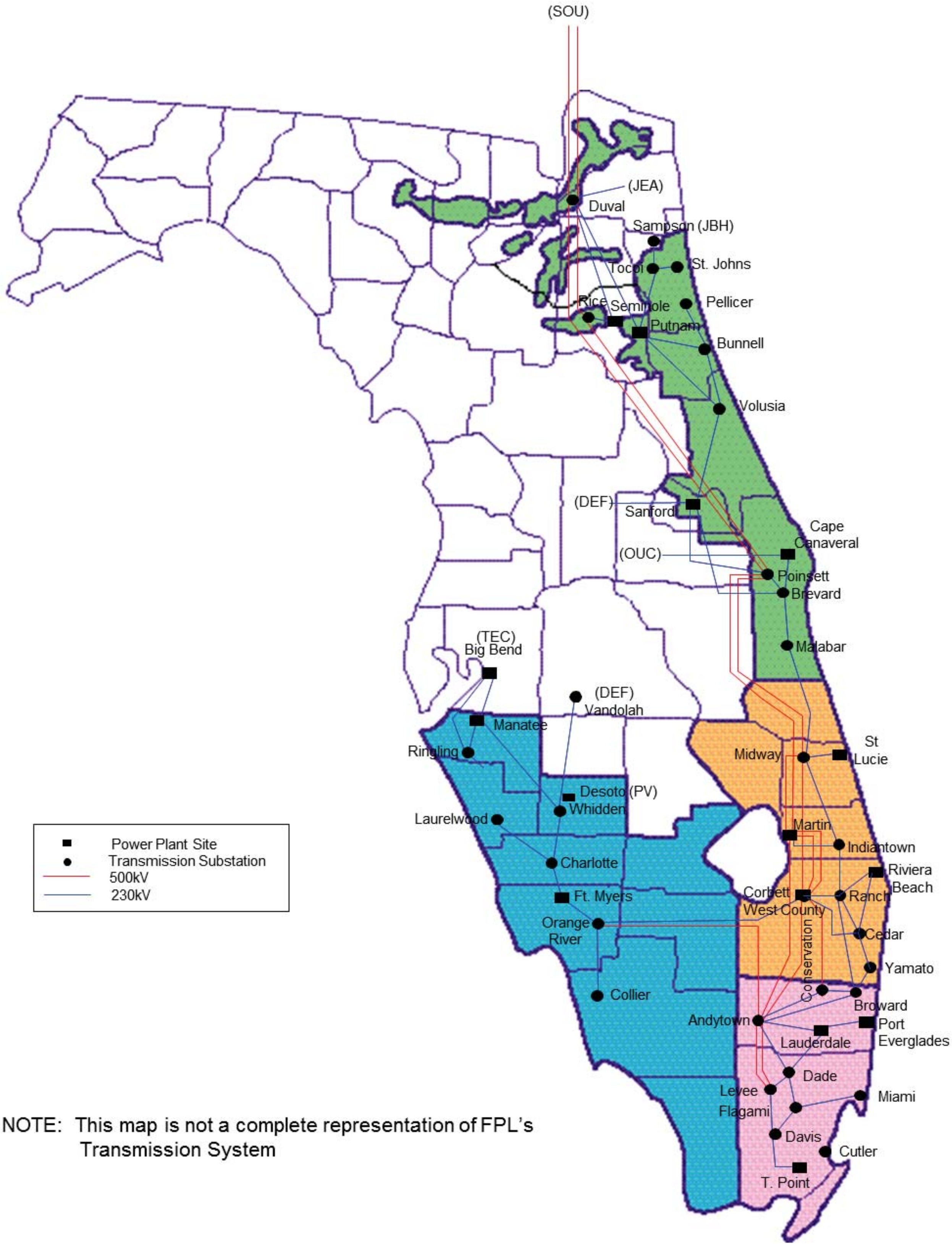


Figure I.A.2: FPL Substation and Transmission System Configuration

Description of Existing Resources

I.B Capacity and Energy Power Purchases

Firm Capacity: Purchases from Qualifying Facilities (QF)

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has contracts with seven qualifying facilities; i.e., cogeneration/small power production facilities, to purchase firm capacity and energy during the 10-year reporting period of this Site Plan. This is shown in Table I.A.3, Table I.B.1, and Table I.B.2.

A cogeneration facility is one that simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) used for industrial, commercial, or cooling and heating purposes. A small power production facility is one that does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses solar, wind, waste, geothermal, or other renewable resources as its primary energy source.

Firm Capacity: Purchases from Utilities

FPL has a Unit Power Sales (UPS) contract to purchase 928 MW from the Southern Company (Southern) through the end of December 2015. This capacity is being supplied by Southern from a mix of gas- and coal-fired units.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 382 MW (Summer) and 389 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. However, due to Internal Revenue Service (IRS) regulations, the total amount of energy that FPL may receive from this purchase is limited. FPL currently assumes, for planning purposes, that this limit will be reached in the second quarter of 2019. Once this limit is reached, FPL will be unable to receive firm capacity and energy from these purchases. (However, FPL will continue to receive firm capacity and energy from its ownership portion of the SJRPP units.)

These purchases are shown in Table I.A.3, Table I.B.1, and Table I.B.2. FPL's ownership interest in the SJRPP units is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.

Firm Capacity: Other Purchases

FPL has two other firm capacity purchase contracts with non-QF, non-utility suppliers. These contracts with the Palm Beach Solid Waste Authority were previously listed as QFs. However, the addition of a second unit in 2015 will cause both units to no longer meet the statutory definition of a QF. Therefore, these contracts are listed as “Other Purchases” following the estimated in-service date of the new unit. Table I.B.1 and I.B.2 present the Summer and Winter MW, respectively, resulting from these contracts under the category heading of Other Purchases.

Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. Table I.A.3 shows the amount of energy purchased in 2014 from these facilities.

Table 1.A.3: Purchase Power Resources by Contract (as of December 31, 2014)

Firm Capacity Purchases (MW)	Location (City or County)	Fuel	Summer MW
I. Purchase from QF's: Cogeneration/Small Power Production Facilities			
Cedar Bay Generating Company	Duval	Coal (Cogen)	250
Indiantown Cogen LP	Martin	Coal (Cogen)	330
Broward South	Broward	Solid Waste	4
Broward North	Broward	Solid Waste	11
Palm Beach SWA - extension	Palm Beach	Solid Waste	40
		Total:	635
II. Purchases from Utilities			
UPS from Southern Company	Various Georgia	Coal/Gas	928
SJRPP	Jacksonville	Coal	382
		Total:	1,310
	Total Net Firm Generating Capability:		1,945

Non-Firm Energy Purchases (MWH)

Project	County	Fuel	Energy (MWH) Delivered to FPL in 2014
Okeelanta (known as Florida Crystals and New Hope	Palm Beach	Bagasse/Wood	87,690
Broward South*	Broward	Solid Waste	93,548
Broward North*	Broward	Solid Waste	57,806
Waste Management Renewable Energy*	Broward	Landfill Gas	34,265
Waste Management - Collier County Landfill*	Broward	Landfill Gas	24,928
Tropicana	Manatee	Natural Gas	7,172
Georgia Pacific	Putnam	Paper by-product	8,606
Rothenbach Park (known as MMA Bee Ridge)*	Sarasota	PV	286
First Solar*	Dade	PV	409
Customer Owned PV & Wind	Various	PV/Wind	1,505
INEOS Bio*	Indian River	Wood	325
Miami Dade Resource Recovery*	Dade	Solid Waste	146,417

*These Non-Firm Energy Purchases are renewable and are reflected on Schedule 11.1, rows 8 and 9, column 6.

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	01/25/94	08/31/15	250	0	0	0	0	0	0	0	0	0
Indiantown Cogen L.P.	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
U.S.EcoGen Clay[2/]	01/01/21	12/31/49	0	0	0	0	0	0	60	60	60	60
U.S.EcoGen Okeechobee[2/]	01/01/21	12/31/49	0	0	0	0	0	0	60	60	60	60
U.S.EcoGen Martin[2/]	01/01/21	12/31/49	0	0	0	0	0	0	60	60	60	60
		QF Purchases Subtotal:	**595**	**345**	**345**	**345**	**345**	**345**	**525**	**525**	**525**	**525**

II. Purchases from Utilities

	Contract Start Date	Contract End Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
UPS Replacement	06/01/10	12/31/15	928	0	0	0	0	0	0	0	0	0
SJRPP[3/]	04/02/82	2nd Qtr/2019	382	382	382	382	0	0	0	0	0	0
		Utility Purchases Subtotal:	**1,310**	**382**	**382**	**382**	**0**	**0**	**0**	**0**	**0**	**0**
		Total of QF and Utility Purchases =	**1,905**	**727**	**727**	**727**	**345**	**345**	**525**	**525**	**525**	**525**

III. Other Purchases

	Contract Start Date	Contract End Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Palm Beach SWA - Extension[1/]	01/10/12	04/01/32	40	40	40	40	40	40	40	40	40	40
Palm Beach SWA - Additional	06/01/15	04/01/32	70	70	70	70	70	70	70	70	70	70
Unspecified Purchases[4/]	05/01/18	09/30/18	0	0	0	207	0	0	0	0	0	0
		Other Purchases Subtotal:	**110**	**110**	**110**	**317**	**110**	**110**	**110**	**110**	**110**	**110**
		Total "Non-QF" Purchases =	**1,420**	**492**	**492**	**699**	**110**	**110**	**110**	**110**	**110**	**110**

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Summer Firm Capacity Purchases Total MW:	**2,015**	**837**	**837**	**1,044**	**455**	**455**	**635**	**635**	**635**	**635**

1/ When the second unit comes into commercial service at the Palm Beach SWA, neither unit will meet the standards to be a small power producer, and it will then be accounted for under "Other Purchases"

2/ The EcoGen units will enter service in 2019, however firm capacity will only be delivered starting in 2021.

3/ Contract end date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.

4/ These Unspecified Purchases are short-term purchases for the summer of 2018 that are included for resource planning purposes. No decision regarding such purchases is needed at this time.

Table I.B.2: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Company	01/25/94	08/31/15	250	0	0	0	0	0	0	0	0	0
Indiantown Cogen L.P.	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA - extension[1/]	01/10/12	04/01/32	0	0	0	0	0	0	0	0	0	0
U.S.EcoGen Clay[2/]	01/01/21	12/31/49	0	0	0	0	0	0	60	60	60	60
U.S.EcoGen Okeechobee[2/]	01/01/21	12/31/49	0	0	0	0	0	0	60	60	60	60
U.S.EcoGen Martin[2/]	01/01/21	12/31/49	0	0	0	0	0	0	60	60	60	60
		QF Purchases Subtotal:	**595**	**345**	**345**	**345**	**345**	**345**	**525**	**525**	**525**	**525**

II. Purchases from Utilities

	Contract Start Date	Contract End Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
UPS Replacement	06/01/10	12/31/15	928	0	0	0	0	0	0	0	0	0
SJRPP[3/]	04/02/82	2nd Qtr/2019	389	389	389	389	389	0	0	0	0	0
		Utility Purchases Subtotal:	**1,317**	**389**	**389**	**389**	**389**	**0**	**0**	**0**	**0**	**0**
		Total of QF and Utility Purchases =	**1,912**	**734**	**734**	**734**	**734**	**345**	**525**	**525**	**525**	**525**

III. Other Purchases

	Contract Start Date	Contract End Date	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Palm Beach SWA - Extension[1/]	01/10/12	04/01/32	40	40	40	40	40	40	40	40	40	40
Palm Beach SWA - Additional	06/01/15	04/01/32	0	70	70	70	70	70	70	70	70	70
		Other Purchases Subtotal:	**40**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**
		Total "Non-QF" Purchases =	**1,357**	**499**	**499**	**499**	**499**	**110**	**110**	**110**	**110**	**110**

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Winter Firm Capacity Purchases Total MW:	**1,952**	**844**	**844**	**844**	**844**	**455**	**635**	**635**	**635**	**635**

1/ When the second unit comes into service at the Palm Beach SWA, neither unit will meet the standards to be a small power producers, and will then be accounted for under "Other Purchases"
2/ The EcoGen units will enter service in 2019, however firm capacity will only be delivered starting in 2021.
3/ Contract end date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.

I.C Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include a number of conservation/energy efficiency and load management initiatives. FPL's DSM efforts through 2014 have resulted in a cumulative Summer peak reduction of approximately 4,793 MW at the generator and an estimated cumulative energy saving of approximately 70,997 Gigawatt-hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2014 have eliminated the need to construct the equivalent of approximately 14 new 400 MW generating units. New DSM Goals for FPL for the 2015 through 2024 time period were set by the FPSC in November 2014. The new DSM Goals are discussed in Chapter III.

Schedule 1

Existing Generating Facilities
As of December 31, 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Plant Name	Unit No.	Location	Unit Type	Fuel Pri.	Fuel Alt.	Fuel Transport. Pri.	Fuel Transport. Alt.	Alt. Fuel Days Use	Commercial In-Service Month/Year	Actual/ Expected Retirement Month/Year	Gen.Max. Nameplate KW	Net Capability [1/] Winter MW	Net Capability [1/] Summer MW
Cape Canaveral		Brevard County											
		19/24S/36E									1,295,400	1,355	1,210
	3		CC	NG	FO2	PL	TK	Unknown	Apr-13	Unknown	1,295,400	1,355	1,210
DeSoto [2/]		DeSoto County											
		27/36S/25E									25,000	25	25
	1		PV	Solar	Solar	N/A	N/A	Unknown	Oct-09	Unknown	25,000	25	25
Fort Myers		Lee County											
		35/43S/25E									2,653,800	2,553	2,403
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,721,490	1,491	1,436
	3		CT	NG	FO2	PL	TK	Unknown	Jun-03	Unknown	188,190	352	319
	1-12		GT	FO2	No	TK	No	Unknown	May-74	Unknown	744,120	710	648
Lauderdale		Broward County											
		30/50S/42E									1,873,968	1,884	1,724
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	483	442
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	483	442
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
Manatee		Manatee County											
		18/33S/20E									2,951,110	2,871	2,761
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	819	809
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	819	809
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,233	1,143
Martin		Martin County											
		29/29S/38E									4,317,510	3,866	3,722
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	829	823
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	832	826
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	489	469
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	489	469
	8 [3/]		CC	NG	FO2	PL	TK	Unknown	Jun-05	Unknown	1,224,510	1,227	1,135
Port Everglades		City of Hollywood											
		23/50S/42E									410,734	459	420
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	459	420
Riviera Beach		City of Riviera Beach											
		33/42S/432E									1,295,400	1,344	1,212
	5		CC	NG	FO2	PL	WA	Unknown	Apr-14	Unknown	1,295,400	1,344	1,212

1/ These ratings are peak capability.

2/ Approximately 46% of the 25 MW (Nameplate, AC) PV facility at DeSoto is considered as firm generating capacity for Summer reserve margin purposes and 0% is considered as firm capacity for Winter reserve margin purposes.

3/ Martin Unit 8 is also partially fueled by a 75 MW solar thermal facility that supplies steam when adequate sunlight is available, thus reducing fossil fuel use.

Schedule 1

Existing Generating Facilities
As of December 31, 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt.		Actual/			
						Fuel		Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Sanford		Volusia County											
		16/19S/30E									2,377,720	2,200	2,010
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,860	1,100	1,005
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	1,100	1,005
Scherer 2/		Monroe, GA									680,368	651	643
	4		ST	SUB	No	RR	No	Unknown	Jul-89	Unknown	680,368	651	643
Space Coast 3/		Brevard County											
		13/23S/36E									10,000	10	10
	1		PV	Solar	Solar	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10
St. Johns River		Duval County											
Power Park 4/		12/15/28E											
		(RPC4)									271,836	260	254
	1		ST	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	130	127
	2		ST	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	130	127
St. Lucie 5/		St. Lucie County											
		16/36S/41E									1,743,775	1,863	1,821
	1		ST	Nuc	No	TK	No	Unknown	May-76	Unknown	1,020,000	1,003	981
	2		ST	Nuc	No	TK	No	Unknown	Jun-83	Unknown	723,775	860	840
Turkey Point		Miami Dade County											
		27/57S/40E									3,380,960	3,322	3,220
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	398	396
	3		ST	Nuc	No	TK	No	Unknown	Nov-72	Unknown	877,200	839	811
	4		ST	Nuc	No	TK	No	Unknown	Jun-73	Unknown	877,200	848	821
	5		CC	NG	FO2	PL	TK	Unknown	May-07	Unknown	1,224,510	1,237	1,192
West County		Palm Beach County											
		29&32/43S/40E									4,100,400	4,005	3,657
	1		CC	NG	FO2	PL	TK	Unknown	Aug-09	Unknown	1,366,800	1,335	1,219
	2		CC	NG	FO2	PL	TK	Unknown	Nov-09	Unknown	1,366,800	1,335	1,219
	3		CC	NG	FO2	PL	TK	Unknown	May-11	Unknown	1,366,800	1,335	1,219
Total System Generating Capacity as of December 31, 2014 6/ =												**26,668**	**25,092**
System Firm Generating Capacity as of December 31, 2014 7/ =												**26,633**	**25,072**

1/ These ratings are peak capability.

2/ These ratings relate to FPL's 76.36% share of Plant Scherer Unit 4 operated by Georgia Power, and represent FPL's 73.923% owernership share available at point of interchange.

3/ Approximately 32% of the 10 MW (Nameplate, AC) PV facility at Space Coast is considered as firm generating capacity for Summer reserve margin purposes and 0% is considered as firm capacity for Winter reserve margin purposes.

4/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Units 1 and 2, excluding the Jacksonville Electric Authority (JEA) share of 80%.

5/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/860.FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively, as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.448% per unit.

6/ The Total System Generating Capacity value shown includes FPL-owned firm and non-firm generating capacity.

7/ The System Firm Generating Capacity value shown includes only firm generating capacity.

CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

II. A. Overview of the Load Forecasting Process

At FPL, long-term forecasts of sales, net energy for load (NEL), and peak loads typically are developed on an annual basis for resource planning work. FPL developed new long-term forecasts in late 2014 that replaced the previous long-term load forecasts used by FPL during 2014 in much of its resource planning work and which were presented in FPL's 2014 Site Plan. These new load forecasts are utilized throughout FPL's 2015 Site Plan and are a key input to the models used to develop FPL's integrated resource plan.

The following pages describe how forecasts are developed for each component of the long-term forecast including: sales, NEL, and peak loads. Consistent with past forecasts, the primary drivers to develop these forecasts include economic conditions and weather.

The projections for the national and Florida economies are obtained from IHS Global Insight, a leading economic forecasting firm. Population projections are obtained from the Florida Legislature's Office of Economic and Demographic Research (EDR). These projections are developed in conjunction with the Bureau of Economic and Business Research (BEBR) of the University of Florida. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects FPL's energy sales and peak demand. Three sets of weather variables are developed and used in FPL's forecasting models::

1. Cooling degree-hours based on 72^{o} F, winter heating degree-days based on 66^{o} F, and heating degree-days based on 45^{o} F are used to forecast energy sales.
2. The maximum temperature on the peak day and the build-up of cooling degree-hours prior to the peak are used to forecast Summer peaks.
3. The minimum temperature on the peak day and the build-up of heating degree-hours based on 66^{o} F on the morning of the peak are used to forecast Winter peaks.

The cooling degree-hours and winter heating degree-days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. Heating degree-days based on 45^{o} F are used to capture heating load resulting from sustained periods of unusually cold weather that are not fully captured by heating degree-days based on 66^{o} F. A composite hourly temperature profile is derived using hourly temperatures across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations where temperatures are obtained. In developing the composite hourly profile, these regional temperatures are weighted by regional energy sales. The resulting composite temperature is used to derive projected cooling and heating degree-hours and heating degree-days. Similarly, composite temperature and hourly profiles of temperatures are used to calculate the weather variables used in the Summer and Winter peak models.

II. B. Comparison of FPL's Current and Previous Load Forecasts

While reflecting some fluctuations by year, FPL's current load forecast is generally in line with the load forecast previously presented in its 2014 Site Plan. Three primary factors drive the current load forecast: projected population growth, the performance of Florida's economy, and energy efficiency codes and standards. An additional fourth factor, which represents a change in assumptions from the 2014 Site Plan, pertains to FPL's previously planned acquisition of the City of Vero Beach's electric system.

In early 2013, FPL came to an agreement with the City of Vero Beach to purchase the City's electric system. This agreement was approved by the City's voters on March 12, 2013. FPL projected in its 2014 Site Plan that it would begin serving Vero Beach's electric load in January 2015. Accordingly, NEL, customers, and peaks for Vero Beach from 2015 through 2023 were included in FPL's load forecasts in its 2014 Site Plan. However, lack of progress among negotiating parties has resulted in uncertainty regarding whether FPL will provide, or when it can begin providing, Vero Beach's electric load. As a result, FPL's current load forecast does not include electric service to Vero Beach.

The customer forecast is based on recent population projections as well as the actual levels of customer growth experienced historically. Population projections are derived from the EDR's July 2014 Demographic Estimating Conference. This forecast is generally consistent with previous forecasts indicating steady growth in Florida's population. On a percentage basis, the projected rates of population growth are expected to be somewhat below the state's long-term historical averages. However, the absolute increases in population are projected to be significant. The state's population is expected to reach 20 million by 2016 and exceed 22 million by 2023. Overall, the state's population is expected to increase by approximately three million between 2014 and 2024.

FPL customer growth is expected to mirror the overall level of population growth in the state. From 2014 through 2024 the total number of customers is projected to increase at an annual rate of 1.3% resulting in a cumulative increase of more than 670,000 customers. By 2019, the total number of customers served by FPL is expected to exceed five million. By 2024, the total number of FPL customers is expected to reach approximately 5.4 million.

The economic projections incorporated into FPL's load forecast are provided by IHS Global Insight. IHS Global Insight projects solid growth in the Florida economy with relatively healthy increases in employment and income levels from 2015 through 2019. This firm projects particularly robust growth for the professional and business services, trade, tourism, and healthcare industries. Consistent with past projections, economic growth in the later years of the forecast is expected to moderate slightly.

Estimates of savings from energy efficiency codes and standards are developed by ITRON, a leading expert in this field. These estimates include savings from federal and state energy efficiency codes and standards, including the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the savings resulting from the use of compact fluorescent bulbs and light-emitting diodes (LEDs)[2]. The impact of these savings began in 2005 and their cumulative impact on the Summer peak is expected to reach 3,568 MW by 2024, the equivalent of an approximately 12% reduction in what the forecasted Summer peak load for 2024 would have been without these codes and standards. The cumulative impact on NEL from these savings is expected to reach 11,405 GWH over the same period while the cumulative impact on the Winter peak is expected to be 2,022 MW by 2024. This represents a decrease of approximately 8% in the forecasted NEL for 2024 and an 8% reduction in forecasted Winter peak load for 2024.

Consistent with the forecast presented in FPL's 2014 Site Plan, the total growth projected for the ten-year reporting period of this document is significant. The Summer peak is projected to increase to 26,771 MW by 2024, an increase of 3,836 MW over the 2014 actual Summer peak. Likewise, NEL is projected to reach 133,276 GWH in 2024, an increase of 17,308 GWH from the actual 2014 value.

II.C. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for the major revenue classes and are adjusted to match the NEL forecast. The results of these sales forecasts for the years 2015 through 2024 are presented in Schedules 2.1 - 2.3 that appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and NEL forecast are outlined below.

[2] Note that in addition to the fact that these energy efficiency codes and standards lower the forecasted load, these standards also lower the potential for efficiency gains that would otherwise be available through utility DSM programs.

1. Residential Sales

Residential electric usage per customer is estimated by using an econometric model. Residential sales are a function of the following variables: cooling degree-hours, winter heating degree-days, twelve-month average Consumer Price Index for Energy, and Florida real per capita income weighted by the percent of the population that is employed. The impact of weather is captured by the cooling degree-hours and winter heating degree-days. The impact energy prices have on electricity consumption is captured through the Consumer Price Index for Energy variable. As energy prices rise, less disposable income is available for all goods and services, including electricity. To capture economic conditions, the model includes a composite variable based on Florida real per capita income and the percent of the state's population that is employed. Residential energy sales are forecasted by multiplying the projected residential use per customer by the projected number of residential customers.

2. Commercial Sales

The commercial sales forecast is also developed using econometric models. The commercial class is forecast using three separate models, based on customer size, including: small accounts (less than 20 kW of demand), medium accounts (21 kW to 499 kW of demand), and large accounts (demand of 500 kW or higher). Commercial sales are driven by economic and weather variables. Specifically, the small commercial sales model utilizes the following variables: Florida real per capita income weighted by the percent of the population that is employed, cooling degree-hours, heating degree-hours, lagged cooling degree-hours, the Consumer Price Index, dummy variables for the month of December and for the specific months of January 2007 and November 2005, and an autoregressive term. The medium commercial sales model utilizes the same variables as the small commercial model with the exception of a January heating degree-day term rather than the heating degree-hours term. The large commercial sales model utilizes the following variables: Florida real per capita income, cooling degree-hours, heating degree-hours, lagged cooling degree-hours, dummy variables for the month of December and for the specific months of January 2007 and November 2005, and an autoregressive term. Cooling degree-hours, heating degree-hours, and the one-month lag of cooling degree-hours are used to capture weather-sensitive load in the commercial sector.

3. Industrial Sales

Like the commercial class, the industrial class is forecast using three separate models, based on customer size. The industrial class is comprised of three distinct groups: small accounts (less than 20 kW of demand), medium accounts (21 kW to 499 kW of demand), and large accounts (demands of 500 kW or higher). The small industrial sales model utilizes the following variables: Florida real household disposable income, cooling degree-hours, heating degree-hours, and autoregressive terms. The medium industrial sales model utilizes the following variables: Florida real Gross State Product, the Consumer Price Index, cooling degree-hours, January heating degree-days, dummy variables for the specific months of February 2005 and November 2005, and autoregressive terms. The large industrial sales model utilizes the following variables: cooling degree-hours, Florida Gross State Product for manufacturing, the Consumer Price Index, the employee to population ratio, and dummy variables for the specific months of October 2004 and November 2004.

4. Railroad and Railways Sales and Street and Highway Sales

This class consists solely of Miami-Dade County's Metrorail system. The projections for railroad and railways sales are based on a historical moving average.

The forecast for street and highway sales is developed by first developing a trended use per customer value, then multiplying this value by the number of forecasted customers.

5. Other Public Authority Sales

This class consists of a sports field rate schedule, which is closed to new customers, and one government account. The forecast for this class is based on its historical usage characteristics.

6. Total Sales to Ultimate Customer

Sales forecasts by revenue class are summed to produce a total sales forecast.

7. Sales for Resale

Sales for resale (wholesale) customers are composed of municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers. There are currently seven customers in this class: Florida Keys Electric Cooperative, Lee County Electric Cooperative, New Smyrna Beach, Wauchula, Winter Park, Blountstown, and Seminole Electric Cooperative[3].

Beginning in May 2011, FPL began providing service to the Florida Keys Electric Cooperative under a long-term full requirements contract. FPL previously served the Florida Keys under a

[3] FPL continues to evaluate the possibility of serving the electrical loads of other entities at the time this Site Plan is being prepared. Because these possibilities are still being evaluated, the load forecast presented in this Site Plan does not include these potential loads.

partial requirements contract. The sales to Florida Keys Electric Cooperative are based on customer-supplied information and historical coincidence factors.

Lee County contracted with FPL for FPL to supply a portion of the Lee County load through 2013, then to serve the entire Lee County load beginning in 2014. This contract began in January 2010. Forecasted NEL for Lee County is based on an econometric model utilizing the following variables: cooling and heating degree-hours, January heating degree-days, real disposable household income, and autoregressive terms.

FPL sales to New Smyrna Beach began in February 2014 and will continue through December 2017.

FPL's sales to Wauchula began in October 2011 and will continue through December 2016.

Sales to Winter Park began in January 2014 and will continue through December 2016.

Blountstown became an FPL wholesale customer in May 2012 under a contract that expires in April 2017.

FPL sales to Seminole Electric Cooperative are based on delivery of 200 MW that began in June 2014 and continues through May 2021.

II.D. Net Energy for Load (NEL)

An econometric model is developed to produce a NEL per customer forecast. The inputs to the model include Florida real per capita income weighted by the percent of the population that is employed, and a proxy for energy prices. The model also includes several weather variables including cooling degree-hours and heating degree-days by calendar month, and heating degree-days based on 45o F. In addition, the model also includes a variable for energy efficiency codes and standards. A dummy variable is included for the specific month of November 2005. There are also two autoregressive terms in the model.

The energy efficiency variable is included to capture the impacts from major codes and standards, including those associated with the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and savings resulting from the use of compact fluorescent bulbs and LEDs. The estimated impact from these codes and standards includes engineering estimates and any resulting behavioral changes. The impact of these savings began in 2005 and their cumulative impact on NEL is expected to reach 11,405 GWH by 2024. This represents an approximately 8% reduction in what the forecasted NEL for 2024 would have been absence these codes and standards. From the end of 2014, the incremental reduction through 2024 is expected to be 6,808 GWH. An additional adjustment is made due to the impact of incremental distributed generation not otherwise included in the forecast. The adjustment to the forecast due to distributed generation begins in 2014 and is expected to reduce the NEL forecast by 444 GWH by 2024.

The forecast was also adjusted for the additional load estimated from hybrid vehicles, beginning in 2014, which resulted in an increase of approximately 616 GWH by the end of the ten-year reporting period. The forecast was further adjusted for the incremental load resulting from FPL's economic development riders which began in 2014 and this incremental load is projected to grow to 242 GWH before leveling off in 2020

The NEL forecast is developed by first multiplying the NEL per customer forecast by the projected total number of customers and then adjusting the forecasted results for the expected changes in load resulting from hybrid vehicles, new wholesale contracts, distributed generation, and FPL's economic development riders. Once the NEL forecast is determined, total billed sales are computed using a historical ratio of sales to NEL. The sales by class forecasts discussed previously are then adjusted to match the total billed sales. The forecasted NEL values for 2015 through 2024 are presented in Schedule 3.3 which appears at the end of this chapter.

II.E. System Peak Forecasts

The rate of absolute growth in FPL system peak load has been a function of the size of the customer base, varying weather conditions, projected economic conditions, changing patterns of customer behavior, and more efficient appliances and lighting. FPL developed the peak forecast models to capture these behavioral relationships. In addition, FPL's peak forecast also reflects changes in load expected as a result of changes in wholesale contracts, distributed generation, and the expected number of hybrid vehicles.

The savings from energy efficiency codes and standards incorporated into the peak forecast include the impacts from the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the use of compact fluorescent light bulbs and LEDs. The impact from these energy efficiency standards began in 2005 and their cumulative impact on the Summer peak is expected to reach 3,568 MW by 2024. This reduction includes engineering estimates and any resulting behavioral changes. This reduction also represents significant energy efficiency that is not funded by FPL's customers through the Energy Conservation Cost Recovery Clause.

The cumulative 2024 impact from these energy efficiency codes and standards effectively reduces FPL's Summer peak for that year by approximately 12%. From the end of 2014, the projected incremental impact on the Summer peak from these energy efficiency codes and standards is projected to be a reduction of 2,035 MW through 2024. By 2024, the Winter peak is expected to be reduced by 2,022 MW as result of the cumulative impact from these energy efficiency standards since 2005. On an incremental basis, net of the reduction already experienced through 2014, the impact on the Winter peak from these energy efficiency standards is expected to reach 1,321 MW in 2024.

The forecast also was adjusted for additional load estimated from hybrid vehicles which is projected to be an increase of approximately 173 MW in the Summer and 86 MW in the Winter by the end of the ten-year reporting period. The incremental impact of distributed generation results in an expected decrease of approximately 105 MW in the Summer and a negligible reduction in the Winter by the end of the ten-year reporting period. The incremental impact from distributed generation is based on forecasted increases in rooftop photovoltaic (PV) installations not otherwise reflected in the load forecast. The ratio of the expected Summer Peak MW reduction relative to the installed nameplate MW (DC) capacity is appropriately 34% for residential PV installations and appropriately 37% for commercial PV installations. The ratio of the expected Winter Peak MW reduction to installed nameplate MW (DC) capacity is close to 0% for both residential and commercial PV installations.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2015 through 2024 are presented at the end of this chapter in Schedules 3.1 and 3.2, and in Chapter III in Schedules 7.1 and 7.2.

1. System Summer Peak

The Summer peak forecast is developed using an econometric model. The variables included in the model are the price of gasoline (lagged one month), Florida real household disposable income, cooling degree-hours two days prior to the peak day, the maximum temperature on the day of the peak, a variable for energy efficiency standards, and a dummy variable for the year 1990. The model is based on the Summer peak contribution per customer which is multiplied by total customers. This product is then adjusted to account for the expected changes in loads resulting from hybrid vehicles, new wholesale contracts, distributed generation, and FPL's economic development riders to derive FPL's system Summer peak.

2. System Winter Peak

Like the system Summer peak model, this model also is an econometric model. The model consists of two weather-related variables: the minimum temperature on the peak day and heating degree-hours for the prior day squared. The model also includes two dummy variables; one for Winter peaks occurring on weekends and one for the year 1994. Also included in the model are a variable for housing starts per capita, and an autoregressive term. The forecasted results are adjusted for the impact of energy efficiency standards. The model is based on the Winter peak contribution per customer which is multiplied by the total number of customers. This product then is adjusted for the expected changes in loads resulting from hybrid vehicles, new wholesale contracts, distributed generation, and FPL's economic development riders.

3. Monthly Peak Forecasts

The forecasting process for monthly peaks consists of the following steps:

a. The forecasted annual summer peak is assumed to occur in the month of August which historically has accounted for more annual summer peaks than any other month.

b. The forecasted annual winter peak is assumed to occur in the month of January which historically has accounted for more annual winter peaks than any other month.

c. The remaining monthly peaks are forecasted based on the historical relationship between the monthly peaks and the annual summer peak.

II.F. Hourly Load Forecast

Forecasted values for system hourly load for the period 2015 through 2024 are produced using a System Load Forecasting "shaper" program. This model uses years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model generates a projection of hourly load values based on these load shapes and the forecast of monthly peaks and energy.

II.G. Uncertainty

Uncertainty is inherent in the load forecasting process. This uncertainty can result from a number of factors, including unexpected changes in consumer behavior, structural shifts in the economy, and fluctuating weather conditions. Large weather fluctuations, in particular, can result in significant deviations between actual and forecasted peak demands. The load forecast is based on average expected or normal weather conditions; i.e. a 50% probability (or P50) forecast. An extreme P90 cold weather event, however, can add an additional 3,000 MW to the Winter Peak and an extreme P90 hot weather event can add an additional 800 MW to the Summer Peak.

In order to address uncertainty in the forecasts of aggregate peak demand and NEL, FPL first evaluates the assumptions underlying the forecasts. FPL takes a series of steps in evaluating the input variables, including comparing projections from different sources, identifying outliers in the series, and assessing the series' consistency with past forecasts. As needed, FPL reviews additional factors that may affect the input variables.

Uncertainty is also addressed in the modeling process. Econometric models generally are used to forecast the aggregate peak demand and NEL. During the modeling process, the relevant statistics (goodness of fit, F-statistic, P-values, mean absolute deviation (MAD), mean absolute percentage error (MAPE), etc.) are scrutinized to ensure the models adequately explain historical variation. Once a forecast is developed, it is compared with past forecasts. Deviations from past forecasts are examined in light of changes in input assumptions to ensure that the drivers underlying the forecast are well understood. Finally, forecasts of aggregate peak demand and NEL are compared with the actual values as these become available. An ongoing process of variance analyses is performed. To the extent that the variance analyses identify large unexplained deviations between the forecast and actual values, revisions to the econometric model may be considered.

The inherent uncertainty in load forecasting is addressed in different ways in regard to FPL's overall resource planning and operational planning work. In regard to FPL's resource planning work, FPL's utilization of a 20% total reserve margin criterion, a Loss-of-Load-Probability (LOLP) criterion of 0.1, and a 10% generation-only reserve margin criterion, are designed to maintain reliable electric service for FPL's customers in light of forecasting (and other) uncertainty. In addition, banded forecasts of the projected Summer peak and net energy for load are produced based on an analysis of past forecasting variances. In regard to operational planning, a banded forecast for the projected Summer and Winter peak days is developed based on historical weather variations. These bands are then used to develop similar bands for the monthly peaks.

II.H. DSM

The effects of FPL's DSM energy efficiency programs implementation through August 2014 are assumed to be embedded in the actual usage data for forecasting purposes. The following are accounted for as "line item reductions" to the forecasts as part of the IRP process: the impacts of incremental energy efficiency that FPL has implemented in the September 2014 through December 2014 time period, incremental energy efficiency that FPL plans to implement in the future based on the new DSM Goals set for FPL by the FPSC in November 2014, and the cumulative and projected incremental impacts of FPL's load management programs. After making these adjustments to the load forecasts, the resulting "firm" load forecast is then used in FPL's IRP work as shown in Chapter III in Schedules 7.1 and 7.2.

Schedule 2.1
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			**Commercial**		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,620,855	2.21	54,570	3,906,267	13,970	44,487	478,867	92,901
2007	8,729,806	2.19	55,138	3,981,451	13,849	45,921	493,130	93,121
2008	8,771,694	2.20	53,229	3,992,257	13,333	45,561	500,748	90,987
2009	8,732,591	2.19	53,950	3,984,490	13,540	45,025	501,055	89,860
2010	8,762,399	2.19	56,343	4,004,366	14,070	44,544	503,529	88,464
2011	8,860,158	2.20	54,642	4,026,760	13,570	45,052	508,005	88,685
2012	8,948,850	2.21	53,434	4,052,174	13,187	45,220	511,887	88,340
2013	9,025,275	2.20	53,930	4,097,172	13,163	45,341	516,500	87,786
2014	9,122,932	2.19	55,202	4,169,028	13,241	45,684	525,591	86,919

Historical Values (2005 - 2014):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent actual energy sales including the impacts of existing conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.1
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			**Commercial**		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2015	9,306,139	2.20	57,634	4,230,063	13,625	45,958	532,023	86,384
2016	9,445,807	2.20	59,347	4,293,549	13,822	46,694	538,297	86,743
2017	9,586,474	2.20	60,613	4,357,488	13,910	47,162	544,230	86,659
2018	9,726,794	2.20	61,841	4,421,270	13,987	47,649	549,723	86,678
2019	9,866,497	2.20	62,967	4,484,771	14,040	48,078	554,918	86,640
2020	10,003,258	2.20	64,192	4,546,935	14,118	48,560	559,848	86,737
2021	10,137,730	2.20	65,090	4,608,059	14,125	48,581	564,581	86,048
2022	10,269,789	2.20	65,922	4,668,086	14,122	48,861	569,300	85,826
2023	10,400,493	2.20	66,903	4,727,497	14,152	49,225	573,828	85,784
2024	10,530,845	2.20	68,082	4,786,748	14,223	49,741	578,049	86,050

Projected Values (2015 - 2024):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent forecasted energy sales that do not include the impact of incremental conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.2
History of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(10) Industrial GWh	(11) Industrial Average No. of Customers	(12) Industrial Average kWh Consumption Per Customer	(13) Railroads & Railways GWh	(14) Street & Highway Lighting GWh	(15) Sales to Public Authorities GWh	(16) Sales to Ultimate Consumers GWh
2005	3,913	20,392	191,873	95	424	49	102,296
2006	4,036	21,211	190,277	94	422	49	103,659
2007	3,774	18,732	201,499	91	437	53	105,415
2008	3,587	13,377	268,168	81	423	37	102,919
2009	3,245	10,084	321,796	80	422	34	102,755
2010	3,130	8,910	351,318	81	431	28	104,557
2011	3,086	8,691	355,104	82	437	27	103,327
2012	3,024	8,743	345,871	81	441	25	102,226
2013	2,956	9,541	309,772	88	442	28	102,784
2014	2,941	10,415	282,398	91	446	24	104,389

Historical Values (2005 - 2014):

Col. (10) and Col.(15) represent actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.2
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(10) Industrial GWh	(11) Industrial Average No. of Customers	(12) Industrial Average kWh Consumption Per Customer	(13) Railroads & Railways GWh	(14) Street & Highway Lighting GWh	(15) Sales to Public Authorities GWh	(16) Sales to Ultimate Consumers GWh
2015	2,929	11,265	260,033	91	461	22	107,096
2016	2,932	12,542	233,811	91	468	22	109,554
2017	2,914	13,496	215,931	91	473	22	111,275
2018	2,871	13,792	208,152	91	479	22	112,952
2019	2,820	13,687	206,006	91	483	22	114,461
2020	2,763	13,594	203,246	91	488	22	116,115
2021	2,696	13,455	200,356	91	492	22	116,971
2022	2,634	13,316	197,791	91	496	22	118,025
2023	2,566	13,138	195,327	91	499	22	119,307
2024	2,493	12,849	193,999	91	503	22	120,931

Projected Values (2015 - 2024):

Col. (10) and Col.(15) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2005	1,506	7,498	111,301	3,156	4,321,895
2006	1,569	7,909	113,137	3,218	4,409,563
2007	1,499	7,401	114,315	3,276	4,496,589
2008	993	7,092	111,004	3,348	4,509,730
2009	1,155	7,394	111,303	3,439	4,499,067
2010	2,049	7,870	114,475	3,523	4,520,328
2011	2,176	6,950	112,454	3,596	4,547,051
2012	2,237	6,403	110,866	3,645	4,576,449
2013	2,158	6,713	111,655	3,722	4,626,934
2014	5,375	6,204	115,968	3,795	4,708,829

Historical Values (2005 - 2014):

Col. (19) represents actual energy sales including the impacts of existing conservation.

Col. (19) = Col. (16) + Col. (17) + Col. (18). Historical NEL includes the impacts of existing conservation and agrees to Col. (5) on schedule 3.3. Historical GWH, prior to 2011, are based on a fiscal year beginning 12/29 and ending 12/28. The 2011 value is based on 12/29/10 to 12/31/11. The 2012-2014 values are based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 2.3
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2015	6,021	6,595	119,713	3,858	4,777,210
2016	6,126	6,727	122,407	3,906	4,848,294
2017	5,882	6,788	123,946	3,947	4,919,162
2018	5,629	6,852	125,433	3,987	4,988,771
2019	5,659	6,950	127,070	4,024	5,057,400
2020	5,700	7,036	128,851	4,058	5,124,436
2021	5,256	7,011	129,237	4,090	5,190,185
2022	4,955	7,097	130,077	4,118	5,254,820
2023	5,013	7,176	131,495	4,145	5,318,608
2024	5,073	7,271	133,276	4,170	5,381,815

Projected Values (2015 - 2024):

Col. (19) represents forecasted energy sales that do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

Col. (19) = Col. (16) + Col. (17) + Col. (18). These values are based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 3.1
History of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2005	22,361	264	22,097	0	902	895	600	611	20,858
2006	21,819	256	21,563	0	928	948	635	640	20,256
2007	21,962	261	21,701	0	952	982	716	683	20,295
2008	21,060	181	20,879	0	966	1,042	760	706	19,334
2009	22,351	249	22,102	0	981	1,097	811	732	20,558
2010	22,256	419	21,837	0	990	1,181	815	758	20,451
2011	21,619	427	21,192	0	1,000	1,281	821	781	19,798
2012	21,440	431	21,009	0	1,013	1,351	833	810	19,594
2013	21,576	396	21,180	0	1,025	1,394	833	827	19,718
2014	22,935	955	21,980	0	1,010	1,444	843	840	21,082

Historical Values (2005 - 2014):

Col. (2) - Col. (4) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) represent actual DSM capabilities starting from January 1988 and are annual (12-month) values except for 2014 values which are through August.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.1
Forecast of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
August of Year	Total	Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2015	23,286	1,231	22,054	0	1,020	46	862	25	21,334
2016	23,778	1,240	22,538	0	1,030	60	873	37	21,778
2017	24,252	1,186	23,066	0	1,040	71	885	50	22,206
2018	24,648	1,145	23,502	0	1,051	82	897	63	22,555
2019	25,045	1,149	23,896	0	1,061	94	909	77	22,904
2020	25,369	1,150	24,219	0	1,071	106	920	91	23,181
2021	25,497	953	24,544	0	1,082	118	932	106	23,260
2022	25,833	957	24,875	0	1,092	131	944	121	23,545
2023	26,286	965	25,321	0	1,102	144	956	136	23,948
2024	26,771	972	25,798	0	1,113	157	968	152	24,381

Projected Values (2015 - 2024):

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected August values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC.

Schedule 3.2
History of Winter Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2005	18,108	225	17,883	0	816	583	542	233	16,751
2006	19,683	225	19,458	0	823	600	550	240	18,311
2007	16,815	223	16,592	0	846	620	577	249	15,392
2008	18,055	163	17,892	0	868	644	636	279	16,551
2009	20,081	207	19,874	0	881	666	676	285	18,524
2010	24,346	500	23,846	0	895	687	721	291	22,730
2011	21,126	383	20,743	0	903	717	723	303	19,501
2012	17,934	382	17,552	0	856	755	722	314	16,356
2013	15,931	348	15,583	0	843	781	567	326	14,521
2014	17,500	890	16,610	0	768	805	590	337	16,142

Historical Values (2005 - 2014):

Col. (2) - Col. (4) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand. For year 2011, the actual peaked occurred in December of 2010.

Col. (5) - Col. (9) for 2005 through 2014 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.2
Forecast of Winter Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
January of Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2015	21,136	1,195	19,941		841	12	593	5	19,684
2016	21,369	1,206	20,163		850	24	598	11	19,886
2017	21,485	1,151	20,334		858	28	603	20	19,976
2018	21,598	1,114	20,484		867	31	609	30	20,061
2019	21,792	1,125	20,667		875	35	614	40	20,227
2020	21,965	1,133	20,833		883	40	620	50	20,372
2021	22,096	1,141	20,956		892	44	625	61	20,475
2022	22,026	948	21,078		900	49	631	72	20,374
2023	22,202	956	21,246		909	53	636	83	20,520
2024	22,408	965	21,443		917	59	642	95	20,695

Projected Values (2015 - 2024):

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected January values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC.

Schedule 3.3
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Net Energy For Load without DSM GWh	Residential Conservation GWh	C/I Conservation GWh	**Actual** Net Energy For Load GWh	Sales for Resale GWh	Utility Use & Losses GWh	Total Billed Retail Energy Sales (GWh)	Load Factor(%)
2005	115,065	1,970	1,793	111,301	1,506	7,498	102,296	56.8%
2006	117,116	2,078	1,901	113,137	1,569	7,909	103,659	59.2%
2007	118,518	2,138	2,066	114,315	1,499	7,401	105,415	59.4%
2008	115,379	2,249	2,126	111,004	993	7,092	102,919	60.0%
2009	115,844	2,345	2,196	111,303	1,155	7,394	102,755	56.8%
2010	119,220	2,487	2,259	114,475	2,049	7,870	104,557	58.7%
2011	117,460	2,683	2,324	112,454	2,176	6,950	103,327	59.4%
2012	116,083	2,823	2,394	110,866	2,237	6,403	102,226	58.9%
2013	117,087	2,962	2,469	111,655	2,158	6,713	102,784	59.1%
2014	121,621	3,125	2,529	115,968	5,375	6,204	104,389	57.7%

Historical Values (2005 - 2014):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5).

Col. (3) & Col. (4) are DSM values starting in January 1988 and are annual (12-month) values. Col. (3) and Col. (4) for 2014 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWh reductions experienced each year .

Col. (5) is the actual Net Energy for Load (NEL) for years 2005 - 2014.

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the mete

Col. (9) is calculated using Col. (5) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 876
Adjustments are made for leap years.

Schedule 3.3
Forecast of Annual Net Energy for Load (GWh)
(All values are "at the generator"values except for Col (8))

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	**Forecasted** Net Energy For Load without DSM GWh	Residential Conservation GWh	C/I Conservation GWh	Net Energy For Load Adjusted for DSM GWh	Sales for Resale GWh	Utility Use & Losses GWh	**Forecasted** Total Billed Retail Energy Sales w/o DSM GWh	Load Factor(%)
2015	119,713	58	51	119,604	6,021	6,595	107,096	58.7%
2016	122,407	98	88	122,221	6,126	6,727	109,554	58.6%
2017	123,946	121	112	123,713	5,882	6,788	111,275	58.3%
2018	125,433	144	137	125,151	5,629	6,852	112,952	58.1%
2019	127,070	168	164	126,738	5,659	6,950	114,461	57.9%
2020	128,851	192	192	128,467	5,700	7,036	116,115	57.8%
2021	129,237	218	221	128,798	5,256	7,011	116,971	57.9%
2022	130,077	244	252	129,581	4,955	7,097	118,025	57.5%
2023	131,495	271	284	130,940	5,013	7,176	119,307	57.1%
2024	133,276	299	318	132,659	5,073	7,271	120,931	56.7%

Projected Values (2015 - 2024):

Col. (2) represents Forecasted Net Energy for Load and does not include incremental DSM from 2015 - on. The Col. (2) values are extracted from Schedule 2.3, Col(19). The effects of conservation implemented prior to September 2014 are incorporated into the load forecast values in Col. (2).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation from Jan 2015 - on and are mid-year (6-month) values reflecting DSM signups occurring evenly thoughout each year.

Col. (5) is the forecasted Net Energy for Load (NEL) after adjusting for impacts of incremental DSM for years 2015 - 2024 using the formula:
Col. (5) = Col. (2) - Col. (3) - Col. (4)

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7).
These values are at the meter.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of
Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2014 Actual		2015 FORECAST		2016 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	17,500	8,634	21,136	8,974	21,369	9,218
FEB	16,297	7,957	18,170	8,036	18,554	8,562
MAR	16,183	8,491	18,030	8,882	18,411	9,109
APR	19,934	9,230	19,033	9,214	19,435	9,414
MAY	20,295	10,400	21,262	10,556	21,712	10,750
JUN	21,786	10,438	22,600	10,974	23,078	11,146
JUL	22,935	11,392	23,001	11,759	23,488	11,920
AUG	22,900	12,125	23,286	11,914	23,778	12,089
SEP	21,673	10,641	22,498	11,057	22,974	11,233
OCT	21,079	10,074	21,145	10,427	21,593	10,616
NOV	17,830	8,129	18,588	8,804	18,982	9,015
DEC	16,095	8,457	18,027	9,115	18,408	9,336
Annual Values:		**115,968**		**119,713**		**122,407**

Col. (3) annual value shown is consistent with value shown in Col.(5) of Schedule 3.3.

Cols. (4) - (7) do not include the impacts of cumulative load management, incremental conservation, and incremental load management.

Cols. (5) and Col. (7) annual values shown are consistent with values shown in Col.(2) of Schedule 3.3.

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CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL utilizes its well established integrated resource planning (IRP) process, in whole or in part as dictated by analysis needs, to determine: when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of new power plants, the primary subjects of this document, are determined as part of the IRP process work.

This section describes FPL's basic IRP process. It also discusses some of the key assumptions, in addition to a new load forecast discussed in the previous chapter, that were used in developing the resource plan presented in this Site Plan.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental steps to FPL's resource planning. These steps can be generally described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Evaluate the competing options and resource plans in regard to system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process

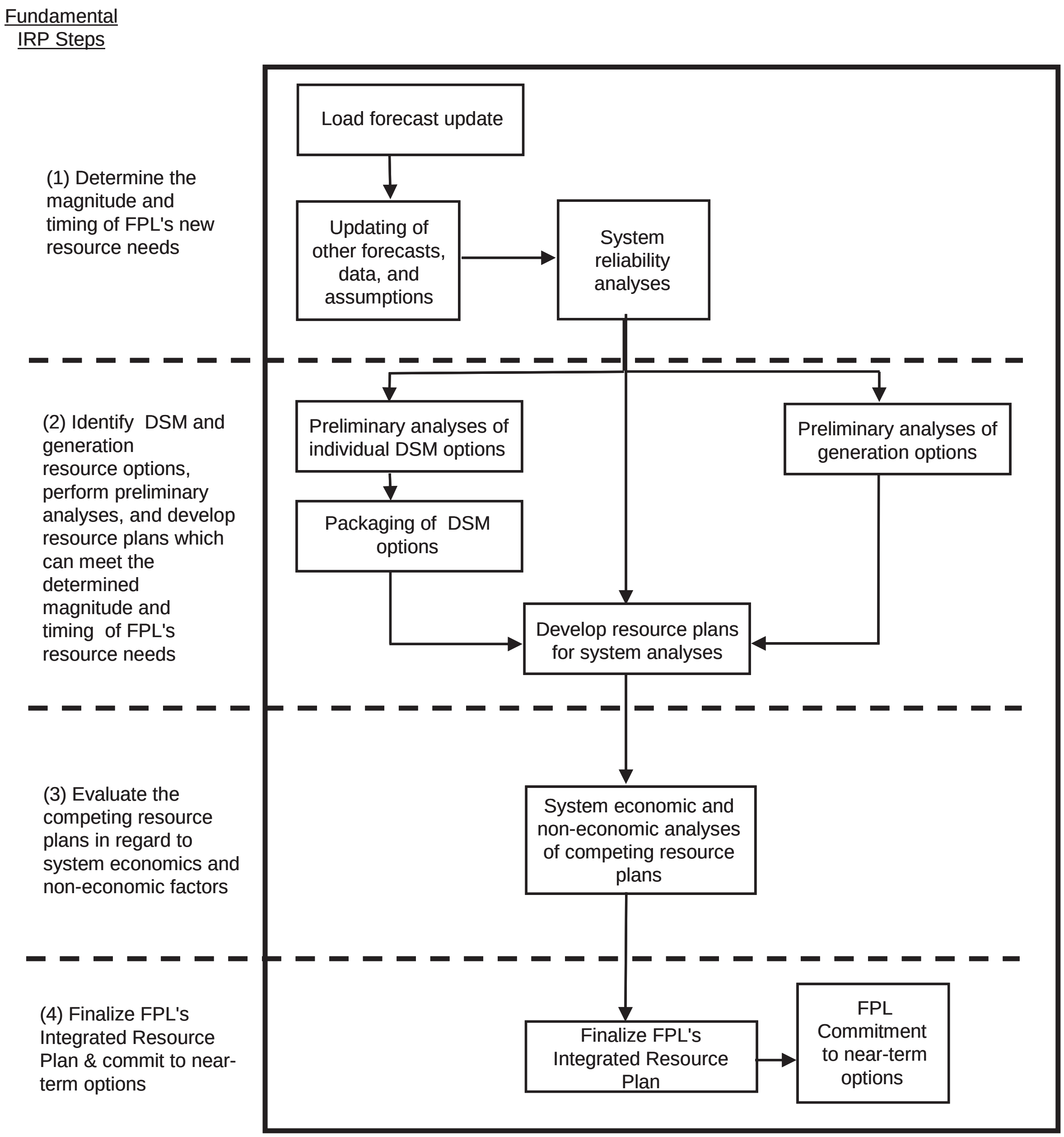

Figure III.A.1: Overview of FPL's IRP Process

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of the four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed to maintain system reliability. Also determined in this step is when the MW additions are needed to meet FPL's reliability criteria. This step is often referred to as a reliability assessment, or resource adequacy, analysis for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include, but are not limited to: delivered fuel price projections, current financial and economic assumptions, current power plant capability and operating assumptions, and current demand side management (DSM) demand and energy reduction assumptions. FPL also includes key sets of projections regarding three specific types of resources: (1) FPL unit capacity changes, (2) firm capacity power purchases, and (3) DSM implementation.

Key Assumptions Regarding the Three Types of Resources:

The first set of assumptions, FPL unit capacity changes, is based on the current projection of new generating capacity additions and planned retirements of existing generating units. In FPL's 2015 Site Plan, there are six (6) such projected capacity changes through the 10-year reporting time frame of this document. These changes are listed below in general chronological order:

1) Retirement of existing Putnam Units 1 & 2:

   As explained in FPL's 2014 Site Plan, analyses conducted during 2013 and early 2014 showed that it would be cost-effective to retire two existing units, Putnam Units 1 & 2, and replace the capacity with new combined cycle (CC) capacity at a later date and at a site to be determined. The new CC capacity would have a significantly better heat rate, thus reducing FPL's system fuel usage and system emissions. As a result, these two units were retired at the end of 2014.

2) CT upgrades at existing CC plant sites:

   In the fourth quarter of 2011, FPL started upgrading the 7FA combustion turbines (CT) that are components at a number of its existing CC units. These upgrades will economically benefit FPL's customers by increasing the MW output of these CC units. 221 MW of the increased capacity from these CT upgrades is already in service. The work for the remaining upgrades is continuing and the project is projected to be completed in early 2016.

3) Modernization of the Port Everglades plant site:
The work to modernize the existing Port Everglades site by adding new combined cycle (CC) capacity continues. The new generating unit, called the Port Everglades Next Generation Clean Energy Center (PEEC), is projected to be in-service in mid-2016 and is projected to have a peak Summer output of 1,237 MW. The FPSC issued the final need order for this modernization project in April 2012 in Order No. PSC-12-0187-FOF-EI. The site certification order for the project, DOAH Case No. 12-0422EPP, was received for the Port Everglades project in October 2012.

4) New Solar Facilities:
FPL currently projects that it will add new photovoltaic (PV) facilities by the end of 2016 at three sites. These sites are FPL's existing Manatee plant site in Manatee County, the Citrus site in DeSoto County, and the Babcock Ranch site in Charlotte County. Each of the PV facilities is projected to have a nameplate rating of approximately 74.5 MW (AC). Therefore, the three PV facilities will have a combined total nameplate (AC) rating of approximately 223 MW. FPL's analyses of these three specific projects have led to a conclusion that approximately 52% of their nameplate (AC) rating can be accounted for as firm Summer capacity, and 0% for firm Winter capacity, in FPL's reliability analyses.

5) GT Replacement:
FPL plans, for economic reasons, to retire a number of its older gas turbine (GT) peaking units at its three GT sites (Lauderdale, Port Everglades, and Fort Myers) and partially replace this peaking capacity with new combustion turbine (CT) capacity at the Lauderdale and Fort Myers sites. In addition, the two existing CTs at the Fort Myers site will be upgraded, which will increase their capacity. These changes are projected to be completed by the end of 2016. The MW impact of these changes to FPL's peaking capacity is a net decrease of approximately 40 MW.

6) New Combined Cycle Capacity:
FPL currently projects a need for a significant capacity addition in 2019. FPL's best self-build option to meet this need is a new combined cycle (CC) unit that would be built in Okeechobee County. In order to ensure that the best generation option for FPL's customers is chosen to meet this need, and in keeping with the FPSC's Bid Rule, FPL issued a Request for Proposals (RFP) in March 2015 that invited generation proposals from outside parties. These proposals are scheduled to be received in May 2015. Once

these proposals and FPL's self-build CC unit have been thoroughly evaluated by both FPL and an independent evaluator, FPL expects to file in mid-2015 for an FPSC determination of need approval, and/or for FPSC approval for cost recovery, for the best option(s).

In addition, FPL's current resource plan presented in this Site Plan also shows potential new CC capacity being added in 2023. No decision on this potential addition is yet needed and FPL expects to make a decision on this capacity addition at an appropriate time in a manner similar to how the decision for the 2019 need will be reached.

The second set of assumptions involves firm capacity power purchases. There are two significant changes in firm capacity power purchases from those shown in FPL's 2014 Site Plan. The first of those is due to the fact that FPL no longer is projecting that it will serve Vero Beach's electrical load (as discussed in Chapter II). Thus FPL is no longer projecting that it will acquire the Vero Beach combined cycle unit (46 MW), or that it will acquire two of Vero Beach's existing power purchase agreements which total approximately 37 MW of coal-fired capacity that were projected to run through the end of 2017. The second change is that FPL anticipates terminating its existing power purchase agreement for 250 MW of coal-fired capacity from the Cedar Bay generating facility at the end of August 2015 as a result of a Purchase and Sale Agreement between FPL and Cedar Bay Generating Company, L.P. FPL would then own the unit starting on September 1, 2015. FPL currently anticipates that it will not need the unit for economic purposes after 2016 and, if that proves to be the case, would retire the unit at that time. FPL filed for FPSC approval of the Purchase and Sale Agreement in the first quarter of 2015.

None of the other purchase projections has changed from those in the 2014 Site Plan. FPL's current projection includes an additional 70 MW of waste-to-energy capacity from the Palm Beach Solid Waste Authority (SWA) starting in mid-2015. In addition, FPL continues to project that Internal Revenue Service (IRS) regulations regarding the amount of energy that FPL can receive under its purchase agreement with Jacksonville Electric Authority (JEA) for St. Johns Regional Power Park (SJRPP) will result in the suspension of the delivery of capacity and energy to FPL in the second quarter of 2019.[4] In addition, FPL projects that it will begin receiving a total of 180 MW of firm capacity in 2021 from biomass-based power purchase agreements with affiliates of U.S. EcoGen.

In total, the projected firm capacity purchases are from a combination of utility and independent power producers. Details, including the annual total capacity values for these purchases, are presented in Chapter I in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's resource planning work.

[4] FPL's projected suspension date for the SJRPP purchase is based on a system reliability perspective and represents the earliest projected date at which the suspension of capacity and energy could occur.

The third set of assumptions involves a projection of the amount of additional DSM that FPL anticipates it will implement annually over the ten-year period of 2015 through 2024. A key aspect of FPL's IRP process is the evaluation of DSM resources. Since 1994, FPL's resource planning work has assumed that, at a minimum, the DSM MW called for in FPL's FPSC-approved DSM Plan will be achieved. In November 2014, the FPSC established new DSM Goals for FPL that address the years 2015 through 2024, a time period that matches the reporting period of this Site Plan. The FPSC's DSM Goals Order No. PSC-14-0696-FOF-EU recognized that two key market forces currently were affecting the feasibility and cost-effectiveness of utility DSM programs. The first of these is the growing impact of federal and state energy efficiency codes and standards. As discussed in Chapter II, the projected incremental impacts of these energy efficiency codes and standards during the 2015 through 2024 time period are: a Summer peak reduction of approximately 2,035 MW, a Winter peak reduction of approximately 1,321 MW, and approximately 6,808 GWh of energy reduction. As a result, these energy efficiency codes and standards significantly reduce the potential for cost-effective utility DSM programs.

The second market force was lower generating costs with which DSM must compete. This is particularly noticeable in regard to current and projected fuel costs compared to those when Florida previously established DSM Goals in 2009. As an example, natural gas cost projections are 50% lower than natural gas costs projections were in 2009. Although lower generating costs, such as lower fuel costs, are very beneficial for FPL's customers, they also negatively impact the economics of utility DSM programs. Therefore, fewer DSM programs are now cost-effective. In addition, for some DSM programs to remain cost-effective, incentive payments to participating customers have to be lowered, thus reducing the attractiveness of these programs to potential participants.

The FPSC recognized the impact these market forces have on utility DSM programs and set the new DSM Goals accordingly. Although the new DSM Goals are lower than the previous goals, the new goals will help ensure that the electric rate impacts to all of FPL's customers from pursuing DSM are minimized. In March 2015, FPL filed for FPSC approval of its DSM Plan that presents specific DSM programs designed to achieve the new DSM Goals. A decision regarding FPL's DSM Plan is expected by mid-2015. In this Site Plan, the resource plan that is presented assumes that the new DSM Goals will be met in each year of the reporting period. FPL's DSM efforts are further discussed later in this chapter in section III.D.

The Three Reliability Criteria Used to Determine FPL's Projected Resource Needs:

These key assumptions, plus the other updated information described above, are then applied in the first fundamental step: determining the magnitude and timing of FPL's future resource needs. This determination is accomplished by system reliability analyses which for FPL have traditionally been based on dual planning criteria of a minimum peak period total reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry. Beginning in 2014, FPL also implemented a third reliability criterion: a 10% generation-only reserve margin (GRM).

Historically, two types of methodologies, deterministic and probabilistic, have been utilized in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units that can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit that can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system. There are a number of probabilistic methods that are in use for performing system reliability analyses. Among the most widely used is loss-of-load probability (LOLP) which FPL utilizes. Simply stated, LOLP is an index of how well a generating system may be able to meet its firm demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in terms of the projected probability that a utility will be unable to meet its entire firm load at some point during a year. The probability of not being able to meet the entire firm load is calculated for each day of the year using the daily peak hourly load. These daily probabilities are then summed to develop an annual probability value. This annual probability value is commonly expressed as "the number of days per year" that the entire system firm load could not be met. FPL's standard for LOLP, commonly accepted throughout the industry, is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

FPL's integrated resource planning work over the last several years examined a projected fundamental change in FPL's resource plans. This change was a significant shift in the mix of generation and DSM resources in which FPL was becoming increasingly reliant on DSM resources to maintain system reliability. As discussed in detail in FPL's 2014 Site Plan, extensive analyses examined this shift from a system reliability perspective.

In these analyses, FPL developed a new metric: a generation-only reserve margin (GRM). This GRM metric reflects reserves that would be provided only by actual generating resources. The GRM value is calculated by setting to zero all incremental energy efficiency (EE) and load management (LM), plus all existing LM, in another version of a reserve margin calculation. The resulting GRM value provides an indication of how large a role generation is projected to play each year as FPL maintains its 20% Summer and Winter "total" reserve margins (which account for both generation and DSM resources).

These analyses examined the two types of resources, DSM and Supply options, from both an operational and a resource planning perspective. Based on these analyses, FPL concluded that resource plans for its system with identical total reserve margins, but different GRM values, are not equal in regard to system reliability. A resource plan with a higher GRM value is projected to result in more MW being available to system operators on adverse peak load days, and in lower LOLP values, than a resource plan with a lower GRM value, even though both resource plans have an identical total reserve margin. Therefore, in 2014 FPL implemented a minimum GRM criterion of 10% as a third reliability criterion in its resource planning process.

The 10% minimum Summer and Winter GRM criterion augments the other two reliability criteria used by FPL: a 20% total reserve margin criterion for Summer and Winter, and a 0.1 day/year LOLP criterion. All three reliability criteria are potentially useful in terms of identifying the timing of the resource need. In terms of identifying the magnitude of the resource need on FPL's system, the total reserve margin and GRM criteria are more useful although the projected magnitudes under each of these criteria may differ. In addition, the GRM criterion provides direction regarding the mix of generation and DSM resources that should be added to maintain and enhance FPL's system reliability.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, preliminary economic screening analyses of new capacity options that are identical, or virtually identical, in regard to certain key characteristics may be conducted to determine which new capacity options appear to be the most competitive on FPL's system. These preliminary analyses can also help identify capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. Similarly, preliminary economic screening analyses of new DSM options and/or evaluation of existing DSM options are often conducted in this second fundamental IRP step.

FPL typically utilizes a production cost model and a Fixed Cost Spreadsheet, and/or an optimization model and spreadsheet analyses, to perform the preliminary economic screening of generation resource options. For the preliminary economic screening analyses of DSM resource options, FPL typically uses its DSM CPF model which is an FPL spreadsheet model utilizing the FPSC's approved methodology for performing preliminary economic screening of individual DSM measures and programs. In addition, a years-to-payback screening test based on a two-year criterion is also used in the preliminary economic screening of individual DSM measures and programs. Then, as the focus of DSM analyses progresses from analysis of individual DSM measures to the development of DSM portfolios, FPL uses two additional models. One of these models is FPL's non-linear programming model that is used for analyzing the potential for lowering system peak loads through additional load management/demand response capability. The other model that FPL typically utilizes is its linear programming model, which FPL uses to develop DSM portfolios.

The individual new resource options, both Supply options and DSM portfolios, emerging from these preliminary economic screening analyses are then typically "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's projected new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet and/or dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans in Regard to System Economics and Non-Economic Factors:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified and these resource options have been combined into a number of resource plans that each meet the magnitude and timing of FPL's resource needs. The stage is set for evaluating these resource options and resource plans in system economic analyses that aim to account for all of the impacts to the FPL system from the competing resource options/resource plans. In FPL's 2014 and early 2015 resource planning work, once the resource plans were developed, FPL utilized the UPLAN production cost model and a Fixed Cost Spreadsheet, and/or the EGEAS optimization model, to perform the system economic analyses of the resource plans. Other spreadsheet models may also be used to further analyze the resource plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM methodology). In analyses in which the DSM contribution has already been determined through the same IRP process and/or FPSC approval, and therefore the only competing options are new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and resource plans in such cases can be evaluated on a system cumulative present value revenue requirement (CPVRR) basis.

Other factors are also included in FPL's evaluation of resource options and resource plans. Although these factors may have an economic component or impact, they are often discussed in quantitative, but non-economic, terms such as percentages, tons, etc. rather than in terms of dollars. These factors are often referred to by FPL as "system concerns" that include (but are not limited to) maintaining/enhancing fuel diversity in the FPL system, system emission levels, and maintaining a regional balance between load and generating capacity, particularly in the Southeastern Florida counties of Miami-Dade and Broward. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL's system, the non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan. These, and other, factors are discussed later in this chapter in section III.C.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps are typically used to develop FPL's current resource plan. The current resource plan is presented in the following section.

III.B Projected Incremental Resource Additions/Changes in the Resource Plan

FPL's projected incremental generation capacity additions/changes for 2015 through 2024 are depicted in Table ES-1 which was previously presented in the Executive Summary chapter. These capacity additions/changes include the 6 generation additions/changes previously discussed in this chapter.

Although FPL's projected DSM additions that are developed in the IRP process are not explicitly presented in this table, these DSM additions have been fully accounted for in all of FPL's resource planning work reflected in this document. The projected MW reductions from these DSM additions are also reflected in the projected total reserve margin values shown in Table ES-1 and in Schedules 7.1 and 7.2 presented later in this chapter. DSM is further addressed later in this chapter in section III.D.

III.C Discussion of the Projected Resource Plan and Issues Impacting FPL's Resource Planning Work

As indicated in the Executive Summary, FPL's resource planning efforts in 2014 and early 2015 resulted in a resource plan that has four (4) key differences compared to the resource plan presented in FPL's 2014 Site Plan. These 4 key differences are discussed below in chronological order.

1. **FPL No Longer Projects That It Will Serve Vero Beach's Electrical Load:**
   Difficulties in the negotiations between the parties involved have led FPL to no longer project that it will serve Vero Beach's electrical load which was assumed in FPL's most recent Site Plans and load forecasts. This factor results in a lowering of FPL's forecasted load and projected resource needs. To the extent circumstances change and a consummation of the sale once again seems likely, FPL will reincorporate this load into its forecast.

2. **FPL's Power Purchase Agreement with Cedar Bay Will Be Terminated in 2015:**
   FPL anticipates terminating its existing power purchase agreement for 250 MW of coal-fired capacity from the Cedar Bay generating facility at the end of August 2015 as a result of a Purchase and Sale Agreement between FPL and Cedar Bay Generating Company, L.P. FPL would then assume ownership of the facility starting on September 1, 2015. FPL currently anticipates that it will not need the unit for economic purposes after 2016 and, if that proves to be the case, would retire the unit at that time. FPL filed for FPSC approval of the Purchase and Sale Agreement in the first quarter of 2015.

3. FPL Will Approximately Triple Its Solar Generation Capacity by the End of 2016:

FPL will be adding three new photovoltaic (PV) facilities by the end of 2016. Each of the PV facilities will be approximately 74.5 MW (nameplate rating, AC). As a result, FPL's solar generation capacity will increase from its current 110 MW to approximately 333 MW. The new PV installations are projected to be sited in Manatee, Charlotte, and DeSoto counties. The economics of these specific PV projects are aided by the fact that the sites are located close to existing electric infrastructure, including tranmission lines and electric substations, and by the fact that bringing these solar facilities into service prior to the end of 2016 will allow the facilities to take advantage of the current 30% investment tax credit that is scheduled to be reduced to 10% beginning in 2017.

4. Turkey Point 6 & 7 Projected In-Service Dates Have Been Moved Outside of the 10-year Reporting Period of This Document.

In recent Site Plans, the earliest practical deployment dates for the new Turkey Point 6 & 7 nuclear units were identified as 2022 and 2023 and these two dates were used as the in-service dates for these units. However, in the second half of 2014, the Nuclear Regulatory Commission (NRC) issued a new schedule for completing its review of FPL's Combined Operating License Application (COLA) for Turkey Point 6 & 7. The NRC's new schedule now projects that its review will not be completed until late 2016 which is a significant delay from the NRC's previous projection of a 2014 completion of its COLA review. As a consequence of the NRC delay, and the impacts of the recently amended Florida nuclear cost recovery (NCR) statute, FPL now projects that the earliest practical deployment dates for Turkey Point 6 & 7 will fall outside of the 10-year time period of 2015 through 2024 that is addressed in this Site Plan document. However, emissions-free, baseload capacity and energy from nuclear power remains an important part of FPL's resource plans. For that reason, Chapter IV provides detailed information regarding the Turkey Point site for these two new nuclear units.

In addition, there are six (6) significant factors that either influenced the current resource plan presented in this document or which may result in changes in this resource plan in the future. These 6 factors are discussed below (in no particular order of importance).

1. Maintaining/Enhancing System Fuel Diversity:

FPL currently uses natural gas to generate approximately two-thirds of the total electricity it delivers to its customers. In the future, the percentage of FPL's electricity that is generated by natural gas is projected to remain at a high level. For this reason, and due to evolving environmental regulations, FPL is continually seeking opportunities to economically maintain and enhance the fuel diversity of its system.

In 2007, following express direction by the FPSC to do so, FPL sought approval from the FPSC to add two new advanced technology coal units to its system. These two new units would have been placed in-service in 2013 and 2014. However, in part due to concerns over potential greenhouse gas emission legislation/regulation, FPL was unable to obtain approval for these units. Several other factors are currently unfavorable to new coal units compared to new natural gas-fired combined cycle (CC) units. The first of these factors is a significant reduction in the fuel cost difference between coal and natural gas when compared to the fuel cost difference projected in 2007 which favored coal; i.e., the projected fuel cost advantage of coal versus natural gas has been significantly reduced. Second is the continuation of significantly higher capital costs for coal units compared to capital costs for CC units. Third is the increased fuel efficiency of new CC units compared to projected CC unit efficiencies in 2007. Fourth are existing and proposed environmental regulations, including those that address greenhouse gas emissions, which are unfavorable to new coal units when compared to new CC units. Consequently, FPL does not believe that new advanced technology coal units are currently economically, politically, or environmentally viable fuel diversity enhancement options in Florida.

Therefore, FPL has turned its attention to: nuclear energy and renewable energy to enhance its fuel diversity, diversifying the sources of natural gas, diversifying the gas transportation paths used to deliver natural gas to FPL's generating units, and using natural gas more efficiently. In regard to nuclear energy, in 2008 the FPSC approved the need to increase capacity at FPL's four existing nuclear units and authorized FPL to recover project-related expenditures that are approved as a result of annual nuclear cost recovery filings. FPL successfully completed the nuclear capacity uprate project. Approximately 520 MW of additional nuclear capacity were delivered by the project which represents an increase of approximately 30% more incremental capacity than was originally forecasted when the project began. FPL's customers are already benefitting from lower fuel costs and reduced system emissions provided by this additional nuclear capacity.

FPL is continuing its work to obtain all of the licenses, permits, and approvals that are necessary to construct and operate two new nuclear units at its Turkey Point site in the future. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. However, as discussed below, a several year delay in the Nuclear Regulatory Commission's (NRC) schedule for completing its review of FPL's Combined Operating License Application (COLA) have resulted in the earliest deployment dates for the two new nuclear units, Turkey Point Units 6 & 7, moving beyond the 2015 through 2024 reporting time period of this Site

Plan. The projected new in-service dates for Turkey Point Units 6 & 7 are June 2027 and June 2028, respectively.

FPL also has been involved in activities to investigate adding and/or maintaining renewable resources as a part of its generation supply. One of these activities is a variety of discussions with the owners of existing facilities aimed at maintaining or extending current agreements. In addition, FPL considers new cost-effective renewable energy projects such as the power purchase agreements with U.S. EcoGen which will result in FPL receiving 180 MW of firm capacity from biomass facilities beginning in 2021.

FPL also sought and received approval from the FPSC in 2008 to add 110 MW of then new renewable facilities through three FPL-owned solar facilities: one solar thermal facility and two photovoltaic (PV) facilities. One 25 MW PV facility began commercial operation in 2009. The remaining two solar facilities, a 10 MW PV facility and a 75 MW solar thermal steam generating facility, began commercial operation in 2010. The addition of these renewable energy facilities was made possible by enabling legislation enacted by the Florida Legislature in 2008. FPL remains strongly supportive of federal and/or state legislation that enables electric utilities to add renewable energy resources and authorize the utilities to recover appropriate costs for these resources.

The capital costs for PV modules have steadily declined. In addition, FPL's on-going analyses of its existing PV facilities have led FPL to develop a methodology with which to determine appropriate firm capacity values for PV facilities for use in reserve margin calculations. This methodology has concluded, in general, that it is possible on FPL's system to develop a utility-scale PV project-specific non-zero firm capacity value for the Summer peak hour, but not for FPL's Winter morning peak hour. Partly as a result of developing this methodology, FPL's current resource plan that is presented in this Site Plan shows that FPL plans to add approximately 223 MW (nameplate, AC) of new PV generation by the end of 2016. These 3 specific PV projects are projected to contribute a total of approximately 116 MW (or 52% of the nameplate AC value for each project) of firm Summer capacity, but no MW of firm Winter capacity. Significant cost advantages that exist at the 3 specific sites selected for the new PV facilities greatly assisted in being able to bring the PV facilities in-service in 2016. In addition, the fact that bringing these solar facilities into service prior to the end of 2016 allows the facilities to take advantage of the current 30% investment tax credit that is scheduled to be reduced to 10% beginning in 2017, also assisted in this regard. The PV facilities are further discussed later in section III.F of this chapter.

In regard to diversity in natural gas sourcing and delivery, in 2013 the FPSC approved FPL's contracts to bring more natural gas into FPL's service territory through a 3rd natural gas pipeline system into Florida. The process by the pipeline companies to obtain approval for the new pipeline system from the Federal Energy Regulatory Commission (FERC) is currently underway. The new pipeline system will utilize an independent route that will result in a more reliable, more economic, and more diverse natural gas supply for FPL's customers and the State of Florida.

In regard to using natural gas more efficiently, FPL received approvals in 2008 from the FPSC to modernize the existing Cape Canaveral and Riviera Beach plant sites with new, highly efficient CC units to replace the former steam generating units on each of those sites. The Cape Canaveral modernization was commissioned on April 24, 2013 and the Riviera Beach modernization was commissioned on April 1, 2014. On April 9, 2012, FPL received FPSC approval to proceed with a similar modernization project at the Port Everglades site. The project is scheduled for completion in mid-2016. All three of these modernized sites will retain the capability of receiving water-borne delivery of ultra-low sulfur diesel (ULSD) oil as a backup fuel.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity. In this regard, FPL is also maintaining the ability to utilize heavy oil and/or ULSD oil at existing units that have that capability. For this purpose, FPL has completed the installation of electrostatic precipitators (ESPs) at the two 800 MW steam generating units at its Manatee site and at the two 800 MW steam generating units at its Martin site. These installations will enable FPL to retain the ability to burn heavy oil, as needed, at these sites while retaining the flexibility to use natural gas when economically attractive. In addition, the new CTs that FPL plans to install at its existing Lauderdale and Fort Myers sites, which will replace older GT units that are being retired, will have the capability to burn either natural gas or ULSD oil.

2. Maintaining a Balance Between Load and Generation in Southeastern Florida:

An imbalance has existed between regionally installed generation and regional peak load in Southeastern Florida. As a result of that imbalance, a significant amount of energy required in the Southeastern Florida region during peak periods is provided by: importing energy through the transmission system from generating units located outside the region, operating less efficient generating units located in Southeastern Florida out of economic dispatch, or a combination of the two. FPL's prior planning work concluded that, as load inside the region grows, either additional installed generating capacity in this region, or additional installed transmission capacity capable of delivering more electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location in Southeastern Florida, four recent capacity addition decisions (Turkey Point Unit 5 and WCEC Units 1, 2, & 3) were determined to be the most cost-effective options to meet FPL's capacity needs in the near-term. In addition, FPL has added increased capacity at its existing two nuclear units at Turkey Point as part of the previously mentioned nuclear capacity uprates project. The Port Everglades modernization project scheduled for completion in 2016 will also assist in addressing this imbalance. Implementing the additional generation capacity through the projects mentioned above has contributed to addressing the imbalance between generation, transmission capacity, and load in Southeastern Florida for much, if not all, of the 2015 through 2024 reporting time frame of this Site Plan. However, due to forecasted steadily increasing load in the Southeastern Florida region, the Southeastern Florida imbalance issue will remain an important consideration in FPL's on-going resource planning work in future years.

3. **Maintaining a Balance Between Generation and DSM Resources in Regard to System Reliability:**

There is another system concern that FPL has considered in its resource planning for several years. This concern surfaced beginning in 2010 when FPL's system was projected to become increasingly dependent upon DSM resources for system reliability in later years. FPL discussed this concern previously in its Site Plans from 2011 through 2014. As a result of this concern, FPL conducted extensive analyses of its system from both a resource planning perspective and a system operations perspective. Those analyses showed that system reliability risk increases, particularly from a system operations perspective, as dependence on DSM resources increases to a point where DSM resources account for more than half of FPL's 20% total reserve margin criterion value. As a result, in 2014 FPL implemented a new reliability criterion of a minimum 10% generation-only reserve margin (GRM) in its resource planning work to complement its other two reliability criteria: a 20% total reserve margin criterion for Summer and Winter, and an annual 0.1 day/year loss-of-load-probability (LOLP) criterion. Together, these three criteria allow FPL to address this specific concern regarding system reliability in a comprehensive manner.

4. **The Significant Impacts of Federal and State Energy Efficiency Codes and Standards:**

As discussed in Chapter II, FPL's load forecast includes projected impacts from federal and state energy efficiency codes and standards. The magnitude of energy efficiency that is now projected to be delivered to FPL's customers through these codes and standards is significant.

FPL currently projects a cumulative Summer peak reduction impact of 3,568 MW from these codes and standards beginning in 2005 (the year the National Energy Policy Act was enacted) and extending through the year 2024 (i.e., the last year in the 2015 through 2024 reporting time period for this Site Plan) compared to what the projected load would have been without the codes and standards. The projected incremental Summer MW impact from these codes and standards during the 2015 through 2024 reporting period of this Site Plan; i.e., from year-end 2014 through 2024, is 2,035 MW compared to what the projected load would have been without the codes and standards. Both of these projections show the significant impact of these energy efficiency codes and standards.

In addition to lowering FPL's load forecast from what it otherwise would have been, and thus serving to lower FPL's projected load and resource needs, this projection of efficiency from the codes and standards also affects FPL's resource planning in another way. The projected impacts from the efficiency codes and standards lower the potential for utility DSM programs to cost-effectively deliver energy efficiency for the appliances and equipment that are directly addressed by the codes and standards. This effect was taken into account by the FPSC in the new DSM Goals for the 2015 – 2024 time period set by the FPSC in November 2014.

5. **The Economic Competitiveness of Utility-Scale Photovoltaics (PV)**:

A factor that is now significantly influencing FPL's resource planning is the increasing attractiveness of utility-scale photovoltaic (PV) facilities. This is due largely to the continued decline of the cost of PV modules. Because utility-scale PV facilities are at least twice as economical on an installed $/kw basis than distributed PV, the declining costs of PV modules has resulted, for the first time, in utility-scale PV in specific locations now being cost competitive on FPL's system. In addition, FPL's analyses of the output from its existing PV facilities in DeSoto and Brevard counties have resulted in FPL establishing a methodology for determining Summer and Winter firm capacity values for utility-scale PV facilities.

Therefore, FPL's current resource plan that is presented in this Site Plan shows that FPL plans to add approximately 223 MW (nameplate AC) of new PV generation by the end of 2016. Details regarding the projected new PV facilities are discussed further in this chapter in section III.F.

6. **Environmental Regulation in General and Specifically, the EPA's Proposed Clean Power Plan:**

Another important factor is environmental regulation in general and, specifically, the U.S. Environmental Protection Agency's (EPA's) proposed Clean Power Plan issued in June 2014. The intent of the Clean Power Plan is to establish carbon dioxide (CO_2) emission limits for each state. The process for finalizing all aspects of the proposed CO_2 regulations will encompass several years at least. The EPA is scheduled to issue final rules and emission limits in the Summer of 2015 (i.e., several months after this Site Plan is filed). The current draft rules then call for each state to submit its state compliance plan by June 2016 (although a delay of at least one year is possible). Legal challenges to the proposed Clean Power Plan are expected and such challenges have the potential to delay the proposed timetable.

FPL's resource planning work will account for the CO_2 limits as they are finalized. In addition, FPL expects to be actively engaged in the development of Florida's statewide compliance plan.

Each of these 6 factors will continue to be examined in FPL's on-going resource planning work during the remainder of 2015 and in future years.

III.D Demand Side Management (DSM)

FPL has sought and implemented cost-effective DSM programs since 1978 and DSM has been a key focus of FPL's IRP process for decades. During that time FPL's DSM programs have included many energy efficiency and load management programs and initiatives. FPL's DSM efforts through 2014 have resulted in a cumulative Summer peak reduction of approximately 4,793 MW (Summer) at the generator and an estimated cumulative energy saving of approximately 70,997 Gigawatt Hour (GWh) at the generator. After accounting for the 20% total reserve margin requirement, FPL's DSM efforts through 2014 have eliminated the need to construct the equivalent of approximately 14 new 400 MW power plants.

FPL consistently has been among the leading utilities nationally in DSM achievement. For example, according to the U.S. Department of Energy's 2013 data (the last year for which the DOE ranking data was available at the time this Site Plan was developed), FPL ranked # 2 nationally in cumulative DSM demand reduction. And, importantly, FPL has achieved these significant DSM accomplishments while minimizing the DSM-based impact on electric rates for all of its customers.

In November 2014, new DSM Goals for FPL for the years 2015 through 2024 were set by the FPSC. These DSM Goals were lower than the previous DSM Goals for FPL due to two factors. The first factor is the significant impact of federal and state energy efficiency codes and standards. The projected impact of these codes and standards has significantly lowered FPL's projected load and resource needs. In addition, these codes and standards have removed a significant amount of potential energy efficiency that otherwise might have been addressed by utility DSM programs. The projected impacts from these codes and standards are discussed in Chapter II.

The second factor why FPL's resource plan currently shows a diminished role for utility DSM is the decline in the projected cost-effectiveness of utility DSM measures and programs. The cost-effectiveness of DSM is driven in large part by the potential benefits that the kW (demand) reduction and kWh (energy) reduction characteristics of DSM programs are projected to provide. The diminished cost-effectiveness of utility DSM programs can be illustrated by looking only at potential benefits that DSM's kWh reductions can provide. There are at least two reasons for projections of lower kWh reduction-based benefits and thus projections of lower DSM cost-effectiveness.

The first reason is lower fuel costs. For example, comparing the current fuel cost forecast (at the time this Site Plan was prepared) with the fuel forecast used in 2009 – the year when FPL's DSM Goals were previously set by the FPSC – shows that current forecasts of fuel costs are now much lower than those forecasted in 2009. This can be seen by comparing the 2009 and current forecasted costs ($/mmBTU) for natural gas for two specific years addressed in this Site Plan and that were addressed in the 2009 DSM goals-setting: 2015 and 2019:

Year	2009 Forecast	Current Forecast
2015	$9.64	$4.02
2019	$12.63	$4.70

As shown from these values, natural gas prices are forecast to be less than 50% of what they were forecast to be in 2009 when DSM goals were previously set. Lower forecasted natural gas costs are very beneficial for FPL's customers because they result in lower fuel costs and lower electric rates. At the same time, lower fuel costs also result in lower potential fuel savings benefits from the kWh reductions of DSM measures. These lowered benefit values result in DSM being less cost-effective.

A second reason for the decline in the cost-effectiveness of utility DSM on the FPL system is the steadily increasing efficiency with which FPL generates electricity. FPL's generating system has steadily become more efficient in regard to its ability to generate electricity using less fossil fuel. For example, FPL used 20% less fossil fuel to generate the same number of MWh in 2012 than it did in 2001. This is a very good thing for FPL's customers because it helps to significantly lower fuel costs and electric rates.

However, the improvements in generating system efficiency affect DSM cost-effectiveness in much the same way that lower forecasted fuel costs do: both lower the fuel costs of energy delivered to FPL's customers. Therefore, the improvements in generating system efficiency further reduce the potential fuel savings benefits from the kWh reduction impacts of DSM, thus further lowering potential DSM benefits and DSM cost-effectiveness.

The two reasons discussed above – lower forecasted fuel costs and greater efficiency in FPL's electricity generation – are good for FPL's customers because they will result in lower electric rates. Although beneficial for FPL's customers, these factors also contribute to lowering the cost-effectiveness of utility DSM programs. Therefore, the reduction in DSM cost-effectiveness, plus the growing impacts of energy efficiency codes and standards, led to the FPSC setting lower DSM Goals for FPL.

Although the new DSM Goals are appropriately lower due to these market forces, the projected cumulative effect of FPL's DSM programs from their inception through 2024 is truly significant. FPL's Summer MW Goals for the 2015 – 2024 time period were set at 526 MW. After accounting for the 20% total reserve margin requirements, the combination of this new Summer MW reduction value, and the Summer MW reductions from FPL's DSM programs from their inception through 2014, represent the equivalent of avoiding the need to build approximately sixteen (16) 400 MW power plants. The resource plan presented in this 2015 Site Plan accounts for the DSM MW and GWh reductions set forth in FPL's new DSM Goals. The reductions from the new DSM Goals are accounted for in Schedules 7.1 and 7.2 which appear later in this chapter.

In the March 2015, FPL filed for FPSC approval of a DSM Plan that consists of numerous DSM programs to meet the new DSM Goals. A decision by the FPSC on these new DSM programs is expected in mid-2015.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy to FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV bulk transmission lines that must be certified under the Transmission Line Siting Act.

Table III.E.1: List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	St. Johns [1/]	Pringle	25	Dec – 18	230	759
FPL	Levee [2/]	Midway	150	Jun – 23	500	2598
FPL	Raven [3/]	Duval	45	Dec – 19	230	759

1/ Final order certifying the corridor was issued on April 21, 2006. This project is to be completed in two phases. Phase I consisted of 4 miles of new 230 kV line (Pringle to Pellicer) and was completed in May-2009. Phase II consists of 21 miles of new 230 kV line (St. Johns to Pellicer) and is scheduled to be completed by Dec-2018.

2/ Final order certifying the corridor was issued in April 1990. Construction of 114 miles is complete and in-service. Remaining 36 miles are scheduled to be completed by Jun-2023.

3/ TLSA is being initiated in 2015 for the Raven to Duval project.

In addition, there will be transmission facilities needed to connect several of FPL's projected generating capacity additions to the system transmission grid. These transmission facilities (described on the following pages) are for the Port Everglades modernization that will be completed in mid-2016, the PV additions in late 2016, and the potential new CC unit in 2019 at the Okeechobee site. At the time the 2015 Site Plan was prepared, no site had been selected for the 2023 combined cycle addition in the resource plan presented in this Site Plan. Therefore, no transmission information for this addition is presented.

II.E.1 Transmission Facilities for Port Everglades Next Generation Clean Energy Center (Modernization)

The work required to connect the Port Everglades Next Generation Clean Energy Center to the FPL grid in 2016 is projected to be:

I. Substation:

1. Construct two string busses to connect two combustion turbines (CT) to the Port Everglades 138 kV Substation.
2. Construct two string busses to connect one CT, and one steam turbine (ST) to the Port Everglades 230 kV Substation.
3. Add four main step-up transformers (3-450 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. Replace ten (10) 138 kV breakers.
5. Replace eight (8) 230 kV breakers.
6. At Port Everglades Switchyard replace twenty-two 138 kV disconnect switches. Also upgrade associated jumpers, bus work, and equipment connections.
7. Expand switchyard relay vault and add relays and other protective equipment.

II. Transmission:

1. Upgrade of existing transmission facilities:
    - An ampacity upgrade up to 1905 amps on the Port Everglades-Port Everglades Tap 138kV line section.
    - An ampacity upgrade up to 1905 amps on the Port Everglades Tap-Port Everglades Tap 2 138 kV line section.
    - An ampacity upgrade up to 1695 amps on the Port Everglades Tap 1-Dania 138 kV line section.
    - An ampacity upgrade up to 1695 amps on the Dania-Hollywood 138 kV line section.

III.E.2 Transmission Facilities for the PV Project at the Existing Manatee Plant Site

The work required to connect the approximate 74.5 MW (nameplate, AC) facility at the existing Manatee site is projected to be:

I. Substation:

1. Build a new 230 kV substation approximately 0.4 miles west of the existing FPL Manatee 230 kV substation.
2. Add one main step-up transformer (80 MVA) to connect solar PV inverter array
3. Construct a new 230 kV breaker bay at the Manatee switchyard.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Construct 0.4 mile 230 kV line from new substation to Manatee switchyard.
2. No upgrades are expected to be necessary at this time.

III.E.3 Transmission Facilities for the Citrus PV Project in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Citrus PV facility in DeSoto County is projected to be:

I. Substation:

1. Construct a new 4-breaker 230 kV ring bus at Sunshine substation.
2. Add one main step-up transformer (80 MVA) to connect solar PV inverter array
3. Construct a string buss to connect the PV array to Sunshine 230 kV Substation
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. No upgrades are expected to be necessary at this time.

III.E.3 Transmission Facilities for the Babcock Ranch PV Project in Charlotte County

The work required to connect the approximate 74.5 MW (nameplate, AC) Babcock Ranch PV facility in Citrus County is projected to be:

I. Substation:

1. Build a new 230 kV Tuckers substation approximately 5 miles north of the planned FPL Hercules 230 kV substation.
2. Add one main step-up transformer (80 MVA) to connect solar PV inverter array
3. Add one (1) mid-breaker to complete bay 2 at Hercules
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Construct 5 miles of 230 kV line from new Tuckers substation to Hercules substation.
2. No upgrades are expected to be necessary at this time.

III.E.4 Transmission Facilities for the Potential New Combined Cycle (CC) Unit in Okeechobee County

The work required to connect the potential new CC unit in Okeechobee County by Summer 2019 is projected to be:

I. Substation:

1. Build a new six breaker 500kV Okeechobee Substation switchyard on the Okeechobee generation site with a relay vault for the two generator string buses and the Martin and Poinsett line terminals.
2. Build new collector yard containing two collector busses with 4 breakers to connect the three CTs, and one ST.
3. Construct two string busses to connect the collector busses and main switchyard to Okeechobee 500kV Substation.
4. Add five main step-up transformers (5-450 MVA) one for each CT, and two for the ST.
5. Add relays and other protective equipment.
6. Breaker replacements:
   Poinsett Sub – Replace three (3) 230 kV breakers.

II. Transmission:

1. No upgrades are expected to be necessary at this time.

III.F. Renewable Resources

FPL's Renewable Energy Efforts Through 2014:

FPL has been the leading Florida utility in examining ways to effectively utilize renewable energy technologies to serve its customers. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. For purposes of discussing FPL's renewable energy efforts through 2014, those efforts will be placed into five categories. FPL's plans for new renewable energy facilities during the 2015 through 2024 time period are then discussed in a separate section.

Two of these categories are Supply-Side Efforts – Power Purchases, and Supply-Side Efforts – FPL Facilities. Since 2011, the combined total energy output (MWh) from these renewable energy sources has been greater than that produced from oil-fired generation. The comparable values for energy delivered by renewable and oil-fired sources for the year 2014 are presented in Schedule 11.1 at the end of this chapter.

1) Early Research & Development Efforts:

In the late 1970s, FPL assisted the Florida Solar Energy Center (FSEC) in demonstrating the first residential PV system east of the Mississippi River. This PV installation at FSEC's Brevard County location was in operation for more than 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. In 1984, FPL installed a second PV system at its Flagami substation in Miami. This 10-kilowatt (kW) system operated for a number of years before it was removed to make room for substation expansion. In addition, FPL maintained a thin-film PV test facility at the FPL Martin Plant Site for a number of years to test new thin-film PV technologies.

2) Demand Side & Customer Efforts:

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers who chose solar water heaters. Before the program ended (because it was no longer cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created in order to broadly disseminate information about passive solar building design techniques that are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for six passive home designs with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, the program received a U.S. Department of Energy award for innovation and also led to a revision of the Florida Model Energy Building Code (Code). The Code was revised to incorporate one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

FPL has continued to analyze and promote the utilization of PV. These efforts have included PV research such as the 1991 research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. FPL's PV efforts also included educational efforts such as FPL's Next Generation Solar Station Program. This initiative delivered teacher training and curriculum that is tied to the Sunshine Teacher Standards in Florida. The program provided teacher grants to promote and fund projects in the classrooms. In addition, FPL assists customers who are interested in installing PV equipment at their facilities. Consistent with Florida Administrative Code Rule 25-6.065, Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned PV systems. Through December 2014, approximately 3,241 customer systems (predominantly residential) have been interconnected.

As part of its 2009 DSM Goals decision, the FPSC imposed a requirement for Florida's investor-owned utilities to spend up to a not-to-exceed amount of money annually to facilitate demand side solar water heater and PV applications. FPL's not-to-exceed amount of money for these applications was approximately $15.5 million per year for five years. In response to this direction, FPL received approval from the FPSC in 2011 to initiate a solar pilot portfolio consisting of three PV-based programs and three solar water heating-based programs, plus Renewable Research and Demonstration projects. FPL's analyses of the results from these programs since their inception have consistently shown that none of these pilot programs is cost-effective using any of the three cost-effectiveness screening tests used by the State of Florida. As a result, consistent with the FPSC's November 2014 DSM Goals Order No. PSC-14-0696-FOF-EU, these pilot programs will expire on December 31, 2015.

FPL also has been investigating fuel cell technologies through monitoring of industry trends, discussions with manufacturers, and direct field trials. From 2002 through the end of 2005, FPL conducted field trials and demonstration projects of Proton Exchange Membrane (PEM) fuel cells with the objectives of serving customer end-uses while evaluating the technical performance, reliability, economics, and relative readiness of the PEM technology. The demonstration projects were conducted in partnership with customers and included five locations. The research projects were useful to FPL in identifying specific issues that can occur in field applications and the current commercial viability of this technology. FPL will continue to monitor the progress of these technologies and conduct additional field evaluations as significant developments in fuel cell technologies occur.

3) <u>Supply Side Efforts – Power Purchases:</u>

FPL also has facilitated a number of renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy, and as-available energy, have been purchased by FPL from these types of facilities. (Please refer to Tables I.A.3, I.B.1, and I.B.2 in Chapter I).

FPL issued Renewable Requests for Proposals (RFPs) in 2007 and 2008 which solicited proposals to provide firm capacity and energy, and energy only, at or below avoided costs, from renewable generators. FPL also promptly responds to inquiries for information from prospective renewable energy suppliers either by e-mail or phone.

On April 22, 2013, in Order No. PSC-13-1064-PAA-EQ, the FPSC approved three 60 MW power purchase agreements with affiliates of U.S. EcoGen for biomass-fired renewable energy facilities. These facilities are expected to provide non-firm energy service beginning in 2019 and to provide firm energy and capacity to FPL's customers beginning in 2021.

In regard to existing contracts that have recently ended, FPL and the Solid Waste Authority of Palm Beach (SWA) agreed to extend their contract that expired March 31, 2010 for a 20-year term beginning in April 1, 2012 through April 1, 2032. However, the SWA refurbished their generating unit ahead of schedule and, as of January 2012, this unit began delivering firm capacity to FPL. In 2011, the FPSC approved a contract for an additional 70 MW between FPL and SWA for a new unit. The new unit is now delivering test energy and will begin delivering firm capacity and energy to FPL beginning in June 2015. At the end of December 2011, the contract between FPL and Okeelanta (New Hope) expired. However, Okeelanta continues to deliver energy to FPL as an as-available, non-firm supplier of renewable energy.

4) <u>Supply Side Efforts – FPL Facilities:</u>

With regard to solar generating facilities, FPL currently has three such facilities: (i) a 75 MW steam generation solar thermal facility in Martin County (the Martin Next Generation Solar Energy Center); (ii) a 25 MW PV electric generation facility in DeSoto County (the DeSoto Next Generation Solar Energy Center); and (iii) a 10 MW PV electric generation facility in Brevard County at NASA's Kennedy Space Center (the Space Coast Next Generation Solar

Energy Center). The DeSoto County project was completed in 2009 and the other two projects were completed in 2010.

These three solar facilities were constructed in response to the Florida Legislature's House Bill 7135 which was signed into law by the Governor in June 2008. House Bill 7135 was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in the State of Florida. Specifically, the bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land, zoning, and transmission rights in place. FPL's three solar projects met the specified criteria and were granted approval for cost recovery in 2008. Each of the three solar facilities is discussed below.

a. <u>The Martin Next Generation Solar Energy Center:</u>

This facility began commercial operation in 2010 and provides 75 MW of solar thermal capacity in an innovative way that directly displaces fossil fuel usage on the FPL system. This facility consists of solar thermal technology which generates steam that is integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired CC plant. This project is the first "hybrid" solar plant in the world and, at the time the facility came in-service, was the second largest solar facility in the world and the largest solar plant of any kind in the U.S. outside of California.

b. <u>The DeSoto Next Generation Solar Energy Center:</u>

This 25 MW (nameplate, AC) PV facility began commercial operation in 2009 which made it one of the largest PV facilities in the U.S. at that time. The facility utilizes a tracking PV array that is designed to follow the sun as it traverses across the sky.

c. <u>The Space Coast Next Generation Solar Energy Center:</u>

Located at the Kennedy Space Center, this facility is part of an innovative public/private partnership with NASA. This non-tracking, 10 MW (nameplate, AC) PV facility began commercial operation in 2010.

During 2014, FPL conducted analyses designed to develop a methodology with which to determine what firm capacity value at FPL's Summer and Winter peak hours would be appropriate to apply to these existing, and potential future, utility-scale PV facilities. (Note that the Martin solar thermal facility is a "fuel-substitute" facility, not a facility that provides additional capacity and energy. The solar thermal facility displaces the use of fossil fuel to produce steam on the FPL system when the solar thermal facility is operating.) Based on the results of these analyses, FPL has concluded that its two existing utility-scale PV facilities can be counted on to contribute certain percentages of their nameplate (AC) ratings (approximately 46% for DeSoto and 32% for Space Coast) as firm capacity at FPL's Summer peak hour (that typically occurs in the 4 p.m. to 5 p.m. hour), but contribute no firm capacity during FPL's Winter peak hour (that typically occurs in the 7 a.m. to 8 a.m. hour). Future FPL utility-scale PV facilities will be evaluated for potential firm capacity contribution on a case-by-case basis using this methodology. Their potential capacity contribution will be dependent upon a number of factors including (but not necessarily limited to) site location, technology, and design. For example, the three new PV facilities that are planned to be added by the end of 2016 are each projected to provide approximately 52% of their nameplate (AC) rating as firm capacity at FPL's Summer peak hour, but provide no firm capacity during FPL's Winter peak hour.

5) <u>Ongoing Research & Development Efforts:</u>

FPL has developed alliances with several Florida universities to promote the development of emerging technologies. For example, FPL supports the newly formed Southeast National Marine Renewable Energy Center (SNMREC) at Florida Atlantic University (FAU), which will focus on the commercialization of ocean current, ocean thermal energy conversion, cold water air conditioning, and hydrogen technologies. FPL has supported FAU in discussions with the U.S. Department of the Interior's Minerals Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE). BOEMRE is working to establish the permitting process for ocean energy development on the outer continental shelf.

FPL has also developed a "Living Lab" to demonstrate FPL's solar energy commitment to employees and visitors at its Juno Beach office facility. FPL has installed five different PV arrays (using different technologies) of rooftop PV totaling 24 kW at the Living Lab. In addition, two PV-covered parking structures with a total of approximately 90 kW of PV are in use at the FPL Juno office parking lot. Through these Living Lab projects, FPL is able to evaluate multiple solar technologies and applications for the purpose of developing a renewable business model resulting in the most cost-effective and reliable uses of solar energy for FPL's customers. FPL plans to continue to expand the Living Lab as new solar products come to market.

FPL has also been in discussions with several private companies on multiple emerging technology initiatives, including ocean current, ocean thermal, hydrogen, fuel cell technology, biomass, biofuels, and energy storage.

FPL's Planned Renewable Energy Efforts for 2015 Through 2024:

FPL has concluded from its implementation and analyses of utility-scale PV and PV demand side pilot programs that utility-scale PV applications are the most economical way to utilize solar energy. In fact, FPL's analysis suggests that utility-scale PV is at least twice as economical on an installed $/kw basis compared to distributed PV systems. This conclusion is supported by FPL's recent analyses discussed above regarding the ability to assign firm capacity value at FPL's Summer peak hour to utility-scale PV. Due to the fact that the price of PV modules has declined in recent years, utility-scale PV has become more cost competitive. However, only the most cost-advantaged sites for utility-scale PV are projected to be cost-effective on FPL's system at this time. Other sites may become cost-effective in later years if PV costs continue to decline as expected. Consequently, the resource plan FPL is presenting in this Site Plan includes three utility-scale PV facilities at specific, cost-advantaged sites which also are able to take advantage of the current 30% investment tax credit (which is scheduled to be reduced to 10% in 2017). If/when utility-scale PV projects at other sites are projected to be cost-effective, additional PV generation sources will be discussed in future Site Plans.

1) FPL Utility-Scale PV Facilities:

In the resource plan presented in this Site Plan, FPL projects the addition of three separate utility-scale PV facilities by the end of 2016. Each PV facility is projected to be approximately 74.5 MW (nameplate, AC). The sites of these three proposed PV additions are: FPL's existing Manatee plant site, a site in DeSoto County, and a site in Charlotte County. These locations are expected to have cost advantages to support early development, including:

- Current ownership of land or low cost land purchase agreement in place;
- Proximity to existing transmission lines with sufficient injection capacity;
- Proximity to existing electric substations;
- Previously performed site development and permitting work;
- Proximity to existing FPL generating facilities which allows for lower operating expenses;
- Support from the associated counties and land developers, with the potential for further cost abatements;

As previously mentioned, bringing these three PV facilities in service before the end of 2016 will also allow the facilities to capture the full benefit of the currently available 30% investment tax credit for such PV facilities. The investment tax credit is scheduled to revert back to a 10% credit for PV projects that are placed in service after 2016.

2) FPL Distributed Generation (DG) PV Pilot Programs:

In regard to distributed generation (DG) PV, FPL is planning to implement two DG PV pilot programs in 2015. The first is a voluntary, community-based, solar partnership pilot to install new solar-powered generating facilities. The program will be at least partially funded by contributions from customers who volunteer to participate in the pilot and will not rely on subsidies from non-participating customers. The second program will implement approximately 6 MW of combined DG PV and battery storage at large commercial customer sites. The objective of this program is to collect grid integration data for DG PV and develop operational best practices for addressing potential problems that may be identified. A brief description of the two pilot programs follows:

a) Voluntary, Community-Based Solar Partnership Pilot Program:

FPL is introducing a Voluntary Solar Pilot Program to provide FPL customers with an additional and flexible opportunity to support development of solar power in Florida. The Commission approved FPL's request for this three-year pilot program in Order No. PSC-14-0468-TRF-EI on August 29, 2014. This pilot program will provide all customers the opportunity to support the use of solar energy at a community scale and is designed to be especially attractive for customers who do not wish, or are not able, to place solar equipment on their roof. Customers can participate in the program through voluntary contributions of $9/month starting in mid-2015.

In this respect, these DG-scale projects differ from FPL's three new utility-scale PV projects proposed for 2016, which are not projected to introduce a net cost to customers over the life of these projects and, therefore, do not require additional contributions from FPL's customers. In contrast, smaller DG-scale projects have a higher cost to construct, operate, and maintain. The cost per MW to construct DG-scale facilities (whether utility-owned and operated or otherwise) is approximately double that of the more cost-efficient utility-scale PV projects. Furthermore, the operations and maintenance costs of DG-scale projects are projected to be three times as much as for utility-scale PV due to the distributed nature of the installations. Thus a voluntary contribution is necessary for this DG-based pilot program so that net costs, and electric rates, do not increase for non-participants.

The first 200 kW of DG-scale PV projects will be built by FPL in the first half of 2015 at locations in the city of West Palm Beach and in Broward County. The first installation is scheduled to be at the Young at Arts Museum in Broward County. Additional PV facilities under this pilot program will be built when the projected voluntary contributions are sufficient to cover on-going program costs without increasing electric rates for all customers, including non-participating customers. The locations of these additional PV facilities will be determined at a later date. While the ultimate amount of PV that will be installed under this voluntary program cannot be known at this time, it is estimated that the project could result in approximately 2 MW (nameplate, DC) of community-located PV installations supported by over 10,000 customer participants by the end of the three-year pilot.

b) <u>C&I Solar Partnership Pilot Program:</u>

This is a research program that will be conducted in partnership with interested commercial and industrial (C&I) customers over an approximate five year period. Limited investments will be made in PV facilities located at customer sites in selected geographic areas of FPL's service territory. The objective of this portion of the pilot program is to examine the effect of high DG PV penetration on FPL's distribution system and to determine how best to address any problems that may be identified. FPL will site approximately 5 MW (nameplate, DC) of PV facilities in areas where DG PV already exists to better study feeder loading impacts. PV installations at Daytona International Speedway, and FIU's Engineering Center campus in West Miami-Dade County have been selected based largely on their interconnection with targeted circuits. In addition, this pilot program will also install a battery storage facility of approximately 1 MW capacity. This facility will be used to investigate the interoperability, and optimization, of multiple DG technologies. A multi-year research partnership agreement has been executed with FIU for the university to assist FPL in the battery storage research and development plan, and in the analyses that will subsequently be conducted.

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fired generation. In the early 1980s, FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership (20%) and additional purchases (30%) from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit 4 which began serving FPL's customers in 1991.

The trend since the early 1990s has been a steady increase in the amount of natural gas that FPL uses to produce electricity due, in part, to the introduction of highly efficient and cost-effective CC generating units and the ready availability of natural gas. FPL placed into commercial operation two new gas-fired CC units at the West County Energy Center (WCEC) site in 2009. A third new CC unit was added to the WCEC site in 2011. In addition, FPL has completed the modernization of its Cape Canaveral and Riviera Beach plant sites and is currently modernizing its existing Port Everglades plant site by removing the steam generating units that previously operated at the site and replacing them with one highly efficient new CC unit. The new CC units at each of these three sites will provide highly efficient generation that will dramatically improve the efficiency of FPL's generation system in general and, more specifically, the efficiency with which natural gas is utilized.

In addition, FPL increased its utilization of nuclear energy through capacity uprates of its four existing nuclear units. With these uprates, more than 520 MW of additional nuclear capacity have been added to the FPL system. FPL is also pursuing plans to obtain licenses, permits, and approvals to construct and operate two new nuclear units at its existing Turkey Point site that, in total, would add approximately 2,200 MW of new nuclear generating capacity.

In regard to utilizing renewable energy, FPL has 110 MW of solar generating capacity consisting of: a 75 MW solar thermal steam generating facility at FPL's existing Martin site, a 25 MW PV facility in DeSoto County, and a 10 MW PV facility in Brevard County. The DeSoto facility was placed into commercial operation in 2009. The other two solar facilities were placed into commercial operation in 2010. As discussed in the preceding section, FPL is planning to add three new approximately 74.5 MW (nameplate, AC) PV facilities by the end of 2016.

FPL's future resource planning work will continue to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance FPL's long-term fuel diversity. These fuel diverse alternatives may include: the purchase of power from renewable energy facilities, additional FPL-owned renewable energy facilities, obtaining additional access to diversified sources of natural gas such as liquefied natural gas (LNG) and natural gas from the Mid-Continent unconventional reserves, securing gas reserves, preserving FPL's ability to utilize fuel oil at its existing units, and increased utilization of nuclear energy. (As previously discussed, new advanced technology coal-fired generating units are not currently considered as viable options in Florida in the ten-year reporting period of this document due, in part, to current projections of relatively small differences in fuel costs between coal and natural gas, significantly higher capital costs for coal units compared to CC units, greater efficiencies of CC units, and concerns over environmental regulations that would impact coal units more negatively than CC units.) The evaluation of the feasibility and cost-effectiveness of these, and other possible fuel diversity alternatives, will be part of FPL's on-going resource planning efforts.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2024 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

2) FPL's Fossil Fuel Cost Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future resource needs. FPL's forecasts are generally consistent with other published contemporary forecasts. A November 2014 fuel cost forecast was used in the analyses whose results led to the resource plan presented in this 2015 Site Plan.

Future oil and natural gas prices, and to a lesser extent, coal prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, and coal. These drivers include U.S. and worldwide demand, production capacity, economic growth, environmental requirements, and politics.

The inherent uncertainty and unpredictability of these factors today and in the future clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed and utilized Low, Medium, and High price forecasts for fossil fuels in some of its 2014 and early 2015 resource planning work, particularly in regard to analyses conducted as part of the nuclear cost recovery filing work.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

a. For 2015 through 2016, the methodology used the November 3, 2014 forward curve for New York Harbor 0.7% sulfur heavy oil, ultra-low sulfur diesel (ULSD) fuel oil, and Henry Hub natural gas commodity prices;

b. For the next two years (2017 and 2018), FPL used a 50/50 blend of the November 3, 2014 forward curve and the most current projections at the time from The PIRA Energy Group;

c. For the 2019 through 2035 period, FPL used the annual projections from The PIRA Energy Group; and,

d. For the period beyond 2035, FPL used the real rate of escalation from the Energy Information Administration (EIA). In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal prices. Coal prices were based upon the following approach:

a. Delivered price forecasts for Central Appalachian (CAPP), Illinois Basin (IB), Powder River Basin (PRB), and South American coal were provided by JD Energy; and,

b. The coal price forecast for SJRPP and Plant Scherer assumes the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for oil, natural gas, and coal prices were based on the historical volatility of the 12-month forward price, one year ahead. FPL developed these forecasts to account for the uncertainty that exists within each commodity as well as across commodities. These forecasts reflect a range of reasonable forecast outcomes.

3. Natural Gas Storage

FPL was under contract through August 2014 for 2.5 billion cubic feet (Bcf) of firm natural gas storage capacity in the Bay Gas storage facility located in Alabama. The Bay Gas storage facility is interconnected with the Florida Gas Transmission (FGT) pipeline. FPL amended the transaction with Bay Gas on September 1, 2014 to increase the capacity to 4.0 Bcf of firm natural gas storage capacity. FPL has predominately utilized natural gas storage to help mitigate gas supply problems caused by severe weather and/or infrastructure problems.

Over the past several years, FPL has acquired upstream transportation capacity on several pipelines to help mitigate the risk of off-shore supply problems caused by severe weather in the Gulf of Mexico. While this transportation capacity has reduced FPL's off-shore exposure, a portion of FPL's supply portfolio remains tied to off-shore natural gas sources. Therefore, natural gas storage remains an important tool to help mitigate the risk of supply disruptions.

As FPL's reliance on natural gas has increased, its ability to manage the daily "swings" that can occur on its system due to weather and unit availability changes has become more challenging, particularly from oversupply situations. Natural gas storage is a valuable tool to help manage the daily balancing of supply and demand. From a balancing perspective, injection and withdrawal rights associated with gas storage have become an increasingly important part of the evaluation of overall gas storage requirements.

As FPL's system grows to meet customer needs, it must maintain adequate gas storage capacity to continue to help mitigate supply and/or infrastructure problems and to provide FPL the ability to manage its supply and demand on a daily basis. FPL continues to evaluate its gas storage portfolio and is likely to subscribe for additional gas storage capacity to help increase reliability, provide the necessary flexibility to respond to demand changes, and diversify the overall portfolio.

4. Securing Additional Natural Gas:

The recent trend of increasing reliance upon natural gas to produce electricity for FPL's customers is projected to continue due to FPL's growing load. The addition of highly fuel-efficient CC units at Cape Canaveral and Riviera Beach due to completed modernization projects, the on-going Port Everglades modernization project, plus the potential for additional CC capacity, will reduce the growth in natural gas use from what it otherwise might have been due to the high fuel-efficiency levels of these new CC units. In addition, FPL plans to add a significant amount of new PV facilities that utilize no fossil fuel. However, these efficiency gains do not fully offset the effects of FPL's growing load. Therefore, FPL will need to secure more natural gas supply, more firm gas transportation capacity, and secure gas reserves in the future as fuel requirements dictate. The issue is how to secure these additional natural gas resources in a manner that is economical for FPL's customers and which maintains and/or enhances the reliability of natural gas supply and deliverability to FPL's generating units.

FPL has historically purchased the gas transportation capacity required for new natural gas supply from two existing natural gas pipeline companies. As more natural gas is delivered through these two pipelines, the impact of a supply disruption on either pipeline becomes more problematic. Therefore, FPL issued a Request for Proposals (RFP) in December 2012 for gas transportation capacity to meet FPL's system natural gas requirements beginning in 2017. The RFP encouraged bidders to propose new gas transportation infrastructure to meet Florida's growing need for natural gas. A third pipeline would benefit FPL and its customers by increasing the diversity of FPL's fuel supply sources, increasing the physical reliability of the pipeline delivery system, and enhancing competition among pipelines.

The RFP process was completed in June 2013, and the winning bidders were Sabal Trail Transmission, LLC (Sabal Trail) and Florida Southeast Connection, LLC (FSC). The contracts with Sabal Trail and FSC were reviewed by the FPSC and approved for cost recovery in late 2013. The order approving this cost recovery became final in January 2014. Sabal Trail and FSC are currently in the process of obtaining Federal Energy Regulatory Commission approval for the new pipelines. The planned in-service date for the pipelines is May 2017.

5. Nuclear Fuel Cost Forecast

This section reviews the various steps needed to fabricate nuclear fuel for delivery to the nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

a) Steps Required for Nuclear Fuel to be delivered to FPL's Plants

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

(1) Mining: Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U3O8 (sometimes referred to as yellowcake).

(2) Conversion: During the second step, the U3O8 is chemically converted into UF6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

(3) Enrichment: The third step is called enrichment. Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to almost five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 2.2% to as high as 4.95%). The output of this enrichment process is enriched uranium in the form of UF6.

(4) Fabrication: During the last step, fuel fabrication, the enriched UF6 is changed to a UO2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) Mining: The impact of the earthquake and tsunami that struck the Fukushima nuclear complex in Japan in March 2011 is still being felt in the uranium market. Current demand has declined and several of the production facilities have announced delays. Factors of importance are:

- Hedge funds are still very active in the market. This causes more speculative demand that is not tied to market fundamentals and causes the market price to move up or down just based on news that might affect future demand.

- Some of the uranium inventory from the U.S. Department of Energy (DOE) is finding its way into the market periodically to fund cleanup of certain Department of Energy facilities.

- Although a limited number of new nuclear units are scheduled to start production in the U.S. during the next 5 to 10 years, other countries, more specifically China, have announced an increase in construction of new units which may cause uranium prices to trend up in the near future.

Over a 10-year horizon, FPL expects the market to be more consistent with market fundamentals. The supply picture is more stable, with laws enacted to resolve the import of Russian-enriched uranium, by allowing some imports of Russian-enriched uranium to meet about 20-25% of needs for currently operating units, but with no restriction on the first core for new units and no restrictions after 2020. New and current uranium production facilities continue to add capacity to meet demands. Actual demand tends to grow over time because of the long lead time to build nuclear units. However, FPL cannot discount the possibility of future periodic sharp increase in prices, but believes such occurrences will likely be temporary in nature.

(2) Conversion: The conversion market is also in a state of flux due to the Fukushima events. Planned production after 2018 is currently forecasted to be insufficient to meet the higher demand scenario, but it is projected to be sufficient to meet most reference case scenarios. As with additional raw uranium production, supply will expand beyond current level once more firm commitments are made including commitments to build new nuclear units. FPL expects long term price stability for conversion services to support world demand.

(3) Enrichment: As a result of the Fukushima events in March 2011, the near-term price of enrichment services has been declining for the last three years. However, plans for construction of several new facilities that were expected to come on-line in the next few years have been delayed. Also, some of the existing high operating cost diffusion plants have shut down. As with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand. Meanwhile, world supply and demand will continue to be balanced such that FPL expects adequate supply of enrichment services. The current supply/demand profile will most likely result in the price of enrichment services remaining stable for the next few years before starting to increase.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the Nuclear Regulatory Commission (NRC), not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand is expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies. The calculations for the nuclear fuel cost forecasts used in FPL's 2014 and early 2015 resource planning work were performed consistent with the method then used for FPL's Fuel Clause filings, including the assumption of refueling outages every 18 months and plant operation at current (i.e., power uprated) levels. The costs for each step to fabricate the nuclear fuel were added to come up with the total costs of the fresh fuel to be loaded at each refueling (acquisition costs). The acquisition cost for each group of fresh fuel assemblies were then amortized over the energy produced by each group of fuel assemblies. DOE notified FPL that, effective May 2014, all high level waste payments would be suspended until further notice. Therefore, FPL is no longer including in its nuclear fuel cost forecast a 1 mill per kilowatt hour net to reflect payment to DOE for spent fuel disposal.

Schedule 5
Fuel Requirements
(for FPL only)

		Actual 1/		Forecasted									
Fuel Requirements	**Units**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
(1) Nuclear	Trillion BTU	273	298	292	300	297	300	305	302	300	305	301	301
(2) Coal	1,000 TON	3,540	2,649	2,585	2,376	2,131	2,061	2,288	1,984	2,081	2,056	2,097	1,962
(3) Residual (FO6) - Total	1,000 BBL	150	409	239	270	6	23	84	52	67	92	73	57
(4) Steam	1,000 BBL	150	409	239	270	6	23	84	52	67	92	73	57
(5) Distillate (FO2) - Total	1,000 BBL	152	197	33	202	3	14	98	36	43	216	235	123
(6) Steam	1,000 BBL	0	4	0	0	0	0	0	0	0	0	0	0
(7) CC	1,000 BBL	140	123	3	43	3	12	80	29	38	147	157	83
(8) CT	1,000 BBL	12	69	30	158	0	2	17	7	4	69	78	41
(9) Natural Gas - Total	1,000 MCF	550,350	571,451	573,213	607,356	562,114	571,538	636,702	655,209	654,003	661,930	641,918	619,543
(10) Steam	1,000 MCF	30,348	24,488	13,043	12,527	5,516	7,135	11,042	10,599	8,193	9,467	7,885	6,042
(11) CC	1,000 MCF	514,793	542,409	559,815	593,301	552,012	557,972	611,146	636,305	639,200	644,223	624,799	607,913
(12) CT	1,000 MCF	5,208	4,555	355	1,529	4,586	6,432	14,514	8,305	6,611	8,241	9,234	5,587

1/ Source: A Schedules.
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual [1/]		Forecasted									
			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
(1)	Annual Energy Interchange 2/	GWH	4,445	4,908	3,604	1,263	1,114	1,202	308	0	0	0	0	0
(2)	Nuclear	GWH	25,243	26,812	27,800	28,527	28,249	28,500	29,048	28,710	28,553	29,048	28,626	28,637
(3)	Coal	GWH	5,981	4,482	4,159	3,805	3,359	3,272	3,667	3,123	3,303	3,262	3,339	3,087
(4)	Residual(FO6) -Total	GWH	75	231	155	171	4	15	52	33	43	58	46	36
(5)	Steam	GWH	75	231	155	171	4	15	52	33	43	58	46	36
(6)	Distillate(FO2) -Total	GWH	120	128	14	103	3	13	91	32	40	183	194	101
(7)	Steam	GWH	2	2	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	114	102	3	41	3	12	83	29	38	144	151	78
(9)	CT	GWH	5	23	11	62	0	1	8	3	2	38	43	22
(10)	Natural Gas -Total	GWH	75,208	79,102	79,906	84,749	79,380	80,416	88,286	92,422	92,707	92,810	94,509	96,618
(11)	Steam	GWH	2,472	1,906	1,279	1,214	537	684	1,077	1,001	790	912	763	577
(12)	CC	GWH	72,308	76,857	78,594	83,405	78,404	79,108	85,809	90,628	91,279	91,100	92,854	95,500
(13)	CT	GWH	428	340	33	130	439	623	1,400	793	638	797	893	540
(14)	Solar [3/]	GWH	155	177	192	314	684	700	695	698	695	693	684	691
(15)	PV	GWH	68	68	71	189	577	575	573	573	569	567	565	565
(16)	Solar Thermal	GWH	87	109	121	126	107	125	122	126	125	125	119	126
(17)	Other [4/]	GWH	428	127	3,882	3,474	11,152	11,315	4,923	3,833	3,896	4,023	4,097	4,107
	Net Energy For Load [5/]	GWH	111,656	115,968	119,712	122,407	123,945	125,433	127,070	128,851	129,237	130,077	131,495	133,276

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report
2/ The projected figures are based on estimated energy purchases from SJRPP, the Southern Companies (UPS contract), and other utilities.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
5/ Net Energy For Load values for the years 2015- 2024 are also shown in Col. (19) on Schedule 2.3.

Schedule 6.2
Energy Sources % by Fuel Type

	Energy Source	Units	Actual [1/] 2013	2014	Forecasted 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
(1)	Annual Energy Interchange [2/]	%	4.0	4.2	3.0	1.0	0.9	1.0	0.2	0.0	0.0	0.0	0.0	0.0
(2)	Nuclear	%	22.6	23.1	23.2	23.3	22.8	22.7	22.9	22.3	22.1	22.3	21.8	21.5
(3)	Coal	%	5.4	3.9	3.5	3.1	2.7	2.6	2.9	2.4	2.6	2.5	2.5	2.3
(4)	Residual (FO6) -Total	%	0.1	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)	Steam	%	0.1	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)	Distillate (FO2) -Total	%	0.1	0.1	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CC	%	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1
(9)	CT	%	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	67.4	68.2	66.7	69.2	64.0	64.1	69.5	71.7	71.7	71.3	71.9	72.5
(11)	Steam	%	2.2	1.6	1.1	1.0	0.4	0.5	0.8	0.8	0.6	0.7	0.6	0.4
(12)	CC	%	64.8	66.3	65.7	68.1	63.3	63.1	67.5	70.3	70.6	70.0	70.6	71.7
(13)	CT	%	0.4	0.3	0.0	0.1	0.4	0.5	1.1	0.6	0.5	0.6	0.7	0.4
(14)	Solar [3/]	%	0.1	0.2	0.2	0.3	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5
(15)	PV	%	0.1	0.1	0.1	0.2	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4
(16)	Solar Thermal	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(17)	Other [4/]	%	0.4	0.1	3.2	2.8	9.0	9.0	3.9	3.0	3.0	3.1	3.1	3.1
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report
2/ The projected figures are based on estimated energy purchases from SJRPP, the Southern Companies (UPS contract), and other utilities.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Total Reserve Margin Before Maintenance MW	% of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	% of Peak	Generation Only Reserve Margin After Maintenance MW	% of Peak
2015	25,008	1,420	0	595	27,022	23,286	1,951	21,335	5,688	26.7	0	5,688	26.7	3,736	16.0
2016	25,585	492	0	345	26,421	23,778	2,000	21,779	4,643	21.3	0	4,643	21.3	2,643	11.1
2017	26,001	492	0	345	26,838	24,252	2,046	22,207	4,631	20.9	0	4,631	20.9	2,585	10.7
2018	26,024	699	0	345	27,067	24,648	2,092	22,555	4,512	20.0	0	4,512	20.0	2,420	9.8
2019	27,665	110	0	345	28,120	25,045	2,140	22,905	5,215	22.8	0	5,215	22.8	3,075	12.3
2020	27,665	110	0	345	28,119	25,369	2,188	23,181	4,938	21.3	0	4,938	21.3	2,750	10.8
2021	27,752	110	0	525	28,387	25,497	2,237	23,260	5,127	22.0	0	5,127	22.0	2,890	11.3
2022	27,838	110	0	525	28,472	25,833	2,287	23,546	4,926	20.9	0	4,926	20.9	2,640	10.2
2023	29,154	110	0	525	29,789	26,286	2,338	23,948	5,841	24.4	0	5,841	24.4	3,503	13.3
2024	29,154	110	0	525	29,789	26,771	2,389	24,381	5,407	22.2	0	5,407	22.2	3,018	11.3

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col(4) + Col(5).
Col.(7) reflects the 2014 load forecast without incremental DSM or cumulative load management. 2014 load is an actual load value.
Col.(8) represents cumulative load management capability, plus incremental conservation and load management, from 9/2014-on intended for use with 2014 load forecast.
Col.(10) = Col.(6) - Col.(9)
Col.(11) = Col.(10) / Col.(9)
Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the summer peak period.
Col.(13) = Col.(10) - Col.(12)
Col.(14) = Col.(13) / Col.(9)
Col.(15) = Col.(6) - Col.(7) - Col.(12)
Col.(16) = Col.(15) / Col.(7)

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled
Maintenance At Time Of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
January of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Winter Peak Demand MW	Total Reserve Margin Before Maintenance MW	% of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	% of Peak	Generation Only Reserve Margin After Maintenance MW	% of Peak
2015	26,758	1,357	0	595	28,710	21,136	1,452	19,684	9,026	45.9	0	9,026	45.9	7,574	35.8
2016	27,205	499	0	345	28,049	21,369	1,483	19,886	8,163	41.1	0	8,163	41.1	6,680	31.3
2017	27,842	499	0	345	28,686	21,485	1,510	19,976	8,710	43.6	0	8,710	43.6	7,201	33.5
2018	27,958	499	0	345	28,802	21,598	1,537	20,061	8,740	43.6	0	8,740	43.6	7,204	33.4
2019	27,978	499	0	345	28,822	21,792	1,565	20,227	8,595	42.5	0	8,595	42.5	7,030	32.3
2020	29,573	110	0	345	30,028	21,965	1,593	20,372	9,655	47.4	0	9,655	47.4	8,063	36.7
2021	29,573	110	0	525	30,208	22,096	1,622	20,475	9,733	47.5	0	9,733	47.5	8,111	36.7
2022	29,648	110	0	525	30,283	22,026	1,651	20,374	9,908	48.6	0	9,908	48.6	8,257	37.5
2023	29,737	110	0	525	30,372	22,202	1,682	20,520	9,852	48.0	0	9,852	48.0	8,170	36.8
2024	31,210	110	0	525	31,845	22,408	1,713	20,695	11,150	53.9	0	11,150	53.9	9,437	42.1

Col. (2) represents capacity additions and changes projected to be in-service by January 1st. These MW are generally considered to be available to meet winter peak loads which are forecasted to occur during January of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col(4) + Col(5).
Col.(7) reflects the 2014 load forecast without incremental DSM or cumulative load management. 2014 load is an actual load value.
Col.(8) represents cumulative load management capability, plus incremental conservation and load management, from 9/2014-on intended for use with the 2014 load forecast.
Col.(10) = Col.(6) - Col.(9)
Col.(11) = Col.(10) / Col.(9)
Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the winter peak period.
Col.(13) = Col.(10) - Col.(12)
Col.(14) = Col.(13) / Col.(9)
Col.(15) = Col.(6) - Col.(7) - Col.(12)
Col.(16) = Col.(15) / Col.(7)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes [1]

Plant Name	Unit No. (2)	Location (3)	Unit Type (4)	Fuel Pri. (5)	Fuel Alt. (5)	Fuel Transpor Pri. (7)	Fuel Transpor Alt. (8)	Const. Start Mo./Yr. (9)	Comm. In-Service Mo./Yr. (10)	Expected Retirement Mo./Yr. (11)	Gen. Max. Nameplate KW (12)	Firm Net Capability [2] Winter MW (13)	Firm Net Capability [2] Summer MW (14)	Status (15)
ADDITIONS/ CHANGES														
2015														
Cape Canaveral Energy Center	3	Brevard County	CC	NG	FO2	PL	TK	-	Jan-15	Unknown	1,295,400	77	-	OT
Fort Myers	2	Lee County	CC	NG	No	PL	No	-	Jan-15	Unknown	1,721,490	9	0	OT
Fort Myers	3	Lee County	CT	NG	FO2	PL	TK	-	Jan-15	Unknown	188,190	6	(5)	P
FT. Myers GT	1-12	Lee County	GT	FO2	No	TK	No	-	Jan-15	Unknown	744,120	28	-	OT
Lauderdale	4	Broward County	CC	NG	FO2	PL	PL	-	Jan-15	Unknown	526,250	17	-	OT
Lauderdale	5	Broward County	CC	NG	FO2	PL	PL	-	Jan-15	Unknown	526,250	16	-	OT
Lauderdale GT	1-12	Broward County	GT	NG	FO2	PL	PL	-	Jan-15	Unknown	410,734	(13)	(8)	P
Lauderdale GT	13-24	Broward County	GT	NG	FO2	PL	PL	-	Jan-15	Unknown	410,734	(13)	(8)	P
Manatee	3	Manatee County	CC	NG	No	PL	No	-	Jan-15	Unknown	1,224,510	20	-	OT
Martin	2	Martin County	ST	FO6	NG	PL	PL	-	Jun-15	Unknown	934,500	-	(3)	OT
Martin	3	Martin County	CC	NG	No	PL	No	-	Jan-15	Unknown	612,000	16	-	OT
Martin	4	Martin County	CC	NG	No	PL	No	-	Jan-15	Unknown	612,000	14	-	OT
Port Everglades GT	1-12	City of Hollywood	GT	NG	FO2	PL	PL		Jan-15	Unknown	410,734	(13)	(8)	P
Riviera Beach Energy Center	5	City of Riviera Beach	CC	NG	FO2	PL	WA	-	Jan-15	Unknown	1,295,400	44	-	OT
Sanford	4	Volusia County	CC	NG	No	PL	No	-	Jan-15	Unknown	1,188,860	2	-	OT
Sanford	5	Volusia County	CC	NG	No	PL	No	-	Jan-15	Unknown	1,188,860	2	-	OT
Scherer	4	Monroe, GA	ST	SUB	No	RR	No	-	Jun-15	Unknown	680,368	-	(9)	OT
St. Lucie	1	St. Lucie County	ST	Nuc	No	TK	No	-	Jan-15	Unknown	1,020,000	(22)	-	OT
St. Lucie	2	St. Lucie County	ST	Nuc	No	TK	No	-	Jan-15	Unknown	723,775	(20)	-	OT
Turkey Point	3	Miami Dade County	ST	Nuc	No	TK	No	-	Jan-15	Unknown	877,200	(28)	-	OT
Turkey Point	4	Miami Dade County	ST	Nuc	No	TK	No	-	Jan-15	Unknown	877,200	(27)	-	OT
Turkey Point	5	Miami Dade County	CC	NG	FO2	PL	TK	-	Jan-15	Unknown	1,224,510	(24)	(22)	OT
West County 1	1	Palm Beach County	CC	NG	FO2	PL	TK	-	Jan-15	Unknown	1,366,800	11	-	OT
West County 2	2	Palm Beach County	CC	NG	FO2	PL	TK	-	Jan-15	Unknown	1,366,800	11	-	OT
West County 3	3	Palm Beach County	CC	NG	FO2	PL	TK	-	Jan-15	Unknown	1,366,800	11	-	OT
											2015 Changes/Additions Total:	**125**	**(64)**	
2016														
Cedar Bay (Ownership)	1	Duval County	ST	BIT	No	RR	No	-	Oct-15	-	-	250	250	P
Fort Myers	2	Lee County	CC	NG	No	PL	No	-	Jun-16	Unknown	1,721,490	216	37	P
FT. Myers GT	1-12	Lee County	GT	FO2	No	TK	No	-	-	Jun-16	744,120	-	(540)	P
Lauderdale GT	1-12	Broward County	GT	NG	FO2	PL	PL	-	-	Jun-16	410,734	-	(412)	P
Martin	2	Martin County	ST	FO6	NG	PL	PL	-	-	Unknown	934,500	(3)	-	OT
Martin	8	Martin County	CC	NG	FO2	PL	TK	-	-	Unknown	1,224,510	-	2	OT
Port Everglades	1	City of Hollywood	GT	NG	FO2	PL	PL	-	Jun-16	Unknown	410,734	-	1,237	U
Sanford	4	Volusia County	CC	NG	No	PL	No	-	-	Unknown	1,188,860	-	3	OT
Scherer	4	Monroe, GA	ST	SUB	No	RR	No	-	-	Unknown	680,368	(16)	-	OT
											2016 Changes/Additions Total:	**447**	**577**	
2017														
Babcock Solar Energy Center	1	Charlotte County	PV	Solar	Solar	N/A	N/A	-	Sep-16	Unknown	-	-	38	P
Cedar Bay	1	Duval County	ST	BIT	No	RR	No	-	-	Dec-16	-	(250)	(250)	OT
Citrus Solar Energy Center	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	Sep-16	Unknown	-	-	38	P
Fort Myers	2	Lee County	CC	NG	No	PL	No	-	Jan-17	Unknown	1,721,490	20	-	P
Fort Myers	3	Lee County	CT	NG	FO2	PL	TK	-	Dec-16	Unknown	188,190	50	50	OT
Ft. Myers - 2 CT	2	Lee County	CC	NG	No	PL	No	-	Dec-16	Unknown	1,721,490	446	462	P
FT. Myers GT	1-12	Lee County	GT	FO2	No	TK	No	-	-	Jun-16	744,120	(615)	-	P
Lauderdale 5CT	5	Broward County	CC	NG	FO2	PL	PL	-	Dec-16	Unknown	526,250	1,115	1,155	P
Lauderdale GT	1-12	Broward County	GT	NG	FO2	PL	PL	-	-	Jun-16	410,734	(446)	-	P
Lauderdale GT	13-22	Broward County	GT	NG	FO2	PL	PL	-	-	Jun-16	410,734	(372)	(343)	P
Manatee	3	Manatee County	CC	NG	No	PL	No	-	Jun-17	Unknown	1,224,510	-	4	OT
Manatee Solar Energy Center	1	Manatee County	PV	Solar	Solar	N/A	N/A	-	Sep-16	Unknown	-	-	38	P
Martin	8	Martin County	CC	NG	FO2	PL	TK	-	Jan-17	Unknown	1,224,510	27	2	OT
Port Everglades	1	City of Hollywood	GT	NG	FO2	PL	PL	-	Jun-16	Unknown	410,734	1,429	-	OT
Port Everglades GT	1-12	City of Hollywood	GT	NG	FO2	PL	PL	-	Dec-16	Unknown	410,734	(446)	(412)	P
Sanford	4	Volusia County	CC	NG	No	PL	No	-	Jan-17	Unknown	1,188,860	52	1	OT
Sanford	5	Volusia County	CC	NG	No	PL	No	-	Jan-17	Unknown	1,188,860	26	4	OT
Turkey Point[3]	1	Miami Dade County	ST	FO6	NG	WA	PL	-	-	Oct-16	402,050	(398)	(396)	OT
Turkey Point	5	Miami Dade County	CC	NG	FO2	PL	TK	-	Jun-17	Unknown	1,224,510	-	23	OT
											2017 Changes/Additions Total:	**637**	**415**	

(1) Schedule 8 shows only planned and prospective changes to generating facilities and does not reflect changes to existing purchases. Those changes are reflected on Tables ES-1, I.B.1 and I.B.2.

(2) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after August each year will be picked up for reserve margin calculation purposes in the following year.

(3) This generating unit will serve as a synchronous condenser and will not be included in reserve margin calculation.

Schedule 8

Planned And Prospective Generating Facility Additions And Changes (1)

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability (2)		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2018														
Manatee	3	Manatee County	CC	NG	No	PL	No	-	-	Unknown	1,224,510	40	-	OT
Martin	8	Martin County	CC	NG	FO2	PL	TK	-	-	Unknown	1,224,510	12	-	OT
Sanford	5	Volusia County	CC	NG	No	PL	No	-	-	Unknown	1,188,860	25	-	OT
Turkey Point	3	Miami Dade County	ST	Nuc	No	TK	No	-	-	Unknown	877,200	20	20	OT
Turkey Point	5	Miami Dade County	CC	NG	FO2	PL	TK	-	-	Unknown	1,224,510	19	3	OT
											2018 Changes/Additions Total:	**116**	**23**	
2019														
Okeechobee Energy Center	1	Okeechobee County	CC	NG	FO2	PL	TK	Jun-17	Jun-19	Unknown	-	-	1,622	P
Turkey Point	4	Miami Dade County	ST	Nuc	No	TK	No	-	-	Unknown	877,200	20	20	OT
											2019 Changes/Additions Total:	**20**	**1,642**	
2020														
Okeechobee Energy Center	1	Okeechobee County	CC	NG	FO2	PL	TK	Jun-17	Jun-19	Unknown	-	1,595	-	P
											2020 Changes/Additions Total:	**1,595**	**0**	
2021														
Cape Canaveral Energy Center	3	Brevard County	CC	NG	FO2	PL	TK	-	Jun-21	Unknown	1,295,400	-	88	OT
											2021 Changes/Additions Total:	**0**	**88**	
2022														
Cape Canaveral Energy Center	3	Brevard County	CC	NG	FO2	PL	TK	-	-	Unknown	1,295,400	75	-	OT
Riviera Beach Energy Center	5	City of Riviera Beach	CC	NG	FO2	PL	WA	-	Jun-22	Unknown	1,295,400	-	86	OT
											2022 Changes/Additions Total:	**75**	**86**	
2023														
Riviera Beach Energy Center	5	City of Riviera Beach	CC	NG	FO2	PL	WA	-	-	Unknown	1,295,400	89	-	OT
Unsited CC			CC	NG	FO2	PL	TK	Jun-21	Jun-23	Unknown	-	-	1,317	P
											2023 Changes/Additions Total:	**89**	**1,317**	
2024														
Unsited CC			CC	NG	FO2	PL	TK	Jun-21	Jun-23	Unknown	-	1,473	-	P
											2024 Changes/Additions Total:	**1,473**	**0**	

(1) Schedule 8 shows only planned and prospective changes to generating facilities and does not reflect changes to existing purchases. Those changes are reflected on Tables ES-1, I.B.1 and I.B.2.

(2) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes. achieved by June. All MW additions/changes occurring after August each year will be picked up for reserve margin calculation purposes in the following year.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Port Everglades Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,237 MW
b. Winter 1,429 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2014
b. Commercial In-service date: 2016

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** Existing Site Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.5%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	95.4%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,330	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2016 $/kW):	928	
Direct Construction Cost ($/kW):	841	
AFUDC Amount ($/kW):	87	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr): (2016 $)	30.00	
Variable O&M ($/MWH): (2016 $)	0.10	
K Factor:	1.51	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Note: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing plant are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Fort Myers CT (2 CTs will be added)

(2) **Capacity (for each CT)**
a. Summer 211 MW plus 20 MW of peaking capacity
b. Winter 223 MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2015
b. Commercial In-service date: 2016

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Water to Air Heat Exchangers

(8) **Total Site Area:** Existing Site Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.0%	
Forced Outage Factor (FOF):	1.0%	
Equivalent Availability Factor (EAF):	96.0%	
Resulting Capacity Factor (%):	Approx. 3%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	10,075	Btu/kWh
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	7,644	Btu/kWh

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2016 $/kW):	441	
Direct Construction Cost ($/kW):	422	
AFUDC Amount (2016 $/kW):	19	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr):	2.63	
Variable O&M (2016 $/MWH):	0.00	
K Factor:	1.38	

* $/kW values are based on Summer capacity.
** Levelized value includes Fixed O&M and Capital Replacement

Note: Total installed cost includes transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing GTs are not included.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Lauderdale CT (5 CTs will be added)

(2) **Capacity (for each CT)**
a. Summer 211 MW plus 20 MW of peaking capacity
b. Winter 223 MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2015
b. Commercial In-service date: 2016

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Water to Air Heat Exchangers

(8) **Total Site Area:** Existing Site Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.0%	
Forced Outage Factor (FOF):	1.0%	
Equivalent Availability Factor (EAF):	96.0%	
Resulting Capacity Factor (%):	Approx. 3%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	10,203	Btu/kWh
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	7,528	Btu/kWh

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2016 $/kW):	433	
Direct Construction Cost ($/kW):	411	
AFUDC Amount (2016 $/kW):	22	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr):	3.26	
Variable O&M (2016 $/MWH):	0.00	
K Factor:	1.39	

* $/kW values are based on Summer capacity.
** Levelized value includes Fixed O&M and Capital Replacement

Note: Total installed cost includes transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing GTs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Citrus Solar Energy Center (DeSoto County)		
(2)	**Capacity (for each CT)**			
	a. Nameplate (AC)	74.5	MW	
	b. Summer Firm (AC)	38.7	MW	
	c. Winter Firm (AC)	-		
(3)	**Technology Type:**	Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**			
	a. Field construction start-date:	2015		
	b. Commercial In-service date:	2016		
(5)	**Fuel**			
	a. Primary Fuel	Sun		
	b. Alternate Fuel	Sun		
(6)	**Air Pollution and Control Strategy:**	Not applicable		
(7)	**Cooling Method:**	Not applicable		
(8)	**Total Site Area:**	841	Acres	
(9)	**Construction Status:**	P	(Planned Unit)	
(10)	**Certification Status:**	---		
(11)	**Status with Federal Agencies:**	---		
(12)	**Projected Unit Performance Data:**			
	Planned Outage Factor (POF):	Not applicable		
	Forced Outage Factor (FOF):	Not applicable		
	Equivalent Availability Factor (EAF):	Not applicable		
	Resulting Capacity Factor (%):	26%	(First Full Year Operation)	
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable		
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable		
(13)	**Projected Unit Financial Data ***			
	Book Life (Years):	30	years	
	Total Installed Cost (2016 $/kW):	1,835		
	Direct Construction Cost ($/kW):	1,835		
	AFUDC Amount (2016 $/kW):	0		
	Escalation ($/kW):	Accounted for in Direct Construction Cost		
	Fixed O&M ($/kW-Yr): (2016 $)	5.39	(First Full Year Operation)	
	Variable O&M ($/MWH): (2016 $)	0.00		
	K Factor:	0.96		

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Manatee Solar Energy Center (Manatee County)	
(2)	**Capacity (for each CT)**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)	38.7	MW
	c. Winter Firm (AC)	-	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2015	
	b. Commercial In-service date:	2016	
(5)	**Fuel**		
	a. Primary Fuel	Sun	
	b. Alternate Fuel	Sun	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	762	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	26%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	Btu/kWh
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	Btu/kWh
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	30	years
	Total Installed Cost (2016 $/kW):	1,835	
	Direct Construction Cost ($/kW):	1,835	
	AFUDC Amount (2016 $/kW):	0	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr): (2016 $)	5.39	(First Full Year Operation)
	Variable O&M ($/MWH): (2016 $)	0.00	
	K Factor:	0.96	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Babcock Solar Energy Center (Charlotte County)

(2) **Capacity (for each CT)**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC) 38.7 MW
c. Winter Firm (AC) -

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2015
b. Commercial In-service date: 2016

(5) **Fuel**
a. Primary Fuel Sun
b. Alternate Fuel Sun

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 443 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable	
Forced Outage Factor (FOF):	Not applicable	
Equivalent Availability Factor (EAF):	Not applicable	
Resulting Capacity Factor (%):	26%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	Btu/kWh
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	Btu/kWh

(13) **Projected Unit Financial Data ***

Book Life (Years):		30	years
Total Installed Cost (2016 $/kW):		1,835	
Direct Construction Cost ($/kW):		1,835	
AFUDC Amount (2016 $/kW):		0	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr):	(2016 $)	5.39	(First Full Year Operation)
Variable O&M ($/MWH):	(2016 $)	0.00	
K Factor:		0.96	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Okeechobee Clean Energy Center

(2) **Capacity**
a. Summer 1,622 MW
b. Winter 1,595 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2017
b. Commercial In-service date: 2019

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra Low Sulfur Light Distillate

(6) **Air Pollution and Control Strategy:** Dry Low Nox Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Mechanical Draft Cooling Towers

(8) **Total Site Area:** 2,842 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.2%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.7%	
Resulting Capacity Factor (%):	Approx. 80% (First Full Year Base Operation)	
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	6,304	Btu/kWh
Average Net Incremental Heat Rate (ANOHR): Peak Operation 75F,100%	7,731	Btu/kWh

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2019 $/kW):	737	
Direct Construction Cost ($/kW):	668	
AFUDC Amount (2019 $/kW):	69	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr):	16.89	
Variable O&M (2019 $/MWH):	0.28	
K Factor:	1.45	

* $/kW values are based on Summer capacity.
** Levelized value includes Fixed O&M and Capital Replacement

Note: Total installed cost includes transmission interconnection and integration, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited 3x1 CC

(2) **Capacity**
a. Summer 1,317 MW
b. Winter 1,473 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2021
b. Commercial In-service date: 2023

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Mechanical Draft Cooling Towers

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.3%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.6%	
Resulting Capacity Factor (%):	Approx. 80%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,307	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2023 $/kW):	923	
Direct Construction Cost ($/kW):	839	
AFUDC Amount ($/kW):	84	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr):	39.5	
Variable O&M (2023 $/MWH):	0.37	
K Factor:	1.51	

* $/kW values are based on Summer capacity.
** Levelized value includes Fixed O&M and Capital Replacement

Note: Total installed cost includes transmission interconnection and integration, and AFUDC. Actual transmission and interconnection costs are unknown for an unsited unit. The transmission interconnection and integration costs for the unsited unit are based on the costs for the Okeechobee Clean Energy Center

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Port Everglades Next Generation Clean Energy Center

The Port Everglades Next Generation Clean Energy Center which will result from the modernization of the Port Everglades power plant site does not require any “new” transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Fort Myers Plant Gas Turbine Replacement and CT Upgrade

The Fort Myers Plant gas turbine replacement and CT upgrade projects do not require any “new” transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Lauderdale Plant Gas Turbine Replacement

The Lauderdale Plant Gas Turbine Replacement project does not require any “new” transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Citrus Solar Energy Center (DeSoto)

The Citrus Solar Energy Center (DeSoto) will require one new line to connect the PV inverter array to the expanded Sunshine Substation.

(1)	Point of Origin and Termination:	Skylight – Sunshine Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL – Owned
(4)	Line Length:	1.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 2015 End date: 2016
(7)	Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on schedule 9
(8)	Substations:	Skylight Substation and Sunshine Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Manatee Solar Energy Center (Manatee)

The Manatee Solar Energy Center will require one new line to connect the PV inverter array to the expanded Manatee Switchyard.

(1)	Point of Origin and Termination:	Helios – Manatee Switchyard
(2)	Number of Lines:	1
(3)	Right-of-way	FPL – Owned
(4)	Line Length:	1.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 2015 End date: 2016
(7)	Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on schedule 9
(8)	Substations:	Helios Substation and Manatee Switchyard
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Babcock Solar Energy Center (Charlotte)

The Babcock Solar Energy Center (Charlotte) will require one new line to connect the PV inverter array to the planned Freeland Substation.

(1)	Point of Origin and Termination:	Webb – Freeland Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL – Owned
(4)	Line Length:	5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 2015 End date: 2016
(7)	Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on schedule 9
(8)	Substations:	Webb Substation and Freeland Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Okeechobee Next Generation Clean Energy Center

The Okeechobee Next Generation Clean Energy Center does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Unsited 3x1 CC

No site has been determined, therefore no transmission analysis is possible.

Schedule 11.1

Existing FIRM and NON-FIRM Capacity and Energy by Primary Fuel Type
Actuals for the Year 2014

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	**Summer (MW)**	**Summer (%)**	**Winter (MW)**	**Winter (%)**	**GWh [(2)]**	**%**
(1)	Coal	897	3.3%	911	3.2%	4,482	3.9%
(2)	Nuclear	3,453	12.8%	3,550	12.4%	26,812	23.1%
(3)	Residual	3,663	13.5%	3,697	12.9%	231	0.2%
(4)	Distillate	648	2.4%	710	2.5%	128	0.1%
(5)	Natural Gas	16,396	60.6%	17,765	62.1%	79,102	68.2%
(6)	Solar (Non-Firm)	35	0.1%	35	0.1%	177	0.2%
(7)	***FPL Existing Units Total [(1)] :***	***25,092***	***92.8%***	***26,668***	***93.2%***	***110,933***	***95.7%***
(8)	Renewables (Purchases)- Firm	55.0	0.2%	55.0	0.2%	473	0.4%
(9)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	445	0.4%
(10)	***Renewable Total:***	55.0	0.2%	55.0	0.2%	918	0.79%
(11)	***Purchases Other :***	1,890.0	7.0%	1,890.0	6.6%	4,117	3.6%
(12)	***Total :***	*27,037.0*	*100.0%*	*28,613.0*	*100.0%*	*115,968*	*100.0%*

Note:

(1) FPL Existing Units Total values on row (7), columns (2) and (4), match the System Firm Generating Capacity values found on Schedule 1 for Summer and Winter.

(2) Net Energy for Load GWh values on row (12), column (6), matches Schedule 6.1 value for 2014.

Schedule 11.2

Existing NON-FIRM Self-Service Renewable Generation Facilities
Actuals for the Year 2014

(1)	(2)	(3)	(4)	(5)	(6) = (3)+(4)-(5)
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh)	Annual Energy Purchased from FPL (MWh)	Annual Energy Sold to FPL (MWh)	Projected Annual Energy Used by Customers
Customer-Owned Renewable Generation (0 kW to 10 kW)	17.25	21,548	191,676	634	212,590
Customer-Owned Renewable Generation (> 10 kW to 100 kW)	8.77	11,087	217,985	661	228,411
Customer-Owned Renewable Generation (> 100 kW - 2 MW)	12.76	36,645	91,007	210	127,442
Totals	39	69,279	500,668	1,505	568,443

Notes:

(1) There were 3241 customers with renewable generation facilities interconnected with FPL on December 31, 2014.

(2) The Installed Capacity value is the sum of the nameplate ratings (DC MW) for all of the customer-owned renewable generation facilities connected as of December 31, 2014. Three systems do not have a DC rating. These are 3 non-solar facilities:

Tropicana - Landfill gas reciprocating generator: 1600 kW AC
Manatee Landfill gas: 1600 kW AC
Bio Mass - Palm Beach County: 750 kW AC

These AC values are included in the (> 100 kW < 2 MW) row.

(3) The Projected Annual Output value is based on NREL's PV Watts 1 program and the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.

(4) The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2014.

(5) The Annual Energy Sold to FPL is an actual value from FPL's metered data for 2014.

(6) The Projected Annual Energy Used by Customers is a projected value that equals: (Renewable Projected Annual output + Annual Energy Purchased) minus the Annual Energy Sold to FPL.

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

Florida's climate can be described as a combination of humid subtropical and tropical savanna supporting an environment which includes a diverse number of distinct ecosystems with many endangered or threatened plant and animal species. These distinct ecosystems, the residents, and industries of Florida compete for the same resources that are necessary for the generation, transmission, and distribution of electricity. FPL is a corporation which practices strong environmental stewardship evidenced by the creation and management of the Everglades Mitigation Bank and the preservation of the Barley Barber Swamp. FPL desires to meet public expectations of such stewardship and conducts their business in a responsible manner by minimizing impacts to Florida's natural environment.

FPL and its parent company, NextEra Energy, Inc. have continuously been recognized as leaders among electric utilities for their commitment to the environment. That commitment is ingrained in FPL's corporate culture. FPL has one of the lowest emissions profiles among U.S. utilities and in 2014 its carbon dioxide (CO_2) emission rate was 38% lower (better) than the industry national average.

On March 3, 2014 NextEra Energy was named No. 1 in its sector on Fortune Magazine's "Most Admired Companies" list for the eighth year in a row. In determining the industry rankings, approximately 15,000 senior executives, outside directors, and industry analysts are surveyed and companies are rated on the following nine attributes:

1.) Ability to attract and retain talented people
2.) Quality of management
3.) Social responsibility to the community and the environment
4.) Innovativeness
5.) Quality of products or services
6.) Wise use of corporate assets
7.) Financial soundness
8.) Long-term investment value
9.) Effectiveness in doing business globally

Fortune recognized that "*in 2013, the output from NextEra Energy's power plants resulted in emissions rates of sulfur dioxide, nitrogen oxide and carbon dioxide that were 97 percent, 80 percent and 53 percent lower, respectively, than the U.S. electric industry's average. In addition, the company provides grants to teachers of science, technology, engineering and math (STEM)* *classes, partners with community colleges on wind technology training, and protects threatened and endangered species where it has operations, including the Florida manatee, American crocodile, and osprey and desert tortoise."*

In March 2014, FPL received the 2014 Florida House Conservation Award in recognition of its extraordinary commitment to the environment. In presenting the award, Bart Hudson, president of the Florida House, declared *"From preserving wildlife and natural resources to bringing the public and private sectors together to support long-term restoration efforts in the Everglades, the southeast Florida marshes and Biscayne Bay, conservation is at the core of FPL's mission"*.

Other conservation efforts noted by the Florida House include FPL's focus on reducing greenhouse gas emissions while helping to keep customer bills low through the use of fuel-efficient power generation and other innovative technologies. Since 2001, FPL has reduced its use of foreign oil by 99 percent by modernizing existing power plants into cleaner, more fuel-efficient plants. It is the first utility to bring commercial-scale solar power to Florida, including the world's first solar-natural gas hybrid.

On April 2, 2014, the Environmental Protection Agency presented Florida Power & Light Company with its Clean Air Excellence Award in recognition of the company's "green" vehicle fleet and customer education programs featuring its electric vehicles and their benefits. The awards recognize innovative programs that protect Americans' health and the environment, educate the public, serve their communities and stimulate the economy.

In 2014, FPL supported a broad base of environmental organizations with donations and memberships totaling in excess of $290,000. The organizations included, but were not limited to, the Everglades Foundation, the Conservancy of Southwest Florida, the Busch Wildlife Sanctuary, Inc., the Arthur R. Marshall Foundation and the Loggerhead Marinelife Center, Inc. In addition, part of the charitable giving was the result of an FPL employee 2014 Power to Care Event that raised funds dedicated to the Friends of MacArthur Beach State Park.

FPL employees serve as board members for many organizations that focus on environmental restoration, preservation, and stewardship. A partial list of these organizations includes: Loggerhead Marinelife Center, Inc., the Everglades Foundation, the Arthur R. Marshall Foundation, The Nature Conservancy, Grassy Waters Preserve, and the Palm Beach Zoo.

IV.B FPL's Environmental Policy

At FPL and its parent company, NextEra Energy, Inc., we are committed to being an industry leader in environmental protection and stewardship, not only because it makes business sense, but because it is the right thing to do. Our commitment to compliance, conservation, communication, and continuous improvement fosters a culture of environmental excellence and drives the sustainable management of our business planning, operations, and daily work.

In accordance with our commitments to environmental protection and stewardship, FPL and NextEra Energy, Inc. endeavor to:

Comply

- Comply with all applicable environmental laws, regulations, and permits
- Proactively identify environmental risks and take action to mitigate those risks
- Pursue opportunities to exceed environmental standards
- Participate in the legislative and regulatory process to develop environmental laws, regulations, and policies that are technically sound and economically feasible
- Design, construct, operate, and maintain our facilities in an environmentally sound and responsible manner

Conserve

- Prevent pollution, minimize waste, and conserve natural resources
- Avoid, minimize, and/or mitigate impacts to habitat and wildlife
- Promote the efficient use of energy, both within our company and in our communities

Communicate

- Communicate this policy to all employees and publish it on the corporate website
- Invest in environmental training and awareness to achieve a corporate culture of environmental excellence
- Maintain an open dialogue with stakeholders on environmental matters and performance

Continuously Improve

- Establish, monitor, and report progress toward environmental targets
- Review and update this policy on a regular basis
- Drive continuous improvement through ongoing evaluations of our environmental management system to incorporate lessons learned and best practices.

FPL's parent company, NextEra Energy, Inc. updated this policy in 2013 to reflect changing expectations and ensure that employees are doing the utmost to protect the environment. FPL complies with all environmental laws, regulations, and permit requirements. FPL designs, constructs, and operates its facilities in an environmentally sound and responsible manner. It also responds immediately and effectively to any known environmental hazards or non-compliance situations. FPL's commitment to the environment does not end there. FPL proactively pursues opportunities to exceed current environmental standards, including reducing waste and emission of pollutants, recycling materials, and conserving natural resources throughout its operations and day-to-day work activities. FPL also encourages the efficient use of energy, both within the Company and in communities served by FPL. These actions are just a few examples of how FPL is committed to the environment.

To ensure that FPL is adhering to its environmental commitment, it has developed rigorous environmental governance procedures and programs. These include its Environmental Assurance Program and Corporate Environmental Governance Council. Through these programs, FPL conducts periodic environmental self-evaluations to verify that its operations are in compliance with environmental laws, regulations, and permit requirements. Regular evaluations also help identify best practices and opportunities for improvement.

IV.C Environmental Management

In order to successfully implement the Environmental Policy, FPL has developed a robust Environmental Management System program to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program, which is described in section IV.D below. Other components of the system include: executive management support and commitment, a dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

As part of its commitment to excellence and continuous improvement, FPL created an enhanced environmental data management information system (EDMIS) which was fully implemented by the end of 2014. Environmental data management software systems are increasingly viewed as an industry best-management practice to ensure environmental compliance. FPL's top goals for this project are to: 1) improve the flow of environmental data between site operations and corporate services to ensure compliance, and 2) improve operating efficiencies. In addition, the EDMIS will help standardize environmental data collection, thus improving external reporting to the public.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities that are designed to evaluate environmental performance, verify compliance with corporate policy as well as legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is an environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The primary objective of performing an environmental audit is to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and FPL policies. In addition to FPL facility audits, through the Environmental Assurance Program, FPL performs audits of third-party vendors used for recycling and/or disposal of waste generated by FPL operations. Vendor audits provide information used for selecting candidates or incumbent vendors for disposal and recycling needs.

FPL has also implemented a Corporate Environmental Governance System, in which quarterly reviews are performed by each business unit deemed to have potential for significant environmental exposures. Quarterly reviews evaluate operations for potential environmental risks and consistency with the company's Environmental Policy. Items tracked during the quarterly reviews include processes for the identification and management of environmental risks, metrics, and indicators and progress / changes since the most recent review.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2014 environmental outreach activities are summarized in Table IV.E.1.

Table IV.E.1: 2014 FPL Environmental Outreach Activities

Activity	Count (#)
Visitors to FPL's Energy Encounter at St. Lucie	2,669
Visitors to Manatee Park, Ft. Myers	216,401
Number of website visits to FPL's Environmental & Corporate Responsibility Websites	580,000
Visitors to Barley Barber Swamp (Treasured Lands Partnership)	8,517
Martin Energy Center Solar Tours	600
Solar Schools Program	• 92 schools and 10 demo sites completed as of 12/31/14 • Installed capacity for the 102 sites is 921 kW and can produce more than one million kWh annually • An additional 24-28 school/demo sites will come online by the end of 2015

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified eight (8) Preferred Sites and three (3) Potential Sites for future generation additions. Preferred Sites are those locations where FPL has conducted significant reviews, and has either taken action, is currently committed to take action, or is likely to take action, to site new generating capacity. Potential Sites are those sites that have attributes that support the siting of generation and are under consideration as a location for future generation. Some of these sites are currently in use as existing generation sites and some are not. The identification of a Potential Site does not indicate that FPL has made a definitive decision to pursue generation (or generation expansion or modernization in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of a generator has been determined. Analyses of any modernization candidates would include evaluation of numerous factors including: fuel delivery, transmission, permitting, etc. The Preferred Sites and Potential Sites are discussed in separate sections below.

IV.F.1 Preferred Sites

For the 2015 Ten Year Site Plan, FPL has identified eight (8) Preferred Sites. These include a combination of existing and new sites for the development of natural gas combined cycle, combustion turbines, and/or solar generation facilities.

The Port Everglades site is a location where a modernization project is in progress. This work consists of replacing the former steam generating units and replacing them with new combined cycle (CC) technology. The modernization work is scheduled to be completed in mid-2016. In addition, all of the existing gas turbines (GTs) at the Port Everglades site, and all but two of the existing GTs at the nearby Lauderdale site, are projected to be retired by the end of 2016. The two GTs that will remain will serve to provide black start capability. Five new combustion turbines

(CTs) are projected to be added at the Lauderdale site by the end of 2016 to partially replace the retired peaking capacity at these sites. These actions, taken to lower FPL's long-term costs, will also aid in addressing compliance with new air emissions standards.

Similarly, and as part of this GT replacement effort, all but two of the existing GTs at the Ft. Myers site will be retired and two new CTs will be added. In addition, the two existing CTs at the Ft. Myers site will be upgraded to increase their capacity. All of the Ft. Myers work is scheduled to be completed by the end of 2016.

The Okeechobee County site has been identified as a Preferred Site for new natural gas CC technology. As discussed in the Executive Summary, the new natural gas CC at this site represents FPL's best self-build generation option in 2019, and it will compete with proposals received in response to a capacity request for proposals (RFP) that was issued in March 2015.

The Okeechobee County site is also under consideration for future new photovoltaic (PV) facilities. In regard to PV, Charlotte, DeSoto, and Manatee Counties have been identified as the locations for new PV facilities that are expected to go in-service by the end of 2016.

Finally, the Turkey Point site is the location at which FPL plans to construct two new nuclear units, Turkey Point Units 6 & 7. The Nuclear Regulatory Commission recently announced a several year delay in their schedule to make a decision on FPL's pending Turkey Point Units 6 & 7 Combined Operating License Application (COLA). Due to this delay in the COLA schedule, and to changes in Florida's nuclear cost recovery rule, the earliest practical date for bringing the Turkey Point 6 & 7 units in-service is now beyond the 2015 through 2024 time period addressed in this Site Plan. Despite this change in timing of the two new nuclear units, this Site Plan continues to present the Turkey Point site as a Preferred Site for the new units.

Preferred Site # 1: Port Everglades Plant, Broward County

FPL is in the process of modernizing the Port Everglades Plant located within the City of Hollywood in Broward County with construction anticipated to be completed in 2016. Previously the site consisted of two 200 MW (approximate) and two 400 MW (approximate) steam generating units. The four units were taken out of service, dismantled, and removed from the site as part of the modernization project. The modernized site, named the Port Everglades Next Generation Clean Energy Center (PEEC), will consist of a single new Combined Cycle unit that replaces the original four steam units. The modernized unit will be highly efficient and have a lower-emission rate and will use less water than the original units at the site.

a. U.S. Geological Survey (USGS) Map

A USGS map of the PEEC site is found at the end of this chapter.

b. Proposed Facilities Layout

A general layout of the PEEC generating facilities is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The Port Everglades Plant formerly consisted of two 200 MW (approximate) and two 400 MW (approximate) generating units with conventional dual-fuel fired steam boilers and steam turbines which were demolished in the Summer of 2013 to make way for the new Port Everglades Next Generation Clean Energy Center. The plant site includes minimal vegetation. Adjacent land uses include port facilities, barge access via port infrastructure, a rail line and associated industrial activities, as well as light commercial and residential development.

e. General Environment Features On and In the Site Vicinity

There are environmental benefits of replacing the former steam units at the Port Everglades Site with a new CC unit including a significant reduction in system air emissions and improved aesthetics at the site such as lower stack heights.

1. Natural Environment

The site is located adjacent to the Intracoastal Waterway (ICW) and is comprised of facilities related to electric power generation. It is located within a highly industrialized port that has active material and fuel handling facilities.

2. Listed Species

No adverse impacts to federal- or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species. The plant provides warm water to the ICW pursuant to the facility's Manatee Protection Plan, which is a benefit to the area's manatees.

3. Natural Resources of Regional Significance Status

The Port Everglades Next Generation Clean Energy Center is located adjacent to the ICW. The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on the ICW, parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design is to replace the four former units, with one new unit of approximately 1,200 MW Summer capacity. The new unit will be a single CC unit that consists of three new CTs, three new heat recovery steam generators (HRSG), and a new steam turbine.

In addition, all of the existing GTs at the Port Everglades site are projected to be removed by the end of 2016 as part of the gas turbine replacement project discussed in the Lauderdale and Fort Myers Preferred Site discussions.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is a combination of “Electrical Generating Facility” and “Utilities Use”. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Port Everglades site has been selected due to consideration of multiple factors including system load, ability to provide generation in the Miami-Dade/Broward region to help balance load and generation in that region, and economics. Environmental issues were considered, but because the site has been previously utilized for power generation facilities, no environmental impacts will result from this modernization.

i. Water Resources

Water from the Intracoastal Waterway via Port Everglades Slip No. 3 is currently used for once-through cooling water supply. The new plant will only utilize portions of the existing once-through cooling water intake and discharge structures due to reduced water demand. Process and potable water for the modernized plant will come from the existing City of Ft. Lauderdale potable water supply.

j. Geological Features of Site and Adjacent Areas

FPL’s Port Everglades Next Generation Clean Energy Center site is underlain by the Surficial Aquifer System (SAS). The SAS in eastern Broward County is primarily composed of sand, sandstone, shell, silt, calcareous clay (marl), and limestone deposited during the Pleistocene and Pliocene ages. The sediments forming the aquifer system are the Pamlico Sand, Miami Oolite, Anastasia Formation, Key Largo Formation, and Fort Thompson Formation (Pleistocene) and the Tamiami Formation (Pliocene). The sediments in the eastern portion of Broward County where the plant is located are appreciably more permeable than in the west. The SAS is underlain by at least 600 feet of the Hawthorn formation (a confining unit). The Floridan Aquifer System (FAS) underlies the Hawthorn formation.

k. Projected Water Quantities for Various Uses

Approximately 600 million gallons per day (mgd) of cooling water will be cycled through the once-through cooling water system which is a reduction of more than 51% in cooling water when compared to that of the previous steam units. The estimated quantity of process water required is approximately 0.24 mgd for uses such as process water and service water. Potable water demand is expected to average 0.001 mgd.

l. Water Supply Sources by Type

The modernized plant will continue to use the Intracoastal Waterway as the source of once-through cooling water. Process and potable water for the new plant will come from the existing City of Ft. Lauderdale potable water supply.

m. Water Conservation Strategies Under Consideration

No additional water resources will be required as a result of the modernization project. The combined cycle technology will result in 51% less water used compared to the traditional steam generation units. Recovery and reuse of steam generator blowdown by mixing with cooling water flow also recycles water reducing need for fresh water. Therefore, no additional water resources will be required as a result of the modernization project.

n. Water Discharges and Pollution Control

The modernized plant will utilize portions of the existing once-through cooling water system for heat dissipation prior to discharge to the Intracoastal Waterway. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant’s once-through cooling water system prior to discharge. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit would be transported to the site via an existing natural gas pipeline to the site. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit will be installed either at the existing site or off-site. Ultra-low sulfur light fuel oil, which is used as a backup fuel, would be received by truck, pipeline, or barge and stored in a new above-ground storage tank.

p. Air Emissions and Control Systems

The regulated air emission rates at the new plant would be approximately 90 % lower than the previous Port Everglades Plant's emission rates, resulting in significant annual emissions reductions and air quality benefits per unit of energy produced. The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize air emissions of sulfur dioxide (SO2), particulate matter, and other fuel-bound contaminates from the unit and ensure compliance with applicable emission standards. Combustion controls similarly minimize the formation of nitrogen oxides (NOx), and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NOx emissions will be controlled using dry-low NOx combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NOx emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. Greenhouse gas emissions (GHGs) from combustion of natural gas at PEEC will achieve an emission rate substantially lower than the EPA proposed new source performance standard for GHGs. The CC design is equivalent to the Best Available Control Technology for air emissions, and minimizes such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of PEEC will incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise from unit construction and operation at the site is expected to be below existing noise levels for residents near the site.

r. Status of Applications

FPL filed a need determination with the FPSC on November 21, 2011. The FPSC's final need order was issued on April 9, 2012. The project's Site Certification Application (SCA) was submitted January 24, 2012 resulting in the issuance, by the Siting Board of the State of Florida, of the Final Order PA 12-57 on October 9, 2012. FPL received a Prevention of Significant Deterioration (PSD) permit on May 1, 2012 and an Industrial Wastewater Facility permit on December 16, 2012. No other permits are required.

Preferred Site #2: Babcock Ranch Solar Energy Center, Charlotte County

The Babcock Ranch Solar Energy Center facility will be sited on approximately 443 acres in Charlotte County. The solar facility will be located approximately 10.5 miles north of the intersection of SR-80 and SR-31 and 0.7 miles east of State Road 31 and north of Tucker's Grade road. The Babcock Ranch Preserve, owned by the State of Florida, borders the facility directly to the north and northwest. The Babcock Ranch Community is located east and south of the facility. The facility is an approximately 74.5 MW (nameplate, AC) photovoltaic (PV) facility.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Charlotte Solar site is found at the end of this chapter.

b. Proposed Facilities Layout

The proposed facilities layout is currently in development and not available at this time.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The Charlotte Solar site and adjacent lands are predominantly used for agricultural production. Currently, the site includes fallow sod fields, improved and unimproved pasture with a portion in a combination of pine flatwoods and freshwater marsh. The existing land use and zoning designations are Babcock Ranch Overlay and Overlay Zoning District. This land use and zoning allows for solar facilities.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of lands dedicated to agricultural production. FPL will mitigate for unavoidable wildlife and/or wetland impacts that occur from facility construction as required.

2. Listed Species

Although the site is predominately in agricultural production, results of protected species surveys performed in 2006, 2007 and 2009 reveal the project limits and surrounding landscape are utilized and/or have the potential to be utilized by a number of listed species. The project is located within the US Fish and Wildlife Service (USFWS) Panther Focus Area and is also located within the Core Foraging Area of known wood stork colonies.

Any impacts to the habitat of protected species associated with the PV facility are included within the mitigation plan for the Babcock Ranch Community. To compensate for the loss of habitat, mitigation activities will be performed in an area known as the “Curry Preserve” which is located on a portion of the Babcock Ranch Preserve owned by the State of Florida.

3. <u>Natural Resources of Regional Significance Status</u>

The Charlotte Solar site is in the area of the Babcock Preserve and east of the Cecil Webb Wildlife Management Area. Both of these natural areas are managed by the Florida Fish and Wildlife Conservation Commission. However, the construction and operation of a PV facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. <u>Other Significant Features</u>

FPL is not aware of any other significant features on the site.

f. <u>Design Features and Mitigation Options</u>

The design includes construction of a PV facility, onsite transmission substation, and site stormwater system to accommodate approximately 74.5 MW (nameplate AC) of power generation.

g. <u>Local Government Future Land Use Designations</u>

The existing and future land use on this site consists of agriculture and barren land. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. <u>Site Selection Criteria Process</u>

The Charlotte site has been selected as the location of the PV facility based on various factors including system load, transmission interconnection, and economics.

i. <u>Water Resources</u>

Minimal amounts of water, if any, would be required for cleaning the PV panels. This water would be trucked to the site or obtained from existing onsite permitted water resources.

j. <u>Geological Features of Site and Adjacent Areas</u>

In general, the soil profile of the Surficial Aquifer System (SAS) consists of loose to medium dense fine sands with occasional thin stratum of slightly clayey fine sand. Groundwater can be encounter at the surface to a depth of a few feet below with fluctuations throughout the year due to seasonal variations in rainfall and other factors. As is typical of the rest of south Florida this site is underlain by the Intermediate Confining Unit and the Floridan Aquifer System.

k. Projected Water Quantities for Various Uses

Solar requires minimal amounts of water, if any, for cleaning the PV panels and would only be required in the absence of sufficient rainfall.

l. Water Supply Sources by Type

A water source is not required for this site. Any needed water may be brought to the site by truck or obtained from permitted water sources.

m. Water Conservation Strategies Under Consideration

The PV site does not require a permanent water source. Water conservation strategies may include selection and planting of low-to-no irrigation grass or groundcover.

n. Water Discharges and Pollution Control

The facility will employ Best Management Practices (BMP) to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Fuel is not required and no waste products will be generated at the site.

p. Air Emissions and Control Systems

This technology does not generate air emissions.

q. Noise Emissions and Control Systems

This technology does not generate noise.

r. Status of Applications

FPL has obtained the required federal USACE 404 permit allowing for impact with mitigation to 9.3 acres of onsite wetlands during construction. The state Environmental Resources Permit (ERP) for the existing on-site facilities will be modified to incorporate revisions to the site layout and stormwater management system. Application will be made to Charlotte County for the local development approval.

Preferred Site #3: Citrus Solar Energy Center, DeSoto County

The Citrus Solar Energy Center site consists of approximately 841 acres and is located at 4051 Northeast Karson Street, approximately 0.3 miles east of U.S. Highway 17 and immediately north of Bobay Road in Arcadia, Florida. The site has been chosen for an approximately 74.5 MW (nameplate, AC) PV facility.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Citrus Solar Energy Center site is found at the end of this chapter.

b. Proposed Facilities Layout

The proposed facilities layout is currently in development and not available at this time.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

Existing land use on the site is agricultural. The adjacent areas include agriculture, forested and non-forested uplands.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The approximate 841 acre site is comprised of lands dedicated for agricultural production with some wetland areas throughout the property.

2. Listed Species

Burrowing owls and gopher tortoises may be present within the proposed project area. If so, burrows of these species will be relocated to adjacent portions of the FPL property prior to construction under permits from Florida Fish and Wildlife Conservation Commission. Previous wildlife surveys have identified Audubon's Crested caracara foraging within the property, but no nests are located within the project area, and caracara have been rarely seen since the removal of cattle from the project area. Based on this information, no negative impacts to threatened or endangered species are anticipated as a result of the PV project.

3. Natural Resources of Regional Significance Status

There are no natural resources of regional significance at, or adjacent to, the site. The construction and operation of a PV generating facility is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design includes construction of a PV facility, onsite transmission substation, and site stormwater system to accommodate approximately 74.5 MW (nameplate, AC) of PV.

g. Local Government Future Land Use Designations

In 2009, DeSoto County instituted an Ordinance amending the Land Development Regulations by adding Utility Grade Solar Plant as a permitted use within an Agriculture-10 zoning district and an Ordinance amending the Future Land Use Map to change the FPL land from the Rural Agricultural category to the Electrical Generating Facility category. Solar facilities are allowed within this category.

A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The site has been selected as the location of a PV facility based on various factors including system load, transmission interconnection, and economics.

i. Water Resources

Minimal amounts of water, if any, would be required for cleaning the PV panels and would only be required in the absence of sufficient rainfall. This water would be trucked to the site or obtained from existing onsite permitted water resources.

i. Geological Features of Site and Adjacent Areas

The Surficial Aquifer System soil types found on the Site include Anclote mucky fine sand (depressional), Basinger fine sand, Basinger fine sand (depressional), Eau Gallie fine sand, Immokalee fine sand, Myakka fine sand, Smyrna fine sand, and Valkaria fine sand. As is typical of the rest of south Florida this site is underlain by the Intermediate Confining Unit and the Floridan Aquifer System.

k. Projected Water Quantities for Various Uses

Solar requires minimal amounts of water, if any, for cleaning the PV panels in the absence of sufficient rainfall.

l. Water Supply Sources by Type

A water source is not required for this site. Any needed water may be brought to the site by truck or obtained from permitted water sources.

m. Water Conservation Strategies Under Consideration

The PV site does not require a permanent water source. Water conservation strategies will be implemented through the selection and planting of low to no irrigation grass or groundcover.

n. Water Discharges and Pollution Control

The facility will employ Best Management Practices (BMP) to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Fuel is not required and no waste products will be generated at the site.

p. Air Emissions and Control Systems

Solar technology does not generate air emissions.

q. Noise Emissions and Control Systems

Solar technology does not generate noise.

r. Status of Applications

Application will be made to FDEP for state Environmental Resources Permit (ERP), USACE for federal wetlands permit, and Desoto County for local development approval.

Preferred Site #4: Manatee Solar Energy Center, Manatee County

The Manatee Solar Energy Center site consists of approximately 762 acres and is located in unincorporated north-central Manatee County. The PV site lies approximately 5 miles east of Parrish, Florida, approximately 5 miles east of U.S. Highway 301 and 9.5 miles east of Interstate Highway 75 (I-75). This site has been chosen for the addition of an approximately 74.5 MW (nameplate, AC) PV facility.

a. <u>U.S. Geological Survey (USGS) Map</u>

A USGS map of the Manatee Solar site is found at the end of this chapter.

b. <u>Proposed Facilities Layout</u>

The proposed facilities layout is currently in development and not available at this time.

c. <u>Map of the Site and Adjacent Areas</u>

A map of the site and adjacent areas is found at the end of this chapter.

d. <u>Existing Land Uses of Site and Adjacent Areas</u>

Existing land use on the site is agricultural. A portion of the site is zoned Planned Development / Public Interest (PD-PI), which will allow for electrical generation. The remainder of the site will be zoned from agriculture to PD-PI. The adjacent areas include agricultural, upland non-forested, forests, transportation, communication, and utilities.

e. <u>Environmental Features</u>

1. <u>Natural Environment</u>

FPL will mitigate for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

2. <u>Listed Species</u>

The site is predominately agriculture and minimal impacts to federal- or state-listed terrestrial plants or animals are expected in association with construction at the site, due to the existing disturbed nature of the site and lack of suitable onsite habitat for listed species. In accordance with Florida Fish and Wildlife Conservation Commission, the project will be designed to maintain an adequate buffer from the active bald eagle nest located west of the site.

3. <u>Natural Resources of Regional Significance Status</u>

There are no natural resources of regional significance at, or adjacent to, the site. The construction and operation of a PV facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. <u>Other Significant Features</u>

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design includes construction of a PV facility, onsite transmission substation, and site stormwater system to accommodate approximately 74.5 MW (nameplate, AC) of power generation.

g. Local Government Future Land Use Designations

Existing land use on the site is agricultural. In 2009, Manatee County instituted an ordinance amending the Manatee County Official Zoning Atlas to rezone approximately 620 acres from General Agriculture (A) to Planned Development Public Interest (PD-PI), as well as approve a General Development Plan to allow solar development. The project area has since been expanded north (approx. 383 acres) and new approvals will be sought to change the Official Zoning Atlas to allow solar development within the additional area.

A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The site has been selected as the location of the PV facility based on various factors including system load, transmission interconnection, and economics.

i. Water Resources

Minimal amounts of water, if any, would be required for cleaning the PV panels. This water would be trucked to the site or obtained from existing onsite permitted water resources and would only be required in the absence of sufficient rainfall.

j. Geological Features of the Site and Adjacent Areas

The soil types found on the site include Anclote mucky fine sand (depressional), Basinger fine sand, Basinger fine sand (depressional), Eau Gallie fine sand, Immokalee fine sand, Myakka fine sand, Smyrna fine sand, and Valkaria fine sand.

k. Projected Water Quantities for Various Uses

Solar requires minimal amounts of water, if any, for cleaning the PV panels in the absence of sufficient rainfall.

l. Water Supply Sources by Type

The PV site does not require a permanent water source. Any needed water may be brought to the site by truck or obtained from permitted water sources.

m. Water Conservation Strategies Under Consideration

Water conservation strategies may include the selection and planting of low-to-no irrigation grass or groundcover.

n. Water Discharges and Pollution Control

The facility will employ Best Management Practices (BMP) to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Fuel is not required and no waste products will be generated by site.

p. Air Emissions and Control Systems

This technology does not generate air emissions.

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q. Noise Emissions and Control Systems

This technology does not generate noise.

r. Status of Applications

Applications will be submitted to rezone the northern extent of the site, to obtain County site plan approval, to modify an Environmental Resources Permit (ERP) to include the expanded project area, and to modify the USACE 404 permit to include the expanded project area.

Preferred Site # 5: Lauderdale Plant Peaking Facilities, Broward County

This site is located at the existing Lauderdale Plant property and consists of approximately 392 acres, within the Cities of Dania Beach and Hollywood in Broward County, Florida, east of U.S. Highway 441, north of Griffin Road, west of SW 30th Avenue, and south of Interstate 595.

The Lauderdale Plant currently includes two combined cycle units and two banks of 12 first generation simple cycle gas turbines (GTs) that began operation in the early 1970s. These GTs are used to serve peak and emergency demands in a quick-start manner. Each bank of GTs has a net capacity of 420 megawatts (MWs) and are authorized to operate on natural gas and distillate oil. FPL plans to retire 22 of the 24 existing GTs and partially replace this peaking capacity with 5 new combustion turbines (CTs). This GT removal with CT replacement is assumed to occur by the end of 2016.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Lauderdale site and adjacent areas is found at the end of this chapter.

b. Proposed Facilities Layout

A facilities plot plan of the Lauderdale generating facilities is found at the end of this chapter.

c. Map of Site and Adjacent Areas

A USGS map of the Lauderdale site and adjacent areas is found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing land use at the site is commercial and the adjacent areas are a mixture of low to high density urban, transportation, communication, utilities, commercial, water, and some open land. The site is zoned general industrial by the City of Dania Beach.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the project site is comprised of facilities related to electric power generation. The project site also includes approximately 14 acres of surrounding forested wetlands and upland spoil piles.

2. Listed Species

Based upon field assessments conducted in 2013, review of United States Fish and Wildlife (USFWS) and Florida Fish and Wildlife Conservation Commission (FWC) literature and databases, the Florida Natural Areas Inventory (FNAI) database of documented listed species occurrences, the lack of suitable habitat, and the land use of the surrounding areas, federally listed species are not anticipated to utilize the CT Project area.

3. Natural Resources of Regional Significance Status

There are no natural resources of regional significance adjacent to the site. The construction and operation of the CT Project at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The project is to retire 22 of the 24 gas turbines (GTs) at the existing Lauderdale Plant (plus retire an additional 12 simple cycle GTs at the nearby Port Everglades Plant) and partially replace this capacity with 5 new highly efficient simple cycle CTs. The CTs operate in simple cycle mode and produce electrical energy by direct connection to an electric generator. The CTs will operate using natural gas and ultra-low sulfur distillate (ULSD) oil as fuel.

g. Local Government Future Land Use Designations

The site is zoned General Industrial by the City of Dania Beach, a designation intended to provide for light and medium intensity industrial, research, and assembly fabrication uses. Electrical power plants are permitted within a General Industrial zoning designation as a special exception use only, see Section r.

A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Lauderdale Plant site has been selected for the location of new CTs based on various factors including maximizing opportunities to utilize existing utility infrastructure, system load, transmission interconnection, and economics.

i. Water Resources

The CT Project will require a marginal increase in demineralized water that will be obtained from the existing Lauderdale Plant's water treatment system.

j. Geological Features of Site and Adjacent Areas

The geological layers beneath the site include the Surficial Aquifer System (SAS), the Intermediate Confining Unit (ICU), and the Floridan Aquifer System (FAS). According to the Natural Resource Conservation Service (NRCS) Soil Survey of Broward County, the SAS in the proposed facilities area is dominated by Okeelanta series muck.

The Okeelanta series consists of very deep, very poorly drained, rapidly permeable soils in large fresh water marshes and small depressional areas. In un-drained areas the water table is at depths of less than ten inches below the surface or the soil is covered by water 6 to 12 months during most years.

k. Projected Water Quantities for Various Uses

The CT Project consists of installing new CTs that are operated in simple cycle mode and do not require a heat dissipation system. Raw water from the Broward County will continue to be used for process water treatment system influent and fire protection. Water used for CT inlet air cooling and water injection for NOx control when using ULSD oil will be demineralized water from the existing process water treatment system.

l. Water Supply Sources by Type

The CTs do not require a heat dissipation system, therefore there are no associated cooling water uses. The proposed facility would continue to acquire water from existing water contracts with Broward County and would continue to use potable water from the City of Hollywood to provide drinking water for employees.

m. Water Conservation Strategies Under Consideration

No additional water resources would be required as a result of the CT Project.

n. Water Discharges and Pollution Control

There would be no surface water discharges required for the operation of the proposed facility. The stormwater management system has been designed to prevent direct discharge to surface waters.

The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The fuel to be used in the CTs is natural gas and ULSD oil. Natural gas will be transported to the facility via existing pipeline. No onsite storage is provided for natural gas. ULSD oil would be trucked or piped to the facility and stored in double walled ULSD oil tanks.

p. Air Emissions and Control Systems

Air emission rates for NOx associated with the operation of the new CTs would be approximately 90 percent lower than the existing GT emission rates, resulting in significantly lower air quality impacts per hour of operation. In addition to lower air emissions, the maximum total air quality impacts for the site facility are predicted to be well below and in compliance with the National Ambient Air Quality Standards (NAAQS). For pollutants such as NO_2, the new CTs' total air quality impacts are predicted to be significantly reduced by 40 percent or more compared to the existing GTs.

The use of clean fuels (natural gas and ULSD oil) and combustion controls would minimize air emissions of SO_2, sulfuric acid mist (SAM), particulates (PM/PM10/PM2.5), and other fuel-bound contaminants and ensure compliance with applicable emission-limiting standards. Combustion controls will minimize the formation of NOx and the formation of CO and VOCs by combustor design. Further NOx reduction will be achieved by water injection during oil firing.

q. Noise Emissions and Control Systems

The construction and operation of the new CTs will not exceed the maximum permissible sound levels in Section 17-86 of the City of Dania Beach.

r. Status of Applications

A 404 dredge and fill permit has been issued by the U. S. Army Corps of Engineers (USACE) to allow for wetland impacts with mitigation associated with the project and a Prevention of Significant Deterioration (PSD) air permit has been issued by the Florida Department of Environmental Protection (FDEP). A modification of the PSD permit to include GHG emissions has been prepared by FPL for submittal to the FDEP. No other licenses or permits have been issued for the CT Project. FPL will submit applications to Broward County for a special exception use permitted within a General Industrial zoning designation and to the U.S. Environmental Protection Agency (EPA) for the Greenhouse Gas air permit.

Preferred Site # 6: Ft Myers Plant Peaking Facilities, Lee County

Florida Power & Light Company (FPL) plans to retire, replace, and upgrade components of the peaking facilities at the Fort Myers Power Plant. This site consists of approximately 460 acres located in the City of Tice (Fort Myers) in Lee County, Florida. The Plant property is located north of State Road 80 (Palm Beach Boulevard), south of the Caloosahatchee River, east of the Caloosahatchee Shores Community, and west of State Road 31.

The existing Fort Myers Plant consists of one natural gas Combined Cycle (CC) units, two natural gas and oil fired Combustion Turbine (CT) units, and one bank of 12 oil fired Gas Turbines (GTs) (peaking facilities) that have a combined capacity of 2,403 summer megawatts.

Presently, the bank of 12 first generation GTs (which started operation in the early 1970s) provide power during periods of peak demand and black start capability in the event of a power outage. FPL plans to add two new CTs and retire ten of the existing GTs by the end of 2016.The two new CTs will be more efficient with cleaner air emissions than the existing GTs. In addition, the two existing CTs will be upgraded to produce additional generation capacity.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Fort Myers site and adjacent areas is found at the end of this chapter.

b. Proposed Facilities Layout

A general layout of the Fort Myers generating facilities is found at the end of this chapter.

c. Map of Site and Adjacent Areas

A USGS map of the Fort Myers site and adjacent areas is found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing land-use at the site is transportation, communication, utilities, barren land, and agricultural. Adjacent properties include low density urban, commercial, rangeland, open land, transportation, communication, and utilities. A Land Use / Land Cover Map is also found at the end of this chapter.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of facilities related to electric power generation.

2. Listed Species

Based on the results of a 2013 biological assessment, which included a field evaluation and review of data obtained from the Florida Natural Areas Inventory (FNAI), the U.S. Fish and Wildlife Service (USFWS), and the Florida Fish and Wildlife Conservation Commission (FWC), no threatened or endangered species are expected to be affected by the proposed Project.

3. Natural Resources of Regional Significance Status

The Caloosahatchee and Orange Rivers are adjacent to the site. The construction and operation of the CT Project at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on the Caloosahatchee River, the Orange River, parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

FPL will retire 10 of 12 GTs at the existing Fort Myers Plant, and replace them with two new highly efficient simple cycle CTs. In addition, the two existing CTs will be upgraded to produce additional capacity and enhanced performance. The CTs operate in simple cycle mode with associated stacks and produce electrical energy by direct connection to an electric generator. The CTs will operate using natural gas and ultra-low sulfur distillate (ULSD) oil as fuel. Two GTs may be retained for peaking and black start capabilities.

g. Local Government Future Land Use Designations

The site is zoned Industrial Light (IL) by Lee County, a designation intended to provide for areas devoted to various light industrial and quasi-industrial commercial uses. Electrical power plants are permitted within an IL designation. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Fort Myers Plant site has been selected for the location of the new and upgraded peaking units based on various factors including maximizing opportunities to utilize existing utility infrastructure, system load, transmission interconnection, and economics.

i. Water Resources

The proposed facility will require a marginal increase in demineralized water that will be supplied by treating potable water obtained from Lee County.

j. Geological Features of Site and Adjacent Areas

According to the Natural Resource Conservation Service Soil (NRCS) Soil Survey of Lee County, Florida (1991), two soil types have been mapped within the proposed Project site: Caloosa fine sand and Urban Land. Notably, the soils within the Project site have been previously excavated to the depth of several meters and refilled, effectively eliminating the natural soil profile.

k. Projected Water Quantities for Various Uses

The project consists of CTs that are operated in simple cycle mode and do not require a heat dissipation system. Water used for CT inlet air cooling and water injection for NOx control when using ULSD oil will be demineralized water. Demineralized water will be obtained by treating potable water provided from Lee County.

l. Water Supply Sources by Type

As stated in the previous section the CTs do not require a heat dissipation system, therefore there are no associated cooling water uses. For all other water supply requirements, the proposed facility would acquire potable water from Lee County.

m. Water Conservation Strategies Under Consideration

No additional water resources would be required as a result of the CTs project.

n. <u>Water Discharges and Pollution Control</u>

There would be no surface water discharges required for the operation of the proposed facility. The stormwater management system has been designed to prevent direct discharge to surface waters.

The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. <u>Fuel Delivery, Storage, Waste Disposal, and Pollution Control</u>

The fuel to be used in the CTs is natural gas and ULSD oil. Natural gas will be transported to the facility via existing pipeline. No onsite storage is provided for natural gas. ULSD oil would be trucked or barged to the facility and stored in existing ULSD oil tanks.

p. <u>Air Emissions and Control Systems</u>

Air emission rates for NOx with the new and upgraded CTs would be approximately 90 percent lower than the existing GT emission rates, resulting in significantly lower air quality impacts during operating hours. In addition to lower air emissions, the maximum total air quality impacts for the CT Project are predicted to be well below and in compliance with the National Ambient Air Quality Standards (NAAQS). For pollutants such as NO2, the CT Project's total air quality impacts are predicted to be significantly reduced by 40 percent or more compared to the existing GTs.

The use of clean fuels (natural gas and ULSD oil) and combustion controls would minimize air emissions of SO2, sulfuric acid mist (SAM), particulates (PM/PM10/PM2.5), and other fuel-bound contaminants and ensure compliance with applicable emission-limiting standards. Combustion controls will minimize the formation of NOx and the formation of CO and VOCs by combustor design. Further NOx reduction will be achieved by water injection during oil firing.

q. <u>Noise Emissions and Control Systems</u>

Noise from the new and upgraded CTs will not exceed the maximum permissible sound levels in Lee County noise control ordinance No. 93-15. The design of these new and upgraded CTs includes components and an enclosure which mitigate the emission of noise to the surrounding environment. Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. Status of Applications

FPL will apply for FDEP ERP for stormwater impacts and a PSD permit for air emissions. A Development Order Approval will be obtained from Lee County.

Preferred Site # 7: Okeechobee Site, Okeechobee County

FPL owns 2,800 acres of land in Northeast Okeechobee County. FPL plans to use approximately 200 acres of this land for development of a combined cycle (CC) unit at this site. A CC unit at this site has been determined to be FPL's best self-build generation option for meeting its capacity needs beginning in 2019. In March 2015, FPL issued a capacity request for proposals (RFP) to solicit proposals from outside parties for meeting this capacity need. FPL's CC unit at the Okeechobee site, and the proposals received in response to the RFP, will be evaluated by FPL and an Independent Evaluator to determine which option(s) is the best selection for FPL's customers.

Natural gas-fired CC generation at the site is possible due to the proximity to existing and planned natural gas pipelines. In addition, FPL currently views the Okeechobee site as one of the most likely sites to be used for future large-scale solar using photovoltaic (PV) generation facilities.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Okeechobee site and adjacent areas is found at the end of this chapter.

b. Proposed Facilities Layout

The proposed facilities layout is currently in development and not available at this time.

c. Map of Site and Adjacent Areas

A USGS map of the Okeechobee site and adjacent areas is found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The Okeechobee site is predominantly used for agricultural production (cattle and citrus). Adjacent land uses include agriculture and conservation. The site is in an unincorporated, rural area of the county. FPL's Poinsett-Martin transmission line corridor abuts the property along the northern boundary.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the 2,800 acre site is comprised of lands dedicated to agricultural production (unimproved pasture and fallow citrus). Approximately 400 acres consist of pine flatwoods, mixed forested wetlands, saw palmetto prairie, and freshwater marsh.

2. Listed Species

Minimal impacts to federal- or state-listed terrestrial plants or animals are expected in association with construction at the site, due to the previously disturbed nature of the site and lack of suitable onsite habitat for listed species.

3. Natural Resources of Regional Significance Status

The Okeechobee site abuts the western boundary of the Ft Drum Marsh, a water conservation area managed by the Saint Johns River Water Management District. The construction and operation of a power generating facility at this location is not expected to have any adverse impacts on that area or any other parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

Options include construction of CC and/or PV technologies. Mitigation for unavoidable impacts, if required, could occur through a combination of on- and off-site mitigation.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is predominantly unimproved pasture. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Okeechobee County site was selected as Preferred based on various factors including system load, transmission interconnection, proximity of the proposed Florida Southeast Connection and other natural gas pipelines, and economics. Expected environmental issues are minimal because the site has been previously disturbed and contains few wetlands that will be impacted by the construction and operation of the planned facilities.

i. Water Resources

Groundwater from the Surficial and Floridan Aquifers is anticipated to supply water to the Northeast Okeechobee County site for the combined cycle unit. Minimal amounts of water, if any, will be required for cleaning the PV panels. This water will be obtained from onsite water resources permitted for the CC unit.

j. <u>Geological Features of Site and Adjacent Areas</u>

The geological features of the Northeast Okeechobee County site are similar to that of most of South Florida. In general, the groundwater system underlying Okeechobee County consists of the SAS, the Intermediate Confining Unit (ICU), and the FAS. In this area, the SAS consists of approximately 100 to 250 feet of undifferentiated deposits of sand, shell, clay and silt. The ICU consists of approximately 200 feet of carbonate rocks interbedded with sandy and silty clay. The multiple layers of the FAS extend thousands of feet below the ICU.

k. <u>Projected Water Quantities for Various Uses</u>

Approximately 9 mgd of cooling water will be used in cooling towers, which reduces water use by 95 to 98% compared to once through cooling, for a CC unit at the Okeechobee site. The estimated quantity of water required for processing at a CC unit is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Potable water demand is expected to average 0.001 mgd. Only minimal amounts of water, if any, would be required for cleaning the PV panels, and would only be required in the absence of sufficient rainfall. This water would be obtained from onsite water resources permitted for the CC unit.

l. <u>Water Supply Sources by Type</u>

The potential water supply source is groundwater from the SAS and the FAS. Additional evaluations are necessary to determine the exact source. Process and potable water for the new plant are also not determined and may come from the surficial aquifer.

m. <u>Water Conservation Strategies Under Consideration</u>

Combined cycle technology utilizes less water by design than traditional steam generation units. PV facilities are expected to have no water demands. Specific water conservation strategies will be evaluated and selected during the detailed design phase of any development project.

n. <u>Water Discharges and Pollution Control</u>

The CC plant is anticipated to utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant’s cooling water flow prior to discharge. A deep injection well system known as an Underground Injection Control system (UIC) is proposed for disposal of non-hazardous industrial wastewater from the power generation process and non-hazardous construction-related water. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ Best Management Practices (BMP) and Spill

Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary. Back-up fuel supplies of ultra-low sulfur light fuel oil will be received by truck or pipeline and stored in an above-ground storage tank to ensure reliability of operations.

p. Air Emissions and Control Systems

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls will minimize regulated air emissions of sulfur dioxide, particulate matter, and other fuel-bound contaminates from a CC unit and ensure compliance with applicable emission standards. Combustion controls similarly minimize the formation of $NO_{x,}$ and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. The CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA's proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida. PV generation does not produce air emissions.

q. Noise Emissions and Control Systems

Noise from unit construction is expected to be minimal. Noise from unit operation will not exceed Okeechobee County maximum permissible sound levels in an agricultural area.

r. Status of Applications

FPL has filed an UIC Exploratory Well and associated Dual Zone Monitoring Well for the Northeast Okeechobee County site. The application has been deemed complete and the Public Notice for the Draft Permit was published in early February 2015. A permit for the construction of the Exploratory Well and Dual Zone Monitoring Well is expected in Summer 2015. FPL will submit applications to the State of Florida for Site Certification as well as other permits needed to support the construction and operation of the project. The applications will be prepared as the planning and development of the project proceeds.

Preferred Site # 8: Turkey Point Plant, Miami-Dade County

The Turkey Point Plant (Turkey Point) is located on the west side of Biscayne Bay, 25 miles south of Miami. Turkey Point is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. The land surrounding Turkey Point is owned by FPL and acts as a buffer zone. Turkey Point is comprised of two natural gas/oil conventional steam units (Units 1 & 2), two nuclear units (Units 3 & 4), one combined cycle natural gas unit (Unit 5), nine small diesel generators, and the cooling canals. A capacity uprate project for the two nuclear units was successfully completed in 2013. The Everglades Mitigation Bank (EMB), an approximately 13,000 acres, FPL-maintained natural wildlife and wetlands area that has been set aside, is located to the south and west of the site.

On May 14, 2014, the Florida Power Plant Siting Board authorized the site certification, with conditions, of Turkey Point 6 & 7. Each of these two units would provide 1,100 MW of nuclear generating capacity. Due to a delay in the Nuclear Regulatory Commission's (NRC) schedule to reach a decision in the Combined Operating License Application (COLA) submittal by FPL until late 2016, and to changes in Florida's nuclear cost recovery rule, the projected earliest practical in-service dates for the two new units are June 2027 (for Turkey Point Unit 6) and June 2028 (for Turkey Point Unit 7). These in-service dates are outside of the current ten-year time period (2015 through 2024) addressed in this Site Plan. However, because these two new nuclear units remain in FPL's resource plans, the Turkey Point site is again presented as a Preferred Site in this year's Site Plan.

In addition to the two new generating units, supporting buildings, facilities, and equipment will be located on the Turkey Point Units 6 & 7 site, along with a construction laydown area. Proposed associated facilities include: a nuclear administration building, a training building, a parking area, an FPL reclaimed water treatment facility and reclaimed water pipelines, radial collector wells and delivery pipelines, an equipment barge unloading area, transmission lines (and transmission system improvements elsewhere within Miami-Dade County), access roads and bridges, and potable water pipelines.

a. U.S. Geological Survey (USGS) Map

USGS maps of the Turkey Point area, with the proposed location of Turkey Point Units 6 & 7 identified, are found at the end of this chapter.

b. Proposed Facilities Layout

Maps of the general layout of Turkey Point Units 6 &7 are found at the end of this chapter.

c. Map of Site and Adjacent Areas

Land Use / Land Cover overview maps of the Turkey Point Units 6 & 7 site and adjacent areas are also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

Turkey Point Plant is currently home to five generating units and support facilities that occupy approximately 150 acres of the approximately 9,400-acre Turkey Point property. Prominent features beyond the power block area include the intake system, cooling canal system, switchyard, spent fuel storage facilities, and technical and administrative support facilities The cooling canal system occupies approximately 5,900 acres.

Two 400-megawatt (MW) (nominal) fossil fuel-fired steam electric generation units at Turkey Point have been in service since 1967 (Unit 1) and 1968 (Unit 2). These units have historically burned residual fuel oil and/or natural gas with a maximum equivalent sulfur content of one percent. Unit 2 is currently serving, not as a power generating unit, but as a synchronous condenser to provide voltage support to the southeastern end of FPL's transmission system. The two original 700-MW (nominal) nuclear units have been in service since 1972 (Unit 3) and 1973 (Unit 4) and were uprated to a combined total of approximately 1,632 (Summer) MW in 2013. Turkey Point Units 3 and 4 are pressurized water reactor (PWR) units. Turkey Point Unit 5 is a net 1,148 (Summer) MW natural gas-fired combined cycle unit that began operation in 2007. The site for the new Units 6 & 7 is south of existing Units 3 and 4 and occupies approximately 300 acres within the existing cooling canal system.

Properties adjacent to Turkey Point property are almost exclusively undeveloped land. The FPL-owned EMB is adjacent to most of the western and southern boundaries of Turkey Point property. The South Florida Water Management District (SFWMD) Canal L-31E is also situated to the west of Turkey Point property. The eastern portions of Turkey Point property are adjacent to Biscayne Bay, the Biscayne National Park (BNP), and Biscayne Bay Aquatic Preserve. The southeastern portion of Turkey Point property is bounded by state-owned land located on Card Sound. The Homestead Bayfront Park, owned and operated by Miami-Dade County, is situated to the north of the Turkey Point property.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

Turkey Point is located directly on the northwest, west, and southwest shoreline of Biscayne Bay and the Biscayne National Park, 25 miles south of Miami. Biscayne National Park was first established in 1968 as a National Monument and was expanded in 1980 to approximately 173,000 acres of water, coastal lands, and 42 keys. A portion of Biscayne Bay Aquatic Preserve, a state-owned preserve, is adjacent to the eastern boundary of the Turkey Point plant property. The Biscayne Bay Aquatic Preserve is a shallow, subtropical lagoon consisting of approximately 69,000 acres of submerged State land that has been designated as an Outstanding Florida Water.

The approximately 300-acre Turkey Point Units 6 & 7 site consists of the plant area and adjacent areas designated for laydown and ancillary facilities. The site includes hypersaline mud flats, man-made active cooling canals, man-made remnant canals, previously filled areas/roadways, mangrove heads associated with historical tidal channels, dwarf mangroves, open water /discharge canal associated with the cooling canals on the western portion of the site, wet spoil berms associated with remnant canals, and upland spoil areas.

2. Listed Species

Threatened, endangered, and/or animal species of special concern known to occur at the site, transmission line corridors, or in the nearby Biscayne National Park, include the peregrine falcon *(Falco peregrinus)*, wood stork *(Mycteria americana)*, American crocodile *(Crocodylus acutus)*, roseate spoonbill (*Ajaja ajaja)*, little blue heron *(Egretta caerulea),* snowy egret *(Egretta thula),* American oystercatcher *(Haematopus palliates),* least tern *(Sterna antillarum)*, the white ibis *(Eudocimus albus)*, Florida manatee (Trichechus manatus latirostris), eastern indigo snake (Drymarchon couperi), snail kite (Rostrhamus sociabilis plumbeus), white-crowned pigeon (Patagioenas leucocephala), and bald eagle *(Haliaeetus leucocephalus)*. No bald eagle nests are known to exist in the vicinity of the site. The federally listed, threatened American crocodile thrives at Turkey Point, primarily in and around the southern end of the cooling canals which lie south of the Turkey Point Unit 6 & 7 area. The majority of Turkey Point is considered American crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American Crocodile and the program is credited with survival improvement and contributing to the downlisting of the American Crocodile from endangered to threatened.

Some listed flora species likely to occur at the site or vicinity include pinepink (Bletia purpurea), Florida brickell-bush (Brickellia mosieri), Florida lantana (Lantana depressa var. depressa), mullien nightshade (Solanum donianum), and lamarck's trema (Trema lamarckianum).

The construction and operation after construction, of Turkey Point Unit 6 & 7 project is not expected to adversely affect any rare, endangered, or threatened species.

3. Natural Resources of Regional Significance Status

Significant features within the vicinity of the site include Biscayne National Park, the Biscayne Bay Aquatic Preserve, Miami-Dade County Homestead Bayfront Park, and Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park. Biscayne National Park contains 180,000 acres, approximately 95 percent of which is open water interspersed with more than 40 keys. The Biscayne National Park headquarters is located approximately two miles north of Turkey Point and is adjacent to the Miami-Dade County Homestead Bayfront Park, which contains a marina and day-use recreational facilities.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

For Turkey Point Units 6 & 7, the technology proposed is the Westinghouse AP1000 pressurized water reactor (PWR). This design is certified by the Nuclear Regulatory Commission (NRC) under 10 CFR 52 and incorporates the latest technology and more advanced safety features than today's nuclear plants that have already achieved record safety levels. The Westinghouse AP1000 unit consists of the reactor, steam generators, pressurizer, and steam turbine/electric generator. Condenser cooling for the Units 6 & 7 steam turbines will be accomplished using six circulating water cooling towers. The makeup water reservoir is the reinforced concrete structure beneath the circulating water system cooling towers that will contain reserve reclaimed water capacity to be used for the circulating water system. The structures for the Westinghouse AP1000 are the nuclear island (containment building, shield building, and auxiliary building), turbine building, annex building, diesel generator building, and radwaste building. The plant area will also contain the Clear Sky substation (switchyard) that will connect Units 6 & 7 to FPL's transmission system. Mitigation plans for Turkey Point Units 6 & 7 include restoration areas as well as credits purchased from the Everglades Mitigation Bank.

g. Local Government future Land Use Designations

The Turkey Point Plant site is designated by the Miami-Dade County Comprehensive Development Management Plan as an IU-3 (Industrial, Utilities, and Communications) Unlimited Manufacturing District that carries a dual designation of MPA (Mangrove Protection

Area) in portions of the property. There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. <u>Site Selection Criteria Process</u>

For Turkey Point Units 6 & 7, FPL conducted an extensive site selection analysis leading to the selection of the Turkey Point site as the site that, on balance, provided the most favorable location for developing new nuclear generation to serve FPL's customers. The Site Selection Study employed the principles of the Electric Power Research Institute (EPRI) siting guidelines and is modeled upon applicable NRC site suitability and National Environmental Policy Act (NEPA) criteria regarding the consideration of alternative sites. The study convened a group of industry and FPL subject matter experts to develop and assign weighting factors to a broad range of site selection criteria. Twenty-three candidate sites were then ranked using the siting criteria. This review allowed the list of candidates to be reduced until the best site emerged. Key factors contributing to the selection of the Turkey Point site include the existing transmission and transportation infrastructure to support new generation, the large size and seclusion of the site while being relatively close to the load center, and the long-standing record of safe and secure operation of nuclear generation at the site since the early 1970s.

i. <u>Water Resources</u>

In regard to Turkey Point Units 6 & 7, the primary source of cooling water makeup will be reclaimed water from the Miami-Dade County Water and Sewer Department (MDWASD), with potable water also from MDWASD. When reclaimed water is not available in sufficient quantity and quality of water needed for cooling, makeup water will be saltwater supplied by radial collector wells that are recharged from the marine environment of Biscayne Bay. Horizontal collector wells (radial collector wells) have become widely used for the purpose of inducing infiltration from surface water bodies into hydraulically-connected aquifer systems in order to develop moderate to high capacity water supplies. Turkey Point Units 6 & 7 wastewater will be discharged via on-site deep injection wells.

j. <u>Geological Features of Site and Adjacent Areas</u>

Turkey Point lies upon the Floridian Plateau, a partly-submerged peninsula of the continental shelf. The peninsula is underlain by approximately 4,000 to 15,000 feet of sedimentary rocks consisting of limestone and associated formations that range in age from Paleozoic to Recent. Little is known about the basement complex of Paleozoic igneous and metamorphic rocks due to their great depth.

Generally in Miami-Dade County, the surficial aquifer (Biscayne Aquifer) consists of a wedge-shaped system of porous clastic and carbonate sedimentary materials, primarily limestone and sand deposits of the Miocene to late Quaternary age. The Biscayne Aquifer is thickest along the eastern coast and varies in thickness from 80 to 200 feet thick. The surficial aquifer is typically composed of Pamlico Sand, Miami Limestone (Oolite), the Fort Thompson and Anastasia Formations (lateral equivalents), Caloosahatchee Marl, and the Tamiami formation. The lower confining layers below the surficial aquifer range in thickness from 350 to 600 feet and are composed of the Hawthorn Group. Beneath the Hawthorn Group, the Floridan Aquifer System ranges from 2,800 to 3,400 feet thick and consists of Suwannee Limestone, Avon Park Limestone, and the Oldsmar Formations.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for the new Turkey Point Units 6 & 7 for industrial processing is approximately 936 gallons per minute (gpm) for uses such as process water and service water. Approximately 55.3 million gallons per day (mgd) of cooling water would be cycled through the cooling towers. Water quantities needed for other uses such as potable water are estimated to be approximately 50,400 gallons per day (gpd) for Units 6 & 7.

l. Water Supply Sources and Type

The water for the various water needs of Turkey Point 6 & 7 will be obtained from a reclaimed water supply supplied by the Miami-Dade Water and Sewer Department, a saltwater supply, and a potable water supply from the Miami-Dade Water and Sewer Department. Reclaimed water will be used as makeup water to the cooling water system with saltwater from radial collector wells as a back-up water source to be used when reclaimed water is not available in sufficient quantity or quality.

Potable water will be used as makeup water for the service water system. The potable water supply will also provide water to the fire protection system, demineralized water treatment system, and other miscellaneous uses.

m. Water Conservation Strategies

Use of reclaimed water from MDWASD Turkey Point Units 6 & 7 helps Miami-Dade County meet approximately half of its wastewater reuse goals and will provide environmental benefits by reducing the volume of wastewater discharged by the County. In the absence of reuse opportunities, this treated domestic wastewater would likely continue to be discharged to the ocean or into deep injection wells.

Miami-Dade County is required to eliminate ocean outfalls and increase the amount of water that is reclaimed for environmental benefit and other beneficial uses. Turkey Point Units 6 & 7 will use reclaimed water 24 hours per day, 365 days per year when operating and when the reclaimed water is available in sufficient quantity and quality.

n. Water Discharges and Pollution Control

Turkey Point Units 6 & 7 will dissipate heat from the power generation process using cooling towers. Blowdown water or discharge from the cooling towers, along with other wastestreams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Stormwater runoff will be released to the closed-loop cooling canal system.

Turkey Point Units 6 & 7 will employ Best Management Practices (BMP) plans and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The Turkey Point Units 6 & 7, reactors will contain enriched uranium fuel assemblies.

New fuel assemblies will be transported to Turkey Point for use in Units 6 & 7 by truck from a fuel fabrication facility in accordance with U.S. Department of Transportation (DOT) and NRC regulations. Spent fuel assemblies being discharged will remain in the permitted spent fuel pool while short half-life isotopes decay.

After a sufficient decay period, the fuel would be transferred to a permitted on-site independent spent fuel storage installation facility or a permitted off-site disposal facility. Packaging of the fuel for off-site shipment will comply with the applicable DOT and NRC regulations for transportation of radioactive material.

The U.S. Department of Energy (DOE) is responsible for spent fuel transportation from reactor sites to a repository under the Nuclear Waste Policy Act of 1982, as amended. FPL has executed a standard spent nuclear fuel disposal contract with DOE for fuel used in Units 6 & 7.

p. Air Emissions and Control Systems

Regarding Turkey Point Units 6 & 7, the units will minimize FPL system air pollutant emissions by using nuclear fuel to generate electric power. This includes avoiding emissions of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), carbon dioxide (CO_2), and volatile organic compounds (VOC). The circulating water cooling towers will be equipped with high-efficiency drift or mist eliminators to minimize emissions of

PM to 0.0005 percent of the circulating water; which represents 99.99-percent control of potential drift emissions based on the circulating water flow.

The diesel engines necessary to support Turkey Point Units 6 & 7 and fire pump engines will be purchased from manufacturers whose engines meet the EPA's New Source Performance Standards (NSPS) Subpart IIII emission limits.

q. <u>Noise Emissions and Control Systems</u>

Field surveys and impact assessments of noise expected to be caused by activities associated with the Turkey Point Units 6 & 7 project were conducted. Predicted noise levels associated with these projects are not expected to result in adverse noise impacts in the vicinity of the site.

r. <u>Status of Applications</u>

The Turkey Point Units 6 & 7 Need Determination for this additional nuclear capacity was issued by the Florida Public Service Commission in April 2008. The Site Certification Application (SCA), under the Florida Electrical Power Plant Siting Act, was filed in June 2009 and on May 14, 2014, the Florida Power Plant Siting Board authorized the site certification, with conditions. In its final order, the Florida Power Plant Siting Board identified the West Consensus Corridor as the primary western corridor (comprising an alternate corridor proposed by the Miami-Dade Limestone Products Association and a portion of FPL's West Preferred Corridor) and FPL's West Preferred Corridor as a back-up western transmission line corridor. The use of the back-up western transmission line corridor will be necessary in the event the pending land exchange with the National Park Service and other agencies is not consummated on a timely basis.

A Combined Operating License Application for Units 6 & 7 was submitted to the NRC in June 2009. There are two components to that application; one is the Environmental Assessment (EA) and the other is the Safety component. In 2014 the US Nuclear Regulatory Commission informed FPL that their decision on the COLA was going to be delayed several years until late 2016. As a result of this delay, and changes in Florida's nuclear cost recovery rules, the earliest practical in-service dates of Turkey Point Units 6 & 7 (June 2017 and June 2028, respectively) have moved beyond the 10-year reporting window (2015 through 2024) of this Site Plan.

Besides the certification and the license, additional approvals have been issued for Turkey Point Units 6 & 7 including Miami-Dade County Unusual Use approvals that were issued in 2007 and 2013 and a Land Use Consistency Determination that was issued in 2013. The

Prevention of Significant Deterioration (Air permit) was issued in 2009. In addition, a permit to construct an exploratory well and a dual zone monitoring well, under the Underground Injection Control Program, was issued in 2010, and a permit to convert the exploratory well, to an injection well and to operationally test the system, was issued in 2013. Permits from the Federal Aviation Administration (FAA) for the containment structure were originally issued in 2009 and renewed in 2012.

IV.F.2 Potential Sites for Generating Options

Three (3) sites are currently identified as Potential Sites for future generation additions to meet FPL's projected capacity and energy needs.[5] These sites have been identified as Potential Sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies, including both renewable energy and non-renewable energy technologies for various sites.

Each of these Potential Sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that will require further definition and attention.

Permits are presently considered to be obtainable for each of these sites. No significant environmental constraints are currently known for any of these sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time, FPL considers each site to be equally viable.

Potential Site #1: Hendry County

FPL has acquired an approximately 3,120-acre site in southeast Hendry County, off CR 833. The Hendry County site has been listed as a Preferred or Potential Site in previous FPL Site Plans as a possibility for a future PV facility and/or natural gas-fired CC generation. FPL currently views the Hendry site as one of the most likely sites to be used for future large-scale generation. A map of the property owned FPL and an overview map of the site and adjacent areas is found at the end of this chapter.

a. Geological Survey (USGS) Map

A USGS map of the site is found at the end of this chapter.

[5] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other Greenfield sites. Greenfield sites that FPL currently does not own, or for which FPL has not currently secured the necessary rights to, are not specifically identified as Potential Sites in order to protect the economic interests of FPL and its customers.

b. Existing Land Uses of Site and Adjacent Areas

The existing and future land uses on the site are Agricultural and Upland Forest. The existing land uses adjacent to the site are predominately agricultural. The property to the south is the Seminole Big Cypress Reservation.

c. Environmental Features

The natural environment adjacent to the north, east, and west of the site are used predominately for agricultural activities such as improved, unimproved, and woodland pasture. The majority of the pasture lands include upland scrub, pine, and hardwoods.

FPL strives to have no adverse impacts on federal- or state-listed terrestrial plants and animals. Much of southwest Florida, including this area is considered habitat for the endangered Florida Panther. Although few or no impacts are expected in association with future construction at the site, FPL anticipates minimizing or mitigating for unavoidable wildlife or wetland impacts.

Future construction and operation of a solar and/or a natural gas-fired CC generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

d. Water Quantities Required

The estimated quantity of water required for processing at a CC unit is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Potable water demand is expected to average 0.001 mgd. Approximately 7.5 mgd of cooling water would be used in cooling towers for one CC unit. Minimal amounts of water would be required for a PV facility.

e. Supply Sources

A Potential water supply source is groundwater, but additional evaluations are necessary to determine the exact source. Process and potable water for the new plant will come from the existing potable water supply. Specific water conservation strategies will be evaluated and selected during the detailed design phase of any development project.

Potential Site # 2: Martin County

FPL is currently evaluating potential sites in Martin County for a future PV facility. No specific locations have been selected at this time.

a. U.S. Geological Survey (USGS) Map

A USGS map of the county has been included at the end of this chapter.

b. Land Uses

This information is not available because a specific site has not been selected at this time.

c. Environmental Features

This information is not available because a specific site has not been selected at this time.

d. Water Quantities Required

Minimal amounts of water would be required for a PV facility.

e. Supply Sources

Minimal water would be required for a PV facility. A small amount, trucked in, may be needed to occasionally clean the PV panels in the absence of sufficient rainfall.

Potential Site # 3: Putnam Plant Site, Putnam County

FPL is currently evaluating the existing Putnam Plant site for future natural gas-fired generation. This 66 acre site is located on the east side of Highway 100 opposite the former FPL Palatka Plant in East Palatka. The Putnam site has been listed as a Potential Site in previous FPL Site Plans as a possibility for future natural gas-fired CC generation. FPL currently views the Putnam site as one of the most likely sites to be used for future large-scale generation.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Putnam site is found at the end of this chapter.

b. Existing Land Uses of Site and Adjacent Areas

The Putnam site is designated as Industrial land use. Adjacent land uses include power generation and associated facilities (the former Palatka Plant) as well as Mixed Wetland Hardwoods, Residential, and Mixed Hardwood-Coniferous.

c. Environmental Features

The majority of the site is developed and has facilities necessary for power plant operations. No significant environmental features have been identified at this time. It is anticipated that there will be minimal impacts (if any) to federal- or state-listed terrestrial plants and animals in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species. The construction and operation of a power generating facility at this location is not expected to have any adverse impacts on natural resources of regional significance and FPL is not aware of any other significant features of the site.

d. Water Quantities Required

The St John's River and/or regional water supply initiatives are potential water sources. Potable water demand is expected to average .001 million gallons per day (mgd). The estimated quantity of water required at a CC unit is approximately 0.24 mgd for uses such as process water and service water. Approximately 7.5 mgd of cooling water would be used in cooling towers for a CC unit.

e. Supply Sources

A potential water supply source is the St. John's River, but additional evaluation is necessary to determine the exact source. Process and potable water for the new plant will come from the existing potable water supply. CC and cooling tower technologies utilize less water by design than traditional steam generation units. Specific water conservation strategies will be evaluated and selected during the detailed design phase of the project development.

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CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information." These 12 items concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints: external limitations and internal limitations. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important because they affect the development of assumptions for the amount of external assistance that is available to the FPL system as well as the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance that is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In the loss of load probability (LOLP) portion of its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system that provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new generating units that minimize adverse impacts to the flow of electricity within FPL's system. The internal transmission limitations are also addressed by developing the direct costs for siting potential new units at different locations, evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system, and/or evaluating the costs of transmission additions that may be needed to address regional concerns regarding an imbalance between load and generation in a given region. Both of these site- and system-related transmission costs are developed for each different unit/unit location option or groups of options. When analyzing DSM portfolios, such as in a DSM Goals docket, FPL also examines the potential for utility DSM energy efficiency programs to avoid/defer regional transmission expenditures that would otherwise be needed to import power into that region by lowering electrical load in Southeastern Florida. In addition, transfer limits for capacity and energy that can be

imported into the Southeastern Florida region (Miami-Dade and Broward Counties) of FPL's system are also developed for use in FPL's production costing analyses. (A further discussion of the Southeastern Florida region of FPL's system, and the need to maintain a regional balance between generation and transmission contributions to meet regional load, is found in Chapter III.)

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's planned transmission facilities to interconnect and integrate generating units in FPL's resource plans, including those transmission facilities that must be certified under the Transmission Line Siting Act, are presented in Chapter III.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements its system [6].

The load forecast that is presented in FPL's 2015 Site Plan was developed in November 2014. The only load forecast sensitivities analyzed during 2014/early 2015 were high load forecast sensitivities developed to analyze the quality of FPL's future reserves.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

[6] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis (i.e., when only new generating options are considered), the lowest electric rate basis approach and the lowest system cumulative present value of revenue requirements basis approach yield identical results in terms of which resource options are more economic. In such cases FPL evaluates resource options on the simpler-to-calculate (but equivalent) lowest cumulative present value system revenue requirements basis.

The basic assumptions FPL used in deriving its fuel price forecasts are discussed in Chapter III of this document. FPL used three fuel cost, and three environmental compliance cost, forecasts in analyses supporting its 2014 nuclear cost recovery filing. Also, in response to a request from the FPSC Staff, FPL used three fuel cost forecasts in sensitivity case analyses for the 2014 DSM Goals docket.

A Medium fuel cost forecast is developed first. Then the Medium fuel cost forecast is adjusted, upwards (for the High fuel cost forecast) or downwards (for the Low fuel cost forecast), by multiplying the annual cost values from the Medium fuel cost forecast by a factor of (1 + the historical volatility in the 12-month forward price, one year ahead) for the High fuel cost forecast, or by a factor of (1 – the historical volatility of the 12-month forward price, one year ahead) for the Low fuel cost forecast.

The resource plan presented in this Site Plan is based, in part, on those prior analyses. For that reason, this resource plan has not been further tested for different fuel cost forecasts.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item # 3, FPL used up to three fuel cost forecasts in its 2014/early 2015 resource planning analyses. While these forecasts did not represent a constant cost differential between oil/gas and coal, a variety of fuel cost differentials were represented in these forecasts.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 in Chapter I and Schedule 8 in Chapter III present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options in its resource planning work. A summary of this information for the new capacity options that FPL currently projects to add over the reporting horizon for this document is presented on the Schedule 9 forms in Chapter III.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

During 2014, FPL used the following financial assumptions: i) an incremental capital structure of 40.38% debt and 59.62% equity; (ii) a 5.14% cost of debt; (iii) a 10.5% return on equity; and (iv) an after-tax discount rate of 7.54%. In February 2015, the cost of debt changed to 5.05% and the after-tax discount rate changed to 7.51%. No sensitivities of these financial assumptions were used in FPL's 2014/early 2015 resource planning work.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item # 2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective yield identical results in terms of which resource options are more economical when DSM levels are unchanged between competing resource plans. Therefore, in planning work in which DSM levels were unchanged, the equivalent, but simpler-to-calculate, cumulative present value of revenue requirements perspective was utilized.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses three system reliability criteria in its resource planning work that addresses generation, purchase, and DSM options. One criterion is a minimum 20% Summer and Winter reserve margin. Another reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). The third criterion is a minimum 10% generation-only reserve margin (GRM) criterion. These three reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability analysis work, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The

FRCC has adopted transmission planning criteria that are consistent with the Reliability Standards established by the North American Electric Reliability Council (NERC). The *NERC Reliability Standards* are available on the internet site (http://www.nerc.com/).

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Facility Rating Methodology* document that are also available on the internet under the "Interconnection Request Information", and "FPL Facility Ratings Methodologies", directories respectively at https://www.oatioasis.com/FPL/index.html.

Generally, FPL limits its transmission facilities to 100% of the applicable thermal rating. The normal and contingency voltage criteria for FPL stations are provided below:

Normal/Contingency

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09
Turkey Point (*)	1.01/1.01	1.06/1.06
St. Lucie (*)	1.00/1.00	1.06/1.06

(*) Voltage range criteria for FPL's Nuclear Power Plants

There may be isolated cases for which FPL may have determined that it is acceptable to deviate from the general criteria stated above. There are several factors that could influence these criteria, such as the overall number of potential customers that may be impacted, the probability of an outage actually occurring, and transmission system performance.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The projected impacts of FPL's DSM programs on demand and energy consumption are revised periodically. Engineering models, calibrated with current field-metered data, are updated at regular intervals. Participation trends are tracked for all of FPL's DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants. For its load management programs, FPL conducts periodic tests of the load control equipment to ensure that the equipment is functioning correctly. These tests, plus actual, non-test load management events, also allow FPL to gauge the MW reduction capabilities of its load management programs on an on-going basis.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The Executive Summary and Chapter III provide a discussion of a variety of system concerns/issues that influence FPL's resource planning process. Please see those chapters for a discussion of those concerns/issues.

In addition to these system concerns/issues, there are other strategic factors that FPL typically considers when choosing between resource options. These include: (1) technology risk; (2) environmental risk, and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology, which has not achieved general commercial acceptance, has a higher risk than a technology in wide use and, therefore, assuming all else is equal, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the FPL system, including environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for FPL's resource plan are those that minimize environmental impacts for the FPL system as a whole through highly efficient fuel use, state-of-the-art environmental controls, generating technologies that do not utilize fossil fuels (such as nuclear and solar), etc.

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decision-making, including its decisions to construct capacity or purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As shown in this 2015 Site Plan, FPL's resource plan currently reflects the following major supply-side or generation resource additions: the on-going modernization at Port Everglades, the replacement of existing GT capacity with new CT capacity, the on-going upgrading of CTs in several existing CCs throughout

FPL's system, the implementation of the previously executed EcoGen PPA, the projected addition of new PV facilities, and the addition of new CC units.

In regard to the modernization project at Port Everglades, the project received a Florida Public Service Commission waiver from the Bid Rule due to attributes specific to the Port Everglades site and to modernization projects in general (such as use of existing land, water, transmission, etc.) plus other economic benefits to FPL's customers. This waiver from the Bid Rule was granted in Order No. PSC-11-0360-PAA-EI for Port Everglades.

CT upgrades are currently taking place at several CC units throughout the FPL system. FPL was approached by the original equipment manufacturer (OEM) of the CTs regarding the possibility of upgrading these units. Following negotiations with the OEM, and economic analyses that showed upgrading was cost-effective for FPL's customers, the decision was made to proceed with the CT upgrades. That process is underway and is scheduled to be completed in 2015.

The EcoGen PPAs, which were approved by the Commission in Order No. PSC-13-0205-CO-EQ dated 5/21/13, were the result of negotiations between U.S. EcoGen and FPL.

In regard to the planned PV facilities, the selection of equipment and installation contractors for these facilities will be done via competitive bidding.

Identification of projected self-build generation resources beyond those units already approved by the FPSC and Governor and Siting Board or units, such as the 2019 and 2023 CC units and the PV projects presented in this Site Plan, is required of FPL in its Site Plan filings. FPL's identification of these resources represents FPL's current view of alternatives that appear to be the best, most cost-effective self-build options at present. FPL reserves the right to refine its planning analyses and to identify and evaluate other options before making decisions regarding future capacity additions. Such refined analyses have the potential to yield a variety of self-build options, some of which may not require an RFP. If an RFP is issued for generation resources, FPL will choose the best alternative for its customers, regardless of whether it is a third party proposal to an RFP or an FPL self-build option. If an RFP for generation resources is not required, FPL will utilize a competitive bidding process to select equipment suppliers and installation contractors based on its assessment of price and supplier capability to realize the best generation option for its customers.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

FPL has identified the need for a new 230 kV transmission line that required certification under the Transmission Line Siting Act that was issued in April 2006. The new line will connect FPL's St. Johns Substation to its Pringle Substation (shown on Table III.E.1 in Chapter III). The line will be constructed in two phases. Phase 1 was completed in May 2009 and consisted of a new line connecting Pringle to a new Pellicer Substation. Phase 2 will connect St. Johns to Pellicer and it is scheduled to be completed by December 2018. The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company.	DOCKET NO. 130198-EI ORDER NO. PSC-13-0505-PAA-EI ISSUED: October 28, 2013

The following Commissioners participated in the disposition of this matter:

RONALD A. BRISÉ, Chairman
LISA POLAK EDGAR
ART GRAHAM
EDUARDO E. BALBIS
JULIE I. BROWN

PROPOSED AGENCY ACTION ORDER ON FLORIDA POWER & LIGHT COMPANY'S PROPOSED SABAL TRAIL TRANSMISSION, LLC AND FLORIDA SOUTHEAST CONNECTION PIPELINES

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

Case Background

On July 26, 2013, Florida Power & Light Company (FPL) filed its petition in this docket requesting a determination by the Florida Public Service Commission (Commission), that its decision to enter into long-term natural gas transportation contracts is prudent, and that the associated costs are eligible for recovery through the Fuel and Purchased Power Cost Recovery Clause (Fuel Clause). The petition included testimony from five witnesses, with exhibits outlining FPL's need for additional firm natural gas transportation, a description of its request for proposals (RFP) process and the resulting contracts, and a request for approval of its planned cost recovery method. The petition was filed following FPL's selection of two projects to develop new natural gas transportation infrastructure into southern Florida, offering the most cost-effective alternative for its customers. These projects are referred to individually in the petition as the Northern Pipeline Project and the Southern Pipeline Project. The two projects are wholly separate pipelines owned and operated by different entities, and therefore are referred to collectively as a matter of convenience.

The instant docket is the culmination of a process, which began in 2009 when FPL petitioned us to develop, build, and operate the Florida EnergySecure Line. On April 7, 2009, FPL filed its petition in Docket No. 090172-EI requesting a determination of need for its proposed Florida EnergySecure Line, a 280-mile long, 30-inch diameter high pressure natural gas transmission pipeline that FPL sought to own and operate primarily for supplying natural gas to its newly modernized Cape Canaveral and Riviera Beach generating units. By Order No. PSC-09-0715-FOF-EI, we denied the petition finding that FPL had failed to adequately demonstrate that its Florida EnergySecure Line was the most cost-effective alternative for providing additional natural gas transmission capacity. However, we agreed that additional gas capacity was necessary for assuring the reliability of Florida's electric generating system in the future. In Order No. PSC-09-0715-FOF-EI, we stated, "we agree with the parties that increased gas transportation infrastructure is needed to meet future electricity needs, given the uncertainty surrounding both coal-fired and nuclear generation in the state."[1] Our Order directed FPL to "renew its request for proposals to fulfill its gas transportation capacity needs," and further stated that the "new RFP shall contain a specific, detailed request for proposals for a new pipeline, and specifications of the long term natural gas needs of FPL."[2] In addition, the Order stated that "[t]he RFP shall be provided to our staff for review prior to its issuance to ensure it is clear and complete."[3]

FPL provided the RFP for review on November 13, 2012. A public meeting was held on November 26, 2012 so that our staff and any other interested parties could have an opportunity to discuss and review FPL's RFP document prior to its issuance. In addition to our staff, representatives of the Office of Public Counsel (OPC) as well as potential project participants and other interested groups were present at the meeting. There were no objections to FPL issuing the RFP.

FPL issued its RFP on December 19, 2012. The RFP was noticed three times in *Platt's Gas Daily*, a widely distributed industry publication. FPL provided an internet website where interested persons could gather information and ask questions. FPL also held a workshop to facilitate understanding of the RFP and the bidding process prior to the April 3, 2013 due date for responses. An additional meeting was held on June 13, 2013 to discuss the results of the RFP solicitation, FPL's evaluation of the proposals, and the next steps to be taken in the process. Attendees included our staff, OPC, and representatives of the Florida Industrial Power Users Group (FIPUG). Based on discussion at the meeting, FPL provided an outline of topics that would be covered in the direct testimony filed with its petition.

FPL is not obligated by law to obtain our approval to enter into a long-term gas transportation contracts for the projects, as both contracts are governed by the Federal Energy Regulatory Commission (FERC). The contracts would only trigger our action at the time FPL seeks recovery of costs in the fuel clause proceeding. However, due to the substantial financial commitments involved, FPL is seeking our determination that FPL's decision to enter into long-term gas transportation contracts is prudent and that the associated costs are eligible for recovery through the fuel clause. FPL included a provision in its precedent agreement with each pipeline that requires our approval of the agreements. The contracts may be terminated without financial

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[1] Order No. PSC-09-0715-FOF-EI, issued October 28, 2009, in Docket No. 090172-EI, In re: Petition to determine need for Florida EnergySecure Pipeline by Florida Power & Light Company, page 5.
[2] Id., page 6.
[3] Id., page 6.

penalty if we do not make a prudency determination satisfactory to FPL. We have jurisdiction over the subject matter by the provisions of Chapter 366, Florida Statutes.

A. Additional Firm Natural Gas Transportation

Description of FPL's Existing Pipeline Capacity

Peninsular Florida is currently served by only two major natural gas pipelines. Florida Gas Transmission Company, LLC (FGT) is the larger of the two pipelines with approximately 3,100 million cubic feet per day (MMcf/day) of total gas deliverability. The second of the two pipelines is owned by Gulfstream Natural Gas System, LLC (Gulfstream) and has a maximum 1,300 MMcf/day of gas deliverability. Currently, FPL has firm contracts with Gulfstream for 53 percent of the design capacity of its system which is 695 MMcf/day. By 2017, FPL will have firm transportation contracts with FGT for 41 percent of its design capacity, a total of 1,274 MMcf/day. The FGT capacity serves approximately 65 percent of FPL's current total gas supply requirements, and Gulfstream serves the remaining 35 percent. However, FPL is not the only firm shipper for either system. The remaining capacity of Gulfstream is currently fully subscribed, and only 6 percent of FGT's capacity (approximately 184 MMcf/day), will *potentially* be available on a long-term firm contractual basis within the 2017 time frame. Additional natural gas transportation capacity will be necessary as FPL's and all of Florida's electric generation systems continue to grow. Nearly 68 percent of the state's electric generation, and more than 72 percent of FPL's total energy, was fueled by natural gas in 2012.

In general, natural gas pipeline transportation capacity availability is firm or non-firm. Firm transportation capacity is acquired through a contract for reservation of a certain portion of a pipe's daily throughput, which is continuously available to a utility to provide fuel for its generators. Utilities typically acquire non-firm transportation capacity by purchasing pipeline capacity that has been temporarily released by another customer, or by purchasing non-reserved capacity. Released capacity becomes available when another customer's need for gas is below their reserved portion. However, this type of capacity cannot be relied upon as it is not guaranteed. If a sufficient supply of fuel is not available when required to meet load, a utility risks a situation where it may be unable to fully utilize its generating assets, and it could be forced to increase its use of more expensive alternative fuels, demand response, or even load shedding. For this reason, it is important for FPL to have adequate gas transportation capacity available on a firm basis.

Description of Proposed Pipeline Projects

In its petition, FPL states that 400 MMcf/day of additional firm natural gas transportation capacity is required beginning in 2017. The primary factors driving this increased need are the three modernization projects currently in progress at FPL's Cape Canaveral, Riviera Beach, and Port Everglades natural gas plants to upgrade older, 1960's-era steam combustion turbine generating units to modern, and more efficient combined cycle technology. FPL proposes to meet this need by implementing two new contracts for firm pipeline capacity within the northern and southern portions of the state.

The Northern Pipeline project consists of a joint venture between a subsidiary of Spectra Energy Corporation, called Sabal Trail Transmission, LLC (Sabal Trail) and a newly formed subsidiary of FPL's parent company, Next-Era Energy, called U.S. Southeastern Gas Infrastructure LLC (USSGI). The Southern Pipeline project will be owned by another newly formed affiliate of FPL, called the Florida Southeast Connection (FSC). FPL has signed precedent agreements with these two companies for the initial 400 MMcf/day beginning in 2017, with options to provide additional increments of 200 MMcf/day in 2020 and beyond.

Our review of FPL's need for additional natural gas transportation capacity began by analyzing its customer load forecast for the period 2013 through 2032. Then we evaluated the planned generation resource portfolio identified to meet customer demand and energy requirements. The resulting natural gas requirement was then compared to both existing pipeline resources and the proposed contracts with Sabal Trail and FSC. In addition to a review of the current proposal, we compared each of the current forecasts with those presented in the request for a determination of need for the Florida EnergySecure Line, which proposed a 600 MMcf/day pipeline with a 2014 in-service date.

Load Forecasting

The load forecast contained in FPL's petition consists of two components: a base case forecast for both net energy for load (NEL) and summer peak demand, and a risk adjustment component for both NEL and summer peak demand that increases FPL's base-case forecast in order to reduce the risk of under forecasting FPL's future load growth.

FPL's base case forecast for NEL and summer peak demand are based upon three econometric models: a customer forecast model, a net energy for load per customer model, and a summer peak demand per customer model. These three models are the same as those used by FPL in their normal annual planning cycle and are used to produce projections of anticipated load growth for FPL's Ten-Year Site Plans (TYSPs) and other proceedings before the Commission. Our staff analyzed these models, including replicating the estimated model coefficients and associated statistics, and find them to be appropriate for forecasting purposes. Our staff also reviewed the forecast assumptions of anticipated economic and demographic conditions in FPL's service territory. These assumptions are drawn from reputable independent third party sources, including the University of Florida's Bureau of Economic and Business Research, the Florida Legislature's Office of Economic and Demographic Research, and IHS Global Insight. We reviewed these forecast assumptions and find them to be appropriate. Finally, the forecast produced by these models are adjusted to incorporate the effects of incremental wholesale and retail contracts, as well as the incremental load resulting from electric plug-in vehicles and Economic Development and Existing Facility Riders, which are not otherwise included in FPL's historical load levels.

The second component of FPL's load forecast is a risk adjustment factor designed to reduce the risk of under forecasting future load growth. The company indicated in its petition that because FPL is so highly dependent on natural gas-fired generation, the company's long term system reliability could be jeopardized if actual load growth exceeds forecasted growth.

To quantify this risk of under forecasting, FPL analyzed the long term forecasts contained in its TYSPs from 1988 through 2012 and compared these forecasts to actual load growth. In particular, for each year of the ten-year forecast horizon contained in the TYSPs, FPL calculated the differences between the forecasted values of NEL and summer peak demand and their corresponding actual values. From these differences, FPL was able to calculate a confidence interval of forecast accuracy for each of the ten years in the forecast horizon. These ten confidence intervals allow FPL to calculate how much their base case forecasts must be increased so that there is a 75 percent probability that actual NEL and summer peak demand will be less than or equal to their risk-adjusted forecasts. For the forecasts beyond the ten-year forecast horizon covered by the Ten-Year Site Plans (years 2023 through 2032), FPL utilized a constant adjustment factor associated with the ten-year forecast horizon for its NEL and summer peak demand forecasts. We reviewed the data from which FPL derived its risk adjustment factors and confirmed that the data was correctly taken from prior TYSPs and that the resultant forecast errors, variances, and confidence intervals were appropriately calculated.

In its response to a data request regarding the use of the risk-adjusted forecasting methodology, FPL stated that this project is the first time it has built contingencies into its gas transportation forecasting. FPL responded that "[t]he recent growth in gas usage and FPL's significant dependence on gas as a primary fuel dictate a measure of conservatism is employed in procuring gas transportation as we go forward."[4] FPL further explained that between 2010 and 2012, it exceeded its natural gas consumption forecasts generated that year by 114 MMcf/day, and anticipated this variation to increase to 140 MMcf/day in 2013.

Although we are unaware of any prior proceeding in which a risk-adjusted load forecast was utilized, we find that FPL's risk adjustment methodology does reasonably account for and adjust for the risk of under forecasting future load growth. This finding is predicated on two factors. First, the specifications of FPL's three forecasting models discussed above have not significantly changed since 1988. This fact implies that the forecast errors upon which the risk adjustment factors are based must be applicable to the current base case forecasts presented in FPL's petition. Second, FPL's methodology of basing the risk adjustment factors on historical forecast accuracy means that the risk adjustment factors include not only the modeling error (the error associated with reducing the complexities of consumer purchasing decisions regarding electricity to a relatively simple econometric model), but also the error associated with not being able to specify precisely what future economic/demographic conditions will prevail over the forecast period. FPL's proposed risk-adjusted methodology appropriately accounts for both sources of error, and we find it is a reasonable approach for controlling the risk of under forecasting future load growth.

FPL's choice of selecting a 75 percent confidence interval for its risk adjustment factor is somewhat subjective. For example, FPL could have selected a different confidence interval such as 67 percent confidence interval (with an attendant 33 percent chance of under forecasting), which would lower their risk adjusted forecasts. However, the intuitive appeal of FPL's

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[4] See Document Number 05759-13, in Docket No. 130198-EI, FPL's response to Staff's Second Data Request, number 7, page 1 of 1, issued September 26, 2013.

selection of a 75 percent confidence interval is that it does reduce by half the risk of under forecasting load growth compared to the base case forecasts.

Overall, FPL's base case forecast for summer peak demand is down from that presented in the Florida EnergySecure Line proceeding. As illustrated in Figure 1, the base case forecast for summer peak demand in 2017 is 7.4 percent lower than the risk-adjusted forecast and 3.7 percent lower than the Florida EnergySecure Line forecast. By 2040, this gap increases to 13.0 percent for the risk-adjusted forecast and 6.3 percent for the Florida EnergySecure Line forecast.

Figure 1: Summer Peak Demand Forecasts (2013 – 2042)

Generation Resource Portfolios

After forecasting the increased future system load, the next step in determining FPL's future natural gas requirements was to develop projections of the generation resources that will be required to meet the increased load.

In its petition, FPL prepared two generation resource plans to analyze the effects of a potential delay in the construction of the new Turkey Point nuclear units 6 and 7 on natural gas requirements. The first (or base) case is consistent with FPL's 2013 TYSP and assumes Turkey Point units 6 and 7 enter service in 2022 and 2023, respectively. The second case, called nuclear delay, assumes these two units come into service four years later, in 2026 and 2027. Outside of the ten-year planning horizon, the next planned generating unit is a 3x1 greenfield combined cycle unit, similar in size to the Cape Canaveral, Riviera Beach, and Port Everglades modernized units, with an in-service date of 2025. The nuclear delay case accelerates the need for this unit, moving its in-service date up to 2022. All further need for new generation is projected to be met by building smaller natural gas-fired combined cycle units. These 'filler' units appear for planning purposes, and do not represent any specific unit planned by FPL. We find the use of filler units and the proposed in-service dates for both cases to be reasonable and we expect the resource plans to meet reserve margin requirements over the period reviewed.

Table 1 illustrates the in-service dates of new generating units under both the base case and nuclear delay case scenarios.

Table 1: Generation Addition Forecasts (2013 – 2030)

Planned Generation Additions By Year		
Year	**Base Case**	**Nuclear Delay**
2013	Cape Canaveral	Cape Canaveral
2014	Riviera Beach	Riviera Beach
2015		
2016	Port Everglades	Port Everglades
2017		
2018		
2019		
2020		
2021		
2022	Turkey Point unit 6	3x1 CC (1,269 MW)
2023	Turkey Point unit 7	
2024		Filler CC (635 MW)
2025	3x1 CC (1,269 MW)	Filler CC
2026	Filler CC (635 MW)	Turkey Point unit 6
2027	Filler CC	Turkey Point unit 7
2028	Filler CC	
2029	Filler CC	Filler CC
2030	Filler CC	Filler CC

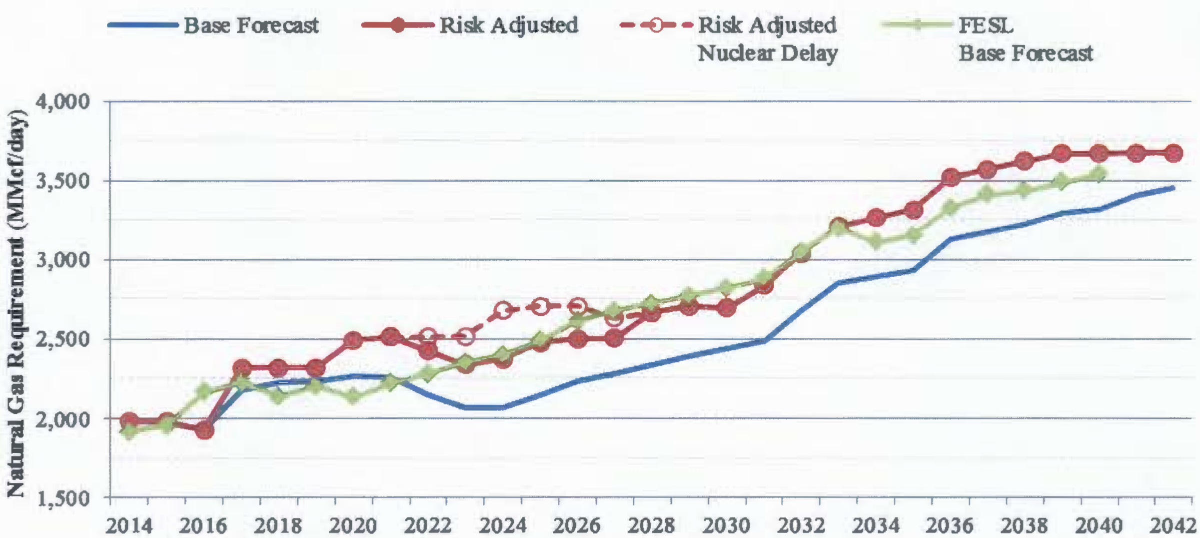
Natural Gas Transportation Requirement

As discussed above, additional natural gas transportation capacity will be necessary within the next few years as more natural gas-fired generating capacity is added. In 2012, FPL consumed more than 600,000 MMcf of natural gas. By 2017, this figure is expected to increase to at least 718,685 MMcf. The total percentage of FPL's electric power generated by natural gas is expected to be somewhat lower in the next few years, due primarily to increased nuclear production from the recently completed uprate projects of FPL's nuclear units. However, without having additional gas transportation infrastructure available in South Florida, FPL's natural gas-fired generating units will not be able to serve its customers efficiently and reliably.

Using the forecast load cases and generation resource portfolios previously discussed, FPL was able to develop forecasts of the resulting natural gas requirements on both an annual and a peak day basis. As only a finite amount of gas can be transported during any one period and no significant storage capacity for natural gas exists at FPL's plant sites, natural gas pipelines must be sized to meet peak daily loads.

FPL developed three forecasts for natural gas transportation requirements. We compared the first two forecasts by using the base generation resource plan with the base and risk-adjusted customer load forecasts. As a worst-case scenario for need, we compared the risk adjusted customer load forecast with the nuclear delay generation resource plan. These three scenarios were also compared to the Florida EnergySecure Line base forecast for natural gas requirements. Figure 2 details the peak day natural gas requirements for each of the scenarios.

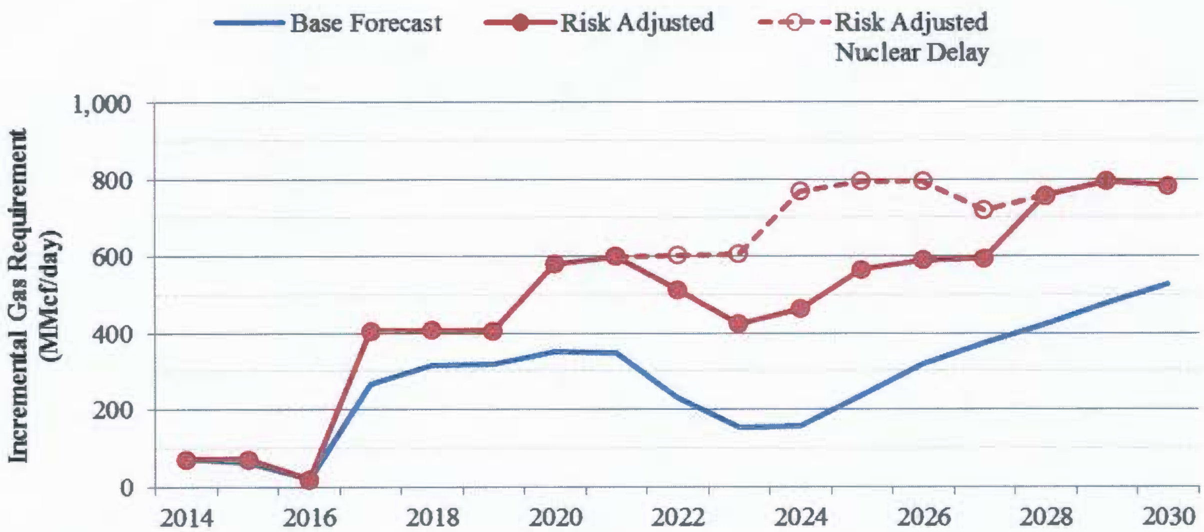
Figure 2: Natural Gas Peak Day Requirements (MMcf/day)



The base forecast projects a substantial increase in natural gas need in 2017 associated with the addition of the Port Everglades Energy Center and the loss of 375 MW of coal-fired capacity from St. John's River Power Park. The base forecast then indicates a slow increase until 2022, when nuclear generation from Turkey Point unit 6 reduces the need for natural gas. The risk-adjusted case projects a similar trend but gas needs rise to a slightly higher level, about 250 MMcf/day above the base forecast. The risk-adjusted nuclear delay case illustrates the additional fuel that will be required if Turkey Point units 6 and 7 are delayed by four years. These two forecasts differ by up to 300 MMcf/day in 2024, but become equivalent again in 2028 when both new nuclear units are in-service. The Florida EnergySecure Line gas requirement was included as an additional comparison. The lower rate of natural gas demand for the years 2017 through 2021 seen in the Florida EnergySecure Line forecast is primarily due to the earlier in-service date for Turkey Point units 6 and 7 discussed previously. Excepting the earlier inclusion of nuclear generation, the trends for increasing gas requirements are similar.

As seen in each of these scenarios, FPL's natural gas requirements exceed its existing firm contracted transportation capacity beginning in 2017. Figure 3 provides a closer look at the incremental firm natural gas transportation requirements for the period 2014 through 2030. The proposed contracts match the additional capacity required under the risk adjusted case, with the first optional incremental capacity addition in 2020 matching both risk adjusted cases. This increased gas requirement in 2020 is a result of all three modernization projects (Cape Canaveral, Riviera Beach, and Port Everglades) being online, as well as the loss of coal-fired generation at St. John's River Power Park.

Figure 3: Incremental Firm Gas Transportation Requirements (MMcf/day)



Decision

We reviewed FPL's forecast for customer load, its proposed generation resource portfolios, and the comparison of its resulting natural gas requirements with its existing natural gas transportation contracted capacity. Based on this review, we find that FPL has adequately demonstrated a need for an additional 400 MMcf/day of firm natural gas transmission capacity by 2017.

B. Most Cost-Effective Solution

Following the conclusion of the RFP process, FPL began the evaluation of the proposals it received as a result. In order to determine whether the projects selected by FPL were the most cost-effective, our staff reviewed the RFP and the selection process that resulted in FPL signing precedent agreements with Sabal Trail and FSC.

Evaluation of Project Proposals

The RFP requested that bidders provide proposals for 400,000 MMBtu/day (approximately equal to 400 MMcf/day)[5] of firm gas transportation capacity in 2017 with an incremental 200,000 MMBtu/day of firm capacity in 2020. In addition, FPL requested that the bidders include an optional incremental capacity of up to 400,000 MMBtu/day beyond the 2020 time period. Bidders could submit pricing on either a fixed or an adjustable demand charge, although FPL expressed its strong preference for fixed pricing in order to obtain pricing security for its customers. Any adjustable pricing had to include a price cap in order to limit exposure to price index volatility.

FPL received four bids for the Northern pipeline and one joint bid for the Northern and Southern pipelines. No separate bids for the Southern portion were received. The entities submitting bids (some of which were joint proposals from companies bidding as partners) represent all active pipelines in the Southeastern U.S. FPL also considered three self-build alternatives for the Southern pipeline, consisting of three configurations of pipe diameters: all 30-inch pipe (labeled proposal Ai), a combination of 30-inch and 36-inch pipe (labeled proposal Aii), and all 36-inch pipe (labeled proposal Aiii). Although FPL had specified its strong preference for fixed pricing, all proposals except the self-build options were based on adjustable demand charges. However, to meet bid requirements, all adjustable pricing included a price cap. The joint proposal for the Northern and Southern pipelines had significant deficiencies, which the bidder elected not to modify, so FPL eliminated it from further consideration. This situation left four proposals for the Northern pipeline and the three FPL self-build options for the Southern pipeline.

Table 2 illustrates the combined project reference numbers assigned by FPL during its evaluation of the RFP responses. Each of the four proposals for the Northern pipeline were evaluated using the three configurations of the pipe diameters for the Southern pipeline (proposals Ai, Aii, and Aiii) and assigned reference numbers 1 through 12.

Table 2 – Combined Project Numbers

Combined Project	1	2	3	4	5	6	7	8	9	10	11	12	13
Northern Proposal	1	2	3	4	1	2	3	4	1	2	3	4	1
Southern Proposal	Aii (36"/30")				Ai (30")				Aiii (36")				B

Combined project 13 consists of the Sabal Trail proposal for the Northern pipeline, and the non-compliant bid for the Southern pipeline. It is included for reference purposes only.

[5] The quantity "MMBtu/day" is equivalent to one million British thermal units of heat energy per day. Because FPL is ultimately concerned with the energy content of the gas, not the volumetric quantity, the contracts will be for units of MMBtu/day rather than MMcf/day (million cubic feet per day). Although the typical heat energy content of one cubic foot of natural gas is approximately one thousand Btus, consistent with industry practice FPL is requiring a quantity of energy to be delivered in its contracts to ensure the necessary amount of electric power can be generated.

The economic evaluation was primarily concerned with a Cumulative Present Value of Revenue Requirements (CVPRR) analysis over a 40-year project term. This type of analysis required that the entire system (including a Northern and a Southern pipeline) be taken into consideration, so FPL created a matrix consisting of each of the four proposals for the Northern pipeline that met the minimum requirements paired with each of the three self-build options submitted by Next-Era Energy for the Southern system. In order to perform the analysis, FPL evaluated the economics of gas transportation using production-cost simulations of its power supply system, including the costs and volumes of gas.

Because only one proposal received for the Southern pipeline was not an FPL self-build option, in order to ensure that the gas transportation charges for the self-build project were reasonably consistent with market prices, FPL performed an economic analysis of the non-compliant proposal using the indicative, non-firm pricing included in that proposal. The result of this analysis was that the non-compliant bid would be between $69 and $105 million more expensive than the best of the three compliant proposals.

The simulation model used in the economic analysis employed the same risk-adjusted load forecast utilized for determining the incremental gas transportation capacity requirement. This analysis took into consideration the fixed and variable costs, as well as the volume and timing of the needed gas transportation. After quantifying fuel and other variable costs, a production-cost modeling program was run in order to determine the differences in the CPVRR for each combined project. The analysis was performed under two different generation resource planning scenarios. The first is the base resource plan, and the second is the nuclear delay resource plan. As previously discussed, the nuclear delay case assumes that the in-service dates of the Turkey Point units 6 and 7 will be delayed by four years, meaning the units will come online in 2026 and 2027 instead of 2022 and 2023, respectively.

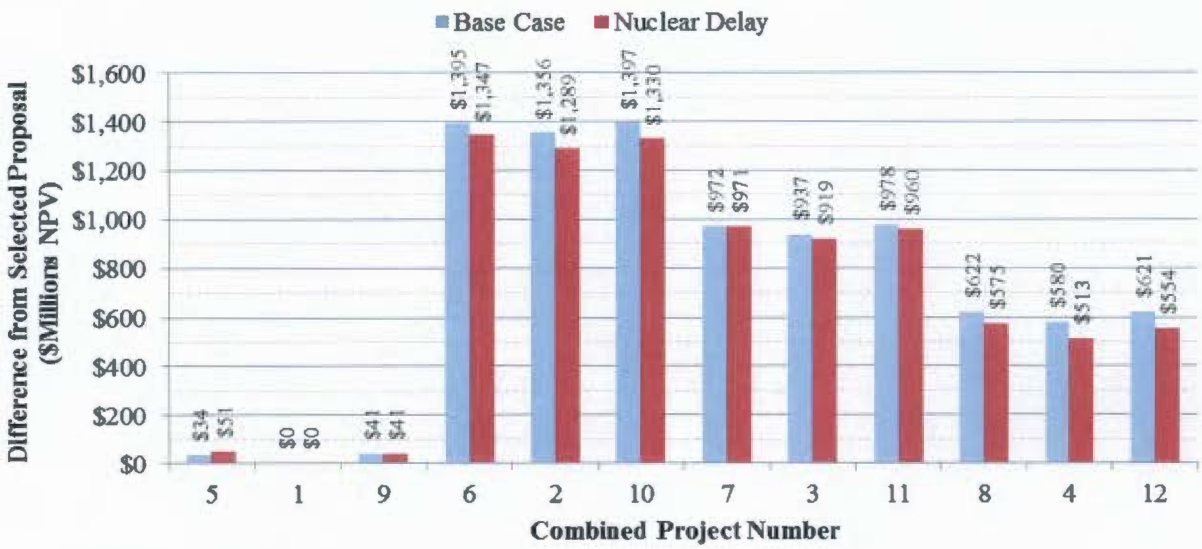
The evaluation of FPL's CVPRR analysis concluded that the combination of projects selected by FPL is indeed the most cost-effective. The magnitude of savings between the selected project's cost and that of the other potential projects depends on which resource plan, load forecast, and gas price forecast is utilized in the analysis.

The smallest margin of savings between the selected project and the next-most cost-effective project is $34 million (using a 40-year term). This comparison is, however, made using the same Northern pipeline proposal paired with two of the FPL self-build options. In fact, the differences between each of the three FPL self-build options are small enough to be insignificant. When using only the FSC for the Southern pipeline, the net present value cost differential between Sabal Trail and the next best Northern pipeline is about $450 million for a 25-year term and about $580 million for a 40-year term. Although the results of the various economic analyses differ widely, the conclusion remains the same: the combination of the Sabal Trail and FSC project is clearly the best alternative in terms of cost.

Cost-Effectiveness of Proposals

Figure 4 shows the cost differentials between the selected combination of projects and the other combined projects for the period 2017 through 2057. The horizontal axis shows the combined project numbers from Table 2. This chart clearly shows the relatively small differences in cost between the three FPL self-build alternatives when compared to the differences between the four Northern project proposals. In general, most of the proposals are also slightly more cost-effective for the nuclear delay case, but the overall difference is small.

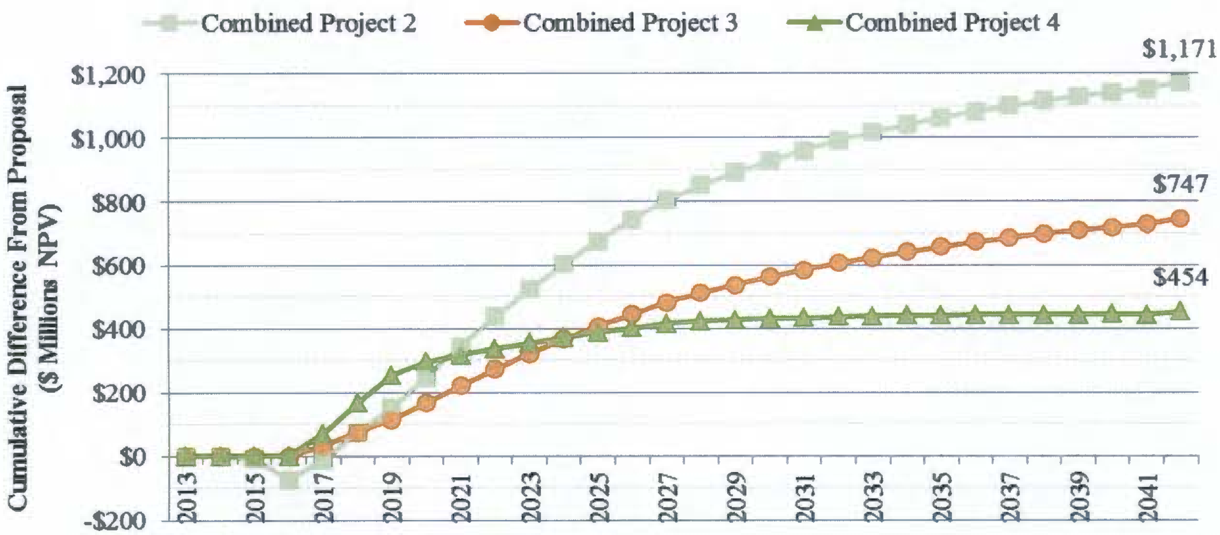
Figure 4: Comparison of the Cost-Effectiveness of the Combined Project Numbers



Source: FPL's response to our staff's second data request, no. 8

As illustrated above, the most cost-effective proposal is combined project 1, the proposed Sabal Trail and the FSC hybrid Aii combination. Using figures provided by FPL in a data request, we evaluated the savings for the various Northern pipeline proposals on an annual basis for the initial 25-year contract term, using the same FSC proposal for the southern segment. The baseline for the comparison is combined project 1. Positive values indicate higher costs, and negative values indicate savings. Only combined project 2 shows savings in any year when compared to combined project 1, but it is higher than the other two alternative proposals over the full contract term. Figure 5 shows the differences in total cost between combined projects 2, 3, and 4 using combined project 1 as a baseline.

Figure 5: Difference in Costs from Combined Project 1 Baseline



Source: FPL's response to our staff's second data request, no. 8

In addition to the economic evaluation, FPL also conducted a non-economic evaluation based on a comparative analysis of each project with respect to attributes that could not be measured in terms of cost. These attributes, while perhaps not as crucial in the overall evaluation, are also important components of the project and must therefore be taken into consideration. For example, a project that offers more opportunities for future expansion would offer a non-economic benefit. The selected Sabal Trail and FSC combined project meets FPL's strong preferences for Greenfield infrastructure and increased diversity of natural gas supply. In addition, the throughput volumes of the selected projects are easily increased using compression. However, in light of the considerable margin of cost-effectiveness for the Sabal Trail and FSC combined project, the significance of any non-economic factors was minimal.

Description of the Proposed Pipeline System

The Sabal Trail and FSC projects will provide FPL with approximately 400 MMcf/day additional capacities beginning in 2017, with an expansion to 600 MMcf/day in 2020. Optional expansions, each for an incremental 200 MMcf/day, are available to FPL, but must be elected by 2020 and 2024, respectively. These additions would become available to FPL between four and five years after the options have been taken.

The commencement point specified for the Sabal Trail pipeline system is identical to that designated in FPL's 2009 Florida EnergySecure Line project. Transcontinental Pipe Line Company's Compressor Station 85 ("Transco Station 85") in Choctaw County, Alabama provides access to non-traditional, onshore suppliers of natural gas, which is an important element to FPL because it introduces supply diversity into the system. Because FPL is currently served by only two natural gas companies, each of which provides gas mostly from Gulf of Mexico and Mobile, Alabama Bay area suppliers, gaining more diversity in its supply is an important component of the project and a primary concern to FPL.

The 2009 Florida EnergySecure Line project specified the "connection point" for the northern and southern parts of the system to be in Bradford County, Florida, near FGT Station 16. However, during the development of the RFP, several interested pipeline companies expressed the opinion that a better option was for a "hub" in the Orlando area due to the large potential customer base for contract opportunities. Therefore, in order to not only meet the primary goal of the RFP to fulfill FPL's increased need for natural gas transportation capacity, but also to further increase the diversity of the supply and to promote competition among suppliers, the chosen termination point is what will become the Central Florida Hub (CFH). The CFH, which is part of the contract for the Sabal Trail pipeline and will be constructed and operated by the same provider, will be an interconnection point between the Northern and Southern pipelines as well as with existing Gulfstream and FGT systems. The CFH will include facilities needed to provide hub wheeling services to deliver contracted capacities interchangeably between and among each of the pipelines, which further increases the flexibility and possible diversity for all the gas shippers in the area.

The Southern pipeline commences at the CFH and terminates at the existing natural gas yard at FPL's Martin Clean Energy Center (Martin), in Martin County, Florida. This terminus location allows for connectivity with the modernized generation plants at Cape Canaveral and Riviera Beach, and because both FGT and Gulfstream currently serve the Martin plant, the addition of the FSC will increase the supply alternatives available to FPL in the event of a pipeline disruption.

Cost Recovery

In response to its RFP, FPL received a total of four proposals for the Northern Pipeline Project and one joint proposal from two companies for the Southern Pipeline Project. Based on FPL's economic and non-economic evaluations, the Sabal Trail proposal was selected for the Northern Pipeline Project and the FSC proposal for the Southern Pipeline Project. Next-Era Energy is an equity stakeholder in Sabal Trail, and has agreed to operate Sabal Trail as a joint venture between Spectra and a newly formed Next-Era Energy subsidiary called USSGI. Also, FSC is a wholly owned subsidiary of Next-Era Energy, and an affiliate of FPL. FPL does not anticipate any charges coming from USSGI associated with the Northern Pipeline Project. However, FPL stated in a data request response that any costs incurred by FPL for goods or services provided to USSGI or FSC, will be charged in accordance with FPL's Cost Allocation Manual or through an Affiliate Management Fee, and would be subject to internal company review and audits to ensure compliance with Rule 25-6.1351 F.A.C. We have the authority to review any transactions with affiliated companies to ensure compliance with Rule 25-6.1351 F.A.C.

Based on Order Nos. 12645[6] and 14546[7], prudent and reasonable transportation charges incurred in the delivery of fuel are allowable expenses in the fuel and purchased power cost recovery clause. Therefore, pipeline charges associated with the delivery of natural gas to FPL's generating stations are eligible for recovery through the fuel clause. While we find that this project is cost effective relative to alternatives, we retain authority to determine the prudent cost and reasonableness of expenses charged to the fuel clause and will review these expenses annually as part of the fuel clause proceedings.

In its response to a data request regarding its plans for dispensing of any unused gas, FPL stated that, in periods of idle capacity due to lower loads, it "can pursue opportunities to release capacity on the new pipelines (or to release capacity on FGT and/or Gulfstream) to other shippers. All revenues generated from the capacity release transactions would be credited back to the customers through the Fuel Clause."[8]

Decision

Upon review, FPL's decision to enter into long-term natural gas transportation contracts with Sabal Trail and FSC was based on a fair and open RFP process. The contracts are projected to save up to $450 million over the term of the contracts when compared to the next most cost-effective proposal. We find that FPL is eligible to seek recovery of costs associated with the firm natural gas transportation contracts with Sabal Trail and FSC in the fuel clause, where they will be reviewed annually. The prudence of the actual transportation costs will be examined in the annual Fuel Docket proceedings.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company has demonstrated a need for 400 MMcf/day of additional firm natural gas transmission capacity by 2017. It is further

ORDERED that Florida Power & Light is eligible to seek recovery of costs associated with firm natural gas transportation contracts in the fuel clause, where they will be reviewed annually. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Commission Clerk, Division of the Commission Clerk, 2540 Shumard Oak Boulevard,

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[6] Order No. 12645, issued November 3, 1983, in Docket No. 830001-EU, In re: Investigation of Fuel Adjustment Clauses of Electric Utilities.
[7] Order No. 14546, issued July 8, 1985, in Docket No. 850001-EI, In re: Cost Recovery Methods for Fuel Related Expenses.
[8] FPL's response to Staff's second data request, no. 5, filed on September 26, 2013.

Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that in the event this Order becomes final, this docket shall be closed.

By ORDER of the Florida Public Service Commission this 28th day of October, 2013.

Ann Cole

ANN COLE
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

TLT

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing that is available under Section 120.57, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on November 18, 2013.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this/these docket(s) before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

Florida Power & Light Company
Docket No. 130199-EI
Staff's Second Set of Interrogatories
Interrogatory No. 55
Attachment No. 1
Tab 1 of 1

	Plan with 10% Generation Only RM				
	Generation Additions (MW)	Cumulative DSM Additions (MW)	Total Reserve Margin (%)	Generation-Only Reserve Margin (%)	LOLP
	---	---	---	---	---
2015	0	26	27.5	16.3	0.000387
2016	0	56	26.6	15.5	0.001819
2017	0	87	22.6	11.9	0.005140
2018	0	120	20.5	10.0	0.007782
2019	1,269	154	21.6	11.0	0.002467
2020	129 (PPA)	189	20.5	10.0	0.006933
2021	168 (PPA)	225	20.6	10.0	0.022382
2022	0	261	22.6	11.9	0.002163
2023	0	298	24.4	13.7	0.000176
2024	0	337	21.3	10.9	0.005863
2025	730 (PPA)	---	20.0	10.0	0.007657

	Plan **without** 10% Generation Only RM				
	Generation Additions (MW)	Cumulative DSM Additions (MW)	Total Reserve Margin (%)	Generation-Only Reserve Margin (%)	LOLP
	---	---	---	---	---
2015	0	26	27.5	16.3	0.000387
2016	0	56	26.6	15.5	0.001819
2017	0	87	22.6	11.9	0.005140
2018	0	120	20.5	10.0	0.007782
2019	1,269	154	21.6	11.0	0.002467
2020	16 (PPA)	189	20.0	9.6	0.008650
2021	38 (PPA)	225	20.0	9.5	0.028727
2022	0	261	22.6	11.9	0.002163
2023	0	298	24.4	13.7	0.000176
2024	0	337	21.3	10.9	0.005863
2025	730 (PPA)	---	20.0	10.0	0.007657

AFFIDAVIT

Steven R. Sim

Steven R. Sim

State of Florida)

County of Miami-Dade

I hereby certify that on this 29th day of May, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steven R. Sim who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. 22, 23, 26, 27, 31-33, 38, 40-42, 50-62, 64, 68 and 70, and co-sponsored Nos. 69 and 73 from Staff's 2nd Set of Interrogatories to Florida Power & Light Company in Docket No. 130199-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29th day of May, 2014.

Carolyn J Smith

Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC STATE OF FLORIDA
CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 53
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-5-B

Q.

What are the annual total reserve margin values and the Loss-Of-Load-Probability (LOLP) analysis for the period 2015 through 2025 with, and without, the Company's proposed 10 percent generation reserve margin?

A.

FPL interprets the interrogatory to be requesting projected total reserve margin and LOLP values for the resource plan that was the basis of FPL's proposed DSM goals both with and without the 10% GRM reliability criterion that FPL has adopted. That information is provided in Attachment No. 1. As indicated in the portion of FPL's response to Staff's Second Set of Interrogatories No. 53 that pertains to the RIM 337 MW resource plan, there is very little difference between this resource plan and how this resource plan would have changed if FPL had not adopted the GRM reliability criterion. The two resource plans differ only in two years and only by relatively small PPA MW amounts in those two years: by 113 MW in 2020 and by 130 MW in 2021. Therefore, there are differences in total reserve margin and LOLP values between the two resource plans in only these two years and these differences are relatively small. The differences that appear show small reliability advantages for the original resource plan that includes the GRM reliability criterion compared to an alternate resource plan that does not include these additional PPA MW amounts.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 54
PARTY: ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA (ECOSWF) – (DIRECT)
DESCRIPTION: Karl Rábago KRR-5-C

EENS 3050	Natural Disasters
Tulane University	Prof. Stephen A. Nelson

Meteorites, Impacts, and Mass Extinction

This document last updated on 01-Dec-2014

Meteorites

On February 15, 2013 a meteor exploded in the sky over Chelyabinsk, southern Russia. Although no people or buildings were hit by the resulting meteorite, the shockwave from the exploding object injured about 1500 people and caused damage to 7200 buildings in the region. The fireball and was caught on video, mainly by dash cameras throughout the region, which were posted on the internet by news organizations individuals. Although the Chelyabinsk meteorite probably weighed about 12,000–13,000 metric tonnes, and measured 17 to 20 m in diameter before it exploded, sientists were quick to point out that it was very small compared to other objects that could potentially hit the earth. The explosion released energy estimated at about 500 kilotons of TNT (about 20 to 30 times more energy than the Hiroshima atomic bomb). The event brought to the world's attention the very real hazards associated with the impact of objects from outer space.

A ***Meteorite*** is a piece of rock from outer space that strikes the surface of the Earth.

A ***Meteoroid*** is a meteorite before it hits the surface of the Earth.

Meteors are glowing fragments of rock matter from outside the Earth's atmosphere that burn and glow upon entering the Earth's atmosphere. They are more commonly known as shooting stars. Some meteors, particularly larger ones, may survive passage through the atmosphere to become meteorites, but most are small objects that burn up completely in the atmosphere. They are not, in reality, shooting stars.

Fireballs are very bright meteors.

Meteor Showers - During certain times of the year, the Earth's orbit passes through a belt of high concentration of cosmic dust and other particles, and many meteors are observed. The Perseid Shower, results from passage through one of these belts every year in mid-August, and Leonid shower occurs in mid-November.

Throughout history there have been reports of stones falling from the sky, but the scientific community did not recognize the extraterrestrial origin of meteorites until the 1700s. Within recent history meteorites have even hit humans-

- 1938 - a small meteorite crashed through the roof of a garage in Illinois
- 1954 - A 5kg meteorite fell through the roof of a house in Alabama.
- 1992 - A small meteorite demolished a car near New York City.

- 2003 - A 20 kg meteorite crashed through a 2 story house in uptown New Orleans

- 2003 - A shower of meteorites destroyed several houses and injured 20 people in India

Meteorite fragments have been found all over the surface of the Earth, although most have been found in Antarctica. In Antarctica they are easily seen on the snow covered surface or embedded in ice.

The fall of meteorites to the Earth's surface is part of the continuing process of accretion of the Earth from the dust and rock of space. When these rock fragments come close enough to the Earth to be attracted by its gravity they may fall to the Earth to become part of it. As we will see the evolution of life on the Earth has likely been affected by collisions with these space objects, and collisions could affect the Earth in the future as well.

Composition and Classification of Meteorites

Meteorites can be classified generally into three types:

- Stones - Stony meteorites resemble rocks found on and within the Earth. They are the most common type of meteorite, although because they resemble Earth rocks they are not commonly recognized as meteorites unless someone actually witnesses their fall. Stony meteorites are composed mainly of the minerals olivine, and pyroxene. Some have a composition that is roughly equivalent to the Earth's mantle. Two types are recognized:

    - ***Chondrites*** - Chondrites are the most common type of stony meteorite. They are made of olivine, pyroxene, and iron - nickel alloys that are magnetic. They are composed of small round spheres, called chondrules, made of the minerals olivine and pyroxene. They appear to have formed by rapid melting followed by rapid cooling early in the history of the solar system. Most chondrites have radiometric age dates of about 4.6 billion years.

    - ***Achondrites*** - Achondrites are composed of the same minerals as chondrites, but lack the chondrules. They appear to have been heated, melted, and recrystallized so that the chondrules are no longer present. Most resemble igneous rocks found on the Earth.

- Irons - Iron meteorites are composed of alloys of iron and nickel. They are easily recognized because they have a much higher density than normal crustal rocks. Thus, most meteorites found by the general populace are iron meteorites. All are magnetic. When cut and polished, iron meteorites show a distinct texture called a Widmanstätten pattern. This pattern results from slow cooling of a once hot solid material. Most research suggest that such slow cooling occurred in the core of much larger body that has since been fragmented. Iron meteorites give us a clue to the composition of the Earth's core.

- Stony Irons - Stony iron meteorites consist of a mixture of stony silicate material and iron. Some show the silicates embedded in a matrix of iron-nickel alloy. Others occur as a breccia, where fragments of stony and iron material have been cemented together by either heat or chemical reactions.

Origin of Meteorites

Most meteorites appear to be fragments of larger bodies called ***parent bodies***. These could have been small planets or large asteroids that were part of the original solar system. There are several possibilities as to where these parent bodies, or their fragments, originated.

- The Asteroid Belt
  The ***asteroid belt*** is located between the orbits of Mars and Jupiter. It consists of a swarm of about 100,000 objects called asteroids. ***Asteroids*** are small rocky bodies with irregular shapes that have a cratered surface. About 4,000 of these asteroids have been officially classified and their orbital paths are known. Once they are so classified they are given a name.

  The asteroids are either remnants of a planet that formed in the region between Mars and Jupiter but was later broken up by a collision with another planetary body, or are fragments that failed to accrete into a planet. The latter possibility is more likely because the total mass of the asteroids is not even equal to our moon. It does appear that some of the asteroids are large enough to have undergone internal differentiation. Differentiation is a process that forms layering in a planetary body (i.e. the Earth has differentiated into a core, mantle, and crust). If these larger asteroids did in fact undergo differentiation, then this could explain the origin of the different types of meteorites. Because of the shapes of the asteroids it also appears that some of them have undergone fragmentation resulting from collisions with other asteroids. Such collisions could have caused the larger bodies to be broken up into the smaller objects we observe as meteorites.

  - The Asteroids as Parent Bodies of Meteorites

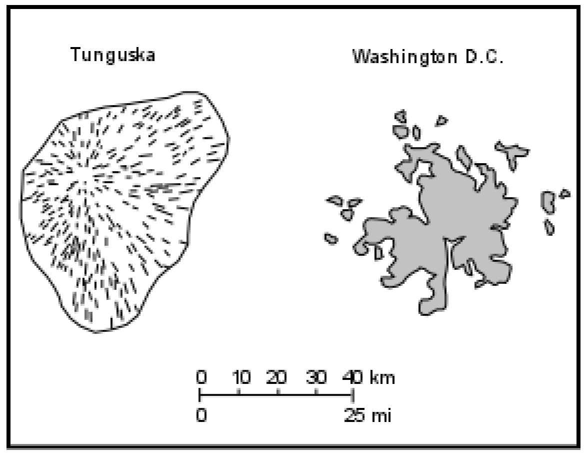
    Much evidence suggests that the asteroids could be the parent bodies of meteorites. The larger ones could have differentiated into a core, mantle, and crust. Fragmentation of these large bodies would then have done two things: First the fragments would explain the various types of meteorites found on Earth - the stones representing the mantle and crust of the original parent body, the irons representing the cores, and the stony irons the boundary between the core and mantle of the parent bodies. Second, the collisions that caused the fragmentation could send the fragments into Earth-crossing orbits.

  Some of the asteroids have orbits that bring them close to Earth. These are called ***Amor objects***. Some have orbital paths that cross the orbital path of the Earth. These are called ***Earth-crossing asteroids*** or ***Apollo objects***. All objects that have a close approach to the Earth are often referred to as ***Near Earth Objects*** or ***NEOs***. About 150 NEOs with diameters between 1 and 8 km are known, but this is only a fraction of the total number. Many NEOs will eventually collide with the Earth. These objects have unstable orbits because they are under the gravitational influence of both the Earth and Mars. The source of these objects is likely the asteroid belt.

- Comets as Parent Bodies of Meteorites

  A ***Comet*** is a body that orbits around the Sun with an eccentric orbit. These orbits are not circular like those of the planets and are not necessarily within the same plane as the planets. Most comets have elliptical orbits which send them to the far outer reaches of the solar system and back toward a closer approach to the sun. As a comet approaches the sun, solar radiation generates gases from evaporation of the comet's surface. These gases are pushed away from the comet and glow in the sun light, thus giving the comet its tail. While the outer surface of comets appear to composed of icy material like water and carbon dioxide solids, they likely contain a more rocky nucleus. Because of their eccentric orbits, many comets eventually cross the orbit of the Earth. Many meteor showers may be caused by the Earth crossing an orbit of a fragmented comet.

  The collision of a cometary fragment is thought to have occurred in the Tunguska region of Siberia in 1908. The blast was about the size of a 15 megaton nuclear bomb. It knocked down trees in an area about 850 square miles, but did not leave a crater. Although still controversial, the general consensus among scientists is that a cometary fragment about 20 to 60 meters in diameter exploded in the Earth's atmosphere just above the Earth's surface. A similar event if it happened over a large city, would be devastating.



- Other Sources

  While the asteroid belt seems like the most likely source of meteorites, some meteorites appear to have come from other places. Some meteorites have chemical compositions similar to samples brought back from the moon. Others are thought to have originated on Mars. These types of meteorites could have been ejected from the Moon or Mars by collisions with other asteroids, or from Mars by volcanic eruptions.

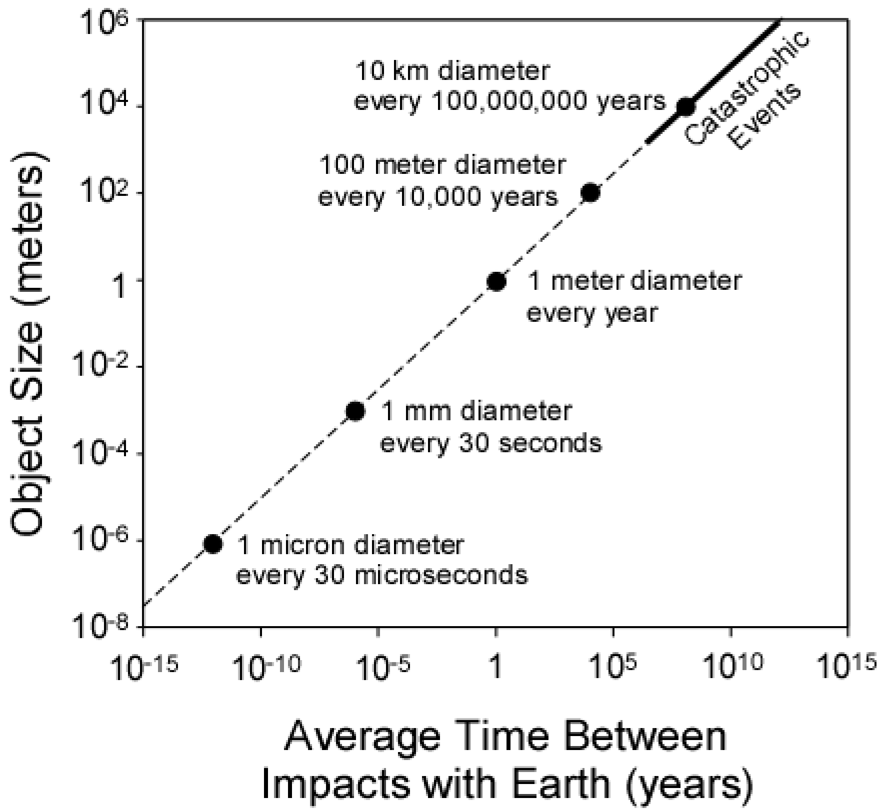
Impact Events

When a large object impacts the surface of the Earth, the rock at the site of the impact is deformed and some of it is ejected into the atmosphere to eventually fall back to the surface. This results in a bowl shaped depression with a raised rim, called an ***Impact Crater***. The size of the impact crater depends on such factors as the size and velocity of the impacting object and the angle at which it strikes the surface of the Earth.

Meteorite Flux and Size

Meteorite flux is the total mass of extraterrestrial objects that strike the Earth. This is currently about 10^7 to 10^9 kg/year. Much of this material is dust-sized objects called ***micrometeorites***. The frequency at which meteorites of different sizes strike the Earth depends on the size of the objects, as shown in the graph below. Note the similarity between this graph and the flood recurrence interval graphs we looked at in our discussion of flooding.

Tons of micrometeorites strike the Earth each day. Because of their small size, they do not usually burn up when entering the Earth's atmosphere, but instead settle slowly to the surface. Meteorites with diameters of about 1 mm strike the Earth about once every 30 seconds. Upon entering the Earth's atmosphere the friction of passage through the atmosphere generates enough heat to melt or vaporize the objects, resulting in so called shooting stars.



Meteorites of larger sizes strike the Earth less frequently. If they have a size greater than about 2 or 3 cm, they only partially melt or vaporize on passage through the atmosphere, and thus strike the surface of the Earth.

Objects with sizes greater than 1 km are considered to produce effects that would be catastrophic, because an impact of such an object would produce global effects. Such meteorites strike the Earth relatively infrequently - a 1 km sized object strikes the Earth about once every million years, and 10 km sized objects about once every 100 million years.

Velocity and Energy Release of Incoming Objects

The velocities at which small meteorites have impacted the Earth range from 4 to 40 km/sec. Larger objects would not be slowed down much by the friction associated with passage through the atmosphere, and thus would impact the Earth with high velocity. Calculations show that a meteorite with a diameter of 30 m, weighing about 300,000 tons, traveling at a velocity of 15 km/sec (33,500 miles/hour) would release energy equivalent to about 20 million tons of TNT.

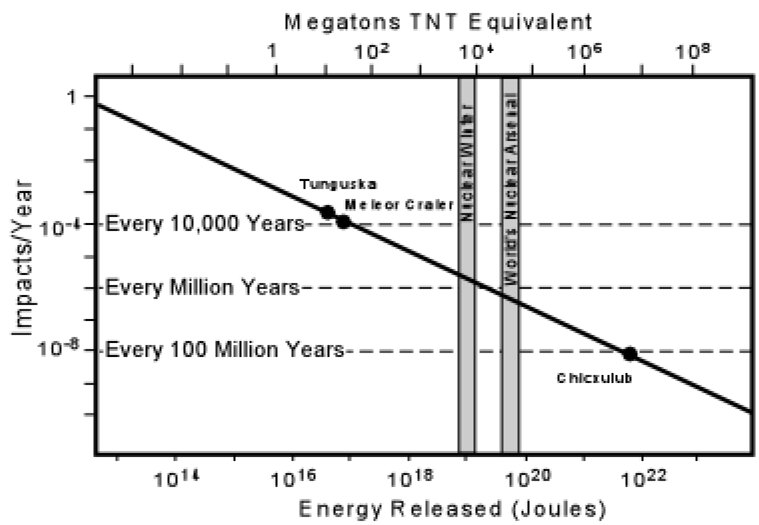
Such a meteorite struck at Meteor Crater, Arizona (the Barringer Crater) about 49,000 years ago leaving a crater 1200 m in diameter and 200 m deep.

The amount of energy released by an impact depends on the size of the impacting body and its velocity.

$$\mathbf{E = ½ MV^2}$$

where E = Energy, M = Mass (depends on size and density of the object), and V = Velocity

An impact like the one that struck the Yucatan Peninsula, in Mexico about 65 million years ago, thought responsible for the extinction of the dinosaurs and numerous other species, created the Chicxulub Crater, 180 km in diameter and released energy equivalent to about 100 million megatons of TNT.



For comparison, the amount of energy needed to create a nuclear winter on the Earth as a result of nuclear war is about 8,000 megatons, and the energy equivalent of the world's nuclear arsenal is about 60,000 megatons.

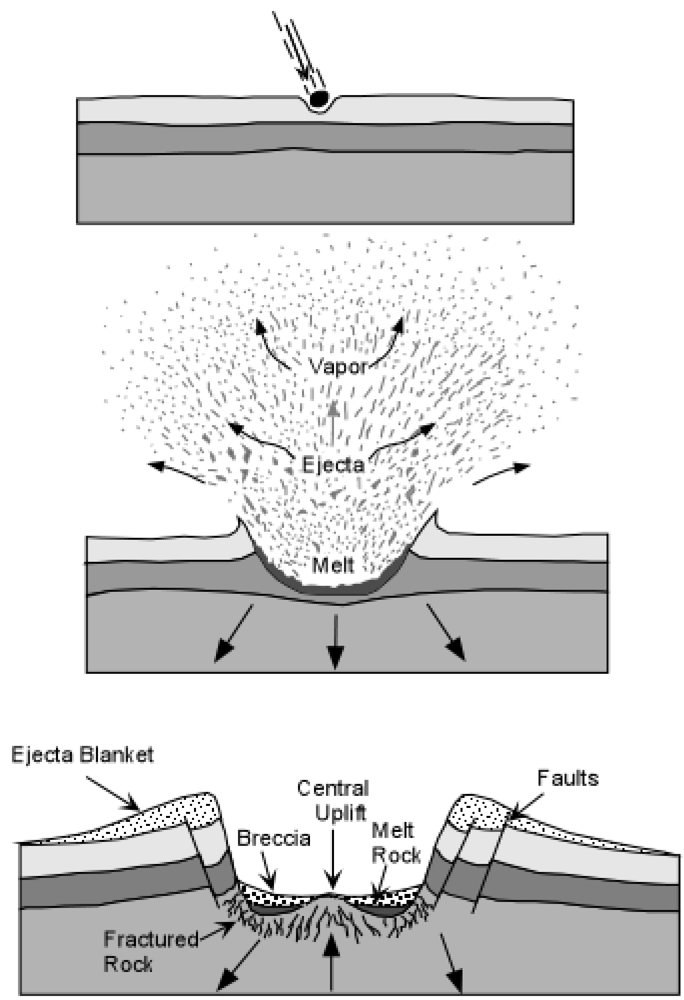
Cratered Surfaces

Looking at the surface of the Moon, one is impressed by the fact that most of the surface features of the moon are shaped by impact craters. The Earth is subject to more than twice the amount of impacting events than the moon because of its larger size and higher gravitational attraction. Yet, the Earth does not show a cratered surface like the moon. The reason for this is that the surface of the Earth is continually changing due to processes like erosion, weathering, tectonism, sedimentation, and volcanism. Thus, the only craters that are evident on the Earth are either very young, very large, or occurred on stable continental areas that have not been subject to intense surface modification processes. Currently, approximately 200 terrestrial impact structures have been identified, with the discovery rate of new structures in the range of 3-5 per year.

The Mechanics of Impact Cratering

When a large extraterrestrial object enters the Earth's atmosphere the initial impact with the atmosphere will compress the atmosphere, sending a shock wave through the air. Frictional heating will cause the object to heat and glow. Melting and even vaporization of the outer parts of the object will begin, but if the object is large enough, solid material will remain when it impacts the surface of the Earth.

Impacts of large meteorites have never been observed by humans. Much of our knowledge about what happens next must come from scaled experiments. As the solid object plows into the Earth, it will compress the rocks to form a depression and cause a jet of fragmented rock and dust to be expelled into the atmosphere. This material is called ***ejecta***. The impact will send a shock wave into the rocks below, and the rocks will be crushed into small fragments to form a breccia. Some of the ejecta will be hot enough to vaporize, and the heat generated by the impact could be high enough to actually melt the rock at the site of the impact. The shock wave entering the Earth will first move in as a compressional wave (P-wave), but after passage of the compressional wave an expansion wave (rarefaction wave) will move back toward the surface. This will cause the floor of the crater to be uplifted and may also cause the rock around the rim of the crater to bent upward. Faulting may also occur in the rocks around the crater, causing the crater to become enlarged, and have a concentric set of rings.



The ejecta will eventually settle back to the Earth's surface forming an ***ejecta blanket*** that is thick near the crater rim and thins outward from the crater. Rocks below the crater that were not melted by the impact will be intensely fractured. All of this would happen in a matter of 1 to 2 minutes.

Meteorite Impacts and Mass Extinctions

The impact of a space object with a size greater than about 1 km would be expected to be felt over the entire surface of the Earth. Smaller objects would certainly destroy the ecosystem in the vicinity of the impact, similar to the effects of a volcanic eruption, but larger impacts could have a worldwide effect on life on the Earth. We will here first consider the possible effects of an impact, and then discuss how impacts may have resulted in mass extinction of species on the Earth in the past.

Regional and Global Effects

Again, we as humans have no firsthand knowledge of what the effects of an impact of a large meteorite (> 1 km in size) or comet would be. Still, calculations can be made and scaled experiments can be conducted to estimate the effects. The general consensus is summarized here.

1. Massive earthquake - up to Richter Magnitude 13, and numerous large magnitude aftershocks would result from the impact of a large object with the Earth.

2. The large quantities of dust put into the atmosphere would block incoming solar radiation. The dust could take months to settle back to the surface. Meanwhile, the Earth would be in a state of continual darkness, and temperatures would drop throughout the world, generating global winter like conditions. A similar effect has been postulated for the aftermath of a nuclear war (termed a nuclear winter). Blockage of solar radiation would also diminish the ability of photosynthetic organisms, like plants, to photosynthesize. Since photosynthetic organisms are the base of the food chain, this would seriously disrupt all ecosystems.

3. Widespread wildfires ignited by radiation from the fireball as the object passed through the atmosphere would be generated. Smoke from these fires would further block solar radiation to enhance the cooling effect and further disrupt photosynthesis.

4. If the impact occurred in the oceans, a large steam cloud would be produced by the sudden evaporation of the seawater. This water vapor and CO_2 would remain in the atmosphere long after the dust settles. Both of these gases are greenhouse gases which scatter solar radiation and create a warming effect. Thus, after the initial global cooling, the atmosphere would undergo global warming for many years after the impact.

5. If the impact occurred in the oceans, giant tsunami would be generated. For a 10 km-diameter object the leading edge would hit the seafloor of the deep ocean basins before the top of the object had reached sea level. The tsunami from such an impact is estimated to produce waves from 1 to 3 km high. These could easily flood the interior of continents.

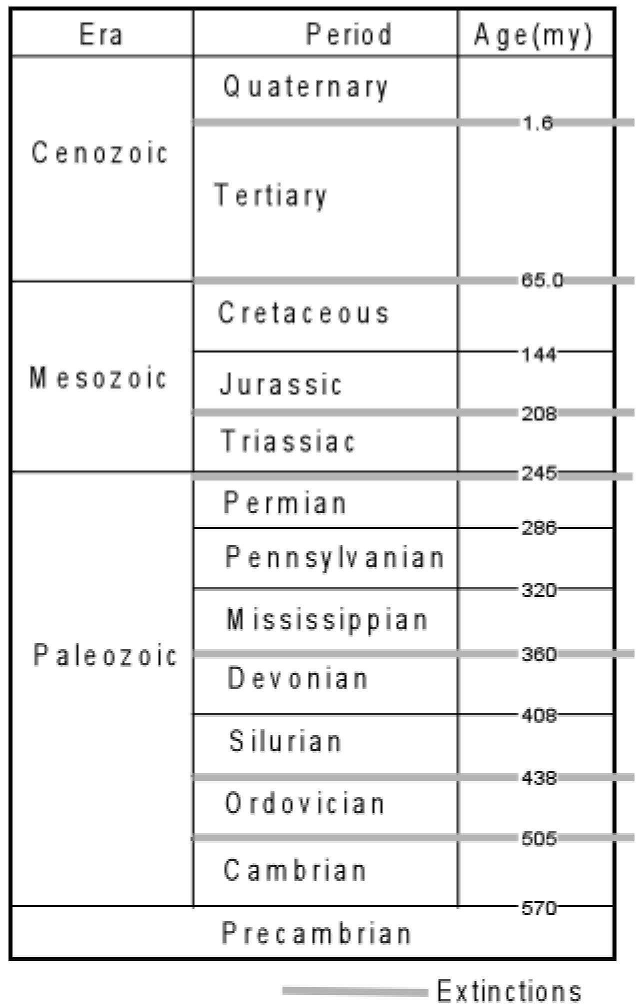
6. Large amounts of nitrogen oxides would result from combining Nitrogen and Oxygen in the atmosphere due to the shock produced by the impact. These nitrogen oxides would combine with water in the atmosphere to produce nitric acid which would fall back to the surface as acid rain, resulting in the acidification of surface waters.

The Geologic Record of Mass Extinction

It has long been known that extinction of large percentages families or species of organisms have occurred at specific times in the history of our planet. Among the mechanisms that have been suggested to have caused these mass extinctions have been large volcanic eruptions, changes in climatic conditions, changes in sea level, and, more recently, meteorite impacts. While the meteorite impact theory of mass extinctions has become accepted by many scientists for particular extinction events, there is still considerable controversy among scientists. In this course we will accept the possibility that an impact with a large object could have caused at least some of the mass extinction events, as it would certainly seem possible given the effects that an impact could have, as discussed above. Still, because of their are many other possibilities for the cause of mass extinctions, please read your book for the arguments against the impact theory.

Major extinction events occurred at

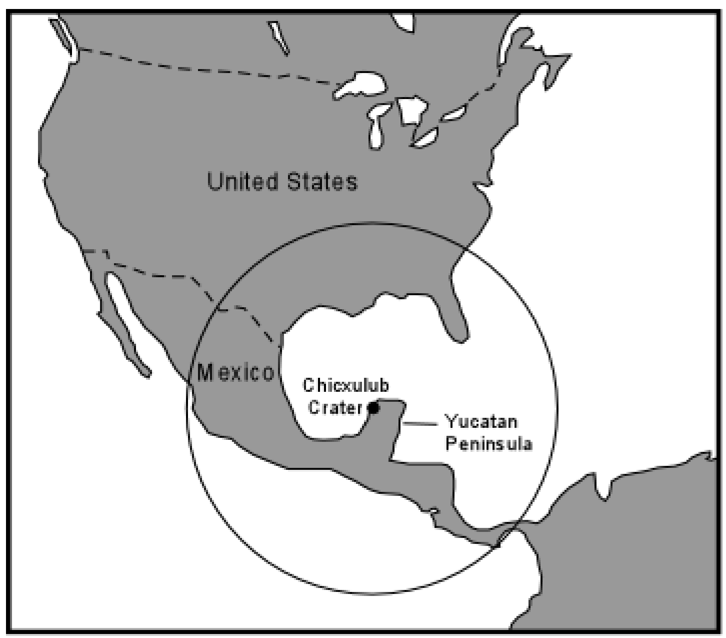
- the end of the Tertiary Period, 1.6 million years (m.y.) ago.
- the end of the Cretaceous Period, marking the boundary between the Cretaceous and Tertiary periods 65 m.y. ago. (Geologists use the letter K to stand for Cretaceous Period and the letter T for the Tertiary Period. Thus this boundary is commonly called the K-T boundary).
- the end of the Triassic, 208 m.y. ago.
- the end of the Permian, 245 m.y. ago (estimated that over 96% of the species alive at the time became extinct).
- the end of the Devonian, 360 m.y. ago
- the end of Ordovician, 438 m.y. ago
- the end of the Cambrian period, 505 m.y. ago



The mass extinction at the end of the Mesozoic Era, that is the Cretaceous - Tertiary boundary (often called the K-T boundary) 65 million years ago, shows much evidence that it was related to an impact with an extraterrestrial object. This event resulted in the extinction of over 50% of the species living at the time, including the dinosaurs. In 1978 a group of scientist led by Walter Alvarez of the University of California, Berkeley, were able to locate the K-T boundary very precisely in layers of limestones near Gubbio, Italy. At the boundary they found a thin clay layer. Chemical analysis of the clay revealed that it contains an anomalously high concentration of the rare element Iridium (Ir). Ir has extremely low concentrations in most crustal rocks, however it reaches very high concentrations in meteorites. The only other possible source of high concentrations of Ir is basaltic magmas. Over the next several years, the K-T boundary was located at several other sites throughout the world, and also found to have a thin clay layer with high concentrations of Ir. Although a large eruption of basaltic magma could not immediately be ruled out as the source of the high concentration of Ir, other evidence began to accumulate that the fallout of impact ejecta had been responsible for both the thin clay layers and the high concentrations of Ir. Among the evidence found at different localities where the K-T boundary is exposed is:

- Clay layers at some localities have a high proportion of black carbon that could have originated as soot produced by wildfires set off by an impact.
- Some of the clay layers contain grains of quartz with a crystal structure that shows evidence that the quartz was severely strained by a large shock.
- In some clay layers tiny grains of the mineral stishovite is found. Stishovite is a high pressure form of SiO_2 that is not found at the Earth's surface except around known meteorite impact sites. The mineral can only be produced as a result of extremely deep burial in the Earth, or by high pressure generated by an impact.
- Other clay layers contain tiny spherical droplets of glass, called spherules. The glass is not basaltic in composition, but could represent droplets of melt formed during an impact event.

At the time of these discoveries, there was no known impact structure on the Earth with an age of 65 million years. This is not unexpected, since 71% of the Earth's surface is covered by water, and is largely unexplored. But, in the late 1980s attention started to be focused on a buried impact site near the tip of the Yucatan Peninsula, in Mexico. Here oil geologists had drilled through layers of brecciated rock and found impact melt rock. Further geophysical studies revealed a circular structure about 180 km in diameter. Radiometric dating reveals that the structure, called the Chicxulub Crater, formed about 65 million years ago.



Although the crater itself is now filled and buried by younger rocks, drilling throughout the Gulf of Mexico has revealed the presence of shocked quartz, glass spherules, and soot in deposits the same age as the crater. In addition, geologists have found deposits from the tsunami that was generated by the impact all along the Gulf of Mexico coast extending considerable distance inland from the current shoreline. (See simulation at http://es.ucsc.edu/%7Eward/chix.mov) The size of the crater suggest that the object that produced it was about 10 km in diameter.

While there is still some debate among geologists and paloebiologists as to whether or not the extinctions that occurred at the K-T boundary were caused by the impact that formed Chicxulub Crater, it is clear that an impact did occur about 65 million years ago, and that it likely had effects that were global in scale. What would happen if another such event occurred while we humans dominate the surface of the Earth, and what could we as humans do, if anything to prevent such a catastrophic disaster?

Human Hazards

It should be clear that even if an impact of a large space object did not cause the extinction of humans, the effects would cause a natural disaster of proportions never witnessed by the human race. Here we first look at the chances that such an impact could occur, then look at how we can predict or provide warning of such an event, and finally discuss ways that we might be able to protect ourselves from such an event.

- **Risk** - It is estimated that in any given year the odds that you will die from an impact of an asteroid or comet are between 1 in 3,000 and 1 in 250,000. The table below shows the odds of dying in the U.S. from various other causes. Although this seems like long odds, you have a about the of dying from other natural disasters likes floods and tornadoes. In fact the odds of dying from an impact event are much better than the odds of winning the Powerball lottery.

Odds of Dying in the U.S. from Selected Causes in a Human Lifetime Data from Abbott (2012)	
Cause	Odds
Motor Vehicle Accident	1 in 90
Murder	1 in 185
Fire	1 in 250
Firearms Accident	1 in 2,500
Drowning	1 in 9,000
Flood	1 in 27,000
Airplane Crash	1 in 30,000
Tornado	1 in 60,000
Asteroid/Comet Impact Global	1 in 75,000
Earthquake	1 in 130,000
Lightning	1 in 135,000
Asteroid/Comet Impact Regional	1 in 1,600,000
Food Poisoning by Botulism	1 in 3,000,000
Shark Attack	1 in 8,000.000
Odds of winning the PowerBall	1 in 195,249,054

In March, 1989 an asteroid named 1989 FC passed within 700,000 km of the Earth, crossing the orbit of the Earth. It was not discovered until after it had passed through the orbit of the Earth. Its size was estimated to be about 0.5 km. Such a body is expected to hit the Earth about once every million years or so, and would release energy equivalent to about 10,000 megatons of TNT, a little greater than the energy released in a nuclear war, and enough to cause nuclear winter event (see graph above). Although 700,000 km seems like a long distance, it translates to a miss of the Earth by only a few hours at orbital velocities.

On March 19, 2004, a 30 m diameter asteroid, named 2004 FH, passed within 26,500 miles (43,000 km) of earth, just beyond the orbit of weather satellites. The object was small , and likely would have only caused a local effect if it had hit the earth's atmosphere, but it was discovered only 4 days before it passed.

On November 8, 2011, Asteroid 2005 YU55, 400 m in diameter passed within the moon's orbit. It was the first time such an object was known and photographed before it reached its nearest point to the earth - http://www.nasa.gov/multimedia/videogallery/index.html?media_id=120141271

In June of 2012, Asteroid 2012 LZ1 passed within about 3 million miles of Earth. Although it was never a threat, the fact that it was discovered only a few days before was alarming. Furthermore, its size was originally estimated to be only 500 m in diameter, as it passed, scientists realized that this was an underestimate. Its size turned out to be about 1 km.

- **The Torino Scale -** In order to develop a better means of communicating the potential hazards of a possible impact with a space object, scientists have developed a scale that describes the potential (see - http://neo.jpl.nasa.gov/torino_scale.html). The scale is called the ***Torino Scale,*** and is shown below.

Events Having No Likely Consequences (White Zone)	**0**	The likelihood of a collision is zero, or well below the chance that a random object of the same size will strike the Earth within the next few decades. This designation also applies to any small object that, in the event of a collision, is unlikely to reach the Earth's surface intact.
Events Meriting Careful Monitoring (Green Zone)	**1**	The chance of collision is extremely unlikely, about the same as a random object of the same size striking the Earth within the next few decades.
Events Meriting Concern (Yellow Zone)	**2**	A somewhat close, but not unusual encounter. Collision is very unlikely.
	3	A close encounter, with 1% or greater chance of a collision capable of causing localized destruction.
	4	A close encounter, with 1% or greater chance of a collision capable of causing regional devastation.
	5	A close encounter, with a significant threat of a collision capable of causing regional devastation.

Threatening Events (Orange Zone)	**6**	A close encounter, with a significant threat of a collision capable of causing a global catastrophe.
	7	A close encounter, with an extremely significant threat of a collision capable of causing a global catastrophe.
Certain Collisions (Red Zone)	**8**	A collision capable of causing localized destruction. Such events occur somewhere on Earth between once per 50 years and once per 1000 years.
	9	A collision capable of causing regional devastation. Such events occur between once per 1000 years and once per 100,000 years.
	10	A collision capable of causing a global climatic catastrophe. Such events occur once per 100,000 years, or less often.

- **Prediction and Warning** - In 1998 scientists and Congress approved the Spaceguard Survey which had a goal of identifying 90% of all NEOs with a size greater than 1 km. In September, 2011, NASA announced that they had identified 93% of all NEOs of this size and that of the total number estimated to exist (989) they had identified 911. For mid-sized NEOs, with sizes between 100 m and 1 km, 5,200 have been found and are being tracked, but it is estimated that there are still over 15,000 of such bodies that have not yet been discovered.

- **Mitigation** - Impacts are the only natural hazard that we can prevent from happening by either deflecting the incoming object or destroying it. Of course, we must first know about such objects and their paths in order to give us sufficient warning to prepare a defense. Sufficient time is usually thought to be about 10 years. This would likely give us enough time to prepare a space mission to intercept the object and deflect its path by setting off a nuclear explosion. Currently, however, there are no detailed plans. But, even if we did not have the ability to destroy or deflect such an object, 10 years warning would provide sufficient time to store food and supplies, and maybe even evacuate the area immediately surrounding the expected impact site.

Examples of questions on this material that could be asked on an exam

1. Define the following: (a) meteorite, (b) meteoroid, (c) shooting star, (d) meteor, (e) comet, (f) Apollo object, (g) asteroid belt, (h) Torino Scale.

2. What would be the global effects if an object greater than 1 km in size collided with Earth?

3. What is the evidence that large objects have collided with Earth in the past?

4. Is there any evidence that large objects have collided with Earth and had an effect on life? If so, what is the evidence and what were the effects?
5. What is the best possible mitigation for an impact disaster? How much time would we need to prepare such mitigation?

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EISPC
EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

The Economic Ramifications of Resource Adequacy White Paper

January 2013

Astrape Consulting
For EISPC and NARUC
Funded by the U.S. Department of Energy

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Disclaimers:

EXECUTIVE SUMMARY

Resource adequacy is of critical importance to utilities, consumers, and regulators. The financial impact of shedding firm load or having scarcity events in the electric energy market can be measured in billions of dollars as evidenced by the California Energy Crisis in the early 2000's and more recently during the extreme weather in Texas in the summer of 2011. These events illustrate that the value provided by electric service far exceeds the physical costs of producing the electricity. Surveys of electric service outage costs indicate that the Value of Lost Load (VOLL) can be $15,000/MWh[1] or greater while the production cost of a marginal unit can be only $50/MWh – a factor of 300x. This comparison, however, ignores a critical component of the economics of resource adequacy – the carrying costs of having excess capacity available during those peak hours. Assuming the carrying cost of new capacity is $100,000/MW-yr and VOLL is $15,000/MWh, the capacity must be used to prevent firm load shed more than 6 hours per year to be economically justified. However, in most regions, marginal capacity is needed to prevent firm load shed much less frequently. The resource adequacy standard many regions plan to is a Loss of Load Expectation (LOLE) of one firm load shed event in 10 years (herein referred to as 1-in-10 LOLE), suggesting the last resource added to the system is only needed approximately 0.3 hours per year[2]. At this frequency of utilization, VOLL would have to be an unrealistic $300,000/MWh to justify the last resource addition. For a point of reference, $300,000/MWh VOLL is comparable to $900 for keeping the power on in a normal sized house for one hour[3]. This review suggests that if marginal capacity's only benefit was avoiding firm load shed events, it is unlikely economics would justify maintaining a system as reliable as we have today. The example above illustrated the economics for only shedding firm load due to generation deficiency once every 10 years. However, actual resource adequacy is typically even higher than that. While distribution related outages occur several hours per year for most customers[4], most regions in the Eastern Interconnection have not experienced generation deficiency caused firm load shed events in decades.

But is resource adequacy solely about having enough capacity to meet firm load obligations? Or are there other benefits of reserves that should be considered when setting target Reserve Margins[5]? When load is high and supplies are scarce, market prices can far exceed the production cost of an efficient Combustion Turbine (CT). How much of these costs should be avoided by building additional capacity? There are also other substantive benefits of having robust levels of reserves such as avoiding the dispatch of high cost units or energy limited resources. Economic resource adequacy assessments should take a

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[1] Estimates of VOLL vary widely. The range of estimates and their impact on resource adequacy planning are discussed in Section IV.

[2] A typical firm load shed event has a 3 hour duration. One event in 10 years equals 3 hours in 10 years or 0.3 hours per year.

[3] An average house uses 3kW on peak. Three kWh divided by 1000 kW/MW times $300,000/MWh = $900.

[4] Newell, Sam, ―ERCOT Investment Incentives and Resource Adequacy", Retrieved August 25, 2012 from http://www.ercot.com/content/news/presentations/2012/The%20Brattle%20Group%20Presentation%20for%20PUCT%20July%2027%202012%20Work.pdf

[5] In this paper, Reserve Margin is calculated by: (Total Capacity Resources – Expected Annual Peak Load) / Expected Annual Peak Load. Conventional resources and demand side programs are counted at full nameplate or designated capacity. Demand side resources are accounted for in projecting the Expected Annual Peak Load. Only a portion of intermittent resource nameplate capacity is counted as a capacity resource.

comprehensive approach to calculating the trade-off between the cost of additional capacity and the economic benefit provided by those resources. This white paper attempts to quantify this trade-off for a defined base case and a number of sensitivities. The point at which the cost of further resource additions is equal to the economic benefit provided by such additions is herein referred to as the economic reserve margin or economically optimal reserve margin or risk neutral economic reserve margin.

For the case study included in this paper, the economic optimal reserve margin is based on minimizing total systems costs from the perspective of the customers of a vertically integrated utility. These costs include all production costs of the utility plus net imports from outside regions plus the societal costs of firm load shed events. In this setup, during reliability events, only incremental purchases are assigned high costs since all load served by the utility's resources is priced at its respective production cost. In these hours, customers continue to receive the benefit of low cost, base load units such as coal and nuclear. The total customer costs then are a combination of low cost energy from existing resources plus incremental energy purchases from the market at higher costs during capacity shortfalls. Also, in this type of environment, a utility pays for incremental capacity costs which are included as part of total system costs. However, in structured markets, the cost of energy is the same for all load since energy is priced based on the marginal resource. If the market price of energy is $800/MWh, then all load must pay this price. However, the mechanism under which energy costs are ultimately passed on to customers can be quite different from region to region depending on market structure and whether or not a load serving entity self supplies a large portion of its load. Also, capacity costs are frequently handled differently. The question of economic reliability is fundamentally different in these markets and is addressed separately in this paper.

The following key conclusions were made based on the resource adequacy assessment research and simulated case study:

- Reviews of various resource adequacy assessments in the Eastern Interconnection indicate wide variations in the way capacity is counted, what level of benefit will be received from emergency operating procedures, and what assumptions and tools are used. Even though many regions use 1-in-10 LOLE or a similar metric, these variations make the comparison of reliability difficult.
- Most prior studies that evaluated the economics of resource adequacy indicated low optimal economic reserve margins. The authors believe this is primarily because only a subset of all customer benefits of the marginal capacity was captured.
- When considering all benefits (production cost savings, import cost savings during shortages, and the societal cost of Expected Unserved Energy (EUE)) of marginal capacity from the perspective of a customer of a single vertically integrated utility, the economic reserve margin is greater than that indicated by 1-in-10 LOLE for many regions. However, system size, resource mix, load shape, market availability and other factors can affect the optimum economic reserve margin and make it either higher or lower than the 1-in-10 LOLE based reserve margin.
- If economic targets were based solely on societal costs (production costs plus the cost of EUE) and ignored scarcity pricing that result in transfers of wealth to outside regions or generators, the economic target would decrease by several percentage points. However, the authors do not believe this setup is realistic or desirable.
- Risk analysis shows that a range of reserve margins slightly above the economic optimal reserve margin can avoid a number of potentially high cost scenarios for little additional cost.

- Modeling assumptions for neighboring regions such as weather diversity and import capability have a significant impact on both the 1-in-10 LOLE and economic optimal reserve margin
- Because unserved energy is de minimus at a 1-in-10 LOLE based reserve margin, the Value of Lost Load has little impact on the economic analysis. Instead it is driven by the dispatch of high cost resources and scarcity pricing events which occur much more frequently than loss of load events.
- Not all capacity resources provide the same value. Most resource planners recognize that wind and solar may provide little load carrying capability relative to their nameplate capacity. However, in addition to those resources, demand response, energy storage, and hydro also have very different load carrying capability as well as economic capacity value, and their respective value should be taken into account.
- Resource adequacy targets should evolve to properly balance the costs and benefits of reliability if the 1-in-10 LOLE based reserve margin level is not justified.
- Merchant generators in energy only markets will likely not recover their fixed costs at a 1-in-10 LOLE based reserve margin or an economic optimal reserve margin based on the perspective of customers in a regulated utility environment.
- Because all generators are paid the same price under current forward capacity market constructs, the total costs to consumers to maintain a 1-in-10 based reserve margin that is above the energy only market economic target will always be higher, however, there is some risk benefit seen by customers due to the reduction of high cost outcomes.

Future Analysis

While this white paper provides a number of informative conclusions to assist regulators in reviewing the reasonableness of resource adequacy plans, many questions remain outstanding that were beyond the scope of the original effort. This paper was not designed to identify the most appropriate economic reserve margins for particular regions, utilities, ISOs and RTOs, but the case studies indicate they could be different from current targets by 5% or more. If current reserve margin targets are 5% too high or 5% too low, the economic inefficiency for individual regions could be in the hundreds of millions of dollars per year. Further, case studies indicated that changing penetrations of demand response and intermittent resources can affect resource adequacy planning, but the way that the impact of these resources should be addressed is highly specific to individual markets. Also, how should economic resource adequacy be addressed by states in structured markets?

The results of this white paper should not be construed to suggest that resource adequacy planning is already approximately optimal in the Eastern Interconnection. There are significant opportunities for resource adequacy planning to produce substantial economic benefits for consumers. Additional analysis could provide key insights into how this could be accomplished.

- Potential Tasks:
  - Assess the economic efficiency of the reliability standards of particular regions, utilities, ISOs and RTOs in the Eastern Interconnect. To perform this assessment, the following steps would need to be performed:
    - Build load, resource, and transmission data for the remainder of the regions in the Eastern Interconnection
    - Refine unit availability data and transmission availability data for the regions already modeled.

    - Perform simulations for the entire Eastern Interconnection and determine one economic optimal reserve margin assuming coordinated planning across the entire Interconnect.
    - Provide comparisons of economically derived reserve margins to current resource adequacy plans.
    - Provide additional sensitivities around key assumptions such as scarcity pricing, economic load forecast uncertainty, and demand response constraints.
    - Analyze different market structures and rules to understand the impact. Use economic reliability simulations to estimate demand curves for capacity markets.
- Demand response programs play a significant and expanding role in addressing resource adequacy. As the penetration of demand response increases, the flexibility and availability required of these resources will also rise. The treatment of these programs in various market structures must also be considered as their value profile can be very different from traditional resources and can change vastly from program to program. Several sensitivities were performed to quantify some of these considerations, but additional work is warranted. The additional work would primarily examine different types of demand response programs with different characteristics. These include reliability only, economic, and real time pricing programs. Optimal demand response portfolios could also be developed.
- Resource adequacy is not just a concern during the peak hours of the year. Changing resource mixes will require different types of assessments to address flexibility requirements for many hours of the year due to wind and other intermittent resources. While the cost of intermittent resource integration has been addressed in a number of studies, the impact of intermittent resources on operational resource adequacy has not received as much focus. An additional assessment that captures the flexibility of existing resources, the variability of loads, and the variability of intermittent resources on time intervals from minutes to days could be performed with the Strategic Energy and Risk Valuation Model (SERVM) used for this white paper. In addition to providing an assessment of potential challenges including the frequency, magnitude, and financial impact of reliability problems due to intermittency, several alternative solutions could be modeled to identify the most reliable and cost effective approaches to mitigating these events.
- The work performed in this study could be leveraged to assess the reliability impact of certain transmission components probabilistically. Pairing SERVM with a transmission model such as EPRI's TransCARE would allow for the assessment of combined generation and transmission reliability. SERVM would be used to develop scenarios of load, weather, and unit commitment and feed subsets of those scenarios to the transmission module to understand the impact of probabilistic operation and failure of specific transmission components.

I. HISTORY OF RESOURCE ADEQUACY AND HOW TARGETS SHOULD EVOLVE

Resource Adequacy is a measure of an electric system‘s ability to provide adequate generation to meet all firm load obligations. If firm load obligations exceed the instantaneous generating capacity of a system, some firm load customers will have their access to electricity cut. This is a firm load shed event. Outages of firm load due to non-generation equipment failures and storms are not considered resource adequacy issues. Typical metrics of resource adequacy include Loss of Load Hours (LOLH), Loss of Load Probability (LOLP), Loss of Load Events (LOLE), and Expected Unserved Energy (EUE). LOLH is a count of the number of hours in a year expected to have firm load shed. LOLP is the ratio of hours or days expected to have any firm load shed to the total hours or days in a year and is expressed as a percentage. LOLE is typically measured as a count of the expected number of days with at least one hour of lost load. EUE is the sum of all the expected firm load energy shed measured in MWh. It is the only one of these metrics that considers the magnitude of the outage. (Section II expands on these definitions, interpretations, and implementations of traditional reliability metrics)

Most electrical systems in North America have a resource adequacy target based on a defined physical reliability metric. While informal reliability targets have likely been utilized since electricity was first commercialized, the first mention of probabilistic resource adequacy assessments using specific physical reliability metrics identified in our research was in technical papers from the 30's and 40's. Giuseppe Calabrese‘ 1947 paper ‗Generating Reserve Capacity Determined by the Probability Method‘ references setting reliability targets based on an expected number of days of loss of load over a given number of years[6]. C.W. Watchorn wrote several papers which discuss the development of appropriate system capacity reserves. In one such paper, Watchorn states "It is believed that a reasonable level of service reliability...is a probability of failure to carry the load of in the order of an average rate of one day in from eight to ten years".[7] However, the basis for that belief was not provided. Similar references to service reliability levels of 1 outage in every 10 years are made in dozens of technical papers from the 50's onward, although it is not clear from our review whether utilities or regions formalized resource adequacy targets around specific reliability metrics until several decades later. (See R. Billinton's bibliography of the history of resource adequacy assessments[8] for further references)

On November 9, 1965, a major electric power disruption in the Northeast US and Eastern Canada left 30 million people without power for over 12 hours. Although the cause of this event was primarily due to operator error, the event did occur during high load conditions.[9] In an effort to prevent the occurrence of similar events, electric utilities formed the North American Electric Reliability Council (NERC) in 1968. NERC reliability standards are focused on operating practices to ensure security (―the ability of the electric system to

[6] Calabrese, Giuseppe, "Generating Reserve Capacity Determined by the Probability Method," American Institute of Electrical Engineers, Transactions of the IEEE, vol.66, no.1, pp.1439-1450, Jan. 1947

[7] Watchorn, C. W., "The Determination and Allocation of the Capacity Benefits Resulting from Interconnecting Two or More Generating Systems," American Institute of Electrical Engineers, Transactions of the IEEE , vol.69, no.2, pp.1180-1186, Jan. 1950

[8] Billinton, Roy, "Bibliography on the Application of Probability Methods in Power System Reliability Evaluation" IEEE Transmission Power Apparatus System, vol.91, no.2, pp.649-660, Mar/Apr 1972

[9] *Northeast Blackout of 1965.* Retrieved August 25, 2012, from http://en.wikipedia.org/wiki/Northeast_blackout_of_1965

withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements."[10]). However, the renewed focus on overall reliability also led to the development of specific resource adequacy targets. Mid Atlantic Area Council (MAAC) Reliability Principles and Standards set in place in 1968 state: ―Sufficient megawatt generating capacity shall be installed to ensure that in each year for the MAAC system the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years."[11] Many other utilities and regions adopted similar standards.

How Should Resource Adequacy Targets Evolve?

One of the interesting aspects of reliability planning is that Resource Adequacy related outages represent a very small percentage of overall outages. As an example, the Brattle Group estimated that customers in Texas would average less than 1 minute per year of outages due to insufficient generation if the system was planned to maintain a 15% reserve margin.[12] This compares to an actual average of 100 - 300 minutes of outages per customer when all types of outages, including transmission and distribution outages, are considered.[13] Statistics are similar nationwide. A survey of utilities shows 107 minutes of outages per customer when all types of outages are considered.[14] Since resource adequacy events comprise only 1% or less of overall outages, why do they receive a high level of focus? Would a 1 in 5 or 1 in 2 LOLE be a reasonable level of physical reliability?

While 1-in-10 LOLE appears to be difficult to support from solely a physical reliability standpoint, several regions note other benefits of high levels of reliability. PJM states that "a well planned and adequate power system will lead to a secure system in day to day operations."[15] The California ISO suggests that high physical reliability supports the proper functioning of markets and that "market economics and reliability are inextricably intertwined." [16] There is little doubt that increased resource adequacy also plays a role in reducing high hourly market price scenarios. Many utilities mention additional unknowns beyond the factors considered in developing the 1-in-10 LOLE target such as fuel availability risk and environmental legislative risk that could force retirements of existing units. These points suggest there may be some margin of error embedded in the 1-in-10 LOLE target for some regions or utilities. In other words, unknown risks may push a system that is planned to

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[10] Glossary of Terms, prepared by the Glossary of terms Task force(GOTTF) North American Electric Reliability Council, GOTTF formed jointly by the NERC Engineering Committee(EC) and Operating Committee(OC), August 1996, www.nerc.com/glossary/glossary-body.html

[11] MAAC Reliability Principles and Standards, As adopted on July 18, 1968 by the Executive Board constituted under the MAAC Agreement, dated December 26, 1967 and revised March 30, 1990, Document A-1.

[12] Newell, Sam, ―ERCOT Investment Incentives and Resource Adequacy", Retrieved August 25, 2012 from http://www.ercot.com/content/news/presentations/2012/The%20Brattle%20Group%20Presentation%20for%20PUCT%20July%2027%202012%20Work.pdf

[13] Ibid.

[14] LaCommare, Kristina, ―Understanding the Cost of Power Interruptions to U.S. Electricity Consumers", September 2004, Ernest Orlando Lawrence Berkeley National Laboratory, Retrieved August 25, 2012 from http://certs.lbl.gov/pdf/55718.pdf

[15] PJM Generation Adequacy Analysis, October 2003, PJM Interconnection L.L.C., Retrieved August 25, 2012 from http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/20040621-white-paper-sections12.ashx

[16] Business Practice Manual for Reliability Requirements, August 9, 2012, California ISO, Retrieved August 25, 2012 from https://bpm.caiso.com/bpm/bpm/doc/000000000001253

a 1-in-10 LOLE target to have reliability that is somewhat lower in actual practice. Beyond the benefits of high levels of reliability afforded by the 1 in 10 standard, resource planners may also have additional motivations for continuing to use the standard. The 1-in-10 LOLE target is simple to calculate and explain and it has substantial precedent.

However, in relation to other cost/benefit analysis performed in the electric power industry, resource adequacy based on the 1-in-10 LOLE standard appears disproportionate. For example, in ERCOT, avoiding a hypothetical addition of 3,250 MW of new combustion turbines (a capital cost savings of more than $1.5B) would only increase customer's average resource adequacy outages from 0.1 minutes per year to 2.8 minutes per year.[17] When compared with 100 - 300 minutes of distribution related outages per customer, the hypothetical combustion turbines do not appear to provide an economically justifiable reliability benefit. Later sections of this white paper quantify some of these other benefits of high reliability mentioned as qualitative motivations supporting the 1-in-10 LOLE standard. Further, with the changing generation resource mixes that include intermittent generation such as wind and solar and a greater penetration of demand response resources, economically optimal reserve margins may vary further from a 1-in-10 LOLE standard than seen in prior studies. Our conclusions in this paper suggest that resource adequacy targets should evolve to properly balance the costs and benefits of reliability if the 1-in-10 LOLE level is not justified.

[17]Newell, Sam, ―ERCOT Investment Incentives and Resource Adequacy”, July 2012, The Brattle Group, Retrieved August 25, 2012 from http://www.ercot.com/content/news/presentations/2012/The%20Brattle%20Group%20Presentation%20for%20PUCT%20July%2027%202012%20Work.pdf

II. 1 DAY IN 10 YEAR STANDARD

A. TERMINOLOGY

- Loss of Load Expectation (LOLE): Expected number of firm load shed events an electric system expects in a given year
- Loss of Load Probability (LOLP): probability of firm load shed events typically expressed as a % of total hours in a year
- Loss of Load hours (LOLH): Expected number of hours of firm load shed events an system expects in a given year
- 1-in-10 LOLE Standard: Most commonly calculated as 1 event in 10 years and equals 0.1 LOLE per year
- Reserve Margin: (Resources – Peak Firm Demand) / Peak Firm Demand
- Capacity Margin: (Resources – Peak Firm Demand) / Resources

Not all regions and planners use the same definitions for all of these terms. Some refer to LOLP as the probability of having one or more hours of loss of load in any year. Others refer to LOLE as an hourly metric.

B. SURVEY SUMMARY

The results of our survey show that most regions use a similar standard for setting or measuring generation adequacy. Under this standard, adequate reliability is defined as the level of reserves that provide an expectation of less than one event in 10 years due to generation deficiency. While there are a few regions or utilities that use different standards, this standard has been in place for several decades for many of the members of the Eastern Interconnection. Details around the approach used in each area including references are provided in the following sections.

Table 1. Survey Summary

NERC Assessment Area	Reliability Criterion
FRCC	Reserve Margin criteria of 15% as a Regional Reserve Margin (20% for Investor Owned Utilities (IOU) and 15% - 18% for other utilities); Loss of Load Probability (LOLP) criteria of 1 day in 10 years or 0.1 LOLP[18])
SERC	SERC does not have a mandatory reserve margin or resource adequacy requirement for its members; Example Approaches: SOCO/TVA: base target reserve margins on minimizing total customer costs including societal

[18] Based on Astrape's understanding of the FRCC documentation, LOLP of 0.1 is consistent with the traditional 1 event in 10 years since LOLP is being calculated in days per year. FRCC has substituted the term LOLP for LOLE.

	costs of unserved energy; Progress Energy Carolinas: base target on 1-in-10 LOLE and minimizing total customer costs similar to SOCO/TVA.
SPP	Capacity Margin Criterion of 12% for RTO members that are steam based and 9% for hydro based; Capacity margins must meet 1 day in 10 years defined as an LOLE of 2.4 hours per year.[19]
PJM	1-in-10 LOLE (0.1 LOLE)
MISO	1-in-10 LOLE (0.1 LOLE)
NPCC - NY-ISO	1-in-10 LOLE (0.1 LOLE)
NPCC - ISO-NE	1-in-10 LOLE (0.1 LOLE)
NPCC - Maritimes	Reserve Margin criterion of 20% and an 1-in-10 LOLE (0.1 LOLE)
NPCC - Quebec	1-in-10 LOLE (0.1 LOLE)
NPCC - IESO	1-in-10 LOLE (0.1 LOLE)
Saskatchewan	Standard is based on an undisclosed level of Expected Unserved Energy (MWh)
Manitoba	Both an energy criterion and a reserve margin criterion due to the fact that the region is predominantly hydro. The energy criterion requires adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. The reserve margin is at least 12%.
MAPP	1-in-10 LOLE (0.1 LOLE); Some of MAPP's members self impose a planning reserve margin of 15% based on the LOLE study performed in 2009.

[19] SPP uses the term LOLE of 2.4 hours which is more traditionally defined as an LOLH of 2.4 hours.

ERCOT	Although ERCOT performs a resource adequacy assessment to determine a target reserve margin necessary to meet 1-in-10 LOLE, there is not a mandatory requirement for the region. ERCOT operates as an energy only market and therefore does not have mandatory capacity requirements.
WECC	In general, each balancing area has responsibility for meeting resource adequacy standards established by respective states in which they operate.

Making the determination of what level of reserves yields 1-in-10 LOLE is a complex task and requires the development of a number of assumptions. There is little consistency in this process from region to region. Recent changes to resource mixes including higher penetrations of wind, solar, and demand response (DR) resources have contributed to even greater disparity between regions. A recent initiative by NERC resulted in a recommended list of modeling assumptions which will help to reconcile some of the disparity[20].

In addition to the disparity of assumptions used in assessing 1-in-10 LOLE, the reporting of the reserve margin that meets 1-in-10 LOLE is not standardized. The primary differences in reserve margin reporting include:

1. The method of capacity accounting. Some regions count all nameplate capacity for all resources. Other regions only count dependable capacity, frequently described as economic load carrying capability (ELCC) of a resource. This is a particular concern for wind, solar, hydro, energy storage, and any other constrained resource. In addition, some regions count expected imports as a capacity resource where others recognize the imports in modeling but do not count those imports as resources in the reserve margin calculation.
2. Emergency operating procedure accounting. Some regions include emergency operating procedures such as voltage control as capacity resources.

The following table attempts to demonstrate the impact of both modeling assumption differences and reserve margin reporting differences for a subset of the regions reviewed in this report to give the reader an appreciation for the different assumptions across regions. Note that some differences are appropriate due to physical differences in either resources or load profiles. The following table does not attempt to differentiate between legitimate and illegitimate assumption differences.

[20] *GTRPMTF Final Report,* Retrieved August 25, 2012, from http://www.nerc.com/docs/pc/gtrpmtf/GTRPMTF_Meth_&_Metrics_Report_final_w._PC_approvals,_revisions_12.08.10.pdf

Table 2: Reserve Margins and Impact on Reserve Margin of Various Assumptions

	PJM	NYISO	NE-ISO	Southern Company	SPP
Reliability Criteria	0.1 LOLE	0.1 LOLE	0.1 LOLE	Economics	2.4 LOLH
Reserve Margin at Reliability Standard	15.30%	16.10%	11.7%	15.00%	10.20%
Study Input Assumptions (Note: these components are not additive.)					
Treatment of Non-Firm Imports (What percentage of capacity resources are from non-contracted external generation)	0.00%	0.00%	2.10%	0.00%	0.00%
Weather Uncertainty (How much higher than normal can load be in extreme cases?)	8.00%	7.30%	10.10%	7.00%	5.30%
Equivalent Forced Outage Rate (Expected percentage of capacity offline during peak conditions)	7.30%	6.80%	4.90%	1.80%	5.90%
Economic Load Growth Uncertainty (How much faster than expected can load grow due to economic conditions?)	1.00%	1.00%	0.00%	2.20%	0.00%
External Assistance Benefit (What percentage of load can be reliably served by external regions)	1.90%	8.60%	5.50%	3.00%	0.00%

ELCC Impact of Wind (Some regions derate their reserve margin to account for variability of wind. For regions that do not, how much would their reported reserve margin drop if they only counted the effective load carrying capability of wind in their reserve margin?)	0.00%	4.70%	0.00%	0.00%	0.00%
ELCC Impact of Demand Response (For regions that discount Demand Response capacity to reflect contract limitations, how much higher would reserve margins be if they counted the full contract capacity?)	0.00%	0.20%	0.00%	1.10%	0.00%
ELCC Impact of Hydro (How much higher would reserve margins be if a region counted full nameplate for all hydro resources?)	0.00%	1.30%	0.00%	0.00%	0.00%
Operating Reserve Procedure Impact (Some regions assume operating reserves would be eliminated before firm load would be shed. Compared to a conservative approach of always maintaining full operating reserves, how much additional capacity do these regions assume?)	1.20%	5.50%	2.10%	0.00%	0.00%
Voltage Reduction Counting (Some regions count voltage reduction as a resource when calculating reserve margin. Other regions do not count voltage reduction as a resource even though they have voltage reduction programs. Compared to the approach of counting voltage reduction as a resource, how does a region's assumption affect their reserve margin?)	2.00%	1.50%	1.50%	0.00%	0.00%

Voltage Reduction Modeling (Some regions do not assume in their modeling that voltage reduction will be used to avoid firm load shed even if it would be called in actual practice. Compared to the standard approach of modeling the expected voltage reduction, how does a region's assumption affect their reserve margin?)	2.00%	0.00%	0.00%	0.00%	0.00%

Table 2 illustrates that a number of reporting and modeling assumptions can have a substantial impact on the reported reserve margin. For instance, in New York, the nameplate capacity of wind is counted in the reserve margin calculation. However, in PJM, the reserve margin calculation only includes the effective capacity of wind. Both regions' studies recognize that wind does not contribute much to reliability, but the accounting difference makes for an unwieldy comparison. If the NYISO accounting treatment was similar to PJM, NYISO's reserve margin would be 11.4% instead of 16.1%. The other items listed in Table 2 further illustrate how difficult it is to compare reserve margins across regions.

Aspects of some regions' modeling approaches seem conservative in some areas or aggressive in other areas. After attempting to normalize for most significant variables, regions may have 1-in-10 LOLE based reserve margins that vary by nearly 10%. Much of this difference is likely due to actual differences in resource mixes, transmission interconnections, and load profiles. However, these factors contribute to making it difficult for Commissioners and other regulators to assess the reasonableness of current resource adequacy planning. Our conclusion is that because of these issues, resource adequacy plans cannot be taken at face value even if all regions plan to a consistent 1-in-10 LOLE standard. If one is interested in comparing resource adequacy from region to region, then it is vital to understand the details surrounding the input assumptions to be able to identify whether a study's results are realistic and can be compared appropriately to studies performed by other entities. The comparisons performed here do not result in an assessment of the reasonableness of any entity's resource adequacy assessment, but rather simply point out the significant differences between studies. As discussed in the future analysis section of this paper, additional work could be performed to assess the reasonableness of each entity's resource adequacy plan.

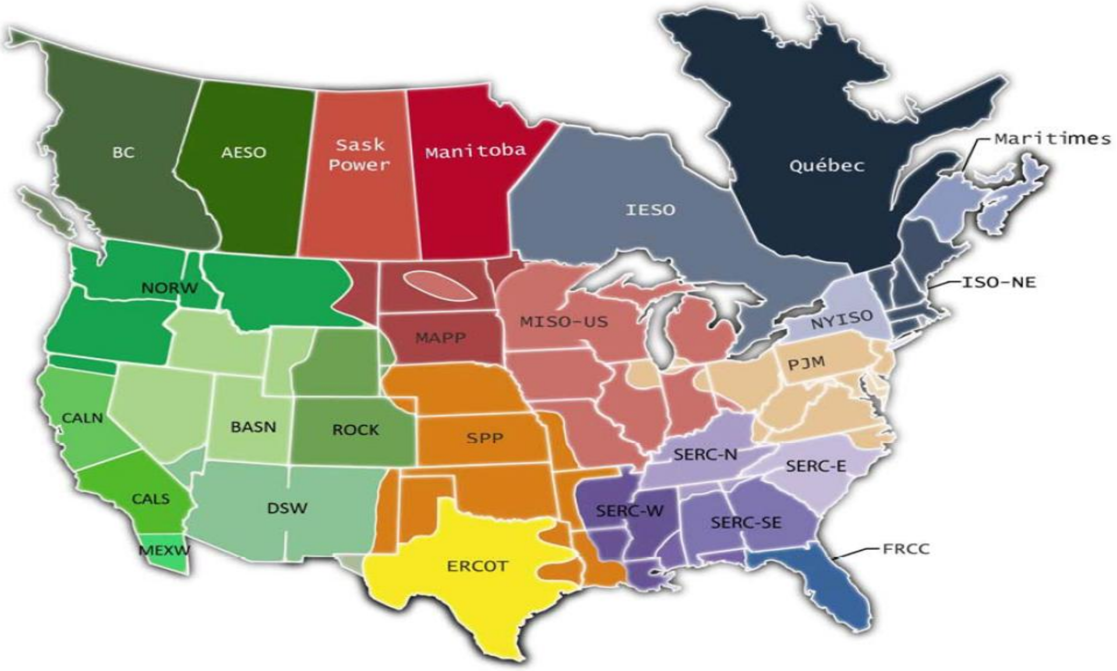
C. Detailed Regional Review

The following sections outline the resource adequacy metric that is used for each NERC Long Term Assessment Area and how it is defined. The sections also contain useful information on how the metric is applied and other key factors impacting resource adequacy decisions.

1. Region Definitions

For this analysis, we will use the NERC Long Term Assessment Areas because resource adequacy criteria and decisions are more often made at this level rather than the other groupings.

Figure 1. NERC Long Term Assessment Areas



2. Eastern Interconnection

- **<u>Florida Reliability Coordinating Council (FRCC)</u>**

Reliability Criterion: Reserve Margin criteria of 15% as a Regional Reserve Margin (20% for Investor Owned Utilities (IOU) and 15% - 18% for other utilities); Loss of load Probability (LOLP) criteria of 1 day in 10 years or 0.1 LOLP.

Based on the FRCC 2012 Load & Resource Reliability Assessment Report,

"The FRCC has a resource criterion of a 15% minimum Regional Reserve based on firm load. FRCC Reserve Margin calculations include merchant plant capacity that is under firm contract to load-serving entities. The FRCC assesses the upcoming ten-year summer and winter peak hours on an annual basis to ensure that the Regional Reserve Margin requirement is satisfied. Since the summer of 2004, the three Investor Owned Utilities (Florida Power & Light Company, Progress Energy Florida, and Tampa Electric Company) are currently maintaining a 20% minimum Reserve Margin planning criterion, consistent with a voluntary stipulation agreed to by the FPSC. Other utilities employ a 15% to 18% minimum Reserve Margin planning criterion."[21]

[21] *FRCC 2012 Load and Resource Reliability Assessment*, retrieved on September 1, 2012 from https://www.frcc.com/Reliability/Shared%20Documents/FRCC%20Reliability%20Assessments/FRCC%202012%20Load%20and%20Resource%20Reliability%20Assessment%20Report%20RE%20PC%20Approved%20071012.pdf

The FRCC performed a Loss of Load Probability (LOLP) study in 2009 to verify that the reserve margin criteria were sufficient to meet a maximum LOLP of 0.1 day in a given year. The usage of the term LOLP is different from the traditional definition because it is measured in days per year similar to LOLE. Based on our review, this LOLP of 0.1 in consistent with the traditional 1 event in 10 years. Based on the report, FRCC is also exploring the possibility of a ―generation only" reserve margin requirement since demand response penetration is projected to be quite high. Having substantial conventional resources may be important in systems with high penetration of demand response resources due to the voluntary aspect of demand response resources.

FRCC used the TIGER Model to perform its most recent LOLP studies.

- **Southeast Reliability Corporation (SERC)**

  SERC does not have a mandatory reserve margin or resource adequacy requirement for all of its members. Instead, resource adequacy targets are set by individual load serving members and may be subject to review by state regulators of individual members. With this approach, the final target reserve margins vary across the region. For this analysis, we focused on three of SERC's members (Southern Company, TVA, and Progress Energy Carolinas) which represent a portion of SERC-SE, SERC-N, and SERC-E. The information is based on recent IRP information.

  - **SERC-SE: Southern Company**

    Reliability Criterion: Target reserve margin is based on minimizing total system costs to customers.

    Southern Company published an ―Economic Study of the System Planning Reserve Margin for the Southern Electric System"[22] in 2009. Based on this report, Southern Company selected a target reserve margin of 15% which approximately minimizes costs and reduces risks to customers.

    To perform this study, Southern used the SERVM model, a resource tool licensed by Astrape Consulting.

  - **SERC-N: TVA**

    Reliability Criterion: Planning reserve margin based on minimizing total system costs to the customer which results in a 15 percent reserve margin.

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[22] *Southern Electric Reserve Economic Study of the System Planning Reserve Margin for the Southern Electric System* , retrieved on September 1, 2012 from http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=125981

Based on TVA's 2011 IRP, titled ―Integrated Resource Plan, TVA's Environmental and Energy Future"[23]

―TVA identified a planning reserve margin based on minimizing overall cost of reliability to the customer. This reserve margin was based on a stochastic analysis that considered the uncertainty of unit availability, transmission capability, economic growth and weather to compute expected reliability costs. From this analysis a target reserve margin was selected such that the cost of additional reserves plus the cost of reliability events to the customer was minimized. This target or optimal reserve margin was adjusted based on TVA's risk tolerance in producing the reserve margin used for planning studies. Based on this methodology, TVA's current planning reserve margin is 15 percent and is applied during both the summer and winter seasons."

TVA used the SERVM Model to perform its analysis.

- **SERC-E: Progress Energy Carolina**

Based on Progress Energy Carolina's 2012 IRP[24], Progress Energy uses a target reliability of one day in ten years LOLE for generation reliability assessments to set its minimum threshold. The company explains that a 14.5% reserve margin satisfies the one day in ten years LOLE criterion**,** but the company targets a range between 14.5% and 17% based on an economic analysis of total system costs to the customer.

Progress Energy Carolinas used the SERVM Model to perform its analysis in 2012.

- **Southwest Power Pool (SPP)**

Reliability Criterion: Capacity Margin criterion of 12% for RTO members that are steam based and 9% for hydro based; Capacity margins must meet 1 day in 10 Years defined as an LOLH of 2.4 hours per year.

Based on SPP'S 2010 Loss of Load Expectation Report[25], the SPP capacity margin criteria requires each control area within SPP to maintain a 12% capacity margin for steam-based utilities and 9% for hydro based utilities. SPP calculates the LOLE of one day in ten years based on probabilistic modeling and the modeling results show that capacity margins could decrease to 9.6% and still meet this LOLE standard. Based on the study, however, SPP defines one day in ten years differently than the traditional definition. SPP assumes that an LOLH of 2.4 hours per year is 1 day in 10 years instead of one

[23] *Integrated Resource Plan TVA's Environmental & Energy Future*, retreived on September 1, 2012 from http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf
[24] *Progress Energy Carolinas Integrated Resource Plan 2012*, retrieved on Dec 1, 2012 from http://www.energy.sc.gov/publications/ProgressEnergyResource%20Plan2012.pdf

[25] *2010 Loss of Load Expectation Report* , retrieved on September 1, 2012 from http://www.spp.org/publications/LOLE%20Report_5%20Draft_cc.pdf

event (0.1 LOLE) in 10 years. The difference is significant because 2.4 hours per year is much less reliable than one event in 10 years.

SPP uses ABB Gridview to assess its reliability.

- **PJM**

Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

Based on PJM's 2011 Reserve Requirement Study[26], the reserve margin requirement is 15.5% for the delivery period 2012/2013, 15.3% for the 2013/2014 delivery period, and 15.4% for the 2016/2017 delivery period. The reserve margin requirement supports a generation Loss of Load Expectation (LOLE) of one occurrence in ten years (LOLE = 0.1). PJM references RFC Standard BAL-502-RFC-01[27] as the reason the LOLE metric was adopted. The LOLE target reserve margin and various other calculations provide key inputs into the PJM Reliability Pricing Model (RPM). Through RPM, PJM ensures there are appropriate reserves to meet load. Individual Load Serving Entities (LSE) are not required to provide a specific reserve margin requirement and are allowed to make up shortfalls in the capacity markets. This aspect is much different than areas such as SERC, SPP, and FRCC where load serving entities are responsible for capacity procurement to meet the reliability criterion.

PJM uses the PRISM model to perform its resource adequacy planning and also uses GE MARS for supplemental modeling.

- **MISO**

Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

According to MISO's 2012 Planning Year LOLE Study[28], MISO uses a minimum planning reserve margin of 16.7% across the entire MISO region and is based on meeting a 1-in-10 LOLE target (0.1 LOLE). It is the LSE's responsibility to meet the reserve margin target provided by MISO. The recently approved annual auction allows LSE's to purchase capacity to overcome deficiencies or opt to pay a penalty rather than purchase in the auction. Since the planning reserve margin of 16.7% provided by MISO is a regional reserve margin that doesn't account for load diversity among its members, the target for individual LSEs is 11.3% of its annual peak load. It should also be noted that State Commissions have the authority to set planning reserve margins for their state.

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[26] *2011 PJM Reserve Requirement Study*, retrieved on September 1, 2012, from http://www.pjm.com/~/media/committees-groups/subcommittees/raas/20110929/20110929-2011-pjm-reserve-requirement-study.ashx

[27] NERC Planning Resource Adequacy Analysis, retrieved on September 1, 2012, from http://www.nerc.com/files/BAL-502-RFC-02.pdf

[28] *Planning Year 2012 LOLE Study Report,* retrieved on September 2, 2012 from https://www.midwestiso.org/Library/Repository/Study/LOLE/2012%20LOLE%20Study%20Report.pdf

MISO uses the GE MARS model to perform its resource adequacy analysis in combination with PROMOD to establish its zonal areas.

- **NPCC**

All five regions within the NPCC region (NY-ISO, ISO-NE, Maritimes, Quebec, and IESO) require a reserve margin that at a minimum maintains an LOLE of 0.1 days per year. However, there are significant variations in how each area models the details of their system, surrounding regions, load, and other components. There are also differences in the application of the reserve requirements as NY-ISO and ISO-NE maintain resource adequacy through their structured capacity markets.

- **NPCC-NYISO**

Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

Based on the Installed Capacity Requirements study performed by NYSRC in Dec. 2011[29], the required reserve margin to meet the 1-in-10 LOLE standard is 16.1% for the period of May 2012 to April 2013. This study is performed annually to set the annual statewide Installed Capacity Requirement (ICR) for the New York control area. Similar to PJM, these required reserve margin results are used in the NYISO's structured forward capacity markets.

The LOLE analysis is performed using GE MARS.

- **NPCC-ISO-NE**

Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

ISO-NE is the planning coordinator for the New England Area of the Northeast Power Coordinating Council (NPCC). Similar to PJM and NYISO, the reserve requirements serve as inputs to the structured Forward Capacity Market (FCM) which is used to procure the required amount of installed capacity resources to maintain system reliability. Based on the ―New England 2011 Comprehensive Review of Resource Adequacy"[30], required resources are planned based on meeting the NPCC LOLE reliability criterion of no more than one day in ten years disconnection of non-interruptible customers.

The LOLE analysis is performed using GE MARS.

[29] *New York Control Area Installed Capacity Requirements For the period May 2012 – April 2013,* retreived on September 2, 2012 from *http*://www.nysrc.org/pdf/Reports/2012%20IRM%20Final%20Report.pdf

[30] *New England 2011 Comprehensive Review of Resource Adequacy*, retrieved on September 2, 2012 from https://www.npcc.org/Library/Resource%20Adequacy/NE_2011_Comprehensive_Review_of_Resource_Adequacy%20-%20RCC%20Approval%20-%2020111129.pdf

- **NPCC-Maritimes**

  Reliability Criterion: Reserve Margin criterion of 20% and 1-in-10 LOLE (0.1 LOLE)

  Maritimes uses a 20% reserve margin criterion for planning purposes but at the same time adheres to the NPCC requirement of not shedding firm load more than 1 day in 10 years. Based on the 2011 Interim Resource Adequacy Review[31], the region meets both of these requirements for 2012 – 2015.

  The LOLE analysis is performed using GE MARS.

- **NPCC-Quebec**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  Quebec adheres to the NPCC resource adequacy criterion. Based on an LOLE of 0.1, Quebec requires a 10% reserve margin for the 2012/2013 winter peak. By the 2015/2016 winter peak, Quebec requires a 12.2% reserve margin[32]. Because of its dependence on hydro generation to meet peak load, Quebec has also developed an energy criterion stating that sufficient resources should be available to go through a sequence of 2 consecutive years of low water inflows.

  The LOLE analysis is performed using GE MARS.

- **NPCC-IESO (Ontario)**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  Based on the Ontario Reserve Margin Requirements Report[33], IESO bases its reserve margin requirement on an LOLE of 0.1 days per year. The target for 2013 to meet the one day in 10 year target is 19.7% which the region meets easily with an anticipated reserve margin of 40.1%.

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[31] *2011 Maritimes Area Interim Review of Resource Adequacy*, retrieved on September 2, 2012 from https://www.npcc.org/Library/Resource%20Adequacy/RCC%20Approved%202011%20Maritimes%20Area%20Interim%20Resource%20Adequacy%20Review%20for%20TFCP.pdf

[32] *2011 Quebec Balancing Authority Area Comprehensive Review of Resource Adequacy*, retrieved on September 2, 2012 from https://www.npcc.org/Library/Resource%20Adequacy/Qu%C3%A9bec%20Comprehensive%20Review%202011.pdf

[33] *Ontario Reserve Margin Requirements*, retrieved on September 2, 2012 from http://www.ieso.ca/imoweb/pubs/marketReports/Ontario-Reserve-Margin-Requirements-2012-2016.pdf

- **<u>Sask Power</u>**

  Reliability Criterion: Based on an unspecified expected unserved energy (EUE) criteria.[34]

  Per NERC's 2011 Long Term Resource Assessment (LTRA), Sask Power uses a 13% reserve margin based on probabilistic analysis of Expected Unserved Energy. The specific EUE metric used to set the target was unavailable. This is different than LOLE in that it takes into account the magnitude of the event. NERC has recently recognized the fact that LOLE does not take into account the magnitude of the event and in its latest probabilistic assessments has requested that EUE as a percent of demand be used instead of LOLE.

- **<u>Manitoba</u>**

  Reliability Criterion: Both an energy criterion and a capacity reserve margin criterion due to the fact that the region is predominantly hydro.

  The energy criterion requires adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. The reserve margin is at least 12%. Based on Manitoba's 2010/2011 Power Resource Plan[35], Manitoba states that "the reserve margin of 12% has been adequate for Manitoba Hydro's predominantly hydro based system because of the relatively low outage rates of hydro generating units combined with relatively small size units."

- **<u>Mid Continent Area Power Pool (MAPP)</u>**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  Per the NERC's 2011 LTRA[36], some of MAPP's members self impose a planning reserve margin of 15% based on the LOLE study performed in 2009.

  Given that the focus of the paper surrounds the Eastern Interconnection, we have only included a few short comments on the ERCOT and WECC interconnections.

3. ERCOT

Reliability Criterion: 1-in-10 LOLE (LOLE of 0.1)

Although ERCOT performs a resource adequacy assessment to determine the reserve margin necessary to meet 1-in-10 LOLE, there is not a mandatory requirement for the region. ERCOT operates as an energy only market and therefore does not have mandatory capacity requirements.

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[34] *2011 Long-Term Reliability Assessment,* retrieved on September 2, 2012 from http://www.nerc.com/files/2011LTRA_Final.pdf

[35] *Manitoba Hydro 2010/11 Power Resource Plan,* retrieved on September 3, 2012 from http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_84.pdf

[36] *2011 Long-Term Reliability Assessment,* retrieved on September 2, 2012 from http://www.nerc.com/files/2011LTRA_Final.pdf

4. WECC

In general, each balancing area has responsibility for meeting resource adequacy standards established by respective states in which they operate. Resource adequacy planning in WECC is similar to that in SERC.

- **CAISO**

The California ISO uses a resource adequacy requirement of 15% reserve margin set by the California Public Utility Commission's Resource Adequacy Program. It is our understanding that the 15% was derived from previous resource adequacy studies.

- **NWPP**

The Pacific Northwest uses an LOLP metric that states the following: "the likelihood of having at least one curtailment five years into the future must be 5% or less for the power supply to be deemed adequate."[37] They also include another metric 2) conditional value at risk (CVaR) to evaluate the likelihood, magnitude, duration, and seasonality of Energy-Not-Served (ENS) events.

[37]Fazio, John, *Pacific Northwest Resource Adequacy Standard*, retrieved on September 3, 2012 from http://ewh.ieee.org/cmte/pes/rrpa/RRPA_files/LBP20120726/Item%2011%20-%20IEEE%20RRPA%20PNW%20Adequacy%2072712.pdf

III. PREVIOUS ECONOMIC STUDIES OF THE 1 DAY IN 10 YEAR STANDARD

A number of studies have been performed that evaluate the value of service reliability. The most common approach taken in these studies compares the direct and indirect costs of outages with the costs of generating capacity at a range of reserve margins. Some of the studies also take into account other benefits of reserve capacity including reduced purchase costs, offsetting higher cost resources, reducing the costs of voltage reduction, and reducing the costs of interrupting non-firm load customers. However, few of the studies surveyed explicitly estimate the reasonableness of existing physical reliability standards by comparing to economically optimal reserve margins. This is likely because the units of physical reliability events do not reflect their magnitude or duration. The cost of 1 event in 10 years is highly dependent on the size and duration of the event, neither of which is reflected in the metric. The following sections review specific studies of the value of service reliability.

A. ECONOMICS OF RELIABILITY FOR ELECTRIC GENERATION SYSTEMS (1973)

M.L. Telson‘s thesis titled the Economics of Reliability for Electric Generation Systems in 1973[38] was one of the earliest relevant studies which specifically addressed the reasonableness of physical reliability standards. His approach was similar to many of the other value of electric service studies which approximate an optimum reserve margin by comparing the cost of carrying additional capacity with the costs of outages at various reserve margins. Since his approach is used frequently, we will analyze it in some depth.

Mr. Telson does explicitly compare economically optimal reserve margins with reserve margins determined by physical metrics such as the 1-in-10 LOLE metric. His analysis suggests that reserve margins set by 1-in-10 LOLE are much higher than would be justified by an economic analysis. An economically set reserve margin might provide reliability as low as 1 event per year according to his analysis. A simplification of the related math states that 1 event per year with an outage cost of ~\$1/kWh and a duration of 12 hours is comparable to the carrying cost of a new unit at \$12/kW-yr. This is the optimal level because additional reserves would provide less than \$12/kW-yr of avoided outages, and fewer reserves would result in more than \$12/kW-yr of additional outages. Mr. Telson's analysis suggests that under typical reliability standards, customers are over-paying on a total cost basis by 4.1% compared to what they would pay under an economically optimal reserve margin even after considering societal outage costs. While the cost figures from 1973 are no longer applicable, more recent studies also make the point that it would take several hours per year of outages even with high outage costs to justify new capacity.

As additional support for a lower reserve margin target than indicated by the 1-in-10 LOLE standard, Mr. Telson compares generation adequacy related outages with transmission and distribution outages which are orders of magnitude more frequent. This report also highlights the conservative assumptions built into many of the 1-in-10 LOLE based reliability studies. Another limitation pointed out by Mr. Telson of most physical reliability studies is their lack of attention to the magnitude and duration of outages.

The support for Mr. Telson‘s position that an economic reserve margin should be less than a 1-in-10 LOLE target is dependent on the system conditions he assumed, many of which are not applicable to systems today. For example, in the early 1970‘s, load growth was

[38] *Economics of Reliability for Electric Generation Systems*, M.L. Telson, 1973

much higher with substantial uncertainty; unit performance was less reliable, the carrying cost of additional reserves was higher in real terms, and the cost of outages was lower in real terms. However, even with updated assumptions, we do not feel that Mr. Telson's approach considers all of the economic factors necessary for valuing the benefits of additional capacity. In fairness, his economic analysis is much more sophisticated than suggested by our example and includes a number of indirect economic impacts in addition to the direct costs mentioned.

B. Cost and Benefits of Over/Under Capacity in Electric Power System Planning (1978)

Another early significant study in our research results is titled ‗Costs and Benefits of Over/Under Capacity in Electric Power System Planning' and was performed for EPRI in 1978[39]. This study analyzed the economics of generation reliability for 4 utilities (Tennessee Valley Authority, Pacific Gas and Electric, Long Island Lighting Company, and Wisconsin Electric Power Company). This study uses a number of unique assumptions:

1. Load growth and capacity expansion uncertainty are primary drivers of the need for planning reserves. This is primarily a function of the high load growth period of the 1970's and is likely not applicable today.
2. Total variable costs for each different reserve margin level studied must be incorporated into the total cost comparison; not just the outage costs and capital costs. This analysis included the variable production costs of each unit plus the cost of purchasing electricity from interties, interrupting certain customers, and reducing voltage.
3. Environmental cost differences between different reliability levels should also be considered. While the costs were not explicitly included in the analysis, qualitative consideration was given to the environmental benefits or penalties at different levels of service reliability.

The study also results in a number of unique observations:

1. Asymmetry of Consumer Cost. Reserve margins much below the optimal reserve margin tend to have much higher costs than reserve margins much above the optimal reserve margin. This suggests that if two reserve margin levels have the same expected value, the higher reserve margin is a more appropriate selection based on its lower risk profile.
2. The total cost curve is relatively flat at a wide range of reserve margins near the optimal economic reserve margin. This also supports carrying higher reserve margins since the cost differences are not substantial.
3. The economically optimal reserve margin can vary substantially depending on the resource mix, unit performance, load and load growth profile, and other factors. The optimum reserve margins for the 4 utilities studied ranged by approximately 15%.

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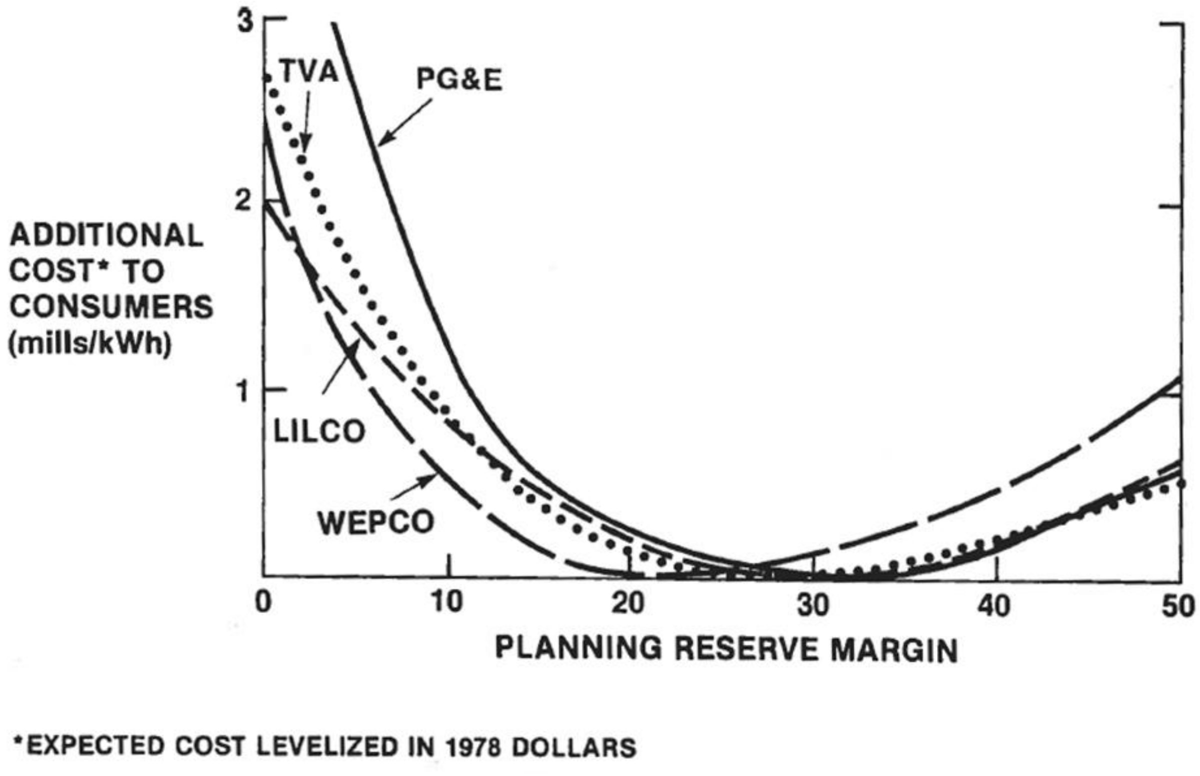
[39] Decision Focus, Incorporated, *Costs and Benefits of Over/Under Capacity in Electric Power System Planning,* EPRI EA-927, Project 1107, October 1978

4. Old technologies can have a substantial impact on the economically optimal reserve margin. If the marginal unit used to increase or decrease reserves has an operating cost less than a substantial portion of a utility's existing resources, the economically optimal reserve margin may be quite high. Regardless of how high the reserve margin is, as long as adding resources is offsetting the dispatch of a significant portion of existing resources, their addition could be economic.

The results of the analysis indicate that reasonable economic reserve margins fall in the range of 15% to 40% as shown in the Figure 2 below. While the study did not explicitly compare these reserve margin levels to 1-in-10 LOLE based reserve margins, the paper suggests that economic reserve margins are not necessarily lower than reserve margins determined by physical reliability metrics. Further, even at reserve margins above those standards, the additional costs are not that substantial. This conclusion is counter to a number of other value of service studies that indicate that economically set reserve margins are always lower than 1-in-10 LOLE based reserve margins.

Figure 2. Total Costs as a Function of Planning Reserve Margin

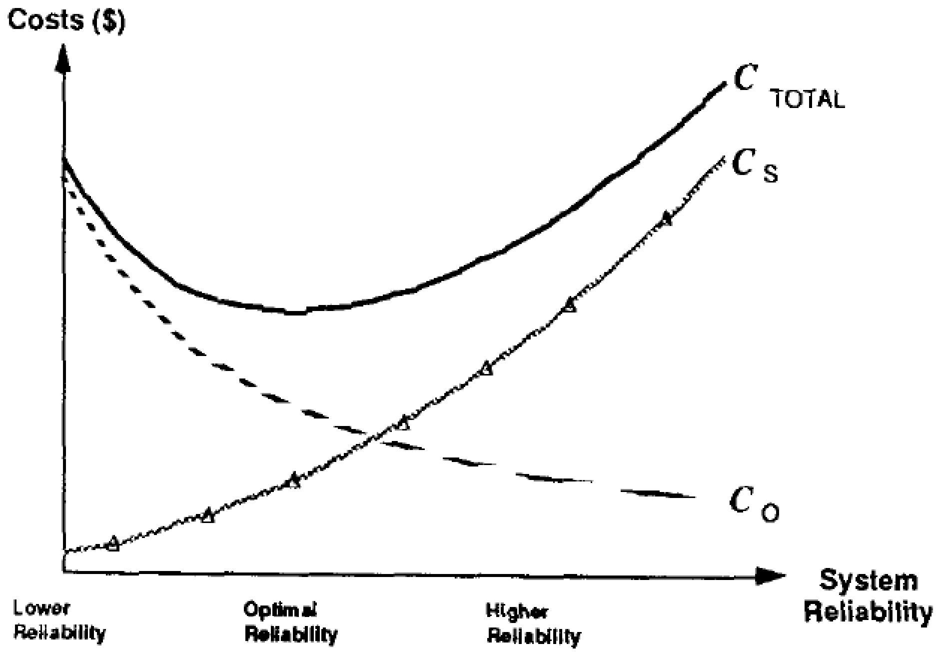


C. PGE Value of Service Reliability (1990)

In 1990 Sandra Burns and Dr. George Gross authored a paper called Value of Service Reliability[40] that studied the Value of Service approach to resource adequacy planning. Ms. Burns and Dr. Gross begin by stating valid points why physical metrics such as LOLE and LOLP are somewhat arbitrary and don't take into account the economic impact on customers. For example the paper said ~~—it~~ is difficult to determine from a societal point of view whether a 1 day in 10 years LOLP is more appropriate than 1 day in 5 years or 1 day in 20 years."

Next the paper discussed the Value of Service framework in which the marginal costs of additional reserves are compared against the marginal benefit of additional reserves. Figure 3 summarizes this method. Co represents cost to customers when demand cannot be met and Cs represents capital investment expenditures. As reliability increases (or reserve margin increases), investment expenditures increase while customer costs due to the utility not meeting demand decrease. At some point the benefit of the additional capacity is not justified.

Figure 3. Variation of Costs as a function of reliability



To develop a proper estimate for Co, PGE used recent customer outage surveys which resulted in a weighted average customer cost of $3/kWh. Next, the author compared the economic approach to two different physical reliability metrics. The first approach used hourly loads and calculated the reserve margin assuming an LOLH of 2.4 hours per year while the second method used daily peaks to calculate an LOLE of 0.1 days per year. The results are seen in Figure 4. The economic approach produced a lower reserve margin than the traditional physical reliability approaches.

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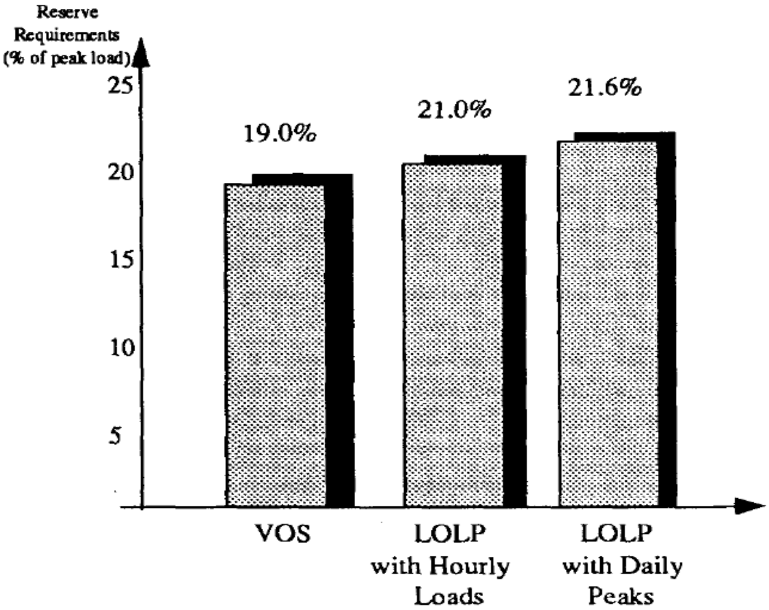
40 Burns, Sandra and Gross, George, *Value of Service Reliability,* IEEE Transactions on Power Systems, Vol.5, No.3, August 1990

Figure 4. Value of Service vs. LOLP



The study implies a general relationship that a reserve margin based on value of service would be less than the 1-in-10 LOLE metric.

D. On an 'Energy Only' Electricity Market Design for Resource Adequacy (2005)

While this paper[41] by William Hogan was not specifically designed to address the economic reasonableness of using specific physical reliability metrics to set target reserve margins, it does address resource adequacy and the missing money problem in structured markets. Mr. Hogan's paper provides informative insights into the economics of resource adequacy from the perspective of generators. He proposes a number of improvements to the design of energy markets that could alleviate the need for additional capacity payments and still provide generators adequate revenue to cover their costs. He recognizes that in current markets, many generators do not fully recover their costs. His explanation for this gap is that "the missing money problem arises when occasional market price increases are limited by administrative actions such as price caps." While we agree that price caps are certainly a component of missing money, in the absence of a reserve margin target, generators theoretically should offer less capacity to the market such that, even with the price caps in place, generators still receive adequate revenue. Imagine a system with price caps at $500/MWh. With this low cap, fewer generating assets should be built since they can't expect adequate returns at a higher reserve margin. This lower reserve margin will result in scarcity situations more frequently producing adequate returns for marginal generators, however the tradeoff would be that physical reliability would decline.

[41] Hogan, William (2005), "On an ―Energy Only" Electricity Market Design for Resource Adequacy."

We are not suggesting that an energy market with low price caps is an ideal market structure. We are simply illustrating that regardless of market structure, generators should theoretically target a reserve margin that produces adequate returns regardless of the reliability implications.

One aspect of Hogan's solution for the missing money problem is to eliminate price caps and implement an administrative scarcity pricing curve. He states: "For any level of capacity that provides a given level of reliability, there is some set of shortage prices that would produce generator revenue streams that if correctly anticipated would be sufficient to sustain that level of capacity." While this is a valuable insight, it does not speak to whether the given level of reliability is economically appropriate. Hypothetically, the given level of reliability could require a 30% reserve margin. The administrative scarcity pricing curve would have to be extremely high, well above the true value of the reserves, in order to achieve cost recovery.

E. Reconsidering Resource Adequacy: Has the one-day-in-10-years criterion outlived its usefulness? (2010)

Mr. James Wilson recently published an article[42] in the Public Utilities Fortnightly examining the one-day-in-ten year standard and whether or not it was economic. Mr. Wilson states ―The 1-in-10 criterion always has been highly conservative--perhaps an order of magnitude more stringent than the marginal benefits of incremental capacity can justify—and capacity planning has been even more conservative in practice." He uses examples comparing the Value of Lost Load x LOLE x hours per event to Net Cost of New Entry (CONE) which represents the capital costs of a new combustion turbine net of energy and ancillary service revenues as shown in the table below. Utilizing the examples, in all cases the optimal amount of LOLE is higher than the 0.1 LOLE standard as shown in the following table. For example, in order to justify a $120,000/MW-year Net CONE, the resource must offset 6 LOLE events per year assuming 5 hours per event and a VOLL of $4,000/MWh. (Note: the units from the article for VOLL should be $/MWh and the units of Net Cone should be $/MW-yr)

[42] Wilson, James, *Reconsidering Resource Adequacy,* retrieved on September 4, 2012 from http://www.fortnightly.com/uploads/04012010_ResourceAdequacyP11.pdf

Table 3. Optimal LOLEs for Various VOLL and Capital Cost Assumptions

Value of service (VOLL)	Net Capital Cost (Net CONE)	Hours per outage event	Optimal LOLE	Optimal Nines
$/MW-year	$/MWH	hours/event	events/yr	
$4,000	$120,000	5	6.0	2.5
$4,000	$80,000	5	4.0	2.6
$4,000	$40,000	5	2.0	2.9
$2,000	$120,000	5	12.0	2.2
$2,000	$80,000	5	8.0	2.3
$2,000	$40,000	5	4.0	2.6
$20,000	$120,000	5	1.2	3.2
$20,000	$80,000	5	0.8	3.3
$20,000	$40,000	5	0.4	3.6

Moreover, Mr. Wilson states the following: ―The tendency is often to adopt conservative assumptions for many of these values, to make the overall result of the analysis conservative (i.e. erring on the side of too much rather than too little capacity and reliability, identifying too large rather than too small a reserve margin).” In conclusion, Mr. Wilson argues that the 1-in-10 LOLE standard is not an economic target and that economics would indicate much lower target reserve margins.

Mr. Wilson‘s article is primarily targeted toward the PJM system. In agreement with his assessment of PJM, our review of regions in the Eastern Interconnection indicates that PJM‘s planning study assumptions are potentially conservative. However, in concurrence with our other assessments, we believe that Mr. Wilson is not including some key components of the value of marginal capacity in his analysis. A marginal resource provides substantially more value than simply displacing firm load shed events.

F. The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On (2010)

Astrape Consulting cooperated with the Brattle Group to write the paper titled ―The Economics of Resource Adequacy Planning”[43] which was published by NRRI in April of 2011.

The paper describes an economic approach to resource adequacy planning and compares it to results utilizing two different definitions of the 1-in-10 LOLE standard. The authors develop a case study using a resource adequacy model that not only calculated LOLE but also takes into account economic dispatch and costs. The methodology balances the cost of new capacity (CT) with the benefit the resource provides. In this study, the benefit is defined as the following:

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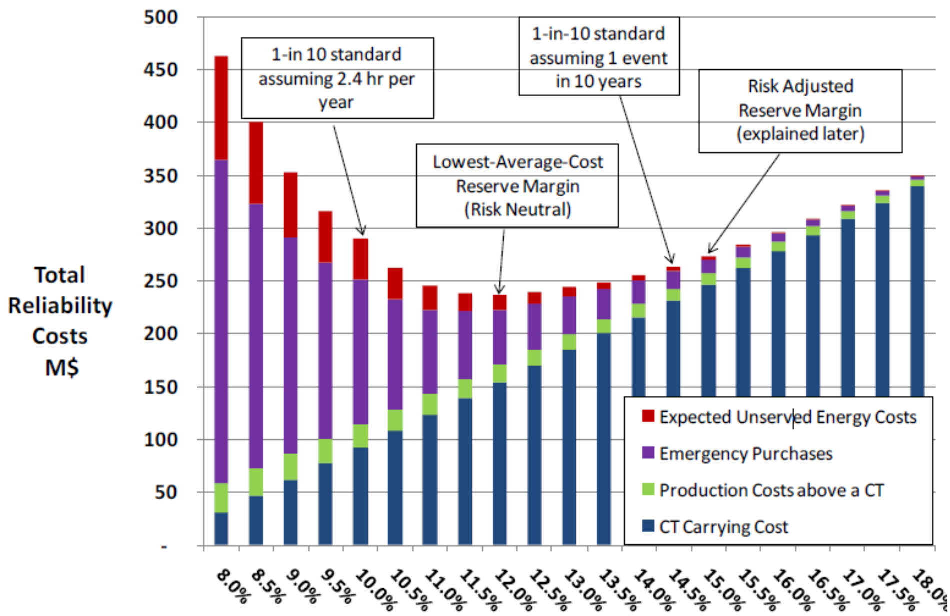
[43] Carden, Pfeifenberger, Wintermantel, *The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On, NRRI, April 2011, retrieved on September 3, 2012 from* http://www.nrri.org/pubs/electricity/NRRI_resource_adequacy_planning_april11-09.pdf

- Production-Related Reliability Costs – defined as any costs of the system's physical generation above the dispatch cost of the new capacity resource. This includes the dispatch of higher-cost generators such as oil-fired turbines and old natural gas turbine units. The addition of a new capacity resource would offset some but not all of these costs.
- Emergency Purchase Costs – defined as the costs of any purchases at prices higher than the cost of the marginal capacity resource. In our simulations, these emergency purchase costs, including purchases associated with demand-side resources, can range from \$1/MWh above the dispatch cost of a CT to the cost of unserved energy (*e.g.*, well in excess of \$1,000/MWh) under extreme conditions.
- Unserved Energy Costs – The value of lost load to customers. This value typically is derived from customer surveys.

The point is made that the majority of costs from the California Energy Crisis were comprised of expensive energy prices in the marketplace and not due to firm load shed. A marginal resource has the ability to reduce scarcity pricing events as well as reduce firm load shed events. The results of the study are seen below. The economic reserve margin target (Lowest-Average-Cost Reserve Margin) was higher than a 2.4 LOLH based reserve margin and lower than a 1-in-10 LOLE based reserve margin. The authors make the point that dependent on the system, the economic reserve margin could be higher or lower than the 1-in-10 LOLE target.

Figure 5. Lowest Average Cost Reserve Margin



The fundamental distinction of this study is that there is a significant focus on the costs of emergency purchases and the impact of scarcity pricing in markets. Dependent on the severity of the weather and load forecast uncertainty in a particular case, it is reasonable to assume that a CT could be dispatched 0 hours up to 1,500 hours in a given year. In years where a CT is dispatched substantially, it is important to recognize all the benefits the resource provides. Alongside the weighted average or expected results, the authors discuss the importance of understanding the full distribution of potential costs from all scenarios comprised of combinations of weather and load forecast uncertainty. Given that reliability events are low-probability high-impact events, the tails of the distribution of possible scenarios are important.

One of the critiques of the approach put forward by Brattle and Astrape is that there was no weather diversity considered causing the scarcity pricing to be too high, and that the load forecast error distribution assumed provides limited flexibility in adjusting resource plans if load grows faster than expected. Reviewers have suggested that the conservative nature of these assumptions led to higher than optimal reserve margins. These critiques have been considered by the authors and have been incorporated in the simulations for this white paper. For example, each region‘s load was modeled based on hourly historical weather to ensure proper weather diversity is taken into account.

Additional Scholarly Works that Address the Economics of Reliability:

- Electric Utility System Reliability Analysis: Determining the Need for Generating Capacity (1988) by Biewald and Bernow
- Reliability Evaluations of Power Systems, Billinton (1990)
- Southern Company Reserve Margin Studies (1997, 2004, 2007, 2009)
- Louisville Gas and Electric Reserve Margin Study (2010)
- Peter Cramton and Steven Stoft (2006), "The Convergence of Market Designs for Adequate Generating Capacity."

In summary, we reviewed multiple economic studies which assessed the reasonableness of the 1-in-10 LOLE standard and summarized the findings of 6 of those studies. The EPRI Over/Under study and the study produced by Astrape Consulting/The Brattle Group demonstrated economic target reserve margins that could be below or above LOLE 1 day in 10 year targets. The remaining studies (Telson, PGE VOS, Wilson) all implied that the economic target would likely be lower than the 1-in-10 LOLE target. Given the sensitivity of the results to input assumptions, it is likely that changes to the cost of carrying capacity, the value of lost load, and load uncertainty since some of those studies were published would affect conclusions. Further, in reviewing methodologies, the major difference was defining the benefits that a marginal resource provides. The benefits defined varied across the studies from including all costs above the dispatch cost of a CT (i.e. emergency purchases, DR costs, and unserved energy) to only including the Value of Lost Load to customers.

Economists may argue that the economic optimal target should only be based on total societal costs which would include only total production costs (fuel burn + O&M) plus the cost of unserved energy and ignore the scarcity pricing situations that occur in the market place. The argument is that these high cost purchases only represent a transfer of wealth from one region to another or from customers to generators rather than an actual societal cost. However, the approach of only considering net societal costs largely ignores the bigger question of how costs and revenues are shared among the participants in the system. Assume an example system minimizes total societal costs at a reserve margin of 8%, and at this level total societal costs annually are $5 billion in fuel, O&M, and capital costs. When the economics of each participant are considered however, there may be significant market distortions. If this was an energy-only system and reserves approximately matched the minimum societal cost reserve margin of 8%, significant scarcity would be prevalent. The market price in many hours would be set by scarcity pricing even though the total production costs are still minimized at this low reserve margin. Because of this scarcity, generators may extract $8 billion in energy costs from consumers in a given year, a $3 billion transfer of wealth. This is ignored in the societal cost minimization approach, but represents a significant concern.

In competitive markets, if there is a distortion resulting in a transfer of wealth from consumers to generators, then new generation would theoretically enter the market until the marginal unit is only recovering its costs. The new capacity would raise the reserve margin and eliminate the wealth transfer. But now the system is no longer targeting the optimum reserve margin based on minimizing societal costs. The reserve margin target becomes the level at which generators recover costs. But as we will discuss in later sections of the report, total systems costs in an energy only market at the point of generator cost recovery may not be optimal when compared to other potential market structures.

The minimization of net societal costs approach is instructive in a number of ways. If an entire system consists only of vertically integrated utilities, and all transfers are passed on to customers at cost, and planning is coordinated between all utilities, the minimization of net societal costs is theoretically correct. The results from such an analysis could be compared to the minimum customer cost approach for a single utility to identify the magnitude of the inefficiency due to not coordinating all planning activities.

IV. VOLL ESTIMATES AND THEIR IMPACT ON RESOURCE ADEQUACY PLANNING

Over the last several decades, there have been many customer surveys and studies performed to estimate the value of lost load to customers. Two comprehensive studies which aggregated many of the individual surveys were performed for the U.S. Department of Energy (DOE) by Ernest Orlando Lawrence Berkeley National Laboratory in November 2003 and updated again in June 2009[44]. For this analysis, we will focus on the results from the June 2009 study. The study takes results from 28 customer value of service reliability studies conducted by 10 major US electric utilities over the 16 year period from 1989 to 2005. The majority of these studies are not available publicly and were only made available by utilities for this specific DOE study. The results were combined into a single meta-database and a regression model was developed to calculate customer costs per event by season, time of day, day of week, and geographical regions within the U.S.

The study divided customer groups into the following:

- Medium and Large Commercial and Industrial (more than 50,000 annual kWh usage)
- Small Commercial and Industrial (less than 50,000 annual kWh usage)
- Residential Customers

The following tables summarize the data found in the study.

Table 4. Value of Lost Load Summary: Summer Weekday Afternoon

Interruption Cost $/event	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I	$ 11,756	$ 15,709	$ 20,360	$ 59,188	$ 93,890
Small C&I	$ 439	$ 610	$ 818	$ 2,696	$ 4,768
Residential	$ 2.70	$ 3.30	$ 3.90	$ 7.80	$ 10.70

$/kWh Unserved Energy at Customer Peak*	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I		$ 30.83	$ 19.98	$ 14.52	$ 11.52
Small C&I		$ 85.50	$ 57.33	$ 47.23	$ 41.77
Residential		$ 1.30	$ 0.77	$ 0.38	$ 0.26

[44] Ernest Orlando Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States,* June 2009

*Peak Loads used to calculate interruption costs in $/kWh for each customer class were based on reported average kWh energy use and assumed an 80% load factor for medium and large customers, 40% load factor for small customers, and 30% load factor for residential[45]

In performing economic resource adequacy analysis, the $/kWh value associated with unserved energy at peak is the value that is typically used as the Value of Lost Load assumption. Assuming that firm load shed would be spread equitably among all customer classes, a weighted average of the system's customer class mix can be calculated to develop a system $/kWh value for the region being studied. The weighted average $/kWh for Unserved Energy using the 1 hour values is $26.02/kWh.

The table shows that as the duration of the outage increases, the $/kWh value decreases. The first hour is typically the most expensive as customers have an opportunity to mitigate the impact of an outage in subsequent hours. The results also show that Residential Customers have the lowest costs while Small C&I Customers have the greatest costs. This is logical as residential customers generally only have some discomfort and minor loss such as spoiled food during outages. We typically see the VOLL for residential customers to be less than $3/kWh. Businesses have a much higher cost. Technology has been a major driver for the increase in commercial business outage costs as computer systems have become so vital in today's work environment. For retail business, there is lost sales revenue as businesses may be forced to close during the outage. For industrial customers, the costs of lost product and lost revenue drive the estimates.

The next table shows how outage costs varied by season, day of week, region, and industry. It is seen that depending on the industry and size of the business, the VOLL can vary greatly. For Medium and Large C&I Customers, the outage costs can vary from $2.8/kWh to $40.9/kWh depending on the industry. For Small C&I Customers, costs range from $21.7/kWh to $108.7/kWh. VOLL is an uncertain value, but as our case study demonstrates, the assumption does not have a significant impact on the economics of resource adequacy. In a system that is planning to the 1-in-10 LOLE standard, the amount of expected unserved energy (EUE) is small and therefore limits its impact on economic results. While the raw average estimates from the aggregated studies indicated a much higher VOLL, due to the large variance in VOLL estimates, $15,000/MWh was assumed in the case study as a blended rate for residential, commercial, and industrial customers.

[45] Ernest Orlando Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States,* June 2009; Table ES-1 costs per event were converted to $/kWh based on the peak load assumption for each customer class.

Table 5. Cost per Event across Season, Day, Region, and Industry[46]

	Cost per Event of 1-Hour Outage					
	Medium and Large Commercial and Industrial Customers 2008$		Small Commercial and Industrial Customers 2008$		Residential Customers 2008$	
Season	Costs $	$/kWh*	Costs $	$/kWh*	Costs $	$/kWh*
Winter	$ 11,129	$ 10.9	$ 543	$ 38.1	2.9	$ 0.6
Summer	$ 15,628	$ 15.3	$ 737	$ 51.6	4.7	$ 0.9
Day						
Weekend	$ 2,249	$ 2.2	$ 459	$ 32.2	8.6	$ 1.7
Weekday	$ 16,478	$ 16.2	$ 765	$ 53.6	4	$ 0.8
Region						
Midwest	$ 12,294	$ 12.1	$ 732	$ 51.3		
Northwest	$ 3,552	$ 3.5	$ 341	$ 23.9	3.2	$ 0.6
Southeast	$ 23,797	$ 23.4	$ 799	$ 56.0	6.6	$ 1.3
Southwest	$ 5,946	$ 5.8	$ 967	$ 67.8	1.8	$ 0.4
West	$ 18,166	$ 17.8	$ 886	$ 62.1	3.7	$ 0.7
Industry						
Agriculture	$ 1,063	$ 1.0	$ 352	$ 24.7		
Mining	$ 18,501	$ 18.2	$ 1,545	$ 108.3		
Construction	$ 3,663	$ 3.6	$ 1,301	$ 91.2		
Manufacturing	$ 41,691	$ 40.9	$ 913	$ 64.0		
Telco. & Utilities	$ 8,837	$ 8.7	$ 810	$ 56.8		
Trade & Retail	$ 2,818	$ 2.8	$ 627	$ 43.9		
Fin., Ins. & R.E.	$ 5,790	$ 5.7	$ 975	$ 68.3		
Services	$ 4,810	$ 4.7	$ 531	$ 37.2		
Public Admin	$ 12,239	$ 12.0	$ 310	$ 21.7		

*Peak Loads for each customer class were based on the report's average kWh energy use and assumed an 80% load factor for medium and large customers, 40% load factor for small customers, and 30% load factor for residential [47]

Based on the variation of VOLL values provided by businesses, it is easy to recognize the need for demand response programs with different characteristics. For a customer with very low outage costs, it would be rational for them to curtail load when prices reach a threshold of $150/MWh while a customer who has high outage costs and no backup generation would likely not participate in a program. As part of the simulation portion of this paper, we analyze what happens to reliability as the penetration of demand resources increase without increasing the dispatch constraints. As DR penetration increases, energy prices will increase and DR resources will be called upon much more frequently. The estimation of

[46] No studies available to be summarized for black shaded cells.

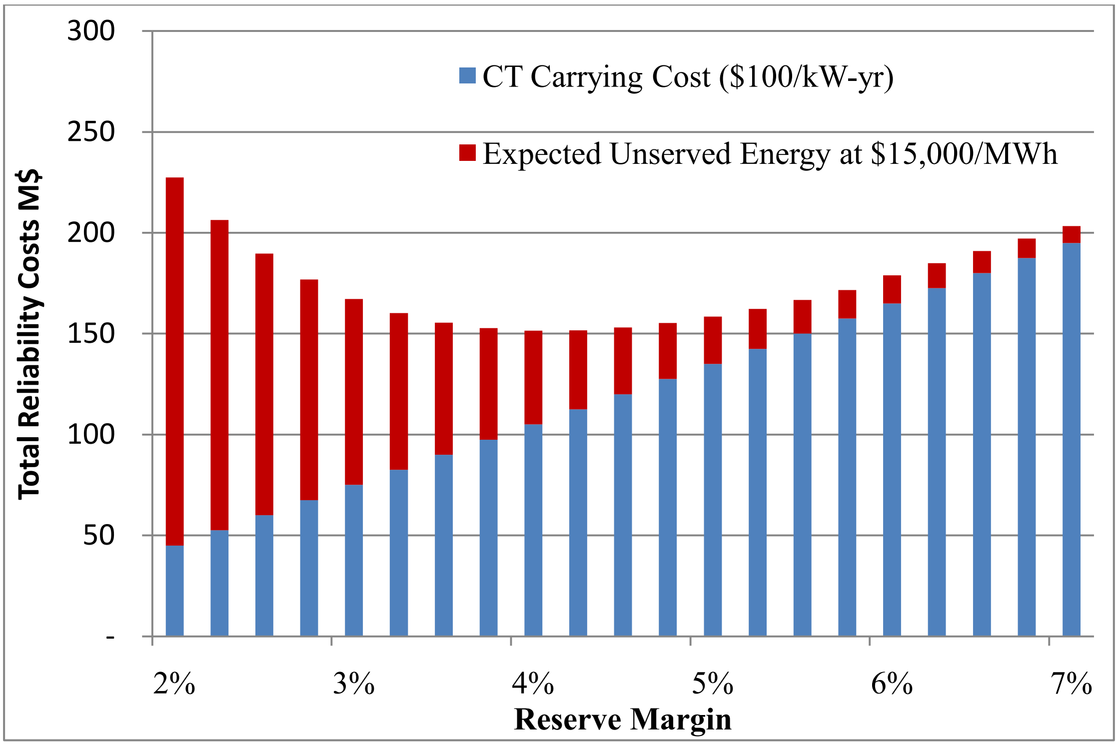
[47] Ernest Orlando Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States,* June 2009; Table 3-4, Table 4-4, and Table 5-4 average costs per event were converted to $/kWh based on the peak load assumption for each customer class.

these calls is going to be vital to resource adequacy planning in the next decade, particularly because DR resource participants are voluntary participants who may choose to discontinue participation if DR resource use hits thresholds of tolerance.

V. DETERMINING THE OPTIMAL RISK NEUTRAL AND RISK ADJUSTED ECONOMIC RESERVE MARGIN

Most of the research papers cited in Section III compared the cost of incremental capacity to the economic benefit of reduced unserved energy costs provided by the capacity under a vertically integrated utility environment. As an example of this methodology, if adding new capacity costs $100/kW-yr, and the value of lost load is $15,000/MWh, the new capacity would need to offset more than 6 hours of lost load per year to be economically justified. However, since the 1-in-10 LOLE standard represents only 0.3 hours of lost load per year, the economic reserve margin would be much lower than the 1-in-10 LOLE based reserve margin as shown in the Figure 6 below. The economic reserve margin is 4% in our case study if only EUE is taken into consideration as the benefit additional capacity provides. Again, this is the economic reserve margin for this particular analysis because adding capacity up to a 4% reserve margin costs less than the economic societal benefits of reduced EUE for this region. Above a 4% reserve margin, adding capacity costs more than the economic societal benefits produced in reducing EUE. A 4% reserve margin results in the minimum capacity plus EUE costs.

Figure 6. Cost of Capacity vs. Reduction in Expected Unserved Energy Costs



However, system planners should be attempting to minimize total system costs to customers, not just a subset of system costs. Every benefit of incremental capacity should be considered. In addition to avoiding the societal costs of shedding firm load, adding new efficient gas turbines would avoid the dispatch cost of many inefficient existing units and avoid expensive market purchases during hours when capacity is scarce. When taking these additional benefits into consideration, total system costs continue to drop as capacity is added well above a 4% reserve margin.

In the following case study we will explore potential methods of determining a risk neutral and optimal risk adjusted target based on total system costs to customers.

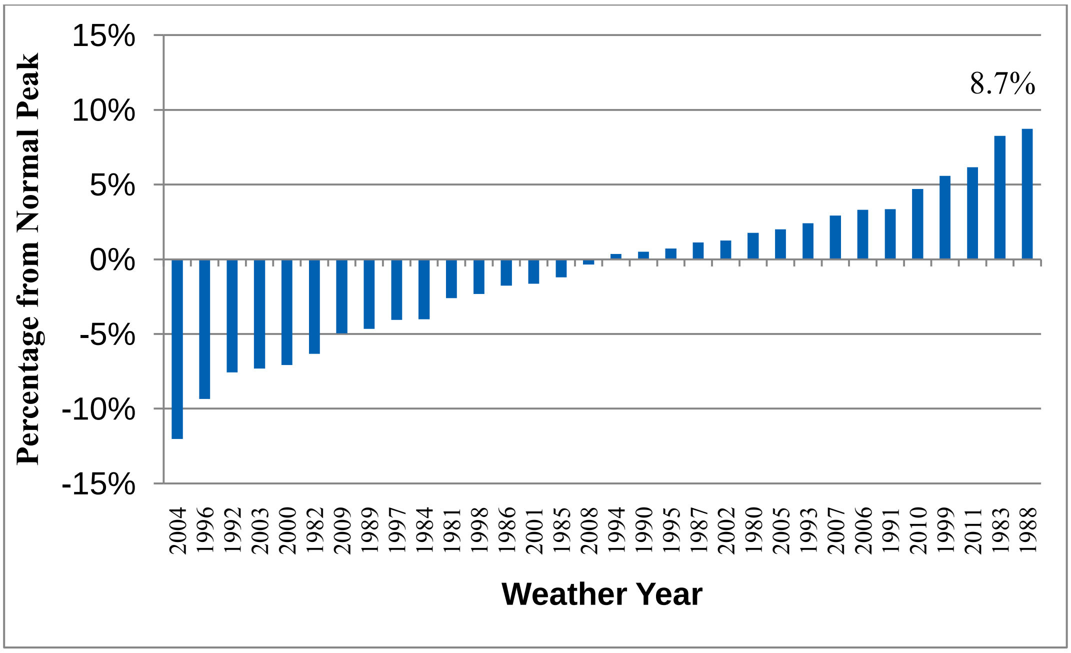
A. Case Study Description

The following is a brief overview of the case study setup. The Eastern Interconnection Planning Collaborative (EIPC) has recently performed its Eastern Interconnection Transmission Study. The primary objective of the EIPC study was to aggregate the modeling and regional transmission expansion plans of the entire Eastern Interconnection and to perform regional analyses to identify potential conflicts and opportunities between regions. The EIPC study simulates all loads, generating resources, and transmission resources for all individual regions. Input data for the case study presented in this report uses data from the EIPC study as inputs, including region definitions, load forecasts, generating resource mixes, and transmission capabilities. Because the scope of this white paper was limited, only a subset of 14 of the NEEM regions from the EIPC study was included. For resource adequacy studies, accurate representation of the uncertainty in loads and generator availability is necessary to capture the frequency of reliability events. Firm load shed and extremely high market prices are typically only concerns when loads are much higher than normal or generating resources are less available than normal.

To accommodate this additional uncertainty, we included distributions around the following variables:

- Weather Uncertainty. Figure 7 demonstrates that summer peak load could be as much as 8.7% higher than normal peak load due to weather uncertainty in the PJM Rest of MAAC (PJM ROM) region. This is fairly typical across most of the regions in the Eastern Interconnection. Weather also impacts hydro, thermal, and intermittent resources which was also captured in the case study (See Appendix A).

Figure 7. Weather Impact on Peak Load for PJM Rest of MAAC



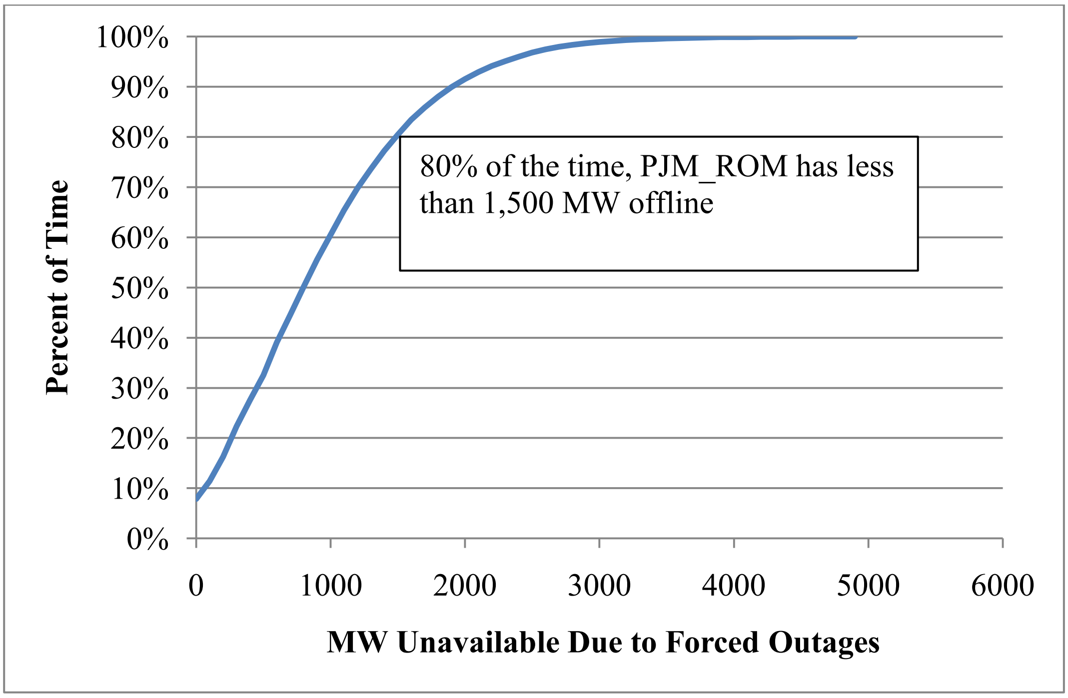
- Load Forecast Uncertainty. All loads for a given year could be as high as 5% higher (although this has a very low probability of occurring) than normal due to unexpected economic growth over a 4 year period as seen in the distribution in the Figure 8. The 6 discrete points in the table with associated probabilities were used in the simulation. This economic uncertainty captures the boom-bust cycle inherent in electric markets. Some years the market will have excess capacity above the target reserve margin and other years markets will be below the target reserve margin. This error distribution was developed from analyzing how well the Congressional Budget Office was able to forecast GDP three to four year out. That distribution of performance was translated to electric demand using a multiplier of .4% load growth for every 1% of GDP growth. The development of this distribution is further explained in the Appendix A.

Figure 8. Economic Load Forecast Error

Load Forecast Error	Probability
5.11%	6.25%
3.90%	18.75%
0.55%	31.25%
-1.76%	18.75%
-2.90%	12.50%
-4.54%	12.50%

- Unit Performance Uncertainty. Figure 9 shows that the study system is expected to have approximately 800 MWs in a forced offline state on average, but there are hours in which the system could have 2,000 MWs offline. The figure also shows that 80% of the time the region will have less than 1,500 MW offline due to forced outages.

Figure 9. Unit Performance Distribution



Additional modeling details can be found in Appendix A.

Each scenario modeled in SERVM[48] consists of one economic forecast error point and one weather year. The first scenario simulated used 1980 historical weather and a 5% under forecast of load growth. To build the loads for this year, the 8760 hour loadshape from the source weather year was multiplied by the economic forecast error multiplier. The resulting 8760 hour loadshape represents what the hourly loads would be expected to be in 2016 if the system experienced the same temperatures as 1980 and loads grew 5% faster than expected due to economic growth. This discrete scenario was simulated for 400 iterations. Each iteration runs for all 8760 hours for a single projected year (2016) attempting to match load and resources at the lowest system cost. Several stochastic variables including unit performance and dispatch error are used and result in independent costs and metrics for each iteration. The average of all the system costs and physical reliability metrics from all these iterations represent the expected values for this scenario.

In all, this process is repeated 192 times. Thirty two weather years combined with 6 economic forecast error points create 192 discrete scenarios. Simulating these scenarios for 400 iterations results in a full distribution of possible outcomes for the year 2016. It should also be noted that this process is applied to all regions in the study. When a 1980 weather year is being simulated, it is used for all regions. This modeling ensures that the actual differences in weather for each respective hour across the study system are captured. For example, when simulating July 9th, 1980, the loads for every region were developed using temperatures from July 9th, 1980. As the sensitivities demonstrate, the ability for one balancing area to provide assistance to another is critical, and understanding load diversity is a necessary component to that ability.

For this particular case study, we focused on the PJM Rest of MAAC (PJM_ROM) NEEM region from the EIPC Study. Although in reality this region is a participant in a structured market, for purposes of the base case analysis, it is treated as a vertically integrated utility. The purpose for this assumption is to simplify the economic comparison. When treated as a single vertically integrated utility, most of the internal load is served by resources within the region at those units‘ production cost. Purchases from outside the region are also assessed at their production cost unless the region is in a scarcity situation. Capacity is self-owned or procured through bilateral transactions between the utility and generators. Modeling the base case this way allows costs for consumers to be easily calculated. The economic reserve margin is based on minimizing total system costs for consumers. The applicability of this analysis to structured markets is discussed in section D of this chapter.

For this study, we set planning reserve margins for all other regions to their defined EIPC Study targets. Next, simulations were run for the study region from 10% reserves to 20% reserves in 2% intervals. To achieve the higher reserve margin levels, natural gas combustion turbine capacity was added. At each reserve margin level, LOLE, total system costs, and hourly market prices were tabulated. While the intent of economic reserve margin planning is to minimize total system costs to customers, the only difference between reserve margin levels is the addition of efficient CT capacity, so all base load costs can be ignored. Only costs that are above the dispatch costs of the marginal CT are tracked which represent the difference in total system costs. These system costs are made up of the following components:

[48] SERVM is an economic resource adequacy model that is used by utilities to develop optimal reserve margin targets using economics as well as LOLE.

1. Production Costs above the dispatch cost of a CT (i.e. the dispatch of oil resources)

2. Net Purchases above the dispatch cost of a CT. Anytime the studied region purchased or sold at costs higher than the marginal cost of a CT, the net purchase costs were tabulated.

3. Unserved Energy Costs (MWh of unserved energy * VOLL) For the base case, the VOLL of was assumed to be $15,000/MWh. A sensitivity around this assumption is included in the sensitivity section.

4. Carrying Cost of additional CT Capacity. For the base case, $100/kW-yr was assumed. Results will be shown ranging from $80/kW-yr to $120/kW-yr.

   For the case study, reserve margin was defined as the following:

   Reserve Margin = (Total Capacity Resources – Expected Peak Load) / (Expected Peak Load)

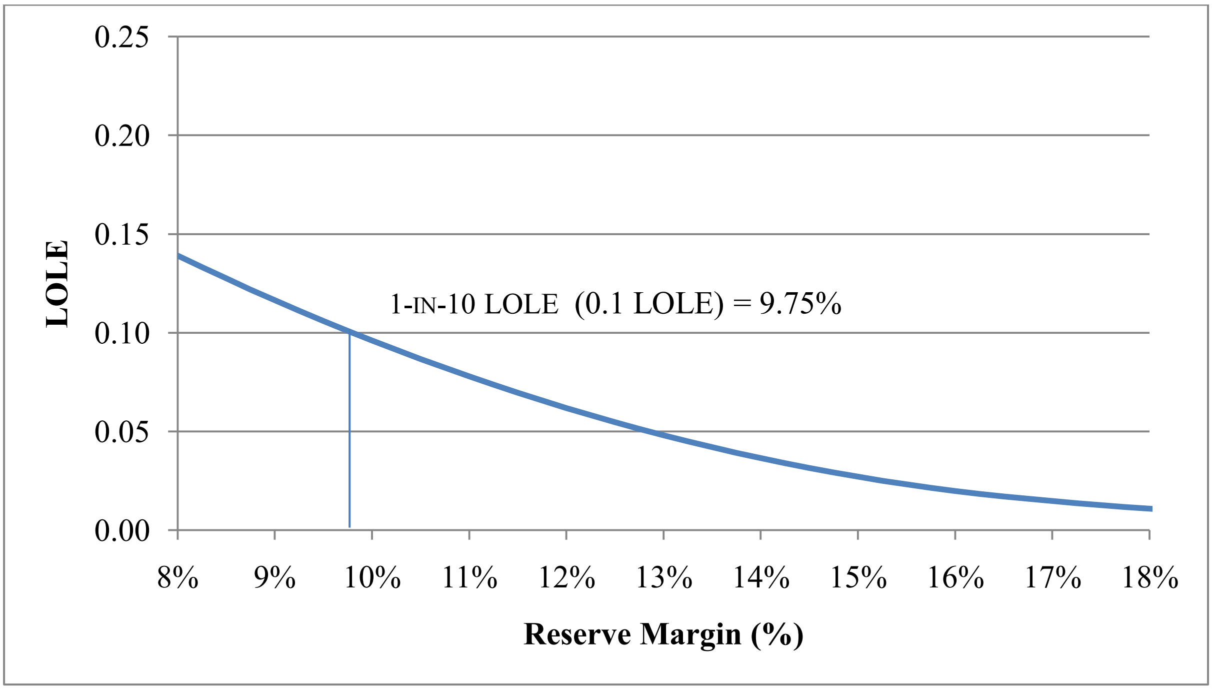
   where total resources includes all demand response resource capacity and the effective load carrying capability of wind and solar resources. See the appendix for these effective load carrying capability values.

B. Base Case Results Assuming a Vertically Integrated Utility

The following figures and sections discuss the Base Case Results.

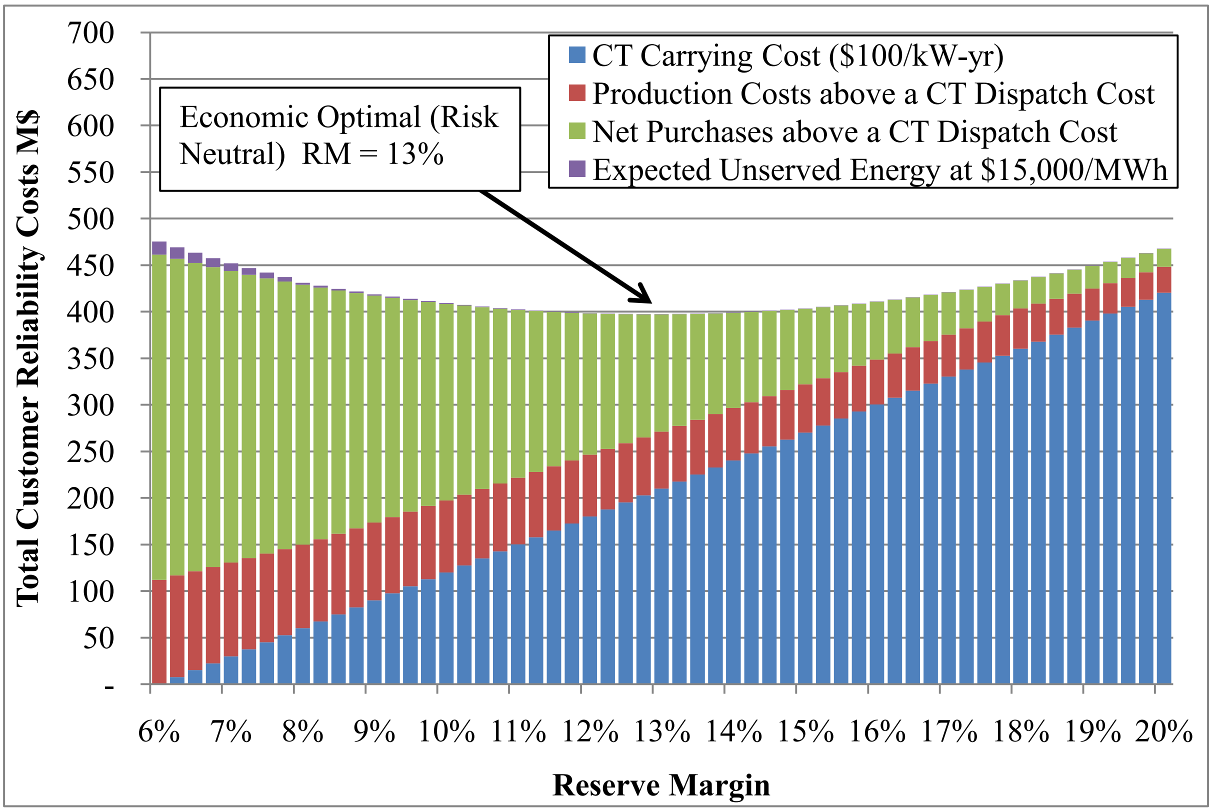
Figure 10 demonstrates that the reserve margin needed to meet the 1-in-10 LOLE standard (LOLE of 0.1) for the PJM_ROM region is 9.75%. An LOLH of 2.4 was met at below 8%. It should be noted that LOLE results are sensitive to input assumptions. As noted in the review of resource adequacy studies, PJM's own assessment indicates 1-in-10 LOLE for the entire PJM RTO falls at 15.3%. The two studies are not directly comparable since this analysis only considers one sub region of PJM and only generic unit outage data was used instead of utilizing actual historical generator availability data. However, one significant reason for this difference is that the PJM study assumes 3,500 MW of import capability, whereas the EIPC inputs assume 9,000 MW+ of import capability. Also, PJM derates 1,800 MW on peak due to temperature. The point here is not to challenge assumptions, but rather to demonstrate how large of a difference the selection of various inputs can change the results of the study. In addition to these, a number of other components that had the capability of shifting the 0.1 LOLE reserve margin by several percentage points were identified– at what point is demand response dispatched, will regions dispatch high cost or energy limited resources to support other regions, will a region shed firm load to maintain operating reserves, how much load diversity can be expected between regions, and will emergency hydro be available during peak load conditions. A few of these questions are addressed in the sensitivity section. While these assumptions can make a substantial difference in LOLE, they only affect a few hours per year or per decade, thus they typically don't have a meaningful impact on total costs or change the optimal economic reserve margin. Since the optimal economic reserve margin is affected by a much larger set of hours and events, it is typically less sensitive to minor inputs.

Figure 10. LOLE



The following figure, Figure 11, demonstrates the differences in system costs at a variety of reserve margin levels. The PJM ROM system represents ~30,000MW at peak load. A change of 1% reserve margin is approximately 300 MW. The carrying cost of this change is $30M/yr assuming the cost of capacity is $100/kW-yr. By adding this incremental capacity when the system is at a 10% reserve margin, total system energy costs (all production costs and purchase costs above the dispatch cost of a CT plus the cost of societal unserved energy) drop by $43M/yr and therefore justify the additional capacity. The additional capacity met a number of distinct needs. In some hours, the additional capacity was used to avoid high cost purchases. In other hours, the capacity avoided the dispatch of high cost resources such as oil turbines. During scarcity pricing conditions, the additional capacity may have avoided purchase costs and lowered market prices. A system that has 300 additional MW available will have lower scarcity prices than one which is 300 MW closer to not being able to serve firm load. And in extreme conditions, the additional capacity may have directly offset firm load shed. In looking at the graph, it is obvious that the benefit of reducing EUE is minor compared to the reduction in other costs as we have stated previously. The cost of EUE could vary greatly and have very little impact on the economics. Reliability at or near a 1-in-10 LOLE target already results in extremely low EUE.

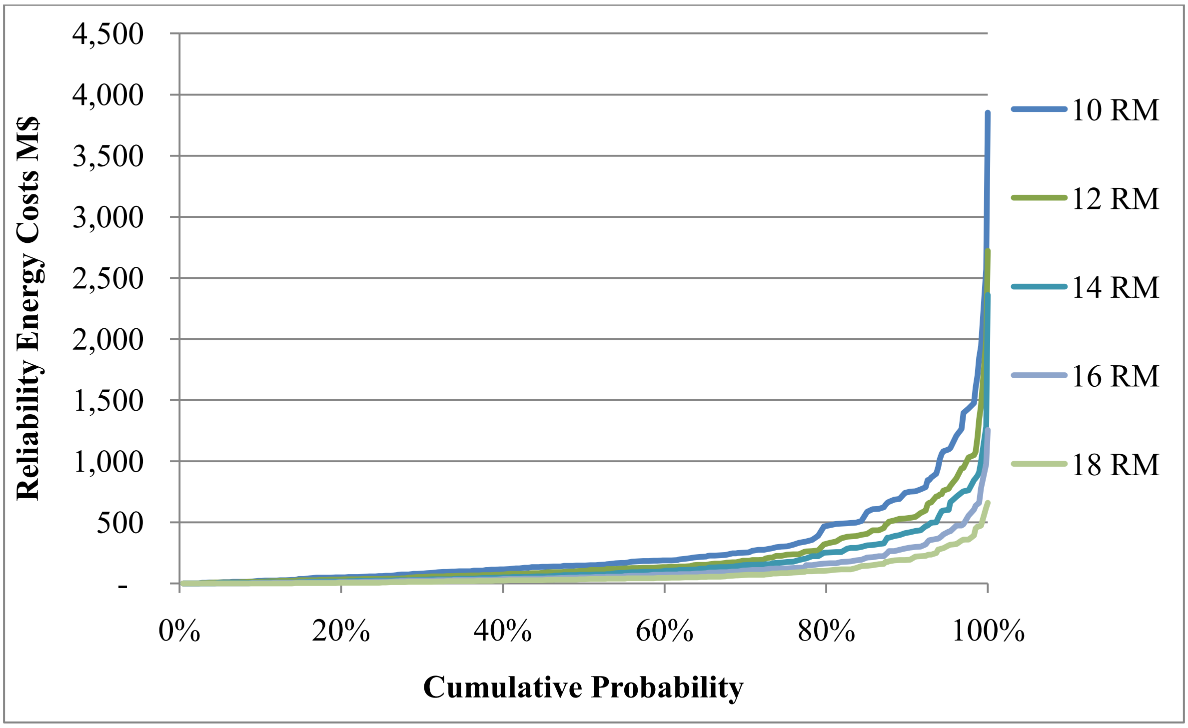
Figure 11. Economic Optimal (Risk Neutral) Reserve Margin[49]



Based on Figure 11, the minimum total system costs to customers is met at a reserve margin of 13%. The figure represents all system costs above the dispatch of a CT plus the cost of unserved energy plus the additional carrying cost of CT capacity over a range of reserve margins. It should be noted how flat the curve is between 12% and 15%. This says that there is some room to move within this range and not be penalized substantially by additional costs. Because this figure represents the average of 1000's of iterations (combinations of weather, load uncertainty, and unit performance), it hides the fact that individual years can be drastically different from the average. This economic target reserve margin doesn't put any additional emphasis on the extreme high cost outcomes, and is therefore defined as the risk neutral target reserve margin. When adding capacity in a regulated, vertically integrated market, the fixed costs are reasonably static whether procured through a PPA or through direct ownership by a utility. Based on detailed engineering estimates of the installed cost of CT capacity, resource planners can be fairly confident in the cost of capacity. In our example, 300 MW will cost approximately $30M per year. However, the incremental capacity may provide less than $1M in benefit in mild weather years during recessions or it may provide >$400M in value in years with extreme weather or unexpected load growth. Figure 12 shows the entire distribution of system energy costs (all production costs and purchase costs above the dispatch cost of a CT plus the cost of societal unserved energy) across different reserve margin levels. The high cost scenarios at the right hand of the chart represent the severe scenarios of extreme weather and under forecast of load.

[49] This figure represents customer system costs for a vertically integrated utility. Structured markets are discussed in later sections.

Figure 12. Distribution of System Energy Costs



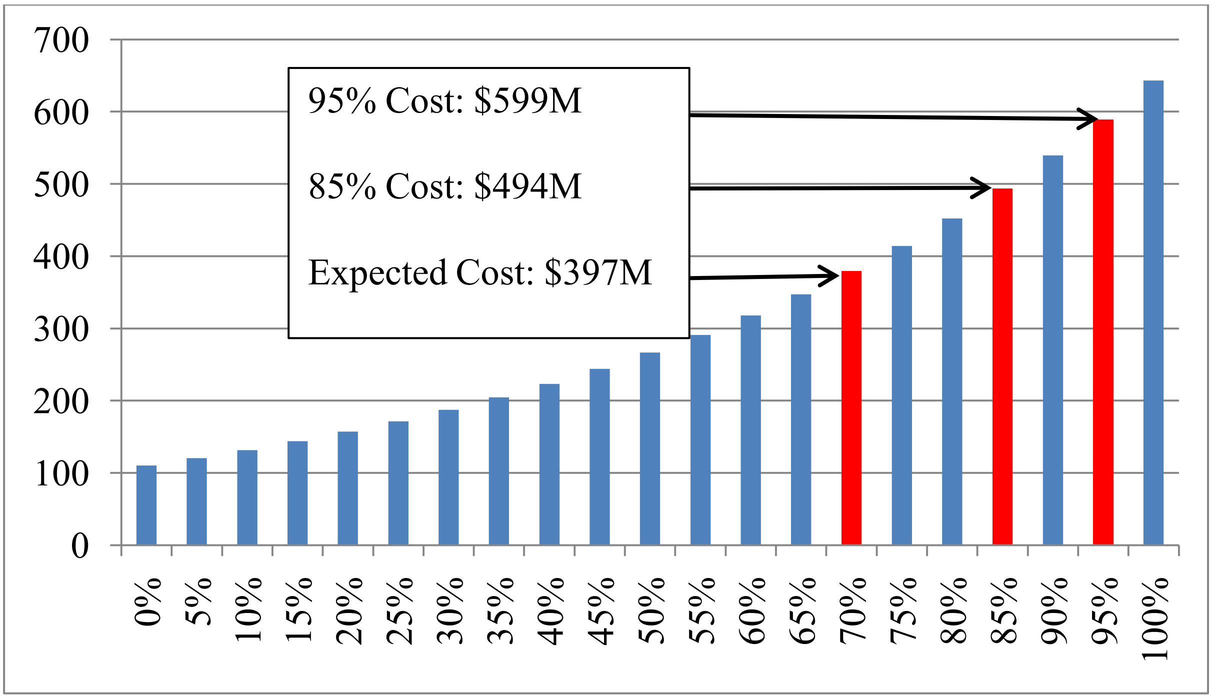
C. RISK ADJUSTED RESERVE MARGINS

To make the trade-off between volatile reliability energy costs (production costs above CTs, purchases above CTs, and EUE costs) and static fixed costs (carrying cost of capacity), a risk adjustment is likely justified to the risk neutral optimum reserve margin. In the same way that a homeowner is willing to pay $1000/year to insure his $100,000 house against loss even though the probability of loss is far less than 1%, load serving entities are likely willing to pay a fixed payment toward installed capacity to insure against an extreme scenarios shown on the previous figure, even if the fixed payment is slightly higher than the average economic benefit. But how much more in fixed costs should customers, planners, and regulators be willing to pay above the amount that is justified by the risk neutral optimum reserve margin?

Traditional risk metrics in the electric power industry include Value at Risk (VaR), Coefficient of Variation, and mean-variance frontiers. Value at Risk is a quantitative measurement of the amount of exposure at various confidence levels within a specific time interval. Coefficient of Variation and Mean-Variance Frontiers are comparisons of variation across various portfolios and planners utilize them to minimize variance in an economically competitive portfolio.

While the conventional definition of VaR is the risk of loss on a specific portfolio of financial assets, it is used in this example as the risk of additional costs above expected costs. The distribution of total production costs above the dispatch cost of a CT plus marginal CT carrying costs for the 13% reserve margin case is shown in Figure 13. The expected cost for this case is $397M. Eighty-five percent of all scenarios in this case have total costs of $494M or less and 95% have total costs below $599M.

Figure 13. Distribution of Total Costs (Production Costs and Purchases Costs Above a CT + CT Carrying Costs + Cost of Unserved Energy) at 13% Reserve Margin



Typically firms will evaluate VaR at 85%, 90%, or 95%. The distributions for each reserve margin in the chart above allow us to calculate the approximate VaR over a 5-year period for the entire range of possible scenarios. Subtracting the total system cost from the average system cost produces the VaR at the respective confidence level. The VaR at 85% is $494M - $397M = $97M. This means that in 85% of all weather scenarios and economic growth scenarios, total costs should not be more than $97M above the expected costs. The table below, Table 6, summarizes VaR at a range of confidence levels for each of several different possible reserve margin targets including the 13% reserve margin example presented in Figure 13 above.

Table 6. Risk Analysis

		Risks Above Expected Costs		
Reserve Margin	Total Expected Costs	VaR 85	VaR 90	VaR 95
%	M$	M$	M$	M$
10%	409.3	145.3	208.4	321.2
11%	402.5	128.2	182.9	277.6
12%	398.5	112.2	159.2	237.8
13%	397.4	97.2	137.2	201.7
14%	399.0	83.3	117.0	169.3
15%	403.4	70.5	98.5	140.7
16%	410.7	58.7	81.8	115.8
17%	420.7	47.9	66.8	94.6
18%	433.5	38.3	53.5	77.1
19%	449.2	29.7	42.0	63.3

As an example from the previous table, moving from 13% reserve margin (economic risk neutral reserve margin) to a 15% reserve margin reduces Var 95 (a measure of the risk above the expected case) from $201.7M to $140.7M while the change in expected system costs from 13% to 15% is only a $6M increase (as seen previouslyin Figure 11). Targeting a 15% reserve margin results in slightly higher costs than the minimum cost reserve margin, but provides substantial risk mitigation from a single utility perspective. The determination of an economic optimal risk adjusted reserve margin which represents the ideal tradeoff in risk and cost will depend on the risk appetite of the decision makers at the respective utility or regulatory body.

D. Structured Markets: The Consumer Perspective

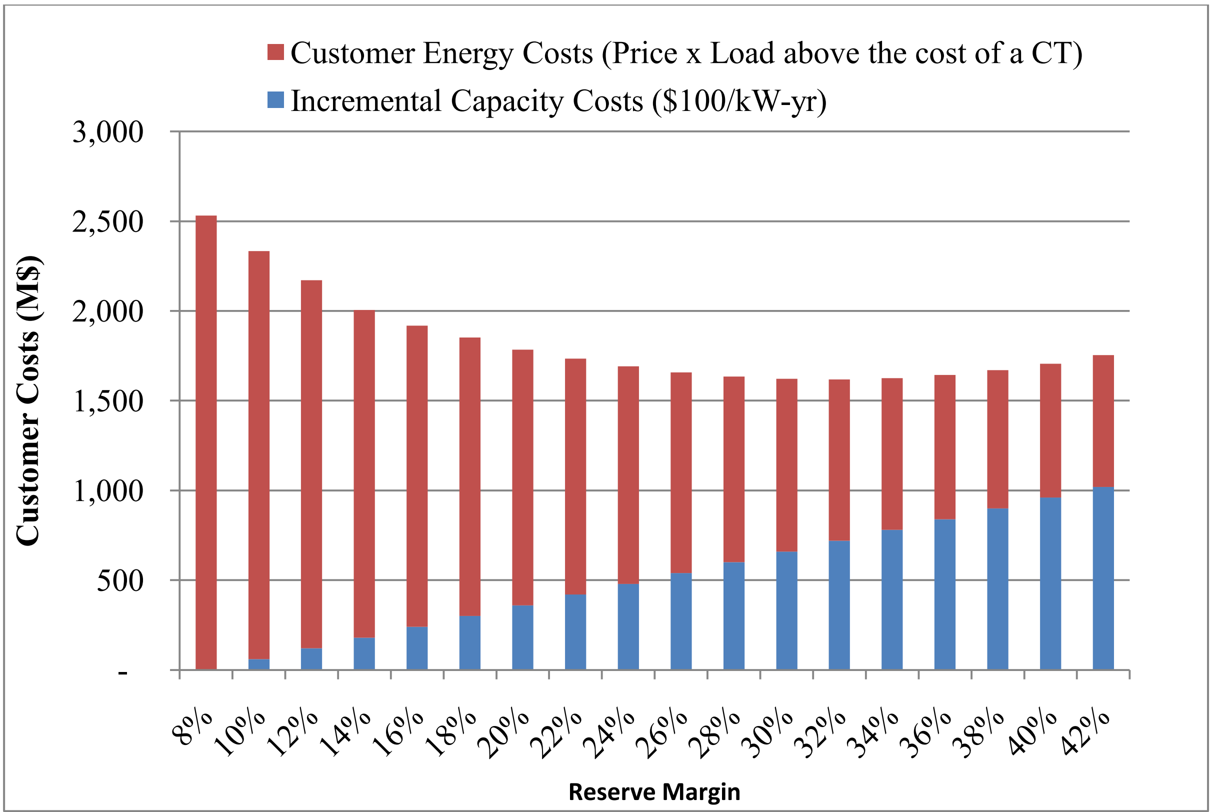
Economic reserve margin planning is contingent on market structure. In a vertically integrated utility environment with rate based assets, adding capacity only affects the cost of serving load that would have otherwise been met by resources with dispatch costs above the dispatch cost of that incremental resource. For example, imagine a utility which had no neighbors. The cost of serving load is only the physical production costs (fuel and variable O&M costs) of generating electricity to meet those loads. If this utility would typically dispatch oil turbines at loads above 30,000 MW at a cost of $300/MWh, the benefit of replacing the oil fleet with efficient gas turbines (with dispatch costs of $100/MWh) would only be the production cost savings ($200/MWh). In this example, if the oil fleet previously ran 100 hours per year, the benefit would only be \$20/kW-yr[50], not nearly enough to justify replacing the oil capacity.

However, under another market construct, the economic decision analysis would be very different. Imagine a wholly competitive energy market where all load serving entities are completely independent from generating companies. The load serving entity is forced to buy all its energy from the energy market at the market clearing price. Generators get paid based on which unit in the marketplace was on the margin, or which was the highest cost unit to be dispatched. For the owners of base load resources, having high cost oil generators on the system and in the dispatch for 100 hours per year could be a boon. Whenever a high cost unit is on the margin, each and every generator will be paid the dispatch cost of that unit, which in this example is \$300/MWh. If the system averaged 30,000 MW in load per hour, generators would receive \$900M[51] in aggregate over these hours. If the average production cost of those units was \$30/MWh, 90% of the revenue is operating profit. If the oil fleet was 1,000 MW in size, suppose replacing it with efficient gas turbines lowers the marginal cost in these hours to \$60/MWh. Now, the net revenue to all generators would only be \$180M[52] for these hours. The reduction in revenue of \$720M for generators is a direct benefit to consumers. In fact, since adding 1,000 MW of efficient CT lowered costs by \$720M per year, consumers would be getting \$720/kW-yr of benefit from capacity that should cost no more than \$100/kW-yr. However, base-load generators, that would no longer be receiving those revenues, may be dependent on this revenue to cover fixed costs. Any approach to identifying the ideal reserve margin target should consider both the generator and consumer‘s perspectives for the market structure being examined.

First, let us further consider the benefits of increased reserve margins to consumers in an energy only market structure. Using the same case study simulations, if we were to compare the energy market costs (assuming customers pay for their entire load at the market clearing prices) as seen below in Figure 14 to a proxy for incremental capacity costs, then the cost/benefit analysis could support reserve margins above 30% meaning there are still energy market savings greater than the incremental capacity costs at these reserve margin levels. The difference between this analysis and the results seen in the single regulated utility example previously shown in Figure 11 is due to the fact that load serving entities (customers) are paying the high spot prices for all load (30,000 MW) in a given hour versus only paying expensive prices for the high cost resources on the margin which may only be a couple hundred MWs of load.

[50] \$200/MWh * 100 hr/year = \$20/kW-yr
[51] \$30,000 MW * \$300/MWh * 100 hrs = \$900 M
[52] \$30,000 MW * \$60/MWh * 100 hrs = \$180 M

Figure 14. Illustration of Economic Target for a Load Serving Entity That Relies 100% on the Energy Market



This is a purely hypothetical exercise however. Setting a reserve margin target based on these customer savings is not feasible or desirable in current structured markets for several reasons. First of all, in energy only markets the incremental capacity costs shown in Figure 14 are not paid by consumers so the consumers would always benefit from higher reserve margins while energy margins for generators continually decrease. In structured markets that have forward capacity markets, all generators are paid the same capacity price. In the above example, only the incremental capacity costs were assumed to illustrate the comparison to the vertically integrated utility analysis in Figure 11. In addition, load serving entities in current RTOs often self supply or enter into bilateral agreements to cover a substantial portion of their load and balance the remainder of their load using the energy market. Under this scenario, the savings to customers would be greatly reduced and would more likely resemble the optimal reserve margin methodology that was shown previously in Figure 11. While the idea that a reserve margin well above 20% is ideal for consumers fully exposed to the energy market may be counterintuitive, it is simple to demonstrate. In PJM in 2010, reserve margins were well above 20%[53], but there were still 81 hours with energy prices more than $100/MWh higher than the dispatch cost of a CT. The load in these hours for the PJM_ROM region averaged 33,000 MW, so the total cost of energy above the cost of CTs was greater than $264M[54]. If an additional 1,100 MW of combustion turbines had been present,

[53] *2011 Long-Term Reliability Assessment,* retrieved on September 2, 2012 from http://www.nerc.com/files/2011LTRA_Final.pdfNERC LTRA

[54] 33,000 MW * 80 hours * $100/MWh = $264 M

presumably the costs above CTs would have been negligible[55]. This suggests that 1,100 MW of CTs can save $264M in one year compared to the carrying cost of that capacity at only $110M[56] per year. This lends some credence to our theory that consumers exposed to the energy markets can receive substantial benefits with new resources even at high reserves margins.

In the same region, however, energy margins for CTs were only ~$50/kW-yr. So CTs were not getting full cost recovery from the energy market, and yet consumers would have benefitted from substantially more capacity.

E. STRUCTURED MARKETS: THE GENERATOR PERSPECTIVE AND THE MISSING MONEY PROBLEM

Wholesale peaking generators have not been able to recover their fixed carrying costs in the past decade from energy markets. Even in regions with capacity markets which pay supplemental revenues to generators, without long-term bilateral agreements, CTs have been unable to cover costs[57].

But how critical of an issue is this? Economic optimal reserve margins for energy only markets are defined as the point at which marginal capacity can earn enough revenues to cover fixed costs. How far from this economic target are most structured markets today? CT energy margins are the summation of all the hourly market prices above the dispatch cost of a CT for a given year. As shown in Table 7, which presents the perspective of a merchant generator in such a market, CT energy margins and the frequency of prices above the dispatch cost of an efficient CT decrease as additional CTs are added to a system. These energy margins represent the weighted average energy margins in the Base Case simulations. Recall that the 1-in-10 LOLE based reserve margin was at 9.75% and the economic optimal reserve margin based on a single regulated utility was 13% (See Figure 11). The CT only receives $86/kW-yr at a 9.75% reserve margin and $73/kW-yr at a 13% reserve margin which is used to go towards covering its fixed costs of $100/kW-yr. The energy only economic optimal target reserve margin for this region is 7% because that is the point where a CT fully recovers its fixed costs.

Table 7. Merchant Generator Perspective

Reserve Margin	8%	10%	12%	14%	16%	18%
Expected CT Energy Margins ($/kW-yr)	$ 94.75	$ 85.63	$ 77.58	$ 70.57	$ 64.62	$ 59.72
CT Hours of Operation	1,211	1,104	1,007	978	926	897

How is it possible then that generators are only able to recover their fixed costs at a 7% reserve margin, but consumers of a vertically integrated utility have financial benefit to having reserve margins at 13%? In many hours in the simulations, the study region is

55 Load in these hours was 1,100 MW higher than in hours with prices equal to the dispatch cost of a CT, suggesting the addition of 1,100 MW of efficient CTs would bring the high prices down close to the cost of a CT.
56 1,100 MW * $100/kW-yr = $110 M
57 PJM, State of Market Report, 2010, Vol. 2, p. 33

purchasing power from outside regions. Take an example hour in which the region is purchasing 2,000 MW at $200/MWh. The addition of 500 MW of resources to the study region does more than just avoid purchase costs of 500 MW at $200/MWh. It actually brings down the cost of the remaining 1,500 MW that needed to be purchased. When the study region was originally purchasing power from the outside region, the clearing price was based on the unit that was on the margin in the outside region. In order for the study region to buy 2,000 MW, the outside region had to dispatch progressively higher cost resources. Since in the change case in which the study region added 500 MW of capacity, only 1500 MW needed to be purchased, the clearing price for the purchase will be lower (for this example assume purchase cost dropped to $150/MWh). So the addition of the resource provided $140/MWh of benefits for the 500 MWh of purchases it avoided[58]. It also achieved $50/MWh benefit for the 1,500MWh of purchases that were still made. The total benefit in this hour is $145,000[59] or $290 for each MWh of energy provided by the new resource[60]. So the benefit to the customer is higher than the revenues that might be seen by the new generator. This disconnect between the consumer perspective and the generator perspective was partially explained above, but there are additional reasons that generators have a difficult time recovering costs in many structured markets today.

1. Price Caps

Many regions have regulatory caps on bid prices at ranges between $1,000/MWh to $3,000/MWh. As discussed, this is less than VOLL and from a theoretical perspective suggests that consumers are not paying enough for resource adequacy. However, there is a reserve margin at which peaking generators would cover the cost regardless of where the price cap was set. If generators could achieve full cost recovery at an 11% reserve margin with no price caps, then generators should be able to achieve full cost recovery at perhaps an 8% reserve margin if there was a $1,000/MWh price cap. The point being that if the maximum price is lower than VOLL, generators should build less capacity such that high prices (but less than $1,000/MWh) are hit more frequently. Price caps are frequently cited as the primary reason for ―missing money"[61], yet the authors believe this is a small component of the overall market design problems.

2. Physical Reliability Targets

ERCOT is one of few energy-only markets in North America. As an energy only market, there is no explicit reserve margin target. However, ERCOT performs an LOLE study periodically which communicates to the system the reserve margin which would achieve 0.1 LOLE. While not a target, several of the LSEs in ERCOT may use that reserve margin for their own generation planning and either build or contract to maintain at least that level of reserves. The potential result of individual LSEs planning to the 0.1 LOLE reserve margin is that the aggregate system reserve margin may be equal to or higher than the 0.1 LOLE reserve margin. If a region consisted of 10 LSEs, all of which planned to the same reserve margin independently, the aggregate reserve margin would be higher since there is diversity between disparate loads. But regardless of how a region

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[58] The load serving entity paid the $60/MWh dispatch price of the resource instead of the $200/MWh market price

[59] (140 * 500 + 50 * 1,500) = $145,000

[60] $145,000 / 500 MWh = $290/MWh

[61] Hogan, William (2005), "On an ―Energy Only" Electricity Market Design for Resource Adequacy."

ends up with a reserve margin that is equal to or higher than the 0.1 LOLE, the impact on CT energy margins is typically negative. As shown in our simulations, the expected CT energy margin at a 0.1 LOLE reserve margin is less than the carrying cost of capacity even with no energy price caps. To clarify the theoretical reason for this disparity, an illustration will be helpful.

Imagine that regions planned to a reliability target of one event in 10,000 years. To achieve this lofty goal, reserve margins may need to be at 30%. With a 30% reserve margin, there would be very few, if any, hours with energy costs much above the dispatch cost of CTs. Unlimited price caps would make no difference since there would almost always be additional capacity available to prevent scarcity prices. So if load serving entities or a portion of the load serving entities in a region plan to an LOLE target, it is possible that system reserve margins may be higher than the levels at which generators would receive cost recovery.

3. Economic Growth Slowdown

Since 2000, the US economy has consistently grown at slower rates each year than was expected 4 years prior.[62] When the economy grows slower than expected, load grows slower than expected. Since generation expansion is planned years in advance, new generation has come online while the load it was meant to serve has not materialized. An example utility may have expected 1,000 MW of load to appear due to a growing economy and so built new generation. However, much of that load did not appear over the past 10 years and so reserve margins rose. With reserve margins not only above the level which would achieve cost recovery for efficient CTs, but also above 0.1 LOLE based reserve margins which typically result in low CT energy margins, returns for peaking generation have been consistently small. Presumably, at some point the economy will begin to grow faster than economists expect and load growth may outstrip resource additions, resulting in lower reserve margins and higher returns for peaking generators. However, as discussed in other sections, reserves would need to drop substantially in order for this to occur.

To be clear, this issue is different from the issue related to the use of physical reliability metrics in setting reserve margin targets. Even if the economy was experiencing robust growth, the use of physical reliability metrics could still negatively affect the energy revenues generators could expect. Slow economic growth simply adds to the disparity produced by high reserve margin targets since realized reserve margins end up being even higher than the high reserve margin targets when the economy grows slowly.

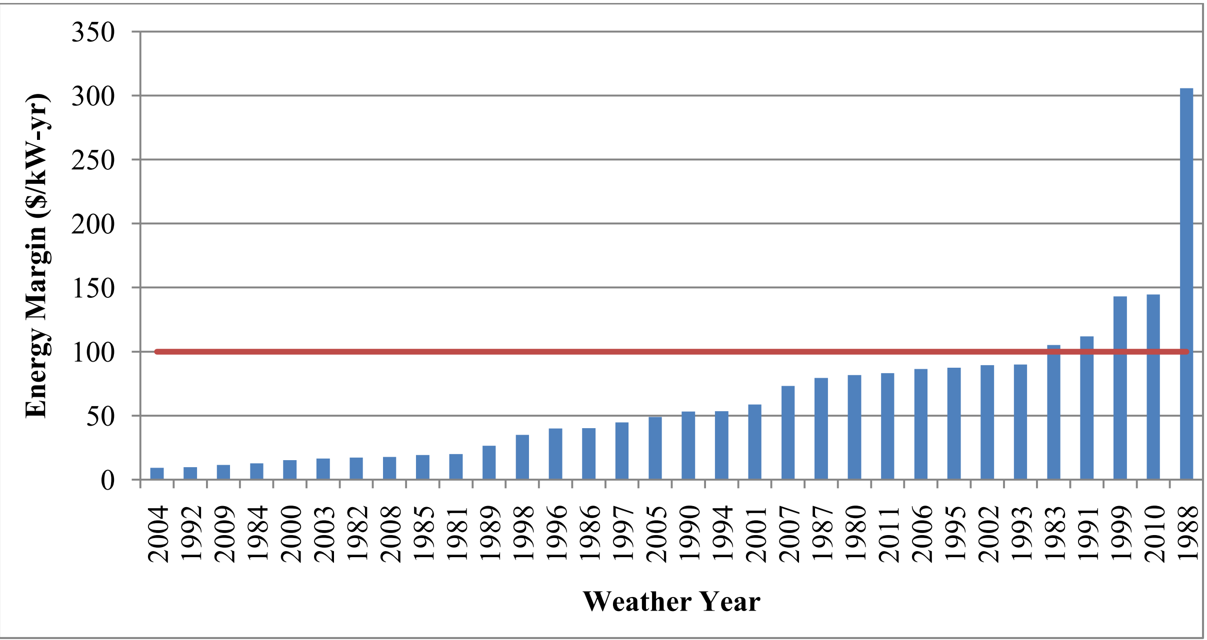
4. Weather Volatility

Even with a regulatory-enforced scarcity pricing curve designed to achieve full cost recovery for peaking generators, differences in weather patterns mean that many years energy prices would be lower than needed for generators to recover costs. Figure 15 shows results from the Base Case simulations for the study region. In a small number of possible weather years, returns would far exceed the necessary levels to cover carrying costs. However, in a large percentage of years, revenues would be far less than necessary. This is not a feasible market space for many developers who rely on debt to

[62] See CBO forecast for 2000-2013

finance the construction of their facilities. If a generator cannot demonstrate its ability to cover specific debt service ratios each year, it will not be eligible for debt financing.

Figure 15. CT Energy Margins by Weather Year



5. Generator Market Forecasting

The authors will not venture to guess the skill level of generators determining when markets will be in equilibrium such that new generation can cover fixed costs. However, this task is quite difficult, so expectations of their accuracy should be quite low. This analysis must typically be performed 5 years in advance of the new generation coming online and take into account dozens of variables including load growth rates, fuel costs, market interaction, regulatory intervention, scarcity pricing, emission prices, resource mix changes, demand response impacts, and bidding strategies.

In summary, each of the components mentioned above contribute to the missing money problem. It is not an isolated issue simply due to a single design flaw as frequently cited. Since generators in energy only markets prefer low reserve margins to achieve cost recovery what is the best way to incentivize generator investment to achieve 1-in-10 LOLE and/or achieve a higher reserve margin that is more economic for consumers. Forward capacity markets have been designed in many of the existing structured markets to alleviate this disconnect. In this capacity market design, all generators are provided additional capacity payments to allow new generators to recover fixed costs at a reserve margin that meets 1-in-10 LOLE standard. The setback to this approach is that while consumer energy costs are reduced at the 1-in-10 LOLE level, the fact that capacity payments are paid to all capacity forces total customer costs to be higher than if reserve margins remained at the lower energy only economic reserve margin target. This is further illustrated in the next section. Another method used to solve this problem is to force load serving entities to enter into bilateral contracts up to a specified reserve margin. This method is used in the California ISO (CAISO) today. One advantage of this method is that it allows generators to enter into long term contracts which provide revenue stability versus a forward capacity market which only provides revenue in the short term. It also allows load serving entities to make decisions on capacity based on long term cost projections.

F. SUMMARY RESULTS FOR DIFFERENT MARKET CONSTRUCTS

Table 8 summarizes the findings of the base case results from the perspective of a single vertically integrated regulated utility, energy only market, and energy plus forward capacity market. Table 8 shows that the economic optimal reserve margin for the regulated utility is 13% based on the consumer‘s total system cost perspective as defined in Section A of this Chapter . This target resides several percentage points above the 1-in-10 LOLE based 9.75% reserve margin. The reserve margin target for the energy only market is 7% based on the level of reserves at which a new CT will recover its costs. Under an energy only construct, consumers would benefit from higher reserve margins but energy margins are lower than the minimum required to sustain the higher reserve margin. For the energy plus forward capacity market construct, the target reserve margin is assumed to be based on 1-in-10 LOLE[63] which is 9.75% and it is assumed that the capacity payment paid to all generators at this level is enough that when combined with energy margins a CT will recover its fixed costs.

From a total system costs perspective, the regulated utility provides the lowest cost at its target reserve margin. It should be noted that the results for each construct were developed from the same simulations meaning there were no benefits recognized from a more coordinated economic dispatch that an RTO/ISO would provide. The energy only construct‘s total costs at a 13% reserve margin are much lower per year, but in theory this reserve margin would not materialize because generators would not recover their fixed costs at this level. The energy plus capacity market construct produces higher costs as reserve margins increase from the 7% energy only economic target because the additional capacity payments are made to all generators. If targeting 1-in-10 LOLE, the total costs including a capacity payment that made generators whole is $7.925 B as shown in the table. It should be noted that there is also some risk benefit seen with the structures that result in higher reserve margin targets because the volatility related to energy costs decreases as reserve margins increase.

Assuming idealized resource mixes and purely competitive or efficiently regulated markets, the cost comparison below illustrates how the structure that results in the lowest reserve margin does not necessarily produce the lowest system cost.[64]

Table 8. Total System Costs at Target Reserve Margin Levels

	Target Reserve Margin	Total System Costs at Target (Billion $)
Regulated Utility	13.00%	$7.805
Energy Only Market	7.00%	$7.860
Energy plus Capacity Market	9.75%	$7.925

To be clear, the point of this table is not to state that the regulated utility environment is the optimal structure. Energy only and energy plus capacity markets offer a number of attributes such as fostering competition and diverse resources that may result in lower total system costs for customers. This table just highlights that market structure can have a

63 Forward capacity markets in the Eastern Interconnection currently base targets on 1-in-10 reliability metrics. These include PJM, NY-ISO, and ISO-NE.

64 These total system costs include all capacity costs and energy costs (not just costs above the dispatch costs of a CT) to meet load as well as the societal costs of unserved energy.

significant impact on both reliability and total system costs and should be considered when performing resource adequacy planning.

G. Selection of Marginal Resource in Economic Reserve Planning

It is important to remember that the identification of a target reserve margin based on economics is contingent on the marginal resource used to vary reserve margins. A single point estimate of the ideal reserve margin assumes that all capacity should be treated as equal. In reality, economic resource adequacy planning must consider the implications for all types of resources that may provide resource adequacy. The economic trade-off analysis is highly dependent on the characteristics of the capacity being added. All capacity is not equal. Adding demand response capacity will not provide as much economic benefit since it is not dispatched until prices are much higher or reliability is a more pressing concern. In generic SERVM modeling runs, the average market price when CTs are dispatched is ~$70/MWh. The average market price when demand response is called may be $500/MWH+. This indicates that the system costs between reserve margins will be drastically different if CTs are the marginal unit type vs. demand responses resources. The carrying costs are also different between the resource types. Also, the incremental decision may not be the addition of a new resource; it may be the retirement of an old high-cost resource. While 1-in-10 LOLE is an attractive metric because of its simplicity, the reserve margin determined through this method treats all capacity the same. If a resource can keep the lights on as effectively as a combustion turbine, the different product characteristics are immaterial. But the metric doesn‘t provide guidance to what type of resources should be used to meet peak requirements and leads to many uneconomic resource procurements. Resource planning is unfortunately a complicated process that requires the assessment of both the economic and physical reliability contributions of resources.

VI. IMPACT OF VARYING DEFINITIONS, CALCULATIONS, AND APPLICATIONS OF 1 IN 10 ON ECONOMICS

Based on the research performed in Section III, the majority of entities in the Eastern Interconnection that use a physical metric for setting reserve margin targets use the 1 day in 10 year standard. Of those that use the 1 day in 10 year standard, all but one use an identical definition for the metric. SPP is the only entity that uses a different definition. SPP assumes 2.4 LOLH versus the standard 1 event in 10 years (0.1 LOLE). The latter is more stringent and leads to a higher reserve margin level. In this study, using the 2.4 LOLH definition typically results in a reserve margin 5% lower than the 0.1 LOLE derived reserve margin. However, although SPP measures reliability against the less stringent 2.4 LOLH metric, their reserve margin target is set at a higher level than suggested by the metric, potentially obviating the difference in expected reliability.

As part of this paper, the authors were asked to address how the varying definitions, calculations, and applications of the 1 day in 10 years standard impact the economics of resource adequacy. If regions planned reliability using the lower 2.4 LOLH instead of the 0.1 LOLE, reliability costs would be much higher. The base case simulations indicate reliability costs (excluding capacity costs) at the 0.1 LOLE equal to $290M/yr while the reliability costs at 2.4 LOLH are $450M/yr, a difference of $160M/yr. The 2.4 LOLH scenario has lower capital costs since it has a lower reserve margin, but even after adjusting for capital cost savings, the less stringent 2.4 LOLH developed reserve margin would result in additional total system costs of $40M/yr compared to planning using the 0.1 LOLE definition. In addition, those numbers do not reflect what would happen if all regions used the lower standard. The base case assumes that other regions still maintain higher reserves, muting the impact of the less stringent standard. If all regions planned using the lower standard, average costs would be expected to be exorbitant. In addition, average economics doesn't adequately consider the risk of high impact scenarios. In cases in which load was much higher than expected or units didn't perform as well as expected, the additional costs of only maintaining reserves to meet the 2.4 LOLH on average could be in the billions of dollars. The base case economic simulations indicated that the difference in costs for the most extreme case if planning to 0.1 LOLE versus planning to 2.4 LOLH could be greater than $2B for a single year.

For a small region with few interconnections, the 0.1 LOLE and the 2.4 LOLH based reserve margins could potentially both be higher than the optimal economic reserve margin, but in general, the base case simulations demonstrate that using the 2.4 LOLH definition likely results in a more risky and high cost system if modeled accurately. Compared to the 0.1 LOLE, the economic optimum reserve margin could be higher or lower depending on a number of system attributes including system size, market structure, neighbor assistance availability, and transmission availability. And depending on assumptions such as how emergency operating procedures will be employed and how capacity is counted, the comparison is further complicated.

The sensitivities presented in the next section show how some of these assumptions drive the 1-in-10 LOLE target and the economics of resource adequacy. Based on our past experience, the 1-in-10 LOLE target is more sensitive to these assumptions than a methodology that uses an economic framework. An LOLE method can be driven by one event or one peak hour while the economics that measure more than the cost of firm load shed are impacted by many more hours across the year and are therefore less sensitive. From our perspective, it is critical for regulators and planners to know if its target reserve margin is economic.

VII. IMPACT OF INTERCONNECTED MARKETS AND BROAD PLANNING ON RESOURCE ADEQUACY AND 1 IN 10 CALCULATIONS

Astrape performed several sensitivities around the regulated utility base case to show the impact that interconnected markets and inter-regional commerce have on the resource adequacy of the region being studied. If markets are highly interconnected and well coordinated among regions, then resource adequacy targets could be lowered. In the base case, there is substantial transmission capability between the study region (PJM_ROM) and surrounding neighbors. In fact, the limit to and from PJM_E and PJM_R_RTO is virtually unlimited as the 8,000 MW transfer capability is rarely fully utilized. With these limits, it is likely that the constraint is capacity on the other side of the interface rather than the transmission capability.

A. Island Sensitivity

The first sensitivity that was simulated treated PJM_ROM as an island. This sensitivity is purely academic since it in no way represents reality. When the case is simulated, the region would need to carry an 18% reserve margin to meet the 1-in-10 LOLE standard. This compares to a 9.75% reserve margin to meet the same criteria in the base case. Given these results, it could be stated that surrounding regions via load diversity and generator diversity provide approximately 8% of reserves for the PJM_ROM region. For this sensitivity, economics were not evaluated.

B. Allow Neighboring Regions To Dispatch Demand Response In Order To Assist Neighboring Regions

The next sensitivity was designed to understand the impact of allowing regions to dispatch demand response resources in order to assist another region. The typical approach to demand response is to only call on it during emergency conditions. In actual practice, it is unlikely that one region would dispatch emergency demand resources in order to be able to sell generation to other regions. However, there is a range of types of demand response, some of which may self-dispatch at lower prices or may have substantial availability. These resources may be dispatched more frequently and may possibly be used in a way that allows one region to sell to other regions. The base case did not allow these resources to be called in order to free up other capacity to be sold to neighbors. The change case was to eliminate this constraint. If one region was able to meet firm load obligations and operating reserve requirements in an hour, and had additional demand response capacity, SERVM was configured to allow the demand response resource to dispatch and sell energy to another region. In this change case, the reserve margin needed to maintain 0.1 LOLE shifted from 9.75% to less than 7%. The economic optimum shifted from 13% to approximately 12%. This change in emergency dispatch affects the 0.1 LOLE based reserve margin more than the economic reserve margin because LOLE is more sensitive to what occurs in these peak hours.

C. Operating Reserve Sensitivity

For the base case simulations, all regions were given a 2% spinning reserve requirement and a 4% total operating reserve requirement. Firm load shed occurred if operating reserves dropped below the 2% spinning reserve requirement. In this sensitivity, the spinning reserve requirement was allowed to be completely depleted before shedding firm load. As expected, the results of the sensitivity showed that both the 1-in-10 LOLE target and economic target dropped by 2%.

D. System Equivalent Forced Outage Rate (EFOR) Sensitivity

The Equivalent Forced Outage Rate (EFOR) is the average percentage of capacity unavailable when needed. The 1-in-10 LOLE target and the economic optimal target both shifted with a 1 to 1 ratio as system EFOR shifted. In other words, when system EFOR for the region was increased by 3%[65], the 1-in-10 LOLE target shifted from 9.75% to 12.75% and the economic target shifted from 13% to 16%.

E. Remove all Load Diversity Among Neighbors

If load diversity is removed completely and all regions reached peak load at the same time, then the target to meet a 1-in-10 LOLE standard shifts from 9.75% to 15.5%. The economic target shifts from 13% to 18%. The impact during peak hours impacts LOLE slightly more than it impacts the economic target.

F. Transmission Sensitivities

Two sensitivities were performed for transmission. In the first, all transfer capabilities between regions were reduced by 50%. In the second a distribution was used for each interface representing the availability of the interface. The distribution for this sensitivity is shown in Figure 16. By using this distribution, the range of transmission availability can be captured from 0% to 100%.

Figure 16. Distribution of Transmission Availability

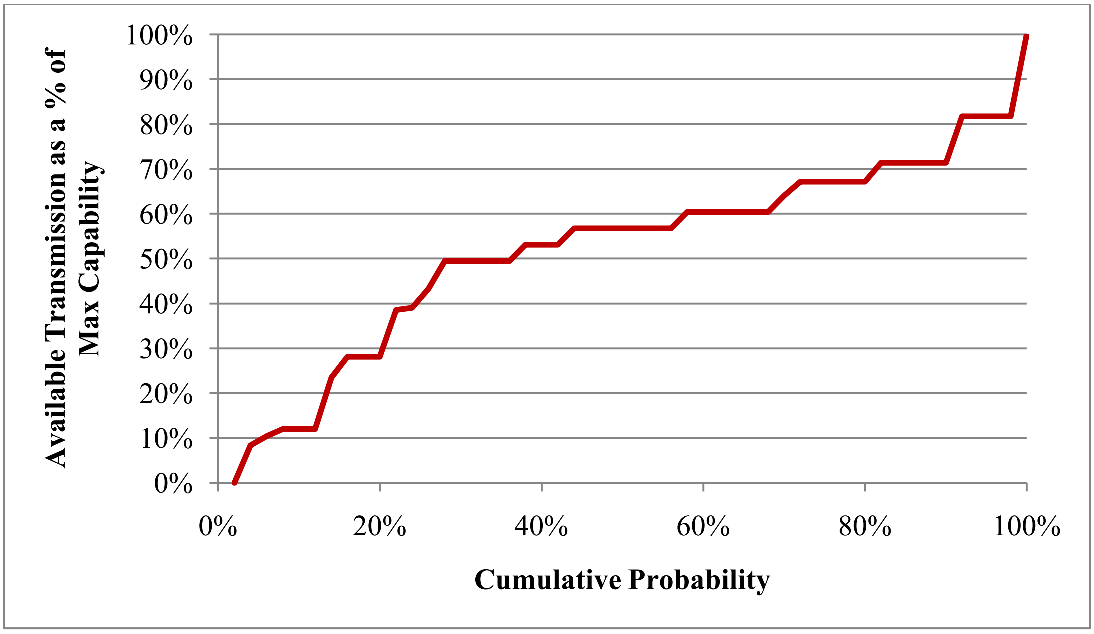


Table 9 shows the results of the two sensitivities. Using the distribution shown above in Figure 16 impacts both the 1-in-10 LOLE and economic optimal reserve margin more than just reducing the capability by 50%. This is logical because the distribution is more stringent in that there are hours where no transfers will be allowed to occur. Because the region being studied has substantial oil resources in its mix, it is purchasing a substantial amount of energy for economic reasons. When transmission is limited, these purchases decrease and the

[65] The starting system EFOR of 5% was increased to 8%.

optimal reserve margin level increases considerably. Accurately capturing the import capability of a region has a high significant impact on results.

Table 9. Transmission Sensitivities

	Reserve Margin @ 1-in-10 LOLE Standard	Economic Optimal Reserve Margin	Avg. Demand Response Call Hours Per Year at 10% RM
Base Case	9.75%	13.00%	4.5
50% Transmission Capability	11.75%	17.00%	15
Transmission Distribution	14.00%	20.00%	13

Since the base case uses static high transfer limits, the base case results are likely too optimistic for both the economic optimal reserve margin and the 1-in-10 LOLE reserve margin. Using refined transfer limits would likely show that for the targeted region, the optimum economic and 1-in-10 LOLE reserve margins would be several percentage points higher. The table above indicates a reasonable upper limit for where these values could fall.

G. Expanding Topology

A sensitivity was performed to understand how expanding the overall topology would impact the optimal reserve margin for PJM_ROM. For the sensitivity, SOCO and NE-ISO were added to the topology. By adding two additional regions, the LOLE target shifted from 9.75% to 9.25% and the economic target shifted from 13% to 12.5%. Even though PJM-ROM is not directly connected to either region, the dynamic market clearing resulted in more efficient dispatch and the additional regions provide extra load and generator diversity. This indicates that modeling the entire Eastern Interconnection could result in lower targets than indicated by the base case results.

H. Summary

A summary of these results for both the base case and numerous sensitivity cases is shown in Table 10. The overall takeaway is that an optimal level of reserves depends greatly on assumptions made about surrounding interconnections and installed capacity of neighboring regions. These sensitivities also illustrate the need for further analysis in which the full Eastern Interconnection is simulated and appropriate assumptions are verified for a number of these categories.

Table 10. Summary of Analysis Results for Base and Sensitivity Cases

	Reserve Margin @ 1-in-10 LOLE Standard	Economic Optimal Reserve Margin	Avg. Demand Response Call Hours Per Year at 10% RM
Base Case	9.75%	13.00%	4.5
Island Case: No Neighbor Assistance	18.00%		21.5
No Weather Diversity Among Neighbors	15.50%	18.00%	9.4
50% Transmission Capability	11.75%	17.00%	15
Transmission Distribution	14.00%	20.00%	13
All Regions Allowed to Share DR Resources	7.00%	12.00%	5
Allowing All Operating Reserves to be Depleted	7.75%	11.00%	4.5
EFOR 3% Increase	12.75%	16.00%	5.9
Expand Topology	9.25%	12.50%	4.25

VIII. ECONOMIC SENSITIVITIES

Sensitivities were performed both on the VOLL and the cost of CT capacity additions. Changing VOLL from $5,000/MWh to $30,000/MWh had no impact on the economic optimal reserve margin. The reason is that the amount of EUE at 13% reserve margin is only ~20MWh and represents reliability above the 1-in-10 LOLE standard. Firm load shed events are not driving the economics to be minimized at a 13% reserve margin. An additional sensitivity analyses varied the cost of CT capacity from $80/kW-yr to $120/kW-yr. Table 11 below shows that the economic optimum is more sensitive to capital costs.

Table 11. Economic Sensitivities

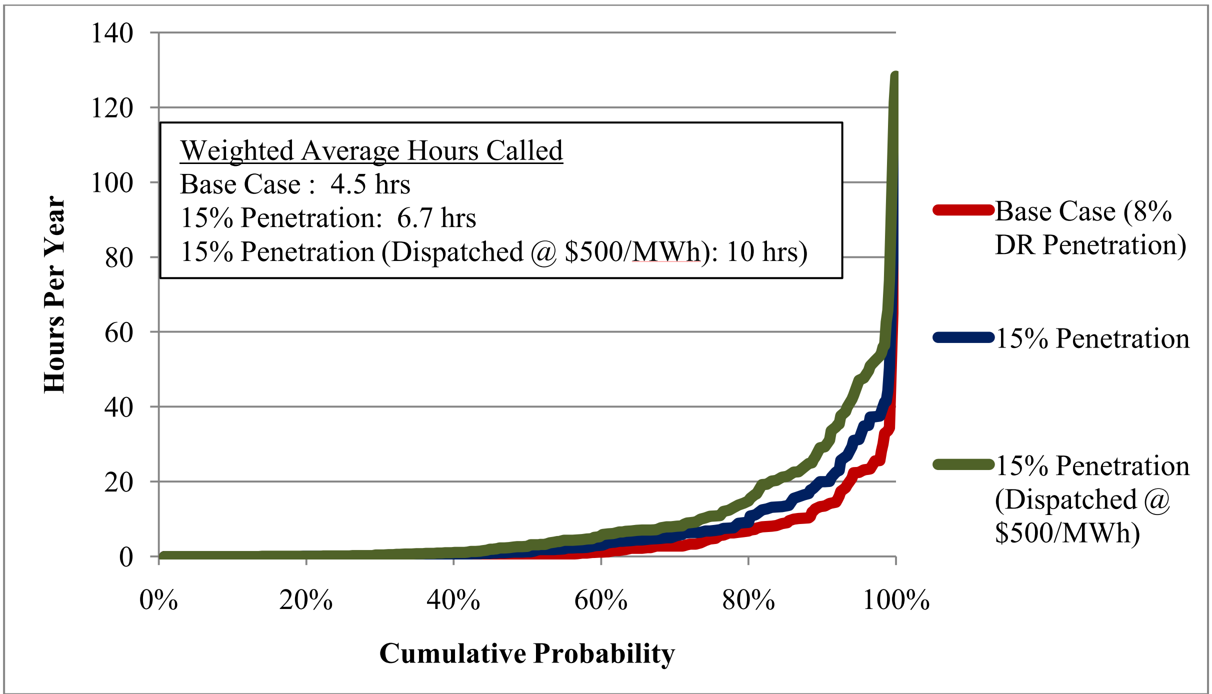
	Economic Optimal Reserve Margin
Base Case: VOLL@15,000/MWh CT Carrying Costs @ $100/kW-yr	13.00%
VOLL @ $5,000/MWh	13.00%
VOLL @ $30,000/MWh	13.00%
CT Carrying Costs @$80/kW-yr	15.25%
CT Carrying Costs @$120/kW-yr	10.25%

IX. RESOURCE MIX SENSITIVITIES AND HOW STATES CAN POSITIVELY INFLUENCE RESOURCE ADEQUACY

A. DEMAND RESPONSE SENSITIVITIES

Demand Response plays a key role in resource adequacy assessments. The key attributes of DR that impacted simulation results are the number of hours the resource can realistically be called in a given year, the point in the dispatch that DR is called, and the percentage of total capacity represented by DR (this percentage is also referred to as the penetration). If DR is called by a utility when prices hit $200/MWh versus $500/MWh, then the resource will provide much more economic value but will obviously need to be available more hours in the year. Figure 17 shows the distribution of expected demand response calls for the base case and two sensitivities with different penetration levels. Recall that the base case assumptions assume that DR is only called after all other options have been exhausted including expensive purchases up to $2,500/MWh and are limited to 150 hours per year. So in the base case, DR is exclusively used for reliability purposes and is always available since its dispatch is so infrequent. Also in the base case, DR provides 8% of the overall capacity mix for the region. The other two curves represent the senstivitiy cases where (1) DR penetration is 15% and resources are called at $2,500/MWh (2) DR penetration is 15% plus resources are called at $500/MWh. Additional sensitivities assuming the resources are called at $200/MWh would show increased frequency of dispatch and the necessary call limits would expand.

Figure 17. DR Call Summary



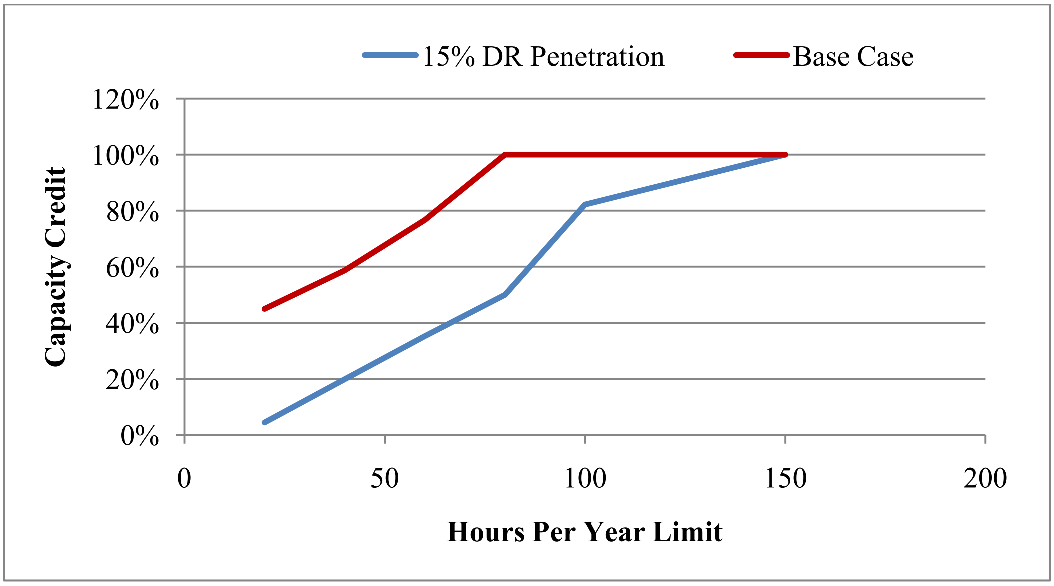
The next step in the evaluation was to determine how the 1-in-10 LOLE and economic reserve margin would change based on moving from 8% to 15% penetration. Table 12 displays the results. Because the DR was still treated as a reliability-only resource, the physical LOLE metric only shifted slightly and the 1-in-10 LOLE target shifted from 9.75% to 11%. This shows that the 150 hour call limits on the resource were almost enough to maintain the same reliability even with a higher penetration. However, the economic reserve margin was impacted more substantially because when the DR was added, a substantial amount of CT capacity had to be removed from the region to keep the same reserve margin level. Now the region is forced to purchase more energy since several thousand MWs of capacity that was being dispatched at less than $100/MWh was removed. Given this, the economic optimal target moves from 13% to 17%.

Table 12. DR Penetration Sensitivity

	Reserve Margin @ 1-in-10 LOLE Standard	Economic Optimal Reserve Margin	Avg. Demand Response Call Hours at 10% RM
Base Case: DR 8% Penetration	9.75%	13.00%	4.5
DR 15% Penetration	11.00%	17.00%	7

The last set of simulations pertaining to DR calculated the capacity credit of the resource assuming different call limits and different penetration levels. For purposes of the analyses, we are defining capacity credit of a resource as the reliability contribution that it provides the system compared to a fully dispatchable resource with 100% availability. So a resource that can only be dispatched 20 hours a year will not provide the same level of reliability as a resource that can be dispatched perfectly for 8,760 hours per year. Figure 18 shows the capacity credit of DR for the base case under different call limits and under a 15% penetration case with the same call limits. The figure shows that in the Base Case (8% penetration level) a 50 hour per year DR resource dispatched for reliability will only provide 63% capacity credit. Under a 15% penetration level, the same resource only provides 28% capacity credit. The higher penetration level would need the capacity more frequently and if it can only be called 50 hours it would be less valuable under that scenario.

Figure 18. DR Capacity Credit

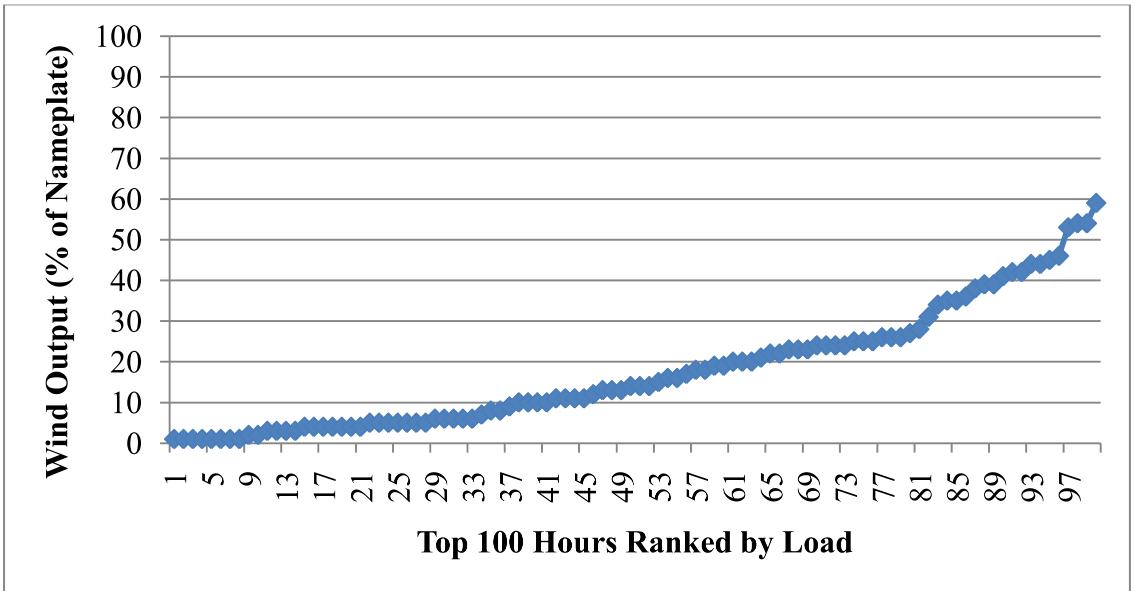


Understanding the risks and benefits offered by DR is critical given the penetration levels that some regions are approaching. Some utilities in Florida are already calculating "generation only" reserve margins and are considering using such a criterion in their resource planning decisions. This is due, in part, because there is uncertainty on how the DR will perform, including DR participant tolerance levels, as they are called upon more frequently. If states are going to consider further implementation of DR, it is important to ensure that the right amount and type are being added and these resources are being incentivized and valued correctly. States will need to understand all the dynamics and risks that could occur with DR. Some of these have been demonstrated in this case study simulation. Further simulations could assist in understanding this dynamic.

B. Intermittent Resource Sensitivities

Intermittent resources have a fundamentally different resource adequacy profile from conventional resources. The forced outage status of thermal generators is nearly completely independent. Fuel supply, transmission issues, and shared facilities can cause some units to be unavailable simultaneously, but typically outages are independent. Intermittent resources such as wind and solar, however, are dependent on weather conditions which are highly correlated across large geographic areas. For example, with a wind fleet of 1,000 MW in a 50,000 MW system, this does not create significant concern. At a higher penetration of 10,000 MW in a 50,000 MW system, the loss of wind resources will be a more significant issue. Because of wind's intermittency, the capacity value or effective load carrying capability (ELCC) of wind is already much lower than its nameplate capacity. Generally, at low penetration, the ELCC of wind should be close to the average output during peak conditions. If peak load occurs in the summer between 2:00 and 4:00 PM, a rough approximation of wind's ELCC would be the average output during these hours. For many regions, this output is between 15% and 25%. For our studied region, the wind output during the top 100 load hours is shown in Figure 19. The distribution is sorted by wind output and not peak load. The average output of wind is 18% of nameplate rating.

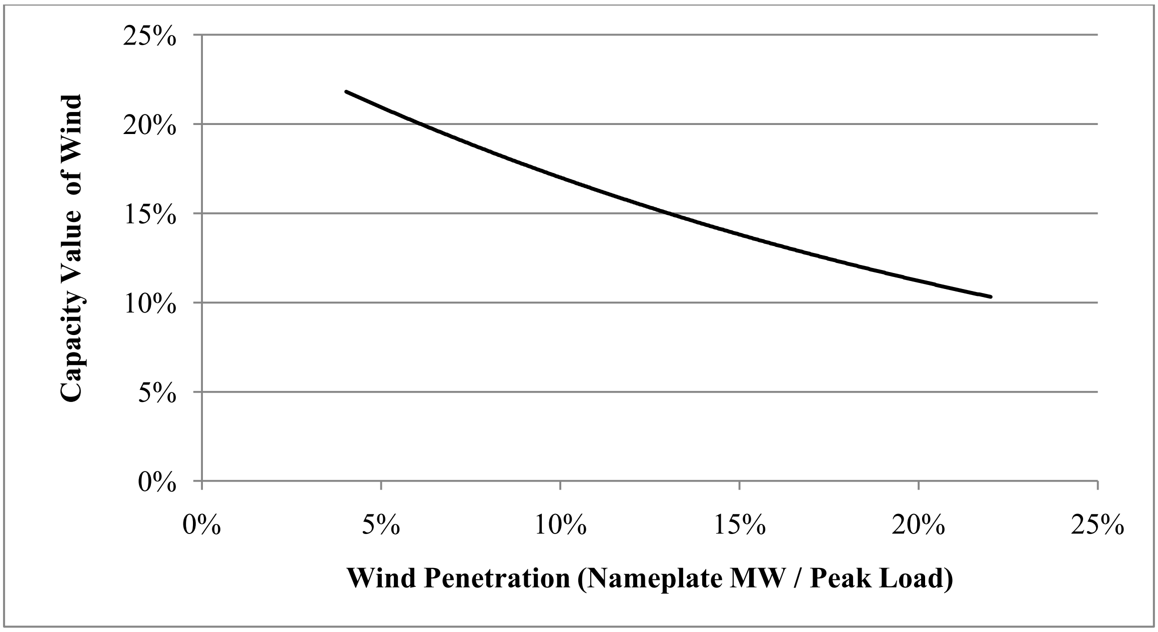
Figure 19. Wind Output During Peak Load Hours



However, this distribution also shows that in some peak hours, the wind output is much less than 18%. At a low penetration of 1,000 MW of nameplate wind, a region giving the wind fleet ELCC credit of 180 MW based on the average output during peak, this is not likely a reliability issue. Getting 180 MW less than expected is not a significant concern. It would be similar to losing a small thermal generator. If the wind fleet is a much larger 10,000 MW, having an output much smaller than the average output during peak conditions has a much larger impact on the system because it would correlate to losing 1,800 MW of capacity - a much more significant event.

To capture this difference, SERVM was used to determine the ELCC of wind at several penetration levels. When increasing the size of the wind portfolio, the same profile was used for all wind, so the correlation was perfect. This assumption is too conservative, because in reality, as penetration increases, a system would get some diversity benefit. But Figure 20 illustrates that as penetration increases, the capacity value or ELCC drops due to the reasons explained above. At low penetration, the ELCC can be slightly greater than the average output during peak if the system is energy limited rather than capacity limited. Having wind available at other times allows the system to conserve energy limited resources such as demand side resources and pumped storage or other hydro in hours that are lower than the peak so that those resources are available during peak hours. At high penetration, the ELCC is approximately half its value at low penetration.

Figure 20. Wind Penetration Study



These simulations did not capture the impact that intermittent resources has on ancillary service needs. Since the output of wind can vary substantially on a minute to minute basis, additional reserves may be necessary to fully integrate the wind profile. This is potentially an additional impact to reliability and warrants further analysis.

As the penetration of intermittent resources increases, regulators need to be aware of and prepared to address the changing impact these resources have on the economics of resource adequacy and on physical reliability.

C. Energy Storage Sensitivities

One proposed solution for intermittent resources is often to use energy storage technologies to firm up wind and other intermittent resources. Energy storage could address intra-hour uncertainties as well as hourly and daily uncertainties due to the intermittent profiles of wind and solar. The incremental intra-hour needs of regulation, operating reserves, and load following due to wind are well met by energy storage because, for these services, only 1-2 hours of storage may be needed. For the longer term uncertainties, the question of how many hours of storage is adequate to fully back-up wind resources. Would 4 hours of storage be adequate to make the wind energy be dependable? 8 hours? 16 hours?

The answer is likely dependent on the existing system as well as the penetration of intermittent resources. At low levels of penetration, energy storage solutions could likely have a lower peak capacity to energy storage ratio. For example, with only 1,000 MW of wind in a 50,000 MW system, each energy storage installation might only need 2 MWh of storage for every 1 MW the installation is able to deliver on peak. At higher penetrations of wind, each energy storage installation might need 10 MWh of storage for every 1 MW of peak output.

The fundamental issue when crafting an energy storage solution for intermittent resources is to identify the most cost effective solution. Given the right energy storage technology, it may be possible to build enough storage capacity with tremendous energy reserves to be able to fully firm up all wind capacity. But is this economically efficient? Even if the cost of energy storage drops substantially in the future, the ideal economic solution likely includes only firming a portion of the wind fleet combined with a mix of types of energy storage. Additional simulations could be performed to design optimal energy storage resource expansion plans that minimize the cost of integrating wind.

D. Distributed Generation

Distributed Generation (DG) is generation that produces electricity at or near the point of use and is generally small compared to centralized power stations. Distributed generation includes on site wind, solar arrays, micro-turbines, fuel cells, combined heat and power, and back-up or emergency power units. Based on a Department of Energy Report[66] released in 2007, there are an estimated 12 million distributed generation units installed in the U.S. with a combined capacity of approximately 200 GW. The report estimates that 84 GW of this capacity is consumer owned combined heat and power (CHP) systems and the majority of the remaining capacity consists of backup power units used only during emergency situations. These on-site units are generally not much larger than 1 MW in size, but in aggregate represent a large amount of capacity.

From a resource adequacy perspective, the difficulty with distributed generation is that utility system operators typically do not have full control to dispatch the resource during times of peak load. Because of this, the majority of these resources are typically not counted toward a reserve margin. An additional complexity raised by these resources is how load forecasts are accounting for the load that these resources are serving. As discussed in other sections of this paper, the proper counting of resources such as DG, DR, wind, and other energy limited resources is essential in optimal resource adequacy planning. To the extent that distributed generation owners and utility planners can better coordinate dispatch schedules and provide operators assurance that the resource will be available when called, there is potential for these resources to provide capacity in resource plans rather than through construction of new generation facilities. Generally, larger cogeneration and backup resources are counted but because the majority of all DG is less than 1 MW, a large percentage of these resources are not contributing to reserve margin calculations. States should continue to encourage this coordination, when cost-effective, in an attempt to further optimize resource adequacy.

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[66] *The Potential Benefits of Distributed Generation and Rate_Related Issues That May Impede Their Expansion,* retrieved on November 2, 2012 from http://www.ferc.gov/legal/fed-sta/exp-study.pdf

Aside from resource adequacy, states should help foster cost-effective DG by ensuring tariff rates and other subsidies such as investment/production tax credits are properly incentivizing these resources. Because of the size of these resources, new DG does not benefit from the economies of scale of a new traditional centralized power station and may need to make up the difference in order to be economically competitive with these traditional generation sources through specific advantages such as co-generation benefits, transmission benefits, fuel source, or subsidies. Regarding transmission, states should continue to ensure that interconnection rules and guidelines are fair and allow these types of resources to be developed.

X. ALTERNATIVES TO THE 1-IN-10 LOLE CRITERIA

A. NORMALIZED EUE

NERC has recently required all long assessment areas to perform probabilistic reliability studies for their systems and report a new metric which it calls ―Normalized EUE". This is the percentage of load that was unserved.

Pros:

- The metric provides more information than LOLE because it incorporates the magnitude of the firm load shed event versus only counting the event.
- The metric is more easily comparable across regions because it calculates the magnitude of EUE as a percentage.

Cons:

- There is currently no threshold in place in the U.S. that has been studied stating that a system should be planned to meet a specific percentage of Normalized EUE.
- Normalized EUE doesn't take into account customer costs.

B. MINIMIZATION OF TOTAL SYSTEM COSTS

As the paper has discussed, assessing the reserve margin which produces the minimum system costs from the perspective of the consumer provides valuable insight.

Pros:

- Evaluating the economics provides customers and regulators with a sense of what the costs are for various levels of reliability and whether or not meeting a 1-in-10 LOLE standard is justified.
- An economic study better portrays the risk of resource adequacy. As seen in the results, reliability events are low probability but high cost events.
- Because firm load shed events are so infrequent, it is difficult to calibrate loss of load expectation models. Analyzing economics allows planners to know whether or not their reliability expectations are reasonable by being able to calibrate their economic results to actual historical costs.

Cons:

- Evaluating the economics alongside physical reliability metrics requires more effort.
- A few key assumptions such as the cost of unserved energy, cost of new capacity, and scarcity pricing have to be developed.

XI. RECOMMEND DETAILED PROCESS AND PROPOSAL TO ASCERTAIN THE ECONOMICS OF RESOURCE ADEQUACY

A. ENTIRE EASTERN INTERCONNECTION ASSESSMENT

Since this case study in this paper only used a subset of the Eastern Interconnection, we propose to the states that there would be value in examining the economics of resource adequacy as well as physical reliability metrics of the entire Eastern Interconnection. Analysis could be performed on an individual region basis as well as for the aggregate Eastern Interconnection. It is expected that an optimal economic reserve margin target for the Eastern Interconnection that is well coordinated and dispatched efficiently would likely be lower than a composite level resulting from target set by individual entities. Another view of the analysis could only analyze societal costs (fuel burn + O&M + unserved energy costs) across the Eastern Interconnection.

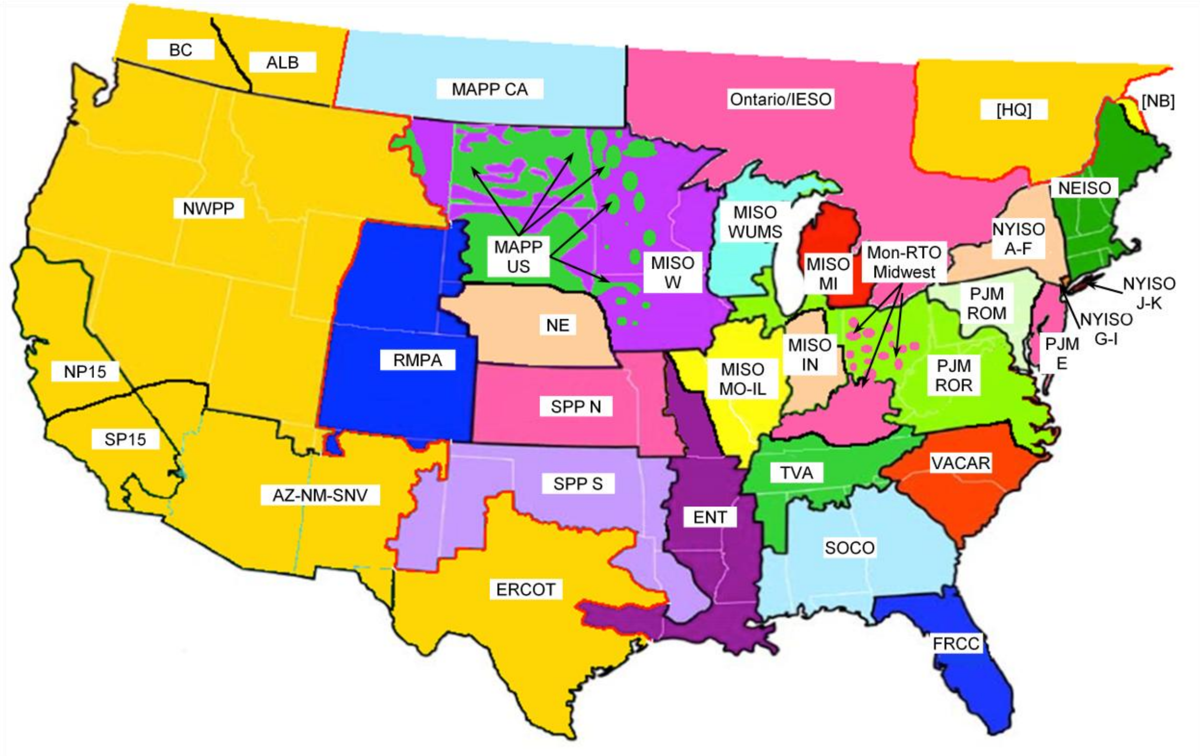
We propose using the EIPC data in a similar fashion to the way the data was used for this study. Load forecasts, fuel forecasts, and unit characteristics could all be obtained from EIPC data because the assumptions have already been well vetted by the participants. The data that would still need to be further developed or gathered to produce accurate resource adequacy results by entity and in aggregate would include the following:

- Distributions of load uncertainty due to weather for the remaining regions
- Distributions of load uncertainty due to economic growth uncertainty
- Actual historical generator availability data (GADS Data) by unit
- Demand resource characteristics
    - Reliability only
    - Economic
    - Call limits
    - Forecasted amounts
- Emergency Operating Procedures
    - Voltage reduction ability
    - Definition of when exactly a firm load shed event occurs (i.e. before or after depleting operating reserves, voltage control, etc)
- Wind and solar profiles by region and correlations to each other
- Hydro variability by region based on historical rainfall
- Energy efficiency projections by region
- Interface capability between regions and distributions around these assumptions representing the interface availability during peak conditions.

Astrape would recommend using a similar approach to the case study included in this paper. SERVM would be necessary to model the major uncertainties surrounding resource adequacy and capture all possible outcomes. It is expected that all benefits and costs associated with adding additional capacity across a range of reserve margins would be tabulated to gain a full understanding of the cost/benefit relationship. At the same time, it would be important to also calculate physical reliability metrics such as LOLE, LOLH, and EUE for all the scenarios simulated.

The topology for the Eastern Interconnection for the recommended study is included in the following figure. The regions within WECC and ERCOT would not be included in the analysis. The regions not already included in this paper's case study include HQ, IESO, NB, NEISO, MAPP US, NE, SPP-N, SPP-S, ENT, SOCO, and FRCC.

Figure 21. Study Topology[67]



The effort required to model the remaining areas in the Eastern Interconnection would not be inordinate given a significant portion has already been done. Astrape would propose incorporating actual historical GADS data rather than using the generic EFOR data provided in the EIPC data. Astrape would also need substantial collaboration regarding emergency operating procedures by each region as well as developing a better distribution of the transfer capability between regions.

Additional sensitivities surrounding market structure, scarcity pricing, demand response, and load forecast error assumptions should also be simulated to understand the impact they may have on the Base Case in this paper. Also the authors suggest simulating analysis using a different marginal resource such as demand response or combined cycle capacity.

It is anticipated that this effort could also result in state by state assessments of both the physical reliability and economic efficiency provided by the resource plans of utilities and other entities.

[67] Study would not include WECC or ERCOT

B. ADDITIONAL RELIABILITY CONSIDERATIONS WITH EVOLVING RESOURCE MIXES

1. Demand Response Analysis

This paper demonstrated the importance of understanding demand response and how it impacts resource adequacy but many important questions have not been answered. If the full Eastern Interconnection model is developed, more meaningful analysis of DR programs is possible. Also, based on the data developed by the national labs for EISPC regarding demand response, there is much to be learned in this area with additional simulations. Scenarios to be explored could include:

- Simulating the 4 DR penetration possibilities developed by Oak Ridge National Laboratories[68] under the full range of weather, load and unit performance scenarios developed by Astrape. The penetration levels range from 6% - 30% and consist of a number of different types of programs.
- Assessing the energy and capacity value of pricing programs under a range of views of the future, including several of the alternate views explored in the EIPC study.
- Additional simulations assessing the impact of other contract constraints including days per week, hours per day, hours per month.
- Additional simulations to explore the impact of potential customer fatigue and changing price responsiveness.

2. Evaluating the Impact of Intermittent Resources on Operational Reliability

Because SERVM performs a full economic dispatch, the effort performed for the long-term physical and economic reliability assessments could be leveraged to analyze operational reliability. Although SERVM is an hourly model, intra-hour impacts could also be assessed by applying a distribution of 5-minute, 15-minute, and 30-minute uncertainty to the available resources in the model. Results of these simulations would allow planners to quantify the economic costs and reliability impact of increasing penetration of wind and solar from an operational standpoint. The costs of the necessary ancillary services such as regulation, load following, and additional operating reserves could be easily captured, as well as the financial impact of having to over commit resources to be able to ensure reliability will not be a concern. Potential mitigation strategies could also be explored using SERVM to identify the technologies and scheduling practices that protect reliability and minimize system costs in future environments.

3. Probabilistic Transmission Availability Impact

The data needs mentioned above anticipate the need for better transmission information, but do not include simulating probabilistic transmission component failures. SERVM could be used in conjunction with transmission modeling tools such as EPRI's TransCARE[69] to assess the combined generation and transmission reliability for discrete regions in the Eastern Interconnection. The scope for such an assessment has been developed separately by NARUC.

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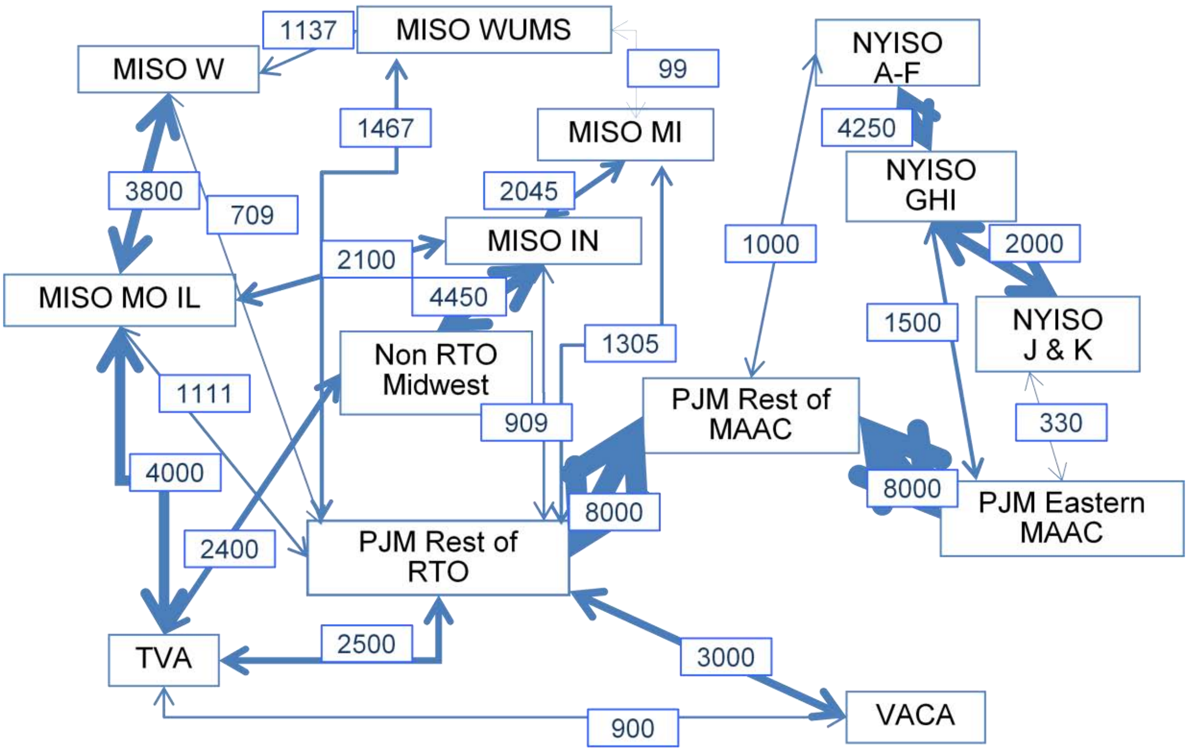
[68] Demand Response Assessment for Eastern Interconnection retrieved on Dec 1, 2012 at http://communities.nrri.org/documents/68668/19533034-7afe-4e7e-98fc-c4b511213871

[69] TransCARE is used is used for reliability assessment of composite generation and transmission systems.

XII. APPENDIX A

For the case study, Astrape Consulting constructed a model that included a significant portion of the Eastern Connection. All of the modeling data was taken from the current EIPC study including load forecasts, existing unit data, and transmission capability between regions. Below is the topology that was used for case study.

Figure A1. Topology



The resource adequacy software used for the case study is the Strategic Energy and Risk Valuation Model (SERVM)[70]. The probabilistic model was specifically designed for this type of analysis because it not only calculates traditional reliability metrics for a system (i.e. LOLE, LOLH) but also incorporates economic commitment and dispatch which allows for economics to be taken into account.

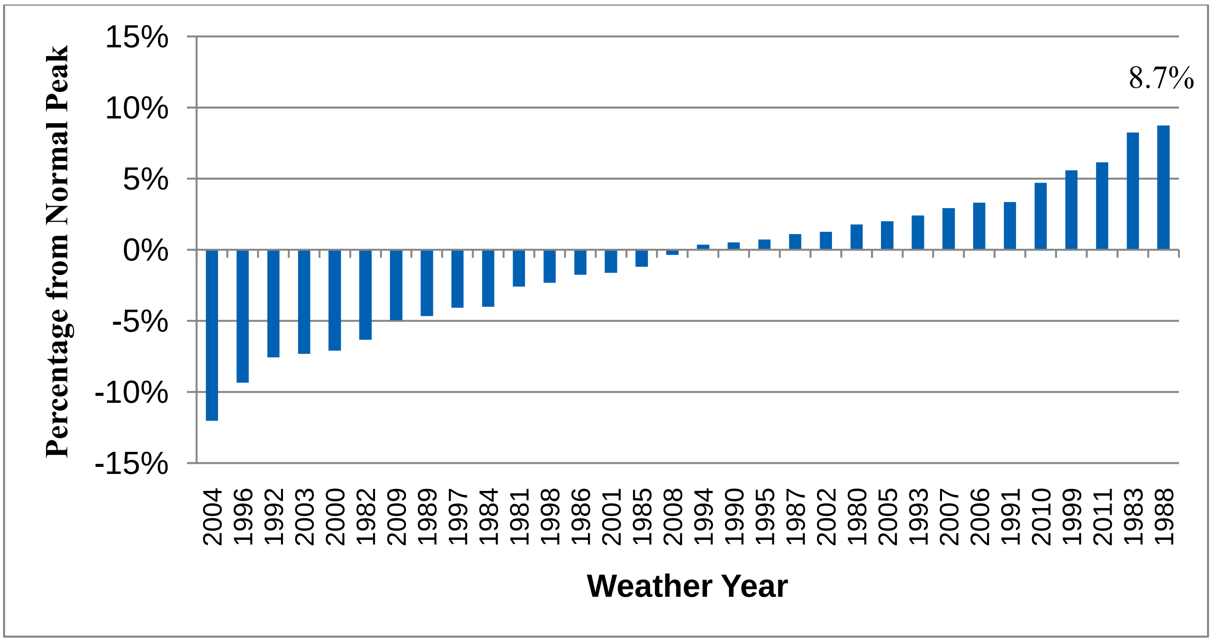
Resource adequacy studies have key attributes that differentiate it from typical production cost modeling studies. First, the study time frame typically examines one year in the near future versus studying longer time frames. This one year is then analyzed for all possible outcomes to assess the probability of a shortfall in capacity. For this case study, the year 2016 was chosen since it provides the lead time for new generation to be installed if reserve margin targets need to be changed. The most important variables driving capacity shortfalls include a combination of the following three uncertainties: weather uncertainty, economic load forecast uncertainty, and unit performance.

[70] SERVM is an economic resource adequacy model that is used by utilities to develop optimal reserve margin targets using economics as well as LOLE.

Weather

Weather uncertainty has an impact on both load and resources. The impact on load was modeled by simulating 32 synthetic load shapes representing the last 32 years of weather. Synthetic load shapes were created by developing a relationship between the last five years of load and temperature history using a neural net model. Each region has a unique load and weather relationship. These relationships were then applied to the last 32 years of weather to create 32 synthetic load shapes for each region. Each of these shapes represent what 2016 load could look like if the region experiences the same weather conditions from a historical year. Each load shape was given equal probability of occurrence in the simulation. The following figure provides an example of how high summer peak load can be above normal peak load for the PJM Rest of MAAC Region.

Figure A.2. Summer Weather Variability on Load for PJM_ROM



The following tables demonstrate the weather diversity incorporated into the loads. The first table shows on average over the 32 years of weather history, where each region is compares to its non-coincident peak load when the entire system peaks. The non-coincident peak of the system is 412,251 MW while the coincident system peak is 394,450MW which represents 4.5% weather diversity across the region.

Table A.1. Weather Diversity

Region	Average Load When Total System is Peaking (MW)	Average Non-Coincident Peak Load (MW)	Load Diversity with Neighbors (Region non-coincidental peak - Region coincidental peak)/(Region coincidental peak) (%)
PJM ROM	29,689	30,031	1.2%
PJM-E	35,731	36,143	1.2%
PJM ROR	105,726	107,319	1.5%
TVA	34,001	35,833	5.4%
VACAR	48,135	50,204	4.3%
NON-MIDWEST-ISO	11,272	11,729	4.1%
NYISO-A-F	11,154	11,934	7.0%
NYISO-G-I	4,220	4,515	7.0%
NY ISO-J-K	16,550	17,708	7.0%
MISO-IN	20,294	21,382	5.4%
MISO-MO-IL	20,434	21,530	5.4%
MISO-W	25,611	29,242	14.2%
MISO-MI	18,906	20,729	9.6%
MISO-WUMS	12,725	13,952	9.6%

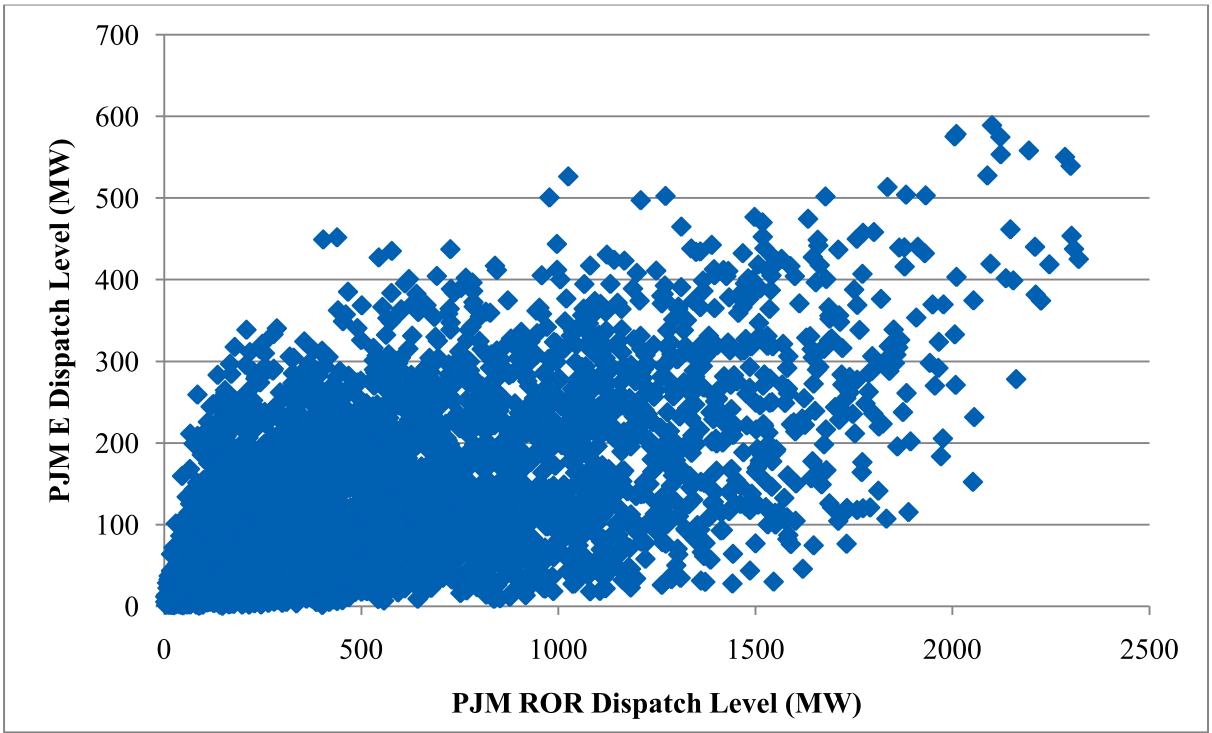
The next table represents the average of how far the neighboring region's load is relative to its own normal peak load in hours when the PJM_ROM is at its peak load. This is an average over 32 years of weather history. So on average, when PJM_ROM is at its peak load, then VACAR is within 6.7% of its normal peak load.

Table A.2. Neighbor Region's Load During PJM_ROM Region Peak

Region	Average Load When PJM_ROM is at its Peak Load (MW)	Average Non-Coincident Peak Load (MW)	Average Diversity with Study Region Peak Load (%)
PJM ROM	30,031	30,031	0.0%
PJM-E	36,143	36,143	0.0%
PJM ROR	103,682	107,319	3.4%
TVA	33,386	35,833	6.8%
VACAR	46,848	50,204	6.7%
NON-MIDWEST-ISO	10,880	11,729	7.2%
NYISO-A-F	11,022	11,934	7.6%
NYISO-G-I	4,170	4,515	7.6%
NY ISO-J-K	16,354	17,708	7.6%
MISO-IN	19,264	21,382	9.9%
MISO-MO-IL	19,397	21,530	9.9%
MISO-W	24,571	29,242	16.0%
MISO-MI	18,051	20,729	12.9%
MISO-WUMS	12,149	13,952	12.9%

Weather uncertainty also impacts the operation of hydro, wind, and solar resources. To take this into account, historical hydro energy data from each region was used to capture the amount of hydro energy available in each of the 32 weather years. For wind resources, the 2004 - 2006 EWITS data was utilized. The model draws stochastically by month and day from the 3 year period ensuring that the correlation from region to region is maintained. In other words, if July 5, 2006 was randomly drawn, then the profiles for all regions from that day were utilized. In examining the data, there was a significant correlation between regions as shown in the following figure. In hours when the PJM wind output was low, it was likely to be low in other regions as well.

Figure A.3. Wind Correlation between Regions (PJM_East/PJM_Rest of RTO)



The table below shows the capacity credit given to intermittent resources by region for the case study.

Table A.3. Capacity Credit of Intermittent Resources

NEEM Region	Technology	Capacity Credit
All Regions	Photovoltaic	30%
All Regions	Solar Thermal	30%
All Regions	Offshore Wind	20%
New York	Wind	10%
PJM (-E, -ROM, -ROR)	Wind	13%
TVA	Wind	12%
All Other Regions	Wind	15%

Economic Load Forecast Error

The second uncertainty - load growth forecast error - is the measure of the extent to which load forecasters will underestimate or overestimate economic growth for the next several years depending on the year being studied. The following distribution was used for the case study. This distribution was developed from a historical analysis of how well the Congressional Budget Office was able to forecast GDP four years in the future. The GDP uncertainty was converted to load uncertainty by multiplying by 40% - the assumed relationship of load growth to economic growth. The figure shows that in the most extreme case (lowest probability), load growth could be under forecasted by 5% over a four year period.

If it is assumed that demand response is the marginal resource, then it is likely that the economic load forecast error could be reduced to examine uncertainty over 1 – 2 years. The analysis completely changes under this approach because the capacity costs and benefit of a marginal DR resource are likely less than a marginal CT. The fact that the acquisition of DR is not unlimited also poses a concern in the authors‘ opinion.

Figure A4. Economic Load Forecast Error

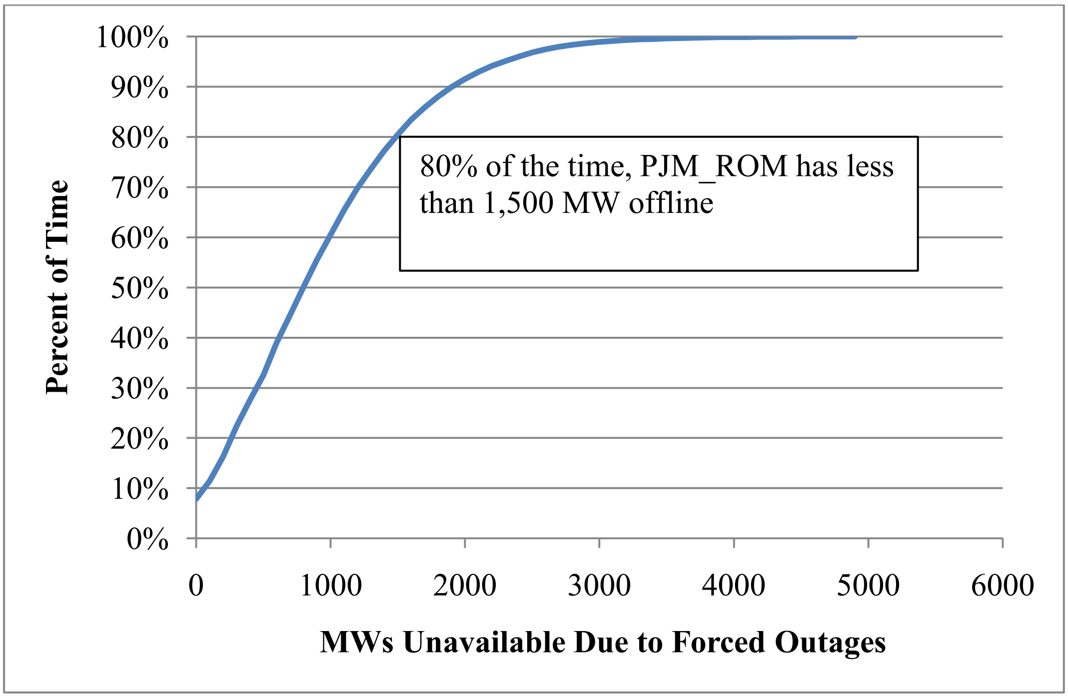
Load Forecast Error	Probability
5.11%	6.25%
3.90%	18.75%
0.55%	31.25%
-1.76%	18.75%
-2.90%	12.50%
-4.54%	12.50%

Unit Performance

The last major driver is unit performance. It is important to simulate the percent of time that a system will have a significant amount of generation offline due to forced outages, including partial outages. The model uses Monte Carlo techniques to simulate random generator failures. SERVM users actually enter in time to fail and time to repair distributions instead of a unit Equivalent Forced Outage Rate (EFOR). For this study, Astrape scaled distributions to achieve the target EFORs that were used in the EIPC Study. It should be noted that the EFOR data provided in the EIPC study was generic by unit type and that real historical GADS data would be needed for these results to provide more than an indicative conclusion.

The following chart shows a distribution representing the amount of MWs offline due to forced outage as a percentage of time. The figure shows that it is expected to have approximately 800 MW of capacity offline in a given hour, but that there are iterations where there can be several thousand MWs offline in a given hour. The chart also shows that 80% of the time the region will have less than 1,500 MW offline due to forced outages.

Figure A.5. Unit Performance Distribution



Hydro Modeling

SERVM utilized 32 years of historical hydro energy in the model. The variability of river flows can impact resource adequacy greatly. SERVM models the resources as either run of river, minimum flow constraints, or peak shaving. The total hydro capacity for each region was separated into the three categories. Run of river is defined as providing constant capacity for all 8760 hours of the year. The minimum flow constraints force the unit to be dispatched for at least a certain amount of hours each day at a certain capacity level. SERVM optimizes the dispatch around the peak for its peak shaving hydro resources.

Pump Storage Modeling

The pump storage resources are dispatched based on economics. The resources will pump during off peak hours and generate during peak hours if economic.

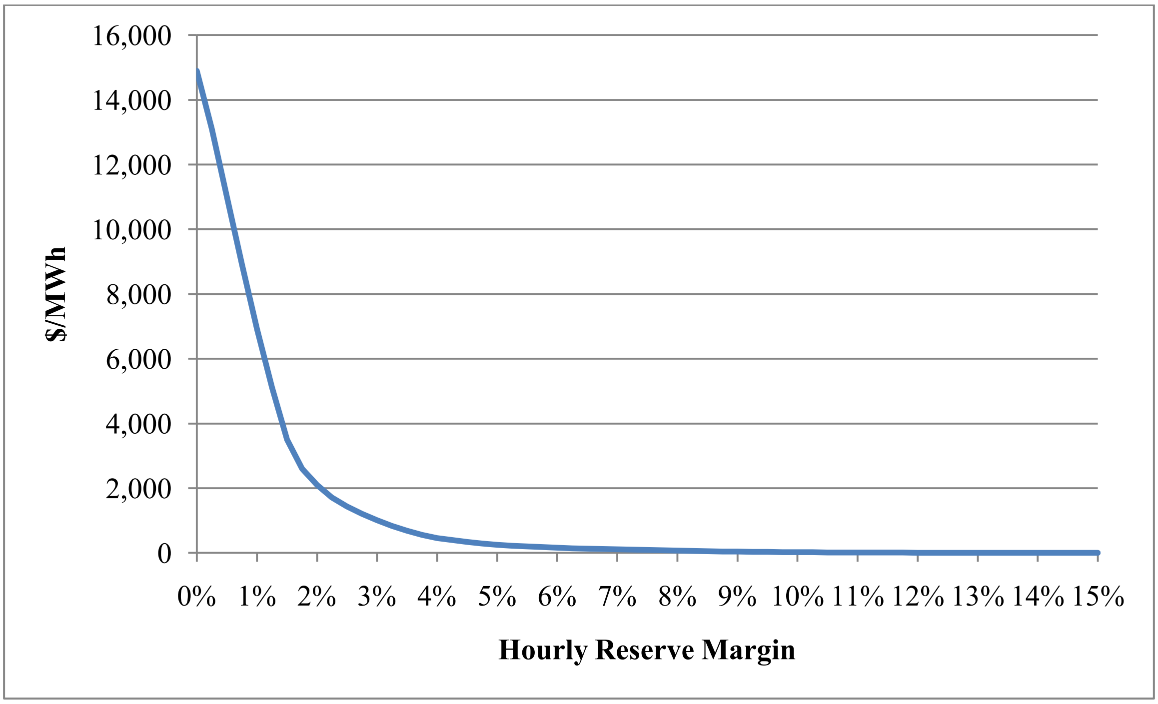
Demand Response Modeling

Demand response resources are modeled as capacity with specific call limits and strike price. For this case study, all demand response was given call limits of 150 hours per year and treated as reliability only with a dispatch price of $2,500/MWh. In other words, demand response was only called after all other alternative have been exhausted including expensive market purchases.

Scarcity Pricing

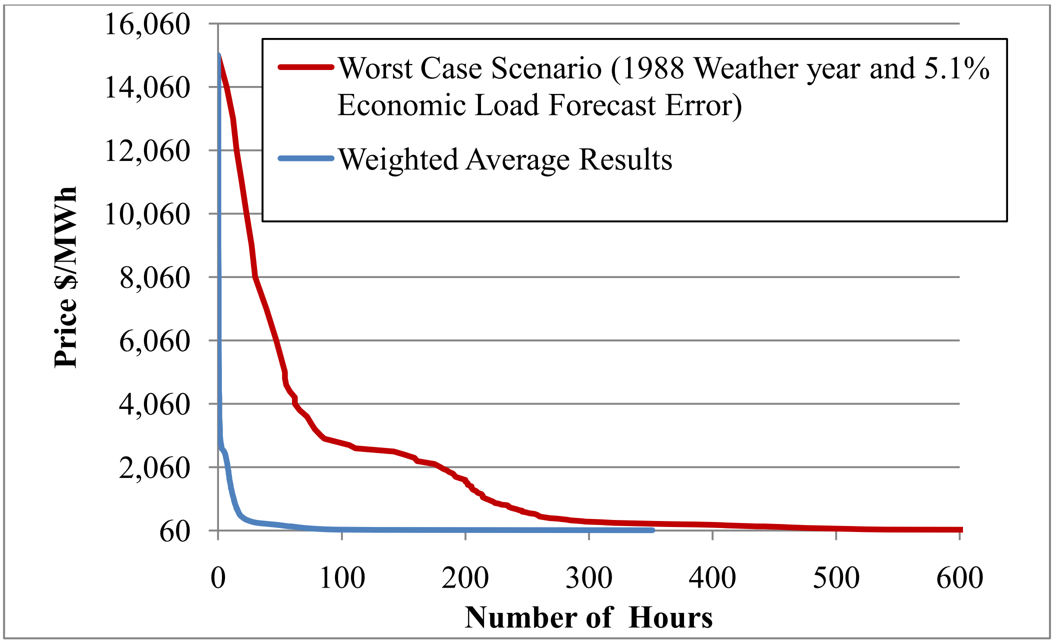
A scarcity pricing curve was developed by Astrape based on past experience of looking at historical market prices in different regions across the country. As the hourly reserve margin for a region decreases, the scarcity price approaches the VOLL. The following figure shows the curve that was actually used in the case study. The 0% level represents the point at which firm load is shed in order to maintain 2% spinning reserves in the case study. Because the modeling takes into account recent weather years, the authors were able to compare energy margins from the model to actual PJM energy margins in 2010-2011 to get comfortable with the scarcity pricing curve.

Figure A6. Scarcity Pricing Curve



Based on the base case results, the following figure shows a price duration curve at a 10% reserve margin level for the weighted average of all scenarios and the worst scenario simulated shows the number of hours that are expected to occur at different market price thresholds. As expected, it is seen that prices above $2,000/MWh are rare.

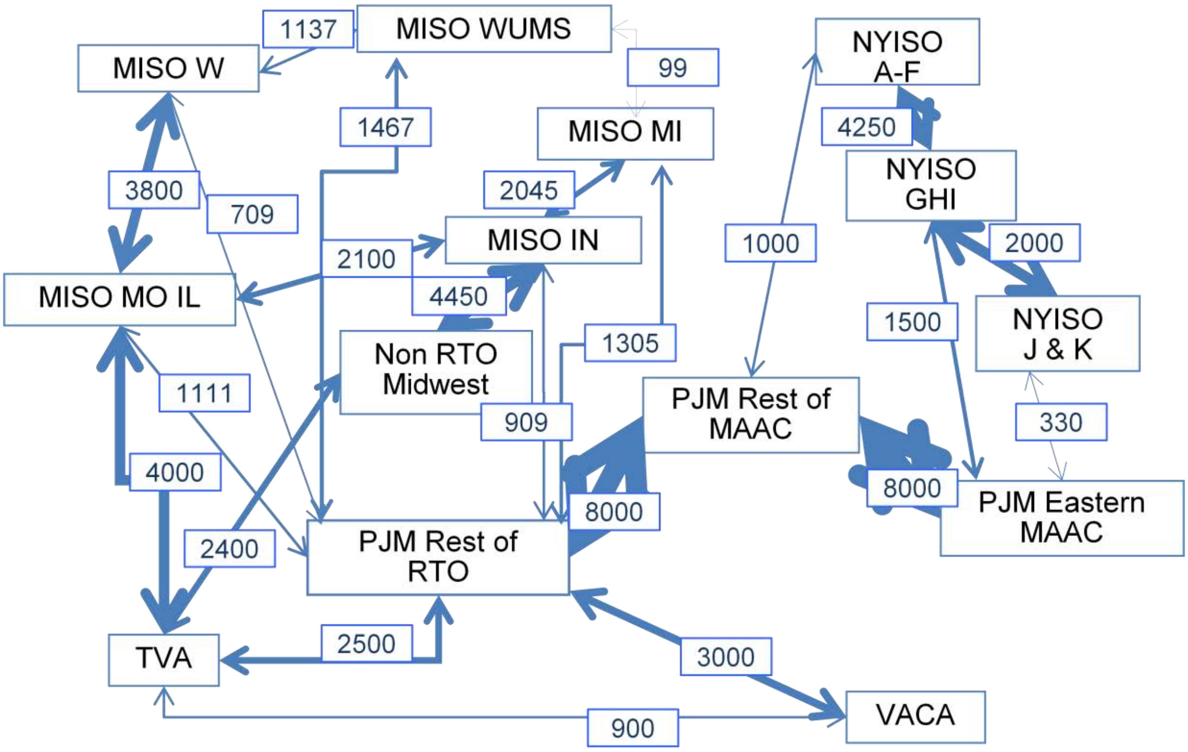
Figure A.7. Frequency of Scarcity Pricing @ 10% Reserve Margin



Transmission Interface

The following figure shows the transmission limits that were used for the Case Study which were direct inputs from the EIPC study. To perform more accurate simulations, Astrape suggests developing availability distributions for these interface limits rather than entering a constant value.

Figure A8. Transmission Interface Limits



Neighbor Modeling

SERVM's market clearing algorithms allow regions to share resources based on economics but subject to transmission limits. For example, if the TVA region is short capacity in a given hour, then their initial market price is equal to the VOLL. If VACAR is long, then VACAR can provide resources to lower the market price in TVA. If there was unlimited transfer capacity, then all regions would have the same hourly market price curve.

It should be noted that SERVM allows users to designate which resources can be shared. For this study, regions were not allowed to dispatch demand response resources in order to sell to other regions. Figure A.8 shows the target reserve levels for each NEEM Region in the study.

Figure A.9. Neighbor Target Reserve Margins

Reserve Margin Area	Reserve Requirement	NEEM Region(s)
MISO	17.4%*	MISO_IN
		MISO_MI
		MISO_MO-IL
		MISO_W
		MISO_WUMS
NonRTO_Midwest	14.0%	NonRTO_Midwest
NYISO	16.5%*	NYISO_A-F
		NYISO_GHI
		NYISO_JK
NYISO_GHI_JK	-5.0%	NYISO_GHI
		NYISO_JK
NYISO_JK	-8.0%	NYISO_JK
PJM	15.3%*	PJM_E
		PJM_ROM
		PJM_ROR
PJM_E	-2.2%	PJM_E**
TVA	15.0%	TVA
VACAR	14.0%	VACAR

** Based on coincident peak in reserve margin area.*

*** For purposes of this study, set equal to actual 2010 Reserve Margin*

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XIV. LIST OF ACRONYMS

CAISO	California ISO
CONE	Cost of New Entry
CT	Combustion Turbine
DR	Demand Response
ELCC	Effective Load Carrying Capability
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FRCC	Florida Reliability Coordinating Council
IESO	Independent Electricity System Operator
IOU	Investor Owned Utility
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
LSE	Load Serving Entity
LOLE	Loss of Load Events
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
MAAC	Mid Atlantic Area Council
MAPP	Mid Continent Area Power Pool
MISO	Midwest Independent System Operator
NERC	North American Reliability Council
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool
NYISO	New York Independent System Operator
PJM	PJM Interconnection
SERC	Southeast Reliability Corporation
SERVM	Strategic Energy and Risk Valuation Model
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority
VOLL	Value of Lost Load
WECC	Western Electricity Coordinating Council

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.	DOCKET NO. 981890-EU ORDER NO. PSC-99-2507-S-EU ISSUED: December 22, 1999

The following Commissioners participated in the disposition of this matter:

JOE GARCIA, Chairman
J. TERRY DEASON
SUSAN F. CLARK
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FREDERICK M. BRYANT, General Counsel, Florida Municipal Power Agency, 2010 Delta Boulevard, Tallahassee, Florida 32315, appearing on behalf of Florida Municipal Power Agency.

THOMAS J. MAIDA, III, Foley & Lardner, Post Office Box 508, Tallahassee, Florida 32302, appearing on behalf of Seminole Electric Cooperative.

KENNETH A. HOFFMAN, Rutledge, Ecenia, Underwood, Purnell and Hoffman, P. O. Box 511, 215 South Monroe Street, Suite 420, Tallahassee, Florida 32302-0551, appearing on behalf of the City of Tallahassee.

MICHAEL B. WEDNER, Office of General Counsel, 117 West Duval Street, Suite 480, Jacksonville, Florida 32202, appearing on behalf of Jacksonville Electric Authority.

ROBERT V. ELIAS, GRACE JAYE and COCHRAN KEATING, FPSC Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

ORDER APPROVING STIPULATION

BY THE COMMISSION:

During our reviews of the Ten Year Site Plans filed in 1997 and 1998, we expressed concerns about the adequacy of the reserve margins planned for Peninsular Florida. At the December 15, 1998, Internal Affairs meeting, we directed staff to open this docket to consider the reserve margins planned for Peninsular Florida electric utilities.

By Order No. PSC-99-1274-PCO-EI, nineteen issues were identified for consideration in this proceeding. The investor-owned utilities, the cooperative utilities, several municipal utilities, the various intervenors, and Commission staff filed testimony concerning these issues. The hearing was scheduled for November 2nd and 3rd, 1999.

At the outset of the hearing, Florida Power & Light Company (FPL), Florida Power Corporation (FPC), and Tampa Electric Company (TECO), presented a proposal designed to settle the case; addressing what they believe are the Commission's major concerns. By the proposal, these three utilities stipulated to voluntarily adopting a twenty percent reserve margin planning criterion. Each of these three utilities would achieve the twenty percent level by the summer of 2004. Further, pursuant to the proposal, no decisions would be made concerning the specifically enumerated issues, and the docket would be closed. FPL, FPC, and TECO would be the only utilities adopting the twenty percent criteria.

Other parties argued in support of and against the proposal. The Florida Industrial Power Users Group (FIPUG) requested additional time to present a counter-proposal. The hearing was continued until November 30, 1999, and the parties were directed to attempt to reach a negotiated settlement. FIPUG offered a counter-proposal on November 17, 1999. No settlement was reached.

At the continued hearing, we considered both proposals. After discussion, FPL, FPC, and TECO agreed to further modifications to their proposal. A document incorporating these agreed-upon changes was filed on December 15, 1999. A copy of this document (hereinafter the "Stipulation") is included in this Order as Attachment A and is incorporated herein by reference. FPL, FPC, and TECO have each agreed to achieve a planned twenty percent reserve margin by the summer of 2004. In response to concerns expressed by some of the other parties, each utility has agreed to make a good faith effort to notify the Commission if it opts to modify the twenty percent criterion. The three utilities signing the Stipulation further acknowledge in paragraph 9 at page 4 that

> the Commission shall retain the ability and discretion to consider all facts and circumstances applicable to a given utility and/or peninsular Florida. Further, with respect to the evaluation of the adequacy of reserves in peninsular Florida, the Commission may employ any methodology and consider any facts and circumstances it deems appropriate, subject to applicable legal requirements.

We approve the Stipulation agreed to by Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company. It addresses the basic concern about the adequacy of planned reserve margins for Peninsular Florida. Collectively, these three utilities plan for approximately 80 percent of the Peninsular Florida load. Thus, a twenty percent planning criterion adopted by these three utilities is a significant increase over the fifteen percent criterion currently employed.

Further, we will convene a workshop to receive and consider information regarding how distributed resources, both demand and supply-side, may be used to meet Florida's energy service reliability needs. In addition, we will convene a workshop for the consideration of the appropriate relationship between the non-firm load of an individual utility and the total reserves required to maintain the utility's appropriate reserve margin.

Based on the foregoing, it is therefore

ORDERED by the Florida Public Service Commission that the Stipulation agreed to by Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company, which is included in this Order as Attachment A and is incorporated by reference herein, is approved. It is further

ORDERED that this docket shall be closed.

By ORDER of the Florida Public Service Commission this 22nd day of December, 1999.

Blanca S. Bayó

BLANCA S. BAYÓ, Director
Division of Records and Reporting

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of Records and reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida
_______________________/

Docket No. 981890-EU

STIPULATION

WHEREAS, the Florida Public Service Commission initiated this proceeding regarding reserve margins of Peninsular Florida utilities in December 1998; and

WHEREAS, subsequent to that date Staff and parties identified certain issues to be addressed and procedures to be followed; and

WHEREAS, Florida Power & Light Company (FPL), Florida Power Corporation (FPC), and Tampa Electric Company (TECO) (collectively, the IOUs) have asserted, and continue to assert, that the scope of the proceeding has been expanded beyond the intent of the Commission, and that the procedural posture of this proceeding is such that the Commission cannot lawfully take formal action that would affect their substantial interests at this time; and

WHEREAS, in Orders No. PSC-99-1274-PCO-EU and No. PSC-99-1716-PCO-EU the Commission overruled the IOUs' procedural objections, clarified the scope of the docket, identified specific issues to be addressed, and confirmed its intent to conduct a formal evidentiary proceeding in this docket and take the actions it deems appropriate; and

WHEREAS, Reliant Energy Power Generation, Inc (Reliant Energy), Florida Industrial Power Users Group (FIPUG), PG&E Generating Company (PG&E), the Legal Environmental Assistance Foundation, Inc. (LEAF), and Duke Energy North America, LLC, and Duke Energy New Smyrna Beach Power Company, Ltd., LLP (Duke Energy), (hereinafter referred to as Intervenors), filed Petitions to Intervene in which they alleged the actions contemplated by the Commission in this docket would affect their substantial interests; and

WHEREAS, the Commission granted Intervenors' petitions to intervene, and Intervenors have participated as full parties to the proceeding; and

WHEREAS, on October 29, 1999, FPC, acting on behalf of the IOUs, submitted to the Commission Staff a proposal for the resolution of the issues in this proceeding; and

WHEREAS, upon receipt of the proposal the Commission continued the hearing scheduled for November 2, 1999 and convened on that date a conference of all parties for the purpose of discussing the proposal of the IOUs; and

WHEREAS, upon consideration of the IOUs' proposal, without waiving their respective litigation positions and for the purposes of compromise and settlement, the undersigned, representing all of the parties to this proceeding that have been identified by the Commission or allowed by Commission to intervene, have decided to prepare this Stipulation, and present it to the Commission for the purpose of concluding this docket.

NOW, THEREFORE, the parties stipulate and agree as follows:

1. The IOUs will each voluntarily adopt a minimum reserve margin planning criterion of twenty percent (20%).

2. The twenty percent (20%) reserve margin planning criterion will be a minimum; no maximum or cap will be represented or implied by this criterion.

3. No utility other than the three IOUs identified hereinabove is agreeing to adopt a twenty percent (20%) reserve margin planning criterion by virtue of this Stipulation.

4. The IOUs will calculate the minimum twenty percent (20%) reserve margin by employing their current methodology; i.e., Reserve Margin (%) = [(Total Firm Capacity – Peak Firm Demand)/Peak Firm Demand] x 100, where Total Firm Capacity will be based on generating capacity owned by the IOUs or capacity for which there is a firm commitment to these IOUs and

where Peak Firm Demand means total demand reduced by demand side resources.

5. The IOUs will undertake to implement the twenty percent reserve margin criterion over a transition period of four years, meaning that they will plan to achieve a twenty percent (20%) reserve margin by the Summer of 2004.

6. The IOUs agree to adopt the twenty percent (20%) reserve margin planning criterion with the good faith intention of maintaining that planning criterion for the indefinite future, but each IOU must reserve the prerogative individually to modify its planning criteria to adapt to relevant circumstances. By the same token, it is understood that the Commission remains free to initiate an investigation or to take other appropriate action to review and to respond to any changes that the IOUs may make in the future regarding their planning criteria.

7. Should any IOU exercise its prerogative to change its twenty percent (20%) minimum reserve margin planning criterion discussed herein, such IOU will make a good faith effort to provide notice of the change to the Commission.

8. Neither the adoption by the IOUs of the minimum twenty percent (20%) planning criterion nor the approval of this Stipulation by the Commission shall be deemed to create any presumption that capacity additions must be through any particular mix of generation and/or demand-side resources. Nor shall said adoption or approval be deemed to create any presumption with respect to any proposals for adding generating capacity or create a presumption that a generating capacity addition proposed by any entity is not needed. All current and future proceedings under the Electrical Power Plant Siting Act, including those for the consideration of merchant plants, and all statutes, rules, regulations, and policies bearing on the Commission's determination of need for new generation (including the need determination criteria in § 403.519, Florida Statutes); the IOUs' obligation to solicit proposals for generating capacity; and the

obligations of the IOUs to otherwise prudently avail themselves of reasonably available conservation alternatives and cost-effective resource options; and the obligations of the IOUs to best serve their retail customers through their respective resource planning processes, are unaffected by this Stipulation and the approval thereof.

9. The parties acknowledge that for all regulatory purposes, the Commission shall retain the ability and discretion to consider all facts and circumstances applicable to a given utility and/or peninsular Florida. Further, with respect to the evaluation of the adequacy of reserves in peninsular Florida, the Commission may employ any methodology and may consider any facts and circumstances it deems appropriate, subject to applicable legal requirements.

10. The Commission is encouraged to take the following actions in conjunction with the approval of this Stipulation:

A. Convene a workshop, with the participation and the assistance of the Regulatory Assistance Project, to receive and consider information regarding how distributed resources, both demand and supply-side, may be used to meet Florida's energy service reliability needs, to be followed by any additional proceedings and/or actions relative to this matter that the Commission deems appropriate.

B. Convene a workshop for the consideration of the appropriate relationship between the non-firm load of an individual utility and the total reserves required to maintain the utility's appropriate minimum reserve margin, to be followed by any additional proceedings and/or actions relative to this matter that the Commission deems appropriate.

11. The parties enter into this Stipulation for the purpose of effecting a compromise and of achieving closure of this docket. By its participation in this Stipulation, no party expresses its endorsement of any individual provision included by any other party.

12. By entering this Stipulation, no party waives any position it has taken with respect to any aspect of this proceeding or any of the issues identified in this proceeding or any other proceeding. Further, no party waives the right and opportunity to petition the Commission to institute any action designed to provide any relief deemed appropriate or desirable by that party at any time.

13. The parties to this Stipulation agree that, by approving this Stipulation, the Commission does not waive its right and ability, pursuant to governing law, to initiate any proceeding or take any action for which it has requisite jurisdiction and authority.

14. In the event the Commission declines to approve this Stipulation in its entirety, it shall become null and void.

AGREED this 14th day of December 1999.

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Rating the States on Their Risk of Natural Gas Overreliance

www.ucsusa.org/naturalgasoverreliance

Technical Document

Union of Concerned Scientists

Rating the States on Their Risk of Natural Gas Overreliance presents the results of an analysis of the current and future potential for natural gas overreliance in the power sector for each of the 50 states. An earlier UCS work (Deyette et al. 2015) examined a range of issues around the risks of natural gas overreliance for electricity generation nationally. This analysis builds on that work with a focus on individual states and a subset of natural gas risks, using multiple metrics to assess those risks.

The text below explains the focus of the analysis, the multiple-metric approach, the details for each metric, and the summary graphics. It also includes a discussion of notes and limitations, and reference materials.

Focus

Rating the States is focused on the financial risks to consumers associated with excessive use of natural gas for electricity generation, with analysis carried out at the state level.

- **Power sector.** The power sector is a subset of the broad range of uses for natural gas, from heating homes and businesses to powering buses to serving as a feedstock for various industrial processes. The power sector has seen rapid change with regard to natural gas usage in recent decades, both in absolute terms and in terms of change within the sector (its portion of overall electricity generation, for example). It has also been the target of substantial investment in new infrastructure due to growing interest in natural gas—in terms of power plants and the pipelines that serve them.
- **Financial risks to consumers.** Natural gas for electricity generation offers potential benefits but also challenges, including environmental and financial, both near- and long-term. For electric ratepayers, financial risks can include those stemming from the volatility of the fuel price, the costs of carbon pollution, and the possibility that investments in natural gas infrastructure (power plants and pipelines) will not pay off, and therefore ratepayers will incur additional costs for such “stranded assets.” In some states, vertically integrated electric utilities both generate electricity and serve end users, while other states have restructured their electricity markets to allow for competition in power generation. In theory, the latter approach insulates customers from some generation risks, leaving them instead to be borne by shareholders of generator companies. The distinction between the two types of state markets is not black and white, however, and either type can lead to customers—rather than utility companies, generators, or shareholders—bearing the bulk of the consequences of natural gas overreliance.[1]
- **States**. Some aspects of the energy sector are multi-state, and are therefore the responsibility of the federal government (approval of interstate pipelines and transmission lines, for example). However, many of the signals provided to the private sector about the role of natural gas in the power sector come from state legislatures, governors, public utility commissions, and others (support for fossil fuels, renewable energy, or energy efficiency, for example). Such decisions can influence the scale and scope of private-sector investment in natural gas or other forms of energy.

Ratings

This analysis assesses states based on five metrics focused on natural gas generation, natural gas capacity, and carbon emissions, either in absolute terms or as a function of some other parameter (overall electricity generation, for example). For each metric, threshold levels identify a high level of risk of overreliance associated with the metric, a moderate level, and a low level.

Rather than attempting to identify what an ideal state looks like with regard to low-risk natural gas use, this analysis points to some aspects of risk of natural gas overreliance, and examines which states exhibit characteristics that suggest higher levels of such risk.

[1] In December 2014, for example, Florida’s public service commission allowed Florida Power & Light Co. to pass on to electricity customers costs (or savings) associated with an investment in natural gas hydraulic fracturing operations in Oklahoma (Testa 2014). In October 2015, the Massachusetts Department of Public Utilities found that electric utilities in that state can enter into long-term contracts with natural gas pipeline companies (Sullivan 2015).

Metrics

The metrics selected for this analysis are aimed at assessing a range of aspects of each state's current and prospective natural gas usage for electricity generation.

METRIC 1. NATURAL GAS GENERATION AS A SHARE OF IN-STATE ELECTRICITY PRODUCTION (2014)

Electricity can be generated from a range of fuels, and most states—like the nation as a whole—produce electricity using a mix of resources, including coal, natural gas, nuclear, and renewables. One indicator of how reliant a state is on natural gas is to compare how much of its in-state electricity generation comes from natural gas versus all other fuels. The more a state's electricity mix is dominated by natural gas, the more consumers in that area can expect to be exposed to the fuel's near- and long-term economic risks, including price volatility. This metric involves calculating the portion of each state's in-state electricity production generated using natural gas.

Source: Electricity Information Administration (EIA 2015a)

Data: Net generation from electricity power plants, annual, by state and fuel type, 2014 (preliminary)

Analysis: For each state, we calculated the percent of electricity generation from natural gas in 2014 by dividing the megawatt-hours (MWh) generated using natural gas by the total MWh generated using all fuels. In 2014, the EIA reported only one region (Washington, DC) not generating any electricity, and two regions not generating electricity from natural gas (Hawaii and Washington, DC). Wyoming was listed as "NM" for "not meaningful" natural gas generation based on preliminary 2014 results.[2] We assigned Hawaii, Washington, DC, and Wyoming a risk rating of "Low."

Threshold setting: States with 50 percent or more of their 2014 in-state electricity generation coming from natural gas were assigned a risk rating of "High." State portfolios ranging from 25 to 49 percent were rated as "Moderate," and states with less than 25 percent of their in-state electricity generation coming from natural gas were rated as "Low." Overall, 26.2 percent of the electricity generated in the United States in 2014 came from natural gas.

METRIC 2. INCREASE IN PERCENT OF IN-STATE ELECTRICITY GENERATION FUELED BY NATURAL GAS (2008–2014)

Natural gas has undergone rapid growth in the electric power sector over the past decade, including to replace large amounts of coal to serve electricity needs on a fairly constant basis (that is, to provide "baseload" generation). From 2008 to 2014, natural gas jumped from generating 20.2 percent of the national electricity mix to 26.2 percent, while coal slid from 49.5 percent to 39.9 percent over the same period. In some states, the shift in natural gas generation was even greater. As a result, electricity consumers in these states now have a rapidly growing share of their electricity coming from a historically volatile fuel, which increases their exposure to natural gas price volatility. This metric measures the change in percent of natural gas in a state's electricity generation portfolio from 2008 to 2014.

Source: Electricity Information Administration (EIA 2015a)

Data: Net generation from electricity power plants, annual, by state and fuel type, 2008 and 2014 (preliminary)

Analysis: For each state, we calculated the percent of electricity generation from natural gas in 2008 and 2014 by dividing the MWh generated using natural gas by the total MWh generated using all fuels. We then subtracted the 2008 value from the 2014 value to arrive at the change in percent. In 2014, the EIA reported only one region (Washington, DC) not generating any electricity, and two regions not generating electricity from natural gas (Hawaii and Washington, DC).

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[2] For reference, over the previous five years Wyoming's generation from natural gas ranged from 37 to 99 MWh per year, representing less than 1 percent of its total annual electricity generation.

Wyoming was listed as “NM” for “not meaningful” natural gas generation based on preliminary 2014 results. In 2008, Hawaii, North Dakota, and Washington, DC, were all recorded as not generating electricity from natural gas. We assigned Hawaii, North Dakota, Washington, DC, and Wyoming a risk rating of “Low.”

Threshold setting: States increasing the share of natural gas in their electricity generation portfolios by 10 or more percentage points between 2008 and 2014 were assigned a risk rating of “High.” States with gains ranging from 5 to 9 percentage points were rated as “Moderate,” and states undergoing a change of less than 5 percentage points were rated as “Low.” Overall, the percent of natural gas in the national generation mix increased by about 6 points over the same period.

METRIC 3. NATURAL GAS CAPACITY AS A SHARE OF POWER PLANTS BEING BUILT (2014–2017)

Power providers, regulators, and elected officials in each state need to plan their future electricity resource mix based on projected increases in demand, scheduled power plant retirements, and reliability needs. One indication of an increasing reliance on natural gas can be captured by analyzing the share of new electricity generating capacity based on natural gas that is expected to come online within the next several years. Significant additions of natural gas capacity may lock states in to investments in power plants and pipelines, whose costs and losses when idled, underused, or abandoned may be passed through to customers. This metric assesses the portion of new power plant capacity coming online between 2014 and 2017 that is fueled by natural gas.

Source: SNL Financial (2015)

Data: Asset data for power plant units scheduled to be in service between 2014 and 2017, with a build phase development status of “Completed,” “Construction Begun,” or “Advanced Development;” asset data for power plant units undergoing fuel conversion from coal to natural gas between 2014 and 2017.

Analysis: For each state, we calculated the generating capacity from natural gas power plant units being built and expected to be in service between 2014 and 2017. We also calculated the additional generating capacity as a result of power plant unit conversions from coal to natural gas during the same period. We then added these two values and divided the result by the total new generating capacity and coal-to-gas conversions between 2014 and 2017.The result is the percentage of natural gas as a share of new generating capacity.

Threshold setting: States in which 50 percent or more of new capacity is to be based on natural gas (new power plants or coal-to-gas conversions) between 2014 and 2017 were assigned a risk rating of “High.” States ranging from 25 to 49 percent were rated as “Moderate,” and states with natural gas accounting for less than 25 percent of new in-state capacity were rated as “Low.” Overall, 56 percent of the generating capacity being built in the United States during this time frame is expected to be fueled by natural gas.

METRIC 4. TOTAL PROJECTED NATURAL GAS CAPACITY IN 2017

Some states already have a significant amount of natural gas capacity, and this total is set to increase in many states given the construction of new natural gas power plants and coal-to-gas conversions already under way. By looking at the absolute value of electricity generating capacity fueled by natural gas, this metric shows several states at risk of relying heavily on natural gas. The greater the generation capacity based on natural gas, the more consumers are at risk of exposure to the negative consequences associated with plants and other infrastructure becoming underused, idled, or even abandoned over time. This metric is based on each state’s total projected natural gas capacity in 2017.

Source: Electricity Information Administration (EIA 2015b), SNL Financial (2015)

Data: From the EIA, “Existing capacity by energy source, by producer, by state back to 2000 (annual data from the EIA-860);” from SNL, asset data for power plant units in service between 2014 and 2017 with a status of “Completed,” “Construction Begun,” or “Advanced Development;” asset data for power plant units switching from coal to gas between 2014 and 2017.

Analysis: For each state, we calculated existing natural gas capacity in 2013 across the entire electric power sector, generating capacity from natural gas being built and expected to be in service between 2014 and 2017, and generating capacity that will be in service between 2014 and 2017 as a result of conversions from coal to natural gas. We added these three values to arrive at the total electric capacity projected to be fueled by natural gas in 2017.

Threshold setting: States with a total natural gas generating capacity of 10,000 megawatts (MW) or more were assigned a risk rating of “High.” For reference, 10,000 MW of natural gas generating capacity is capable of powering several million households. States ranging from 5,000 to 9,999 MW were rated as “Moderate,” and states with less than 5,000 MW of total natural gas generating capacity in 2017 were rated as “Low.”

METRIC 5. POWER SECTOR CARBON DIOXIDE EMISSIONS (2013)

As the single largest contributor of global warming emissions in the United States (and with a range of viable low-carbon alternatives available to it), the electric power sector has a major role to play in reducing the carbon intensity of the national economy. With the recent issuance of the Environmental Protection Agency’s Clean Power Plan, states must now choose how they will meet the plan’s carbon-reduction requirements for power plant emissions. Critically, although natural gas burns cleaner than coal for electricity generation, even a wholesale shift from coal to natural gas would be insufficient to meet long-term climate goals, as natural gas still emits significant emissions upon combustion (Fleischman, Sattler, and Clemmer 2013). For states with particularly high carbon emissions, then, an existing or developing overreliance on natural gas means that more drastic action will be required over the long term to continue reducing carbon emissions. In the interim, electricity consumers in those states will be forced to pay for shortsighted decisions their states are making today. This metric assesses the total carbon dioxide emissions released by the electric power sector in each state in 2013.

Source: Electricity Information Administration (EIA 2015c)

Data: U.S. electric power industry estimated emissions by state, 1990–2013 (EIA-767, EIA-906, EIA-920, EIA-923)

Analysis: For each state, the EIA provides annual data on carbon dioxide, sulfur dioxide, and nitrogen oxide emissions released by type of power producer and energy source. We pulled carbon dioxide data for the entire electric power industry across all energy sources in 2013. Each data point was converted from metric tons to million metric tons (MMT).

Threshold setting: States with total electric power industry emissions of 50 MMT or more of carbon dioxide in 2013 were assigned a risk rating of “High,” while states emitting between 25 and 49 MMT were rated as “Moderate,” and those emitting less than 25 MMT were rated as “Low.”

SUMMARY METRIC: STATES AT HIGHEST RISK OF NATURAL GAS OVERRELIANCE

Each metric within this analysis is intended to stand on its own as an indicator of a state’s exposure to one of the multiple risks associated with natural gas overreliance. However, the metrics can also be viewed in aggregate to better appreciate the constellation of risk factors that a state may face. Because the metrics are designed to gauge different aspects of risk exposure, a state with multiple “High” risk ratings may be exposing its electricity consumers to more risks associated with natural gas than a state with a single “High” risk rating.

Further, there are some states that just miss a “High” rating but are still exposing their consumers to greater risks than others; therefore, a consideration of states’ “Moderate” ratings in combination with their “High” designations can provide a more complete picture of their potential for overreliance on natural gas.

Data Table

Dark red indicates "High" risk rating, medium red indicates "Moderate", and pink indicates "Low".

State	Metric 1	Metric 2	Metric 3	Metric 4	Metric 5	Number of "High" Risk Ratings	Number of "Moderate" Risk Ratings
Alabama	32%	17.2	98%	14,200	67.0	4	1
Alaska	51%	-9.9	89%	1,400	3.8	2	-
Arizona	24%	-8.3	66%	14,600	55.3	3	-
Arkansas	16%	0.3	0%	6,200	37.3	-	2
California	58%	2.5	22%	46,300	57.3	3	-
Colorado	23%	-2.6	53%	6,600	39.4	1	2
Connecticut	42%	16.2	6%	3,100	8.7	1	1
Delaware	83%	63.4	100%	2,600	4.7	3	-
District of Columbia	NA	0.0	0%	-	0.0	-	-
Florida	62%	14.1	89%	39,500	108.4	5	-
Georgia	33%	23.4	56%	16,700	56.8	4	1
Hawaii	0%	0.0	0%	-	7.4	-	-
Idaho	17%	2.2	4%	1,100	1.9	-	-
Illinois	2%	0.5	73%	15,600	97.8	3	-
Indiana	8%	5.6	75%	7,000	98.9	2	2
Iowa	2%	-1.7	52%	3,700	39.2	1	1
Kansas	3%	-1.5	23%	4,800	33.1	-	1
Kentucky	3%	1.7	86%	6,900	85.3	2	1
Louisiana	43%	7.4	100%	20,100	58.3	3	2
Maine	35%	-10.4	0%	1,700	3.7	-	1
Maryland	6%	1.8	87%	4,100	18.9	1	-
Massachusetts	58%	7.9	71%	6,700	14.7	2	2
Michigan	11%	2.1	71%	12,200	67.2	3	-
Minnesota	7%	1.5	19%	5,100	29.3	-	2
Mississippi	60%	16.0	94%	12,000	22.6	4	-
Missouri	4%	-1.3	49%	5,500	78.3	1	2
Montana	2%	1.6	7%	400	17.0	-	-
Nebraska	1%	-1.3	0%	1,900	28.0	-	1
Nevada	63%	-5.0	0%	7,400	15.7	1	1
New Hampshire	22%	-8.6	0%	1,200	3.4	-	-
New Jersey	45%	13.4	95%	12,800	15.8	3	1
New Mexico	27%	6.0	13%	3,400	28.5	-	3
New York	40%	8.3	73%	19,500	33.5	2	3
North Carolina	23%	19.3	0%	10,700	56.9	3	-
North Dakota	0%	0.0	31%	600	30.3	-	2
Ohio	18%	15.9	89%	11,900	102.5	4	-
Oklahoma	38%	-6.1	21%	14,200	46.3	1	2
Oregon	21%	-7.6	82%	3,700	9.5	1	-
Pennsylvania	24%	15.2	97%	15,800	108.7	4	-
Rhode Island	95%	-2.4	0%	1,700	2.8	1	-
South Carolina	12%	6.0	99%	5,800	28.8	1	3
South Dakota	4%	0.4	0%	1,000	3.2	-	-
Tennessee	8%	7.3	1%	5,200	38.1	-	3
Texas	42%	-1.5	58%	77,000	257.5	3	1
Utah	18%	2.5	42%	2,700	35.7	-	2
Vermont	0%	0.0	0%	-	0.0	-	-
Virginia	28%	14.3	98%	12,500	34.7	3	2
Washington	10%	0.7	0%	3,400	12.5	-	-
West Virginia	1%	0.6	0%	1,100	68.9	1	-
Wisconsin	13%	5.1	94%	6,500	47.7	1	3
Wyoming	NM	NA	100%	300	50.7	2	-

Notes and Limitations

This analysis is focused on the financial risks facing consumers living in states that are, or are moving toward being, overly reliant on natural gas for electricity generation. The analysis focuses on the state level because, as noted above, many of the decisions that shape the electric sector are made at the state level. States are not, for the most part, islands when it comes to electricity generation and consumption, however; indeed, states commonly import and export electricity across state lines. Data about such imports and exports are generally available only as net flows, however, without a breakdown of shares of specific fuel sources in such flows (that is, what type of power plant generated the electricity flowing across a particular state boundary). A state's electricity generation portfolio may therefore not be perfectly representative of the fuel mix of electricity actually consumed within a state's borders, and consumers may be exposed to fewer or greater risks of natural gas overreliance than their state's own generation portfolio would suggest.

The purposefully tight scope of this analysis means that indicators are also limited in their capacity to capture broader risks to consumers from their state's overreliance on natural gas, making the analysis a conservative estimate of the risks facing consumers. Major environmental challenges associated with natural gas production and transport, for example, are not included. Should the issue of methane leakage over the life cycle of natural gas use remain insufficiently resolved, for example, states (and their consumers) may need to contend with higher costs due to higher greenhouse gas emissions being associated with the fuel.

This analysis also does not attempt to identify the ideal role for natural gas within a state's generation portfolio. Instead, it works to identify those states in—or heading toward—a position of overreliance. Given that, indicators actively identify those states exhibiting the highest risk levels, but do not identify any states as definitively "overreliant" on natural gas. Conversely, states without broad indications of risk of overreliance on natural gas are not necessarily free of reliance and risk. Also, states with low natural gas usage (and risk) by most measures may be in such a position because of heavy dependence on coal generation, which presents a host of problems and risks of its own.

Acknowledgments

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The opinions expressed herein do not necessarily reflect those of the organizations that funded the work or the individuals who reviewed it. The Union of Concerned Scientists bears sole responsibility for the content.

This analysis was conducted by Paula Garcia, Julie McNamara, and John Rogers.

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FPL's Response to Staff's Interrogatories, Nos. 1-10, 32-34, 44 (including supplemental), 45, 58-63, 65, 76, 84, 85. See also excel files contained on Staff Exhibit CD for Nos. 5, 33-34, 44-45, 60, 62, 84.

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FPL's Response to Staff's Request for Production of Documents, Nos. 1, 2, 3 (excel file), 4, 5. See also excel files contained on Staff Exhibit CD for Nos. 1, 2, 3, 4, 5.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 59
PARTY: STAFF
DESCRIPTION: FPL's Response to Staff's Interrogatories, Nos. 1-10, 32-34, 44 (including supplemental), 45, 58-63,...

QUESTION:
On page 5, lines 8-10, of Witness Feldman's direct testimony, Witness Feldman states that FPL's base case load forecasts presented in his testimony are the same forecasts presented in FPL's 2015 Ten Year Site Plan (TYSP). The following questions relate to FPL's 2015 TYSP and 2014 TYSP.

a. Referring to the last paragraph on page 30 of FPL's 2015 TYSP and page 29 of FPL's 2014 TYSP, please explain why FPL reduced its projected customer growth from 1.4% for the period 2014 – 2023 to 1.3% for the period 2015 – 2024.

b. Referring to Schedule 2.1 of FPL's 2015 TYSP, columns 8 and 9 (Commercial class), please explain why the current projections of the Average No. of Customers and the Average kWh Consumption Per Customer are both lower than the projections in FPL's 2014 TYSP for every year throughout the common forecast time horizon.

c. Referring to Schedule 2.2 of FPL's 2015 TYSP, columns 11 and 12 (Industrial class), please explain why the projection of the Average No. of Customers is higher than the projection developed in the 2014 TYSP, while the projection of the Average kWh Consumption Per Customer is significantly lower than the projection developed in FPL's 2014 TYSP for every year throughout the common forecast time horizon.

d. Referring to Schedule 3.1 Forecast of Summer Peak Demand (MW) of FPL's 2015 TYSP column (3), please explain why the forecasted annual Wholesale is increased significantly from 2014 level for the period 2015 – 2020 then drops back to 2014 level for the period 2021 – 2024.

e. Referring to Schedule 3.1 Forecast of Summer Peak Demand (MW) of FPL's 2015 TYSP column (7), please explain why the forecasted annual Residential Conservation is reduced for the period 2015 – 2018 but increased for the period 2020 – 2023, compared to the forecast presented in FPL's 2014 TYSP.

f. Referring to Schedule 4 Previous Year Actual and Two-year Forecasts of Retail Peak Demand and Net Energy for Load (NEL) by Month contained in the 2015 and the 2014 TYSPs, please explain the reasons (other than the weather) which caused FPL's 2014 actual NEL to be lower than FPL's 2014 forecast.

RESPONSE:

a. The projected customer growth forecast in the 2015 TYSP was reduced from 1.4% in the 2014 TYSP to 1.3% because of the removal of Vero Beach from

FPL's forecast. In the 2014 TYSP it was assumed that FPL would begin serving the City of Vero Beach beginning in 2015. In the 2015 TYSP Vero Beach was removed from the forecast.

b. Similar to the response to subpart (a) above, the projected number of commercial customers in the 2015 TYSP is lower than that projected in the 2014 TYSP due to the removal of Vero Beach from the 2015 TYSP forecast. This also results in a lower use-per-customer as the Vero Beach commercial customers were forecast to have a higher use-per-customer than FPL commercial customers.

c. The average number of industrial customers is higher in the 2015 TYSP than in the 2014 TYSP due to a higher projection of small GS-1 industrial customers. These customers are primarily temporary and construction accounts. The increase in the number of these accounts is due to an improving economy and improving housing market. Since these customers comprise the largest share of industrial customers and have significantly lower use per customer, the faster growth of this group of customers results in a lower overall use per customer for the industrial class.

d. The wholesale summer peak forecast increases during the 2015-2020 time period due to the inclusion of the Seminole Electric Cooperative (Seminole) as a wholesale customer. The contract with Seminole ends in May 2021, therefore Seminole does not contribute to FPL's 2021-2024 summer peaks.

e. The forecast for Residential Conservation in FPL's 2015 TYSP is lower in the 2015-2018 time period because the 2014 TYSP includes the 2014 contributions to DSM of approximately 120 MW based on FPL's then-current DSM Goals, which were reset by the commission to the 2004 Goals levels. Residential Conservation is higher in the 2015 TYSP for the 2020-2023 time period because FPL's 2014 TYSP utilized a forecast for Residential Conservation based on FPL's proposed DSM Goals of 337MW of total DSM, while FPL's 2015 TYSP utilized FPL's DSM Plan of 526MW of total DSM.

f. In evaluating any energy forecast variance, weather must be considered. The actual level of cooling degree hours and heating degree days were both lower than normal in 2014. This accounts for nearly one-quarter of the difference between actual and forecast NEL in 2014. Other than weather, the first reason why NEL was lower than projected was the actual CPI for energy was more than 5% higher than forecast during 2014, resulting in lower sales. Second, the forecast presented in Schedule 4 of our Ten Year Site Plan does not have any adjustments for DSM. Adjusting for DSM would have resulted in a lower forecast than that presented in the Ten Year Site Plan. Third, with the improving economy and housing market, it was expected that there would be an uplift in sales as empty homes became occupied. This uplift in sales did not materialize as anticipated.

QUESTION:
Referring to page 8, lines 17-19 of Witness Feldman's direct testimony, please identify and explain in detail the term "consistent set of assumptions" used throughout the load forecast.

RESPONSE:

All of the variables used in the customer, peak, and NEL models are from the same data sources and are of the same forecast vintage. Additionally, weather used in all of the models are calculated consistently using the same weather stations and the same methodology in developing the composite temperature.

QUESTION:
Referring to page 9, lines 14-16 of Witness Feldman's direct testimony, please explain how the population growth projections provided by the Bureau of Economic and Business Research and the Office of Economic Demographic Research are used to forecast growth of customers.

RESPONSE:

The population projection provided by the University of Florida's Bureau of Economic and Business Research is used as an explanatory variable in our econometric models used to forecast total customers and residential customers. Florida population growth is an important driver of customer growth and has historically been the most significant variable in projecting the number of customers in FPL's service territory.

QUESTION:
Referring to page 11 of Witness Feldman's direct testimony, please explain in detail how FPL forecasts the annual summer peak?

RESPONSE:

We begin by updating our databases with the most recent year of data for variables which may be considered or used in the summer peak model. Next, we review the previous year's weather normalized forecast variance in order to evaluate the prior year's model. Drivers which may affect the summer peak such as population growth, weather, codes and standards, and the economy, among others, are considered. Variables are developed from these drivers which are likely to affect the summer peak. Any variables considered must be consistently measurable over the model calibration period and there must be a reasonable forecast available from a reliable third party source for each variable considered for use in the model. A potential summer peak per customer model is then developed with the variables identified. A review of the model statistics, including the R^2, MAPE, and Durbin-Watson statistic are evaluated, along with ensuring that the coefficients are significant and have the correct signs and that there is no observable pattern in the residuals. Modifications to the model are made as dictated by the model statistics. The model output is then multiplied by the forecast number of customers to develop a preliminary summer peak forecast. Next, factors that may affect the forecast, but are not included in the historical data and therefore not picked up in the econometric model, such as plug-in electric vehicles, distributed solar generation, changes in wholesale contracts, and the impact of the Economic Development riders are developed and included in the forecast. The summer peak forecast is evaluated for reasonableness by looking at historical trends and comparisons with the prior forecast.

QUESTION:
On page 13, lines 11-12, of Witness Feldman's direct testimony, Witness Feldman states that the real price of gasoline, which "lagged one month," was incorporated into the summer peak model as a proxy for energy prices.

a. Please identify whether FPL's actual electricity price, Consumer Price Index (CPI) – Energy, or a gasoline price proxy were included as model variables for capturing the impact of energy price on FPL's Peak Demand Forecasts and NEL Forecasts appearing in each of FPL's TYSPs from 2010 through 2015.

b. For each year-to-year change in model variables identified in Interrogatory No. 5a, please explain the rationale for making the change.

c. Please explain the reasons FPL used the gasoline price proxy, instead of FPL's actual electricity price, as an explanatory variable for model construction.

d. Please explain why the real price of gasoline was used as a proxy for energy prices.

e. Please explain why the real price of gasoline used as a proxy for energy prices lagged one month.

f. Please the differences, in terms of forecasting accuracy, when using the proxy of real price of gasoline lagged one month versus using the actual variable of real FPL's electricity prices. Please support your response with a comparison of the forecasted versus actual summer peak demand data for 2013 – 2014, and a list of model accuracy data (standard errors, t-statistics, as well as the summary statistics) for 2015 – 2019.

RESPONSE:

a.	2010 TYSP	NEL used real electric prices (12 month moving average) Summer peak used real electric prices
	2011 TYSP	NEL used real electric prices (12 month moving average) Summer peak used real electric prices
	2012 TYSP	NEL used CPI for energy Summer peak used real electric prices
	2013 TYSP	NEL used CPI for energy Summer peak used CPI for Energy (three month moving average)
	2014 TYSP	NEL used CPI for energy Summer Peak used the real price of gasoline lagged one month
	2015 TYSP	NEL used CPI for energy Summer Peak used the real price of gasoline lagged one month

There are no price terms used in the winter peak model.

b. Effective with the 2012 TYSP, the NEL forecast began incorporating the CPI for energy as a model variable rather than the real price of electricity. This change was made because modelling showed that customers at the time were becoming less sensitive to the price of electricity (which was then declining in real terms), and more sensitive to overall energy prices (which at the time were increasing significantly). Effective with the 2013 TYSP, the summer peak forecast began incorporating the CPI for energy as a model variable rather than the real price of electricity. This change helped maintain a good statistical fit in the forecasting model. Effective with the 2014 TYSP, the summer peak forecast began incorporating the real price of gasoline lagged one month rather than the CPI for energy for similar reasons.

c. FPL has found that using a proxy for energy prices, in some cases can be superior to using the real price of electricity as a variable in its forecasting models. This can be particularly the case when electricity prices are stable or declining while other energy prices are increasing and volatile, as has been the case in recent years. Under these conditions, many consumers must budget for their total energy purchases, not just electricity. The use of a proxy for energy prices, be it the CPI for energy or the real price of gasoline lagged one month, reflects the fact that consumers must frequently manage to an overall energy budget. The use of the real price of gasoline lagged one month can be appropriate as a proxy for energy prices in forecasting the summer peak because of the prominent role the price of gasoline plays in the decisions of consumers, particularly during the summer months.

d. Please see the response to subpart (c) above.

e. Lagging the real price of gasoline one month in the summer peak model improved the significance of the gasoline price term and helped maintain a good statistical fit in the forecasting model.

f. Please see Attachment No. 1.

QUESTION:
Referring to Witness Feldman's direct testimony, page 26, lines 9-11, please explain why FPL used the Consumer Price Index for determining impact of energy price on electric consumption per customer but used real gasoline prices for determining impact of energy prices in summer peak demand as testified on page 13, lines 11-12.

RESPONSE:
The Consumer Price Index for Energy Prices and the real price of gasoline were both used as proxies for the overall cost of energy goods to consumers. The real price of gasoline can be more volatile than the CPI for Energy Prices. As a result, the more stable CPI for Energy Prices generally provided better model statistics when used in the Net Energy for Load model. The volatility in the real gasoline prices has been less of an issue in modelling the annual summer peak which is not subject to month-to-month fluctuations. Depending on the time period being evaluated, either the real price of gasoline or the CPI for Energy Prices may be appropriate for modelling the summer peak.

QUESTION:

Referring to Witness Feldman's direct testimony, page 25, lines 7-9:

a. Please compare the NEL forecast to the aggregate of billed sales by rate class forecasts.

b. Please explain whether FPL has previously used the total NEL versus billed energy sales approach to forecast energy sales. If yes, what is the modelling accuracy for each approach (forecasted vs. the actual energy sales)?

RESPONSE:

a. Below is a table comparing FPL's NEL forecast with the aggregate of the billed sales forecast by revenue class.

MWh	NEL	Forecasted Billed Sales
2015	119,712,544	113,117,490
2016	122,406,843	115,679,613
2017	123,945,598	117,157,296
2018	125,432,505	118,580,271
2019	127,069,635	120,119,803
2020	128,851,360	121,815,566
2021	129,237,426	122,226,832
2022	130,076,692	122,979,639
2023	131,495,329	124,319,680
2024	133,275,800	126,004,519

Note: values are not adjusted for DSM

b. FPL has consistently used the NEL forecast in calibrating the billed sales forecasts since the 2001 TYSP. The improvement in the forecast accuracy from using this methodology is shown below for recent history.

	2014 TYSP	2013 TYSP	2012 TYSP	2011 TYSP
Actual Weather-Normalized NEL	116,623,974	112,175,798	111,348,964	109,322,958
Forecasted NEL based on Output of the Revenue Class Models	118,690,918	115,381,625	111,796,366	113,526,646
NEL Variance based on Revenue Class Sales Models	-1.7%	-2.8%	-0.4%	-3.7%
Official NEL Forecast based on NEL Model	117,784,561	112,935,144	111,020,889	111,430,252
NEL Variance based on Official NEL Forecast	-1.0%	-0.7%	0.3%	-1.9%
Improvement in Absolute Variance using Official NEL Forecast	0.8%	2.1%	0.1%	1.8%

Note: Forecasts are for current year, i.e., 2014 TYSP Forecast is for the year 2014

QUESTION:
Referring to pages 14-16 of Witness Feldman's direct testimony regarding the out-of-model adjustments made to forecasts of NEL and summer peak demands:

a. Apart from the existing energy contracts FPL owned, please state whether FPL used any other information to project the annual incremental wholesale loads for the period 2015 to 2024.

b. Please explain how the annual projected amounts of Economic Development Rider and Existing Facility Economic Rider were derived for years 2016 – 2024. In particular, please explain how the 2019 addition of 27 MW to summer peak was derived.

c. Referring to page 16, lines 13-18m, of Witness Feldman's direct testimony, please explain how FPL determines its share of the state forecast of installed capacity of distributed solar generation for years other than 2014. Please also explain and clarify the term "solar profiles".

RESPONSE:
a. The projection of the incremental wholesale loads for the period 2015 through 2024 is based strictly on wholesale transactions where there is signed contract for a power sale.

b. Adjustments due to the Economic Development Rider and Existing Facility Economic Rider are developed by FPL's Economic Development Department. Based on negotiations with potential or existing customers, and knowledge of potential customers considering locating in FPL's service territory, an estimate of the number of customers and their associated KW is projected. For the year 2019, the 27 MW is based on 15 new commercial and industrial customers expected to be added. An expansion factor is used to take the estimated KW associated with these customers to the generation level. Historical data from our existing customers for the appropriate rate class are used to estimate the portion of the new load that will be coincident with FPL's summer peak. In this manner, the projected contribution to the summer peak by this group of customers is derived.

c. FPL begins with a state of Florida forecast of installed capacity of distributed solar generation developed by Greentech Media (GTM). The forecast for residential and commercial customers is purchased by year. FPL then uses our net metering data to determine the 2014 installed capacity of distributed solar generation for our own residential and commercial customers. From these data, and GTM's statewide estimates, we calculated our share of the state total distributed solar generation for residential and commercial customers. These shares are held constant throughout the forecast horizon.

Solar profiles are the estimated hourly profiles, by month, showing the percentage of annual distributed solar generation for each hour. For example, all months between the hours of 9 pm and 7 am show zero solar generation. Conversely, March through May, for hours ending 1 pm and 2 pm show the highest solar generation. All other hours would be somewhere in between these two levels of solar irradiance.

QUESTION:
Referring to Witness Feldman's direct testimony, page 29, lines 11-14, please specify the "minor modifications" FPL made to improve its forecasting models used in the instant petition.

RESPONSE:
Minor modifications made to the 2015 TYSP forecasts include updating the estimation period to include more recent actuals, removing the variable for empty homes from the NEL model since it was no longer a statistically significant variable, and incorporating adjustments to account for distributed solar generation.

Additionally, some of the weather terms in the winter peak model were changed. The average winter peak temperature on the day of the peak and the heating degree day buildup two days prior to the peak were replaced with the minimum temperature on the day of the winter peak. Also, the dummy for winter peaks with a minimum temperature below 40 degrees was dropped from the current model.

QUESTION:
Referring to Staff's First Set of Production of Documents No. 1:

a. Please identify the filename and worksheet responsive to each requested electronic document(s).

b. For each electronic document request, please specify a fully descriptive name of each row and column of data if not already provided in the worksheets, and

c. Please define the units of the data appearing within each of the electronic worksheets if not clearly identified within the worksheet itself.

RESPONSE:
Filename: 2015_TYSP_no_inact RevNEPACT EstThruAug
Worksheets: Data, Coef, MStat
The column headings and units in the Data worksheet from column C to column W are as follows:

NEL per customer (MWh), HDD based on 45 degrees, January HDD, February HDD, March HDD, December HDD, Impact of Codes and Standards (MWh per customer), Weighted real per capita income, lag of CPI for Energy Prices, January CDH, February CDH, March CDH, April CDH, May CDH, June CDH, July CDH, August CDH, September CDH, October CDH, November CDH, and December CDH.

The variable names in rows 3 – 22 of column A in the Coef worksheet correspond directly to columns D to W in the Data worksheet.

Filename: Summer_Peak_2014TYSP_model_updated
Worksheets: Data, Coef, MStat
The column headings and units in the Data worksheet from column B to column G are as follows:

Summer peak per customer (KW), CDH two days prior to peak day, maximum temperature on the peak day, Impact of Codes and Standards (KW per customer), Disposable household income, and the real price of gasoline lagged one month.

The variable names in rows 3 – 7 of column A in the Coef worksheet correspond directly to columns B to G in the Data worksheet.

Filename: Total_Customers_2015TYSPAltDummy Jul14Pop Thru July and Res_Cust_2015_TYSP AltDummy Jul14Pop Thru July
Worksheets: Data, Coef, MStat
In the Data worksheet, column D is population, and column E is a dummy variable for the impact of the implementation of Smart Meters.
The variable names in rows 3 – 4 of column A in the Coef worksheet correspond directly to columns D and E in the Data worksheet.

Filename: GS1_Customers OUT JULY21 2014
Worksheets: Data, Coef, MStat
In the Data worksheet, column C is GS1 Industrial Customers, Column D is the Florida employment to population ratio, and column E is the 16 month lag of housing starts.
The variable names in rows 3 – 4 of column A in the Coef worksheet correspond directly to columns D and E in the Data worksheet.

Filename: STHwy_Cust and Sales July_2014
Worksheets: Data, Coef, MStat
In the Data worksheet, column C is Street & Highway customers, and column D is the lag of Street & Highway customers.
The variable name in row 3, column A in the Coef worksheet is the lag of Street & Highway customers.

AFFIDAVIT

Richard Feldman

State of Florida)

County of Palm Beach)

I hereby certify that on this 7TH day of OCTOBER, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Richard Feldman who is personally known to me, and she acknowledged before me that she sponsored the answer(s) to Interrogatory No(s). 1-10 from Staff's 1st Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) is true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 7th day of october, 2015.

Neyla Cheraso

Notary Public, State of Florida

Notary Stamp:

NEYLA CHERASO
Notary Public - State of Florida
Commission # FF 898678
My Comm. Expires Sep 22, 2019
Bonded through National Notary Assn.

NOTARY PUBLIC STATE OF FLORIDA

QUESTION:
Page 62 of Exhibit SRS-1 of Dr. Sim's direct testimony, contains a table identifying firm purchase power changes during the timeframe 2014-2023. For each purchase power agreement that is expiring, please discuss, in detail, FPL's efforts to extend the life of the contract.

RESPONSE:

The following Florida Power & Light Company (FPL) purchased power contract expirations are identified on Page 62 of Exhibit SRS-1:

1. **Cedar Bay PPA retirement – 2016**

   The Cedar Bay PPA was cancelled on September 24, 2015, pursuant to the acquisition of Cedar Bay approved by the Commission in Order No. PSC-15-0401-AS-EI in Docket No. 150075. As shown in the exhibit, the PPA retirement is offset in 2016 by the addition of Cedar Bay to FPL's generation fleet. The unit will be available throughout 2016 for reliability purposes and then will be retired in 2017. The overall transaction saves customers $70 million (CPVRR).

2. **UPS Replacement – 2016**

   The UPS Replacement contract is actually three contracts with affiliates of Southern Company. These contracts are for the output from Plant Scherer Unit 3 (165 MW), Plant Franklin (190 MW) and Plant Harris (600 MW). After transmission losses this accounts for 928 MW delivered to FPL's system. These contracts were approved by the Commission in Docket No. 040001-EI.

   All three contracts have a normal termination date of December 31, 2015. Both the Franklin and Harris contracts contained an option to extend the contract through December 31, 2017, which option had to be exercised prior to the end of 2010. In 2010, FPL evaluated the option and found it not cost effective for FPL's customers.

   In the spring of 2015, FPL explored the feasibility of extending all or portions of the Southern Company contracts or purchasing energy and capacity from other Southern Company units. Due to the high fixed costs of transmission and the associated transmission losses on Southern's system, none of the options offered by Southern Company were cost effective for FPL's customers.

3. **St. John's River Power Park (SJRPP) suspension of energy – 2019**

   FPL purchases 30% of the output of SJRPP under a power purchase agreement with JEA. Since JEA funded their ownership interest in SJRPP with tax-free municipal bonds, the portion of the energy produced that can be sold to an IOU is limited by IRS regulations.

This limit is expected to be reached in the 2nd quarter of 2019. Since the delivery restriction is a function of IRS rules, purchases under the PPA are not subject to extension.

QUESTION:

Page 101 of Exhibit SRS-1 of Dr. Sim's direct testimony, provides that analyses conducted during 2013 and early 2014 showed that it would be cost-effective to retire the existing units, Putnam Units 1 and 2, and replace the capacity with new combined cycle capacity at a later date. Please provide a detailed summary of the analyses described in above-referenced statement.

RESPONSE:

Please see Attachment No. 1 for the requested detailed summary.

QUESTION:
Page 105 of Exhibit SRS-1 of Dr. Sim's direct testimony, provides that the generation only reserve margin value is "calculated by setting to zero all incremental energy efficiency and load management, plus all existing load management."

a. Please state whether FPL has ever experienced reduced customer participation in load management programs as a result of FPL interrupting or curtailing customers participating in load management programs. If yes, please provide an explanation of such event(s).
b. For each year since 1998, please provide the information in the table below for commercial and industrial customers. Please provide all requested data electronically in MS Excel format with all formulas intact.

Total Load Control Capabilities (MW)	Number of Load Control Events	Maximum Demand Reduction During a Single Event (MW)

c. For each year since 1998, please provide the following information in the table below for residential customers. Please provide all requested data electronically in MS Excel format with all formulas intact.

Total Res. Interruptible Load Control Capabilities (MW)	Number of Res. Load control customers interrupted during Load Control Events	Maximum Demand Reduction from residential load control During a Single Event (MW)

RESPONSE:
a. To date, FPL has not experienced significant voluntary drop outs by participants in its load management programs similar to the widespread drop outs that occurred in the late 1990s for other Florida utilities. However, FPL notes that concern over potential voluntary drop outs from load management programs is not the sole driver, nor even one of the primary drivers, of FPL's use of generation-only reserve margin (GRM) reliability criterion. FPL provided a detailed discussion of the reasons why a GRM criterion was adopted on pages 53 to 55 of its 2014 Ten Year Site Plan and on pages 55 to 56 of its

2015 Ten Year Site Plan and has addressed the GRM criterion in several other of its recent Site Plans, dating back to 2011.

b. The requested information is presented in Table Staff-34b, which is contained in Attachment No. 1. Capacity values are at the generator.

c. The requested information is presented in Table Staff-34c, which is contained in Attachment No. 1. Capacity values are at the generator.

QUESTION:
For each self build option identified in Exhibit SRS-5 (page 1 of 2) of Dr. Sim's direct testimony, please provide the projected capacity changes for each year of the analysis. Please provide this information in a format similar to Table ES-1 in FPL's 2014 Ten-Year Site Plan. Please provide all requested data electronically in MS Excel format with all formulas intact.

RESPONSE:

Please see Attachment No. 1 for the requested information.

QUESTION:

For each self build option identified in Exhibit SRS-5 (page 1 of 2) of Dr. Sim's direct testimony, please provide the projected capacity changes for each year of the analysis. Please provide this information in a format similar to Table ES-1 in FPL's 2014 Ten-Year Site Plan. Please provide all requested data electronically in MS Excel format with all formulas intact.

RESPONSE:

Please see Attachment No. 1 (Table Staff Supplemental-44).

QUESTION:
For each self build option identified in the table titled Third Step found in Exhibit SRS-5 (page 2 of 2) of Dr. Sim's direct testimony, please provide the projected capacity changes for each year of the analysis. Please provide this information in a format similar to Table ES-1 in FPL's 2014 Ten-Year Site Plan. Please provide all requested data electronically in MS Excel format with all formulas intact.

RESPONSE:

Please see Attachment No. 1 for the requested information.

AFFIDAVIT

Heather C. Stubblefield

State of Florida)

County of Palm Beach)

I hereby certify that on this 13 day of October, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Heather C. Stubblefield, who is personally known to me, and she acknowledged before me that she sponsored the answer(s) to Interrogatory No(s). 32, 55, 56, and 57 from Staff's 2nd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) is true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 13 day of October, 2015.

Maritza Miranda-Wise

Notary Public, State of Florida

Notary Stamp:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

AFFIDAVIT

Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 20th day of October, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 17-31 and 33-47 from Staff's 2nd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20th day of October, 2015.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn.

QUESTION:
On page 11, lines 6-9, of FPL Witness Feldman's direct testimony, Witness Feldman indicates that weather conditions, economic growth, codes and standards, and changing patterns of customer behavior are the factors affect FPL's summer peak demand. Please explain how "changing patterns of customer behavior" are incorporated into FPL's summer peak per customer model in a way similar to Witness Feldman's discussion regarding how weather conditions, economic conditions and codes and standards are incorporated into the summer peak per customer model. (See pages 11–13 of Witness Feldman's direct testimony.)

RESPONSE:
Changing patterns of customer behavior are incorporated into FPL's summer peak per customer model via the model coefficients and intercept term. Each coefficient captures behavioral changes of customers in terms of energy usage, due to changes in weather, income, gasoline prices, and the implementation of energy efficiency measures.

QUESTION:
Please refer to FPL Witness Feldman's direct testimony, page 11, lines 17–19, for the following questions:

a. Please explain in detail how the summer peak per customer model was calibrated and provide all the relevant information.
b. Please specify the years of which the annual historical data are used for the model calibration.
c. Please state whether FPL always uses the historical data on the same two weather series, the maximum temperature on the day of the summer peak and the sum of the cooling degree hours two days prior to the peak day, to calibrate its summer peak per customer model. (See page 11, lines 18–19)
d. Please explain the reasons FPL specifically choose the aforementioned two weather series for model calibration.
e. If the response to No. 59(c) is negative, please explain why. Please also specify the type of weather data series used for model calibration and identify the corresponding docket number as well.
f. Apart from the historical weather data series discussed in No. 59(c) above, please state whether FPL used any other historical data series for the model calibration.

RESPONSE:

a. The summer peak per customer model is a multiple linear regression model and was calibrated using the software program MetrixND. This software was developed by Itron. Please refer to FPL's response to Staff's First Request for Production of Documents, No. 1 for the historical data used to calibrate the model, along with forecasted data and model statistics, including the coefficients.
b. The model is calibrated using the historical years 1990-2014.
c. FPL has used, in our summer peak model, the same two weather series, namely, the maximum temperature on the day of the summer peak and a term for the heat buildup since the 2011 Ten Year Site Plan. The summer peak models utilized in the 2006 through 2010 Ten Year Site Plan forecasts also utilized one weather variable for the temperature and one for the heat buildup. However, the average daily temperature on the peak day was used rather than maximum peak day temperature in the 2006 through 2010 Ten Year Site Plan forecasts. The change to the maximum temperature on the day of the summer peak was made to improve the statistical fit of summer peak model. In the 2005 Ten-Year Site Plan forecast, only a temperature variable was included in the summer peak model. The addition of a variable for the heat buildup was made effective with the 2006 Ten-Year Site Plan forecast in order to improve the statistical fit of the summer peak model.
d. The maximum temperature on the day of the summer peak and the sum of the cooling degree hours two days prior to the peak day are used to calibrate the summer peak model

for two reasons. One, they have strong statistical significance, and two, they make logical sense as variables that significantly influence the summer peak.

e. As explained in subpart (c) of the response to this interrogatory, small refinements to the weather variables incorporated into the summer peak model have been made over time in order to improve the model's statistical fit based on the available historical data. Listed below are the weather data series used in model calibration where these series differ from what is in the current summer peak model, along with the corresponding docket number in which the forecast was utilized.

Weather Data Series	Docket No.
1) Average temperature on the summer peak day and heat buildup	080677-EI and 090172-EI
2) Maximum temperature on the summer peak day	050045-EI

f. Non-weather historical data series used to calibrate the summer peak model include real disposable income per household, one month lag in the real price of gasoline, and a variable to account for Codes and Standards. Also included in the model is an indicator variable for the year 1990.

QUESTION:
Please refer to FPL Witness Feldman's direct testimony, page 16 for the following questions:

a. Please state the actual/ estimated impact of distributed solar generation, in MW, for each year 2014 through 2019. (See page 16, lines 5–8)
b. Please provide details of the "solar profiles" FPL used to derive Megawatt hours (MWh) of distributed solar. (See page 16, line 18)

RESPONSE:
a.

	Installed MWdc	Solar Summer Peak (MW)	Solar Impact on FPL Summer Peak (MW)
2014	**34**	**11**	**0**
2015	**51**	**17**	**6**
2016	**82**	**28**	**17**
2017	**104**	**36**	**25**
2018	**133**	**46**	**35**
2019	**164**	**57**	**46**

Notes: Impact on FPL summer peak is incremental from 2014. 2014 solar summer peak MW is included in historical data.

b. Please see Attachment No. 1 for "solar profiles" used to calculate the MWh of distributed solar generation. Below is a brief description of the methodology used to develop these profiles.

1) Solar profiles are developed based on average hourly output. Profiles are in a 12X24 matrix format.
2) Profiles are based on three types of system orientations:

	Orientation	Share
Residential	South	50%
	Southwest	25%
	Southeast	25%
Commercial	South	80%
	Southwest	10%
	Southeast	10%

3) Average hourly output values are converted to represent Annual kWh/kW_{DC}.
4) Hourly values are calculated as a percentage of total annual kWh.

QUESTION:
Referring to FPL's response to Staff's First Set of Interrogatories No. 2, please specify what each of the assumptions is and explain why that assumption is necessary and appropriate for developing FPL's forecasts of customer growth, summer peak demand, and net energy for load.

RESPONSE:
Listed below are each of the assumptions used in developing the load forecast and the reasons why each is necessary and appropriate to use in FPL's forecasts.

1. **Population growth** is the primary driver of FPL's customer growth. Florida population is the most important variable in determining the forecast number of customers. As the population increases, so do the number of households, and hence customers along with the businesses needed to support these households. The statistics from FPL's customer model confirms the importance of population growth on the FPL customer forecast.
2. **Weather** is a key driver in electricity usage and is an important input into FPL's summer peak and net energy for load models. While the specification for weather varies between the models, the weather data used in developing these weather variables are based on the same hourly weather values.
3. **The economy** affects both the summer peak and net energy for load. The economy determines how much income consumers have to spend on all goods and services, including electricity. In addition, the economy determines the overall level of energy prices which also influences the amount of electricity consumption.
4. **Codes and Standards** directly impact both the summer peak and net energy for load. As codes and standards mandate efficiency improvements in energy using equipment, less usage is required. As such, improving efficiencies due to codes and standards need to be accounted for in FPL's forecasts.

QUESTION:
Please refer to FPL's response to Staff's First Set of Interrogatories No. 13 for the following questions:

a. Please provide FPL's 7/27/2015 base case natural gas and light fuel oil short term and long term price forecasts (annualized and monthly).
b. Please provide FPL's 7/27/2015 high band natural gas and light fuel oil short term and long term price forecasts (annualized and monthly).
c. Please provide FPL's 7/27/2015 low band natural gas and light fuel oil short term and long term forecasts (annualized and monthly).
d. Please provide CPVRR first stage analyses, similar to that provided in Exhibit SRS-4 of FPL Witness Dr. Sim's Direct Testimony, based on FPL's 7/27/2015 base case, high band, and low band natural gas and light fuel oil price forecasts.
e. Please provide CPVRR second stage analyses, similar to that provided in Exhibit SRS-5 of FPL Witness Dr. Sim's Direct Testimony, based on FPL's 7/27/2015 base case, high band, and low band natural gas and light fuel oil price forecasts.

RESPONSE:

a. Please see Attachment No. 1 (Table Staff-62 (Part a), (Part b), and (Part c)).

b. Please see Attachment No. 1 (Table Staff-62 (Part a), (Part b), and (Part c)).

c. Please see Attachment No. 1 (Table Staff-62 (Part a), (Part b), and (Part c)).

d. Staff Interrogatory 62 d & e requested that FPL update two analyses that FPL had performed as part of its overall next planned generating unit (NPGU) analyses in 2014 and early 2015. The request was to update these analyses substituting FPL's July 27, 2015 fuel cost forecast for the fuel cost forecasts that were used at the time for each of the two analyses.

The updated analyses utilize this July 2015 fuel cost forecast (low, base, and high bands). However, FPL has also updated a number of other inputs to the analyses. These other updates include:

- A new October 2015 load forecast; and,
- Various other assumptions that were not then available and, therefore, had not been utilized during each stage/step in the NPGU analyses, but which were updated and incorporated into FPL's 2015 Ten-Year Site Plan, including: (i) the 2016 PV additions, (ii) the new schedule for GT replacements in Broward and Lee counties, (iii) the mutually agreed upon decision with Cedar Bay to sell that generating unit to FPL and FPL's plans to subsequently retire that unit, and (iv) the 2027/2028 in-service dates for Turkey Point 6 & 7.

Utilizing all of these updated assumptions and forecasts, FPL performed three scenario analyses. One scenario utilizes the July 2015 base case fuel cost forecast, another scenario utilizes the July 2015 low band fuel cost forecast, and the third scenario utilizes the July 2015 high band fuel cost forecast.

FPL has combined key generating options analyzed in the two previous, separate stages of analyses presented in Exhibits SRS-4 and SRS-5 into one set of analyses which examines the following self-build generating options. Please see Attachment No. 2 (Table Staff-62 (Parts d & e)):

- The 1,622 MW OCEC Unit 1 that was designated as FPL's NPGU in the capacity RFP;

- An enhanced 1,633 MW version of the OCEC Unit 1 (as referenced on page 36 of FPL witness Sim's direct testimony);
- Enhanced CT designs of 231 MW (Summer) capacity in 5 x 0, 6 x 0, and 7 x 0 configurations; and,
- The two most competitive non-GE CC units from the original analyses.

As shown in this response, the original 1,622 MW OCEC Unit 1 is still projected to be more economic than any of the CT and non-GE generation options; thus, the overall conclusions and recommendations reflected in the Petition for a determination of need and the supporting pre-filed testimony remain unchanged.

e. Please see the response to subpart (d) above.

QUESTION:
Please refer to FPL's response to Staff's First Request for Production of Document No. 1, regarding FPL use of historical annual data to estimate the summer peak demand forecasting model, for the following questions:

a. Please explain the reasons FPL did not use historical monthly data for the model estimation in the instant case.
b. Please identify FPL's summer peak demand forecasts produced since 2005 that were estimated based on monthly data, and the purpose for which such forecasts were used.

RESPONSE:
a. FPL did not use historical monthly data to estimate the summer peak demand forecasting model because the summer peak occurs once per year. As such, annual data and not monthly data are appropriate for estimation purposes.
b. FPL has never used monthly data in estimating the summer peak demand forecasts.

AFFIDAVIT

Richard Feldman

State of Florida)

County of Palm Beach)

I hereby certify that on this 9 day of NOVEMBER, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Richard Feldman who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. 58, 59, 60, 61, and 63 from Staff's 3rd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 9th day of November, 2015.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn.

AFFIDAVIT

Steven R. Sim
Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 4th day of November, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s).62 from Staff's 3rd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 4th day of November, 2015.

Traci D. Goldwire
Notary Public, State of Florida

Notary Stamp:

TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn.

QUESTION:
On page 12, lines 17-23, of Dr. Sim's direct testimony, Dr. Sim states the following:

> "FPL utilizes three reliability criteria to project the timing and magnitude of its future resource needs. The three reliability criteria are:
>
> - A minimum total reserve margin (total RM) for Summer and Winter of 20%;
> - A minimum generation-only reserve margin (GRM) for Summer and Winter of 10%; and
> - A maximum loss-of-load-probability (LOLP) of 0.1 day per year."

Please describe how FPL determined that 10% is an appropriate level for a generation-only reserve margin (i.e., did FPL start with a 5 percent GRM and incrementally evaluate different levels).

RESPONSE:

The rebuttal testimony of FPL witness Sim in this docket details why and how the GRM reliability criterion was developed by FPL. A summary of this information is as follows:

- FPL conducted analyses that utilized both a resource planning perspective and a system operations perspective.
- FPL also used both historical and projected perspectives in these analyses.
- The analyses looked at pairs of resource plans that had identical total reserve margins (for example, each of the two resource plans might have a 20.4% total reserve margin), but that total reserve margin would have been reached in one resource plan with more incremental DSM MW/less incremental generation MW, while the other resource plan would have less incremental DSM MW/more incremental generation MW.
- FPL used the generation-only reserve margin (GRM) calculation as a metric by which to refer to these differences in these resource plans. A resource plan with more incremental DSM MW/less incremental generation MW has a lower GRM than a resource plan with less incremental DSM MW/higher incremental generation MW.
- From the resource planning perspective, the plan with more incremental DSM MW/less incremental generation MW (*i.e.*, a lower GRM) consistently was projected to have higher LOLP values than the other plan consisting of less incremental DSM MW/more incremental generation MW (*i.e.*, a higher GRM), even though both resource plans had an identical total reserve margin value. Thus, from an LOLP perspective, a resource plan with a lower GRM results in a less reliable FPL system than a resource plan with a higher GRM.

- From the system operations perspective, the plan with a lower GRM was consistently projected to have less MW in reserve for the system operators' to use, compared to the resource plan with a higher GRM, when examining projections of unexpected higher load and/or unexpected higher levels of generating unit unavailability.
- In regard to specific GRM levels, shortly after the 2009 DSM Goals decision, when very high levels of DSM were set as FPL's DSM Goals, FPL projected that its GRM would drop to 4.7% near the end of the decade. Consequently, FPL's analyses of the comparative reliability of the FPL system used 5% as a low end of the range of possible GRM values. The upper end of the GRM range that was examined was approximately 13%. The two results described above, both for the resource planning perspective and the system operations perspective, were consistently projected for all analyses throughout this 5% to 13% GRM range.
- FPL decided upon a minimum GRM value of 10% based on a recommendation from its system operations department. Their recommendation attempted to ensure that their operators have approximately 2,650 MW of generation reserves. This value was based on the following assumptions (MW values are approximate): (i) 1,500 MW for possible loss of the largest unit, (ii) 700 MW as an average of the total MW out-of-service at any given time for both planned and unplanned maintenance, and (iii) 450 MW for FPL's share of Florida's reserve-sharing obligations. The total 2,650 MW was a close match to a 10% GRM value. Therefore, FPL selected 10% as its minimum GRM criterion value. This specific value is expected to be reviewed in future FPL reliability analyses.
- This third reliability criterion is designed to complement, not replace, the maximum 0.1 day/year LOLP and 20% minimum total reserve margin reliability criteria that FPL also uses. In regard to the 20% total reserve margin criterion, the GRM criterion essentially provides guidance regarding what mix of DSM and generation resources should be added to maintain/enhance the reliability of FPL's system while meeting the minimum total reserve margin criterion of 20%.

QUESTION:

Referring to FPL's response to Staff's Second Set of Interrogatories No. 34, Attachment 1, Tab 2 of 2, FPL's response for the year 2008 indicates that the Company's maximum demand reduction during a single event (1,249 MW) exceeded the Company's total load control capabilities (966 MW). Please describe in detail, the 2008 event that resulted in the demand reduction of 1,249 MW.

RESPONSE:

FPL's residential load management customers can select that their air conditioners can be interrupted in either a "cycle" or "shed" mode. If the cycle mode is selected, FPL will interrupt each air conditioner during a load management event for a period of 15 or 17.5 minutes each half hour. This process repeats as needed until an event ends. FPL staggers the interruptions of these cycle customers so that a levelized amount of aggregate load management is achieved. In contrast, the air conditioners for customers who select the shed option are interrupted at the start of an event and remain interrupted for the duration of the event. FPL reports its residential load management capability reflecting the normal method of operation (*i.e.*, the mix of "cycle" and "shed" mode selected by customers). Load management under normal operations would have yielded a maximum 966 MW of load reduction in 2008. However, in an extreme emergency such as occurred on February 26, 2008, FPL is permitted to control the "cycle" customers in "shed" mode. Because all customers' air conditioners are interrupted simultaneously (without the cycle mode's staggering), more MWs can be produced. This emergency method was used during the 2008 event, which yielded the reduction of 1,249 MW.

AFFIDAVIT

Steven R. Sim

Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 12th day of November, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 65, 66, 68-70, 72, 73, 74, 77 - 83 from Staff's 4th Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of November, 2015.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC STATE OF FLORIDA
TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn

<u>**AFFIDAVIT**</u>

Thomas R. Koch

State of Florida)

County of Miami-Dade)

I hereby certify that on this 16th day of November 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Thomas R. Koch, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No. 76 from Staff's 4th Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16th day of November, 2015.

Carolyn J Smith
Notary Public, State of Florida

Notary Stamp:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2018
Commission # FF 122975

QUESTION:

On page 38, lines 17-19, of Dr. Sim's rebuttal testimony, Dr. Sim states that "the FPSC order [in the 2009 DSM Goals docket] meant that FPL's resource plans would be more dependent on DSM resources, and less reliant on generation resources…." Please revise Exhibit SRS-2, of Dr. Sim's direct testimony, assuming DSM additions per the 2009 DSM Goals docket for 2015 through 2019.

RESPONSE:

Table Staff 84 provides three different versions of Exhibit SRS-2, see Attachment No. 1. The first version, Table Staff-84a, is essentially identical to Exhibit SRS-2 except that it has added 3 new columns (1a, 6a, and 6b) with blank values in two of the columns (1a and 6a). These two columns with blank values will be used in the second and third versions of the tables. The projected results on the right hand side of Table Staff-84a are identical to those in Exhibit SRS-2.

Table Staff-84b assumes that the incremental difference between the 2015 through 2019 DSM additions and the 2014 DSM Goals are added in those years on top of the 2014 DSM Goals (as shown in Column 6a), and that no new generation is added (as shown in Column 1a).

Table Staff-84c assumes that just the 2014 DSM Goals are added (as is the case in Table Staff-84a) by showing zeroes in Column 6a. This table also shows that OCEC Unit 1 is added as planned in 2019 as shown in Column 1a.

In regard to the results, Table Staff-84a, and the original Exhibit SRS-2, both show that FPL has a large resource need beginning in 2019, which increases in 2020. The 20% total reserve margin criterion shows that FPL needs 988 MW by 2019 to meet that criterion. The 10% generation-only reserve margin (GRM) criterion shows that FPL needs an additional 64 MW of generation resources by 2019, *i.e.,* for a total of 1,052 MW, to enable FPL to also meet the GRM criterion.

Table Staff-84b assumes that FPL adds approximately 463 MW more DSM by 2019 than the 252 MW that is currently planned for FPL (and which is accounted for in Column 6). This results in approximately 715 MW of DSM additions in this scenario. However, no new generation is assumed to be added in this scenario. Thus, FPL would definitely become more reliant on DSM for meeting its reliability needs in this scenario. This table also shows that this significant amount of additional DSM only reduces, but does not meet the FPL's 988 MW need dictated by the 20% total reserve margin criterion. In addition to these reliability concerns, such high levels of DSM were found not to be cost-effective under the RIM screening test in both the 2009 and 2014 DSM Goals dockets. As discussed in the 2014 DSM Goals docket and in this docket, DSM is less cost-effective now for FPL's system than it was in 2009. Therefore, this additional DSM would be even less cost-effective now than it was projected to be in 2009, thus raising electric rates for all FPL customers and significantly increasing monthly bills for non-participants.

Furthermore, this DSM addition does nothing to meet FPL's 10% generation-only reserve margin criterion. The projected GRM value in 2019 is still at 5.8%, which remains well short of the 10% minimum GRM requirement. This very low GRM level is also at a level that led to the system reliability and system operations concerns that resulted in the need for FPL to establish the GRM criterion. Therefore, FPL's 2019 resource needs in this scenario remain at 1,052 MW of generation capacity.

Table Staff-84c assumes that FPL adds OCEC Unit 1 in 2019 and adds the amount of DSM set in the 2014 DSM Goals docket. In this scenario, which represents FPL's resource plan, both FPL's total reserve margin and GRM reliability criteria are met. Thus, FPL is projected to both meet all of its reliability criteria and to do so with the most cost-effective DSM and generation resource additions.

QUESTION:

On page 49, lines 8-12, of Dr. Sim's rebuttal testimony, Dr. Sim states that not allowing FPL to build the Okeechobee Clean Energy Center Unit 1 would result in "lower reliability for all utility customers in peninsular Florida."

a. Please state whether, if constructed, Okeechobee Clean Energy Center Unit 1 would be the largest generating unit in Florida and explain your response.
b. If yes, please explain how this would impact other utilities in peninsular Florida.

RESPONSE:

a. In part, yes, and in part, no. By 2019, the OCEC combined cycle Unit 1 will be the largest generating unit in terms of Summer capability. However, Fort Myers combined cycle Unit 2 would be the largest generating unit in Florida in terms of Winter capability.

b. The statement above quoted in FPL witness Sim's rebuttal testimony refers to the negative impact that would occur to system reliability for both customers served by FPL's system, and customers served by other utility systems in peninsular Florida, if OCEC Unit 1 is not allowed to be built and brought into service in 2019. If that scenario were to occur, FPL's total reserve margin would drop to 15.7% in 2019 and 14.3% in 2020 as explained in FPL's witness Sim's direct testimony. There would also be a corresponding drop in the total reserve margin for peninsular Florida, thus signifying a lower level of reliability for the peninsular Florida electric system without OCEC Unit 1. Therefore, the reliability of peninsular Florida's electric system will definitely be lowered if OCEC Unit 1 were not added in 2019.
In regard to other considerations, the addition of OCEC Unit 1 will increase fuel supply diversity in Florida by its access of the new Sabal Trail/FSC natural gas pipeline. OCEC Unit 1 is also projected to burn natural gas more efficiently than any natural gas-fired unit in Florida, thus putting downward pressure on natural gas usage, natural gas pricing, and emissions (including CO_2 emissions) compared any other natural gas-fired unit that might be substituted for OCEC Unit 1.

AFFIDAVIT

Steven R. Sim

Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 12th day of November, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 84-85 from _Staff's 5th __Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of November, 2015.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC STATE OF FLORIDA
TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn.

QUESTION:
On page 5, lines 7-8, of Witness Feldman's direct testimony, Witness Feldman indicated that FPL's long-term forecasts include base case projections of customers, peak demands, and net energy for load.

a. Please provide any documents containing the historical data used to estimate the econometric model that projects the number of customers by rate class and total.

b. Please provide any documents containing the projected independent variables used to project the number of customers through 2024. Please include any adjustments made to the output of the model to derive the final forecasted number of customers by rate class and total.

c. Please provide any documents containing the customer growth forecast model equation as well as any assumptions used in the model development. Please also provide the coefficients, standard errors, t-statistics, as well as the summary statistics of such model.

d. Please provide any documents containing the historical data used to estimate the econometric model that projects summer peak demand per customer.

e. Please provide any documents containing the projected independent variables used to project summer peak demand per customer through 2024. Please include any adjustments made to the output of the model to derive the final forecasted summer peak demand.

f. Please provide any documents containing the summer peak demand per customer forecast model equation as well as the assumptions used in the model development. Please also provide the coefficients, standard errors, t-statistics, as well as the summary statistics of such models.

g. Please provide any documents containing the historical data used to estimate the econometric model that projects Net Energy for Load (NEL).

h. Please provide any documents containing the projected independent variables used to project net energy for load through 2024. Please include any adjustments made to the output of the model to derive the final forecasted NEL.

i. Please provide any documents containing the NEL forecast model equation as well as the assumptions used in the model development. Please also provide the coefficients, standard errors, t-statistics, as well as the summary statistics for such model.

RESPONSE:
Attached are the files containing the historical data used to estimate the econometric models for summer peak and net energy for load. These files also contain the projections for all of the independent variables in the models along with the associated model statistics.

Also attached are the files containing the same information as described above for all of our customer forecasts that utilize econometric models. Please note that we produce forecasts by revenue class, not by rate class. For the commercial and industrial revenue classes the forecasts are developed for small, medium, and large customers, however, only the small commercial and GS-1 industrial groups are developed using econometric models.

QUESTION:
On page 5, lines 11-17, of Witness Feldman direct testimony, Witness Feldman indicated that FPL's long-term forecasts include risk-adjusted projections of summer peak demands which were based on analysis of the differences between actual and forecasted values of the summer peak.

a. Please provide any documents containing the historical forecast accuracy data used to calculate the risk-adjustment incorporated into the risk-adjusted summer peak demand per customer forecast.

b. Please provide any documents containing the historical forecast accuracy data used to calculate the risk-adjustment incorporated in the risk-adjusted NEL forecast, if any.

RESPONSE:
Please see the provided file for the historical forecast accuracy data, for the summer peak and net energy for load, used to calculate the risk-adjusted forecasts. Please refer to the worksheets named "SP_fan_Current" and "NEL Fan Current."

FPL's Response to Staff's Request for Production of Documents, No. 3.

Note: See excel file contained on Staff Exhibit CD for No. 3

QUESTION:
On page 28, lines 7-12, of Witness Feldman's direct testimony, Witness Feldman testified that similar out-of-model adjustments are made to forecasts of NEL, summer and winter peak demands. Please provide any documents containing the actual adjustment amounts related to each adjustment factor for each year from 2015 – 2024 in an Excel Table format similar to Table 1 below.

Table 1. Adjustment Amounts Made to the Forecasting Models

	Summer Demand (MW)						Net Energy for Load (GWh)					
	Wholesale	Plug-in Electric Vehicles	Economic Development Rider	Existing Facility Economic Rider	Distributed Solar Generation	Total	Wholesale	Plug-in Electric Vehicles	Economic Development Rider	Existing Facility Economic Rider	Distributed Solar Generation	Total
2015												
2016												
2017												
2018												
2019												
2020												
2021												
2022												
2023												
2024												

RESPONSE:
Please see the documents provided, specifically the worksheets named "Summer Peak", "Winter Peak", and "Monthly_NEL_Model."

QUESTION:
Referring to page 14, lines 2-4, of Witness Feldman's direct testimony, please provide any documents identifying, by year starting in 2015 through 2024, the source, quantity, level of firmness, and contractual status of incremental wholesale load which, when summed by year, matches the year to year differences in the Wholesale Load Forecast (Column 3) found in Schedule 3.1 of FPL's 2015 TYSP.

RESPONSE:
See document provided. Please refer to the worksheet named "Summary CP" column L.

150196 – Staff's 1st POD No.1 – 2015_TVSP_no_inact RevNEPACT EstThruAug.xlsx

150196 – Staff's 1st POD No.1 – GS1_Customers Out JULY21 2014.xlsx

150196 – Staff's 1st POD No.1. – Res_Cust_2015_TYSP AltDummy Jul4Pop Thru July.xlsx

150196 – Staff's 1st POD No.1 – SMALL Comm_Cust OUT JULY21 2014.xlsx

150196 – Staff's 1st POD No.1 – STHwy_Cust and Sales July_2014.xlsx

150196 – Staff's 1st POD No.1 – Summer_Peak_2014TYSP_model_updated.xlsx

150196 – Staff's 1st POD No.1 – Toal Customers_2015TYSPAltDummy Jul4Pop Thru July.xlsx

150196 – Staff's 1st POD No.2 – NEL SP WP Fans for P75 Fcst Errors Nov2014Fcst.xlsx

150196 – Staff’s 1st POD No. 3 – BEBR Population Forecast July2014.xlsx

150196 – Staff's 1st POD No.4 – Peak and Energy 2015 TYSP no DSM no-links PART1.xlsx

150196 – Staff's 1st POD No.4 – Peak and Energy 2015 TYSP no DSM no-links PART2.xlsx

150196 – Staff’s 1st POD No.5 – Wholesale Forecast_Aug2014_update.xlsx

150196 – Staff's 1st INT No. 5 Att1.xlsx

150196 – Staff's 2nd INT No.33 – Att1.xlsx

150196 – Staff's 2nd INT No. 34 – Att1.xlsx

Staff's 2nd INT No. 44 – Att1 – Supplemental.xlsx

150196 – Staff's 2nd INT No. 44 – Att1.xlsx

2015 Need Exhibit SRS-2 Updated for Load and Generation Capability.xls

150196 – Staff's 2nd INT No. 45 – Att1.xlsx

150196 – Staff's 3rd INT No. 60 – Att1.xlsx

150196 – Staff's 3rd INT No. 62 – Att1.xlsx

150195 – Staff's 3rd INT No. 62 – Att2 Corrected.xlsx

150196 – Staff's 5th INT No.84 – Attachment No. 1.xlsx

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FPL's Response to Staff's Interrogatories, Nos. 19, 25, 26, 66, 71, 74, 75

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 60
PARTY: STAFF
DESCRIPTION: FPL's Response to Staff's Interrogatories, Nos. 19, 25, 26, 66, 71, 74,

QUESTION:
On page 11, lines 1-2 of Dr. Sim's direct testimony, Dr. Sim states that FPL took account of all identified cost-effective renewable energy.

a. Please state how much (MW) wind generation FPL identified in determining the need for OCEC Unit 1.
b. Please state whether FPL considers wind generation a firm resource, and provide an explanation.

RESPONSE:
a. FPL has not identified any cost-effective wind generation in its service territory to-date primarily due to relatively low average wind speeds in FPL's service territory. Consequently, there are no wind MW of generation included in the resource plan which was used to project FPL's 2019 capacity needs.

b. Wind energy is an intermittent energy source. Therefore, FPL believes that only a portion, if any, of a wind turbine's nameplate rating would be appropriate to assign as firm capacity. This is the same fundamental view that FPL takes with solar energy, another intermittent energy source. For solar, the firm capacity value for any specific solar facility is based on several factors including specific location, orientation, and type of solar facility.

QUESTION:
On page 23, lines 7-10, of Dr. Sim's direct testimony, Dr. Sim states that a significant amount of land would be required to site the amount of photovoltaic (PV) that would be needed to supply 1,052 firm MW of solar capacity. Please describe the number of acres FPL estimates would be required to site 1,052 firm MW of solar capacity.

RESPONSE:
FPL is currently assigning a 52% of nameplate value as firm capacity to its three 74.5 MW photovoltaic (PV) projects that are scheduled to go in-service by late 2016. FPL also projects that as more PV is added to its system, the firm capacity value will diminish because the earlier PV will move the remaining peak load that will be met by non-PV resources towards a later hour in the day, thus reducing the contribution from additional PV to meeting that later peak. Based on that projection, if FPL were to assume a 50% of nameplate firm capacity value for future PV, and a 10 acres per MW-AC (nameplate) value, as reasonable assumptions, then approximately 21,040 acres would be needed to meet a 1,052 MW firm capacity need in 2019 with PV.

(1,052 firm MW / 0.50 firm MW-to-nameplate MW) x (10 acres/nameplate MW) = 21,040 acres.

QUESTION:
On page 24, lines 2-5, of Dr. Sim's direct testimony, Dr. Sim testifies that "FPL has now begun applying a methodology for determining what firm capacity values PV facilities are projected to deliver."

a. Please describe, in detail, FPL's methodology for determining what firm capacity values PV facilities are projected to deliver.
b. For the years 2015-2025, please provide FPL's estimated firm capacity contribution from solar PV facilities.

RESPONSE:

a. The new methodology employed by FPL for determining firm capacity value for photovoltaic (PV) facilities is based on measuring the output of a specific solar facility at the time of the system's summer peak load. Summer peak load is assumed to take place annually in August between 4 and 5 p.m. For existing facilities, the firm capacity value is based on historical data, while for solar facilities under consideration the value is based on projections of a specific project's hourly energy output. This summer firm capacity value varies based on the location, orientation, technology, and other design characteristics of the specific facility. Because the output of PV panels degrades over time, FPL assumes that the firm capacity value of PV facilities will similarly degrade over time.

   Similar analysis was performed for the FPL system's winter peak load which usually occurs early in the morning. At this time of the day, there is little or no solar energy generated by solar facilities, so FPL assumes that solar facilities have no firm capacity value at time of winter peak.

b. FPL's current resource plan as shown in FPL's 2015 Site Plan projects the following firm capacity values for existing and projected PV facilities through 2025:

- Space Coast PV: 10 MW nameplate rating and approximately 3 MW firm capacity;
- DeSoto PV: 25 MW nameplate rating and approximately 12 MW firm capacity; and,
- 2016 PV facilities (3): 223.5 MW nameplate rating (3 74.5 MW units) and approximately 116 MW total firm capacity.

<u>**AFFIDAVIT**</u>

Steven R. Sim

Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 20th day of October, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 17-31 and 33-47 from Staff's 2nd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20th day of October, 2015.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp: TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn.

QUESTION:

On page 13, lines 19-20, of Dr. Sim's direct testimony, Dr. Sim states that: "FPL's new DSM goals for 2015 through 2024 were fully accounted for in the reliability analysis." Please explain how FPL accounted for incremental conservation and load management beyond 2024.

RESPONSE:

FPL first notes that projected DSM impacts after 2024 have no impact on FPL's reliability needs for the year 2019.

FPL assumed that 50 MW per year of incremental DSM from FPL DSM programs would be added beyond 2024 through the year 2030. Furthermore, this projected impact from FPL DSM programs is in addition to the projected impacts of energy efficiency codes and standards that are accounted for in FPL's load forecast.

QUESTION:

Referring to page 16, lines 5-8, of Witness Feldman's direct testimony, please estimate the number of roof-top solar facilities that would be needed to meet FPL's projected need in 2019.

RESPONSE:

It would require approximately 400,000 average-sized residential roof-top photovoltaic (PV) systems to meet FPL's projected need in 2019. As a point of reference, FPL residential customers have installed approximately 3,200 PV systems to-date. This calculation is based on the following assumptions:

1. 2013-2015 weighted average size of residential customers' PV systems of 7.8 KW.
2. Summer peak coincidence factor of 34% based on FPL's Measurement & Verification study.

QUESTION:

Referring to FPL's response to Staff's Second Set of Interrogatories No. 25, FPL states that "FPL is currently assigning a 52% of nameplate value as firm capacity to its three 74.5 MW photovoltaic (PV) projects." Please state whether FPL assigned a firm capacity value to PV facilities in any of its previous need determination proceedings and explain your response.

RESPONSE:

No. Prior to 2015, FPL had not assigned a firm capacity value to its existing PV facilities, or to planned PV facilities, in any previous need determination proceedings. As indicated in FPL's last few Site Plans (prior to FPL's 2015 Ten-Year Site Plan), FPL had not assigned a firm capacity value to its PV facilities but has been examining whether a non-zero firm capacity value might be appropriate. During 2014, FPL finalized a methodology it now uses to evaluate firm capacity values for future PV facilities. FPL introduced the results of applying that methodology for both its existing and future PV facilities in its 2015 Ten-Year Site Plan. That methodology is now being used in FPL's resource planning work for which PV is a generation alternative.

QUESTION:

Referring to FPL's response to Staff's Second Set of Interrogatories No. 25, FPL assumes 10 acres per MW-AC for the calculation provided in its response. On page 102 of FPL's 2015 Ten-Year Site Plan, FPL summarizes a proposed solar facility that is projected to have a capacity of 74.5 MW-AC sited on 443 acres. Please describe the site-specific characteristics of the proposed solar facility that result in approximately 6 acres per MW-AC.

RESPONSE:

The planned solar facility referenced in the question is the Babcock Ranch Solar Energy Center in Charlotte County, FL. This planned solar facility benefits from very efficient site characteristics that allowed it to utilize significantly less acreage than the more typical metric of 10 acres per MWac. It has an approximately square shape and has limited natural or manmade features that needed to be avoided. Both of these features allow for a highly optimized solar field layout. The other two solar projects being planned in the 2015 Ten Year Site Plan (Citrus Solar Energy Center in DeSoto County and Manatee Solar Energy Center in Manatee County) have natural features such as wetlands and protected habitats coupled with manmade features such as oddly shaped boundaries, drainage ditches, roads, and other improvements which allow for the construction of approximately 1 MW per 10 acres. When planning a large portfolio of solar projects, it is more typical to have site features that require some reduction in the practical area on which solar projects can be built. In FPL's experience, 10 acres per MWac is an average result that is suitable for long term planning assessments.

<u>**AFFIDAVIT**</u>

Steven R. Sim

Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 12th day of November, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 65, 66, 68-70, 72, 73, 74, 77 - 83 from Staff's 4th Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of November, 2015.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn.

AFFIDAVIT

Richard Feldman

State of Florida)

County of Palm Beach)

I hereby certify that on this 12 day of NOVEMBER, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Richard Feldman**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 71 from Staff's 4th Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12 day of November, 2015.

Notary Public, State of Florida

Notary Stamp:

ANNETTE L.
NOTARY PUBLIC
Comm. # EE 854124
My Comm. Expires
Mar 15, 2017
STATE OF FLORIDA

AFFIDAVIT

Jacquelyn Kingston

Jacquelyn Kingston

State of Florida)

County of Palm Beach)

I hereby certify that on this 10th day of November, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Jacquelyn Kingston**, who is personally known to me, and she acknowledged before me that she sponsored the answer(s) to Interrogatory No(s). 75 from Staff's 4th Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 10th day of November, 2015.

Lisa A. Fowler

Notary Public, State of Florida

Notary Stamp: LISA A. FOWLER
Notary Public - State of Florida
My Comm. Expires Nov 14, 2018
Commission # FF 168308
Bonded through National Notary Assn.

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FPL's Response to Staff's Interrogatories, Nos. 11, 12 (without Confidential Attachment No. 1), 13, 14, (including Confidential response in Document No. 06341-15, part 3 of 4), 15, 16, 39, 49, 52, 53, 57 (non-confidential response), 64, 68, 77, 78, 80, 82. See also excel files contained on Staff Exhibit CD for Nos. 39, 80.

&

FPL's Response to Staff's Request for Production of Documents, Nos. 6a and 6b (the latter includes Confidential Document No. 07172-15, part 4)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 61
PARTY: STAFF
DESCRIPTION: FPL's Response to Staff's Interrogatories, Nos. 11, 12 (without Confidential Attachment No. 1), 13,...

QUESTION:
On page 7, line 14, and page 5, lines 9-11, Witness Stubblefield stated that OCEC Unit 1 will burn natural gas as the primary fuel source, and utilize a form of light fuel oil as a backup fuel source. Please identify and discuss expected industry trends and factors for natural gas and light fuel oil that will affect the FPL during the period 2015 through 2024.

RESPONSE:

The U.S. Energy Information Administration (EIA) determines industry trends that will potentially affect the industry as a whole and, in turn, the end users of the commodities, such as natural gas and light fuel oil. The industry trends identified by the EIA include growth in U.S. energy production, a modest growth rate of U.S. energy demand, and improved efficiency in the end-use sectors.

The EIA expects the growth in U.S. energy production to be led by crude oil, including refined products such as light fuel oil, and natural gas. It expects strong growth in domestic crude oil production from tight formations, which will lead to a decline in net petroleum imports and growth in net petroleum product exports. In addition, the EIA projects LNG exports to begin a large ramp of 0.3 trillion cubic feet (TCF) in 2016 to 2.6 TCF in 2024. Although exports seem to be rising, the EIA forecasts that U.S. energy demand will grow at a modest rate of about 0.2% per year from 2015 through 2024, driven mainly by the adoption of more energy-efficient technologies and existing policies that promote increased energy efficiency.

QUESTION:
Referring to Witness Stubblefield's direct testimony, pages 6, lines 21-22 and page 7, lines 1-2, please identify the independent variables representing worldwide demand, production capacity, economic growth, environmental legislation, and politics in the model used to forecast the future price of fossil fuels.

RESPONSE:

Florida Power & Light Company (FPL) does not forecast fossil fuel commodity pricing. FPL relies on NYMEX (which is not based on a model but on the actual natural gas futures market) and PIRA Energy Group to determine fossil fuel commodity pricing. PIRA, one of the leading fuel forecasting providers serving over 80% of US gas and electric companies, presents their clients with an annual update that describes many of the forecasting assumptions and drivers behind their commodity models. We have provided a copy of the most recent information available from PIRA as Confidential Attachment No. 1 to this response. This information describes the many variables considered by PIRA in its model to forecast the future price of fossil fuels.

Confidential Attachment No. 1 will be provided to Staff with FPL's Request for Confidential Classification (RFCC). The confidential information will be made available to the other parties for inspection at FPL's Tallahassee Office at 215 South Monroe Street, Suite 810, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon completion of a Non-Disclosure Agreement and upon reasonable notice to FPL's counsel.

QUESTION:
Please identify the sources and dates of FPL's most recent short term and long term fuel price forecasts (natural gas and light fuel oil).

RESPONSE:

Florida Power & Light Company (FPL) periodically updates/refreshes its fuel cost forecasts.

FPL utilizes the following data sources:

- Gas & Oil price data: NYMEX, PIRA Energy Group, and EIA
- SO2 and NOX Allowances: Amerex Brokers LLC
- Unit Emissions Rates: EPA Clean Air Markets Division – Part 75 Monitor data

FPL's most recent fuel price forecast for natural gas and light fuel oil had the following dates:

- Short Term: 07/27/2015
- Long Term: 07/27/2015

QUESTION:
Please refer to the U.S. Energy Administration's (EIA) *Annual Energy Outlook 2015*, found at http://www.eia.gov/beta/aeo/#/?id=13-AEO2015 (Table: Total Energy Supply, Disposition, and Price Summary, Reference Case).

a. Please complete the following table comparing FPL's natural gas price forecast (commodity) with the EIA's natural gas price forecast (nominal, $/MMBtu) as referenced above, including unit and percent differences for all years 2015 – 2024. Please also provide an electronic version of this table in excel format.

	FPL's 11/3/14 Forecasted Natural Gas Price	EIA's 2015 Reference Case Forecasted Natural Gas Price	Difference (FPL-EIA)	Difference
	(Nominal ¢/mmBtu)	(Nominal ¢/mmBtu)	(Nominal ¢/mmBtu)	(%)
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				

b. Please explain on whether the two forecasts referenced above in Interrogatory No. 14a are directly comparable for projecting natural gas prices for all years 2015 – 2024. Why or why not?

c. If the FPL and EIA's natural gas price forecast are comparable, please identify the most likely reasons known to FPL for any significant price difference in the forecasts.

RESPONSE: (do not edit or delete this line or anything above this)

a. Please see below for the completed table comparing Florida Power & Light Company's (FPL) natural gas price forecast (commodity) with the U.S. Energy Administration's (EIA) natural gas price forecast. Portions of this table have been identified as confidential. The table below is also being provided in excel format as Confidential Attachment No. 1.

The confidential portions of this response and Confidential Attachment No. 1 will be provided to Staff with FPL's Request for Confidential Classification (RFCC). The confidential information will be made available to the other parties for inspection at FPL's Tallahassee Office at 215 South Monroe Street, Suite 810, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon completion of a Non-Disclosure Agreement and upon reasonable notice to FPL's counsel.

Year	FPL's 11/3/14 Forecasted Natural Gas Price $/MMBtu	EIA's 2015 Reference Case Forecasted Natural Gas Price ($/MMBtu)	Difference (FPL-EIA) ($/MMBtu)	Difference (%)
2015	[redacted]	$3.82	[redacted]	
2016		$3.90		
2017		$4.09		
2018		$4.61		
2019		$5.07		
2020		$5.54		
2021		$5.79		
2022		$5.97		
2023		$6.25		
2024		$6.48		

b. FPL and EIA's forecasted prices could be comparable as they are both forecasting the same commodity. However, because FPL incorporates a forecast from The PIRA Energy Group as part of its forecasting methodology, FPL's forecast differs from EIA's forecast. While PIRA may use the same high level drivers as EIA, such as LNG export demand or increased productivity in shale production and their effects on the natural gas price, each agency develops their models independently and may interpret each input differently. As FPL does not have access to the models or their differences, it becomes increasingly difficult to explain the variances listed in response to subpart (a) above. FPL's methodology, which has been consistent for many years, uses the forward curve for natural gas commodity prices to project 2015 and 2016. For the next two years (2017 and 2018), FPL used a 50/50 blend of the November 3, 2014 forward curve and the most current projections at the time from The PIRA Energy Group. The remaining years use the annual projections from The PIRA Energy Group.

c. As referenced in the response to subpart (b) above, FPL's methodology differs from EIA's methodology. The differences make it difficult to compare the prices and give an accurate description of each of the variances included in the response to subpart (a) above.

Florida Power & Light Company
Docket No. 150196-EI
Staff's First Set of Interrogatories
Interrogatory No. 14 - Redacted
Attachment No. 1
Tab 1 of 1

Year	FPL's 11/3/14 Forecasted Natural Gas Price $/MMBtu	EIA's 2015 Reference Case Forecasted Natural Gas Price ($/MMBtu)	Difference (FPL-EIA) ($/MMBtu)	Difference (%)
2015	[redacted]	$3.82	[redacted]	[redacted]
2016	[redacted]	$3.90	[redacted]	[redacted]
2017	[redacted]	$4.09	[redacted]	[redacted]
2018	[redacted]	$4.61	[redacted]	[redacted]
2019	[redacted]	$5.07	[redacted]	[redacted]
2020	[redacted]	$5.54	[redacted]	[redacted]
2021	[redacted]	$5.79	[redacted]	[redacted]
2022	[redacted]	$5.97	[redacted]	[redacted]
2023	[redacted]	$6.25	[redacted]	[redacted]
2024	[redacted]	$6.48	[redacted]	[redacted]

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QUESTION:
Please identify and discuss steps that FPL has taken to ensure natural gas supply availability and transportation over the years 2015 through 2024.

RESPONSE:

Florida Power & Light Company (FPL) continues to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance FPL's access to natural gas supplies. These alternatives include obtaining additional access to diversified sources of natural gas such as shale gas from the Mid-Continent, the prolific gas supplies in the Marcellus and Utica shale basins, and securing natural gas reserves. In addition, FPL has secured 4.0 Bcf of firm natural gas storage capacity, which remains an important tool to help mitigate the risk of supply disruptions. FPL continues to evaluate its gas storage portfolio and is likely to subscribe for additional gas storage capacity to help increase reliability, provide the necessary flexibility to respond to demand changes, and diversify its overall portfolio.

Over the past several years, FPL has acquired upstream gas transportation capacity on several pipelines (the Southeast Supply Header, LLC, Gulf South Pipeline Company, LP, and the Transcontinental Gas Pipeline Company, LLC) to allow for greater diversity and access to multiple supply basins. FPL will continue to pursue upstream alternatives that further diversify and enhance FPL's gas transportation portfolio. FPL's existing contracts with Florida Gas Transmission Company and Gulfstream Natural Gas System, which serve FPL's natural gas power plants, are long-term in nature and include provisions which allow FPL to extend these contracts through a right of first refusal. FPL has also contracted for long-term gas transportation on the Sabal Trail Transmission (Sabal Trail) and Florida Southeast Connection (FSC) pipelines. Sabal Trail and FSC will significantly enhance FPL's gas supply diversity and reliability when the pipelines are placed into service in 2017.

QUESTION:
Please identify and discuss expected liquefied natural gas (LNG) industry factors and trends that will impact FPL, including the potential impact on the price and availability of natural gas, for the period 2015 through 2024.

RESPONSE:

According to the U.S. Energy Administration's (EIA) 2015 AEO Reference Case, annual LNG Exports are expected to rise about 200% to 0.3 TCF and an incremental 160% to 0.75 TCF in 2016 and 2017, respectively. Annual LNG Exports will then begin to stabilize and finally stay constant beginning in 2030 at about 3.4 TCF annually. However, EIA forecasts little to no change in the natural gas price for 2016 and a 3% increase in 2017. This indicates that the drastic increase in forecasted LNG exports will not make a large impact in the near term gas prices. However, as the forecasted exports begin to grow larger in volume, natural gas prices begin to rise. For example, in 2018, the EIA forecasts LNG exports to be above 1 TCF, while it forecasts natural gas prices to rise 11% year over year , showing that there would be more of an impact in the latter years due to higher export volumes. The EIA states that LNG exports depend largely on the effects of resources levels and oil prices.

AFFIDAVIT

Heather Stubblefield

State of Florida)

County of Palm Beach)

I hereby certify that on this 5 day of Oct., 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Heather C. Stubblefield who is personally known to me, and she acknowledged before me that she sponsored the answer(s) to Interrogatory No(s). 11, 12, 13, 14, 15 & 16 from Staff's 1st Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) is true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 5 day of October, 2015.

Maritza Miranda-Wise

Notary Public, State of Florida

Notary Stamp:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

QUESTION:
Referring to Exhibits SRS-4 and SRS-5 of Dr. Sim's direct testimony, please state whether FPL considered environmental costs in its CPVRR analyses.

a. If not, please explain the reasons.
b. If yes, please discuss FPL's methodology for developing its environmental costs.
c. If yes, please complete the table below summarizing FPL's estimated environmental costs for each year of FPL's CPVRR analysis. Please provide all requested data electronically in MS Excel format with all formulas intact.

Year	CO2 ($/ton nominal)	SO2 ($/ton nominal)	NOx ($/ton nominal)

RESPONSE:

a. FPL did include projected environmental compliance costs for SO2, NOX, and CO2 in its analyses of self-build generation options.

b. To develop the environmental costs used in the evaluation of FPL's self-build generation options, FPL relied on ICF International's National Emission Price forecasts developed in 2012 for SO_2, NO_X, and CO_2 as the starting points. These ICF forecasts were provided in 2010 (real) dollars for each year starting in 2012 for SO_2 and NO_X, and for the years 2023 through 2030 for CO_2. Based on discussions with ICF, FPL both converted those 2010 real dollar values to nominal dollars and extrapolated the values out into the future.

c. The Table in Attachment No. 1 provides the nominal \$/ton values for SO_2, NO_X, and SO_2 used in the analyses. The table shows two different sets of values for these three types of emissions. The values used in the first stage of FPL's analyses are on the left-hand side of the table and show that CO_2 costs were projected to start in the year 2023. The right-hand side of the table presents the updated values that were used in the second stage of the analyses and these show that CO_2 costs were projected to start in the year 2020. The reason for the change in the start date for CO_2 costs was to match the projected start year in the draft rules for EPA's Clean Power Plan.

The changes in SO2 and NOX values from the first stage to the second stage of the analyses were due to the Supreme Court's ruling in 2014 that countermanded a late 2011 District Court of Appeals in D.C. decision to stay the EPA's Cross-State Air Pollution Rule. This more recent decision resulted in changes in the compliance cost projections for both SO_2 and NO_X. After discussions with ICF, FPL incorporated these new compliance cost projections into its second stage analyses.

QUESTION:
On page 14 lines 19-21, of Witness Kingston's direct testimony, Witness Kingston testifies that peak firing and wet compression can be turned on for additional power production. Please explain, in detail, how peak firing differs from duct firing.

RESPONSE:

Peak firing, as used in Witness Kingston's direct testimony, refers to increasing the firing temperature in the combustion section of the gas turbine resulting in increased power output from the gas turbine as well as increased power output in the steam turbine as a result of additional gas turbine exhaust energy.

Duct firing refers to combusting natural gas with additional burners installed in the heat recovery steam generator resulting in additional steam production and increased power output from the steam turbine.

QUESTION:
On page 20, lines 21-22, of Witness Kingston's direct testimony, Witness Kingston testifies that the principal components of OCEC Unit 1 are estimated to cost $1,031.5 million. Please describe, in detail, how FPL estimated the cost of the principal components.

RESPONSE:

FPL estimates costs internally using staff personnel. The estimate is based on previous project experience with adjustments for project schedule, specific site conditions and scope, and anticipated market conditions during the period of project execution.

QUESTION:
For each project identified in Exhibit JKK-3 of Witness Kingston's direct testimony, please provide FPL's estimated heat-rate at time of approval, and the actual heat-rate realized by the project.

RESPONSE:

FPL Combined Cycle Plants Heat Rate Comparison

Project	Estimated heat rate at time of PSC approval (Btu/kWh)[1]	Actual heat-rate at the Commercial In Service Date[2] (Btu/kWh)
Martin Unit 8	6,850	6,714
Manatee Unit 3	6,850	6,696
Turkey Point Unit 5	6,835	6,732
West County Units 1 and 2	6,582 Unit 1 6,582 Unit 2	6,606 Unit 1 6,613 Unit 2
West County Unit 3	6,582	6,517
Cape Canaveral Unit 3	6,580[3]	6,314
Riviera Beach Unit 5	6,576[3]	6,302

[1] Represents estimated base average net operating heat rate @ 75°F/60% relative humidity as stated in the direct testimony of the applicable witness for each PSC need determination case.
[2] Represents the actual heat rate from the performance test conducted to validate performance guarantees
[3] Estimated heat rate in subsequent Ten Year Site Plan Filings (2010-2013) decreased due to revised technology selection (Cape Canaveral Unit 3 = 6,484 Btu/kWh; Riviera Beach Unit 5 = 6,480 Btu/kWh).

QUESTION:
On page 8, lines 8-9, of witness Heather C. Stubblefield's direct testimony, Witness Stubblefield testifies that the cost of additional gas transportation facilities has been included in the evaluation of OCEC Unit 1.

a. Please state the cost of the additional gas transportation facilities included in the evaluation of OCEC Unit 1.
b. Please describe, in detail, how the cost of additional gas transportation facilities was developed.
c. Please describe, in detail, the additional gas transportation facilities included in the evaluation of OCEC Unit 1.

RESPONSE:

a. The costs were provided in $/MMBtu and were added to the original demand charge Florida Power & Light Company (FPL) had negotiated for the Florida Southeast Connection (FSC) pipeline. Please see Confidential Attachment No. 1 for the revised pricing utilized by FPL.

b. FSC furnished a proposed transportation rate inclusive of all costs to develop, own, and operate a new lateral from the FSC to OCEC. The lateral will be sized to transport approximately 206,000 Mcf per day of natural gas at 650 psig to the meter and pressure regulation interconnection gas yard at the OCEC site.

   FSC prepared the proposal based on an evaluation of technical and physical requirements to build, own and operate a new greenfield lateral. Evaluation criteria used in the development of the lateral project scope include: FPL's gas transport and delivery requirements by the required commercial operation date; interconnection requirements at both FSC and the OCEC gas yard; pipeline routes and route conditions; and required permits, approval and authorizations required to site, construct and place the pipeline into service.

c. The facilities that are planned to be installed to serve OCEC include:

- Yard piping, valves, fittings, and pig launcher at the connection point to the Florida Southeast Connection Pipeline
- Approximately 4.5 miles of 16" pipeline to the OCEC
- Yard piping, valves, fittings, and pig receiver at the gas yard located on the OCEC site
- Isolation/Insulating flange assemblies at point of Custody Transfer
- Filter/separator and associated condensate storage tank
- Multipath ultrasonic flow meters with flow conditioners and block valves and actuators
- Gas quality monitoring equipment (*e.g.*, gas chromatograph)

- Electronic flow measurement equipment with control enclosure
- Electric power system including grounding and lightning protection
- Instrumentation
- Perimeter fencing and gates

Confidential Attachment No. 1 will be provided to Staff with FPL's Request for Confidential Classification (RFCC). The confidential information will be made available to the other parties for inspection at FPL's Tallahassee Office at 215 South Monroe Street, Suite 810, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon completion of a Non-Disclosure Agreement and upon reasonable notice to FPL's counsel.

	A	B	C	D	E	F
1	**FSC Contract Transport Rates with Cost of Okeechobee Lateral**					
2				[redacted]		
3	Period	Dates	MMBtu/day	[redacted]		
4	1	May 1, 2017 - April 30, 2018	400,000	[redacted]		
5	2	May 1, 2018 - Aug 31, 2018	400,000	[redacted]		
6	3	Sep 1, 2018 - April 30, 2019	400,000	[redacted]		
7	4	May 1, 2019 - April 30, 2020	400,000	[redacted]		
8	5	May 1, 2020 - April 30, 2021	600,000	[redacted]		
9	6	May 1, 2021 - April 30, 2022	600,000	[redacted]		
10	7	May 1, 2022 - April 30, 2023	600,000	[redacted]		
11	8	May 1, 2023 - April 30, 2024	600,000	[redacted]		
12	9	May 1, 2024 - April 30, 2025	600,000	[redacted]		
13	10	May 1, 2025 - April 30, 2026	600,000	[redacted]		
14	11	May 1, 2026 - April 30, 2027	600,000	[redacted]		
15	12	May 1, 2027 - April 30, 2028	600,000	[redacted]		
16	13	May 1, 2028 - April 30, 2029	600,000	[redacted]		
17	14	May 1, 2029 - April 30, 2030	600,000	[redacted]		
18	15	May 1, 2030 - April 30, 2031	600,000	[redacted]		
19	16	May 1, 2031 - April 30, 2032	600,000	[redacted]		
20	17	May 1, 2032 - April 30, 2033	600,000	[redacted]		
21	18	May 1, 2033 - April 30, 2034	600,000	[redacted]		
22	19	May 1, 2034 - April 30, 2035	600,000	[redacted]		
23	20	May 1, 2035 - April 30, 2036	600,000	[redacted]		
24	21	May 1, 2036 - April 30, 2037	600,000	[redacted]		
25	22	May 1, 2037 - April 30, 2038	600,000	[redacted]		
26	23	May 1, 2038 - April 30, 2039	600,000	[redacted]		
27	24	May 1, 2039 - April 30, 2040	600,000	[redacted]		
28	25	May 1, 2040 - April 30, 2041	600,000	[redacted]		
29	26	May 1, 2041 - April 30, 2042	600,000	[redacted]		
30	27	May 1, 2042 - April 30, 2043	600,000	[redacted]		

AFFIDAVIT

Steven R. Sim
Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 20th day of October, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 17-31 and 33-47 from Staff's 2nd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20th day of October, 2015.

Traci D. Goldwire
Notary Public, State of Florida

Notary Stamp: TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn.

AFFIDAVIT

Jacquelyn Kingston
Jacquelyn Kingston

State of Florida)

County of Palm Beach)

I hereby certify that on this 14th day of October 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Jacquelyn Kingston, who is personally known to me, and she acknowledged before me that she sponsored the answer(s) to Interrogatory No(s). 48-54 from Staff's 2nd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 14th day of October, 2015.

Lysa A. Fowler
Notary Public, State of Florida

Notary Stamp

LYSA A. FOWLER
Notary Public - State of Florida
My Comm. Expires Nov 14, 2018
Commission # FF 168308
Bonded Through National Notary Assn.

AFFIDAVIT

Heather C. Stubblefield

State of Florida)

County of Palm Beach)

I hereby certify that on this 13 day of October, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Heather C. Stubblefield, who is personally known to me, and she acknowledged before me that she sponsored the answer(s) to Interrogatory No(s). 32, 55, 56, and 57 from Staff's 2nd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) is true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 13 day of October, 2015.

Notary Public, State of Florida

Notary Stamp:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

QUESTION:
Please refer to FPL's response to Staff's First Request for Production of Documents No. 6 for the following questions:

a. Please state the source(s) and date(s) of each of FPL's reported natural gas and fuel oil transportation price forecasts (variable and, as applicable, fixed).
b. Please describe the methodology FPL used to forecast natural gas and fuel oil transportation price (variable and, as applicable, fixed).

RESPONSE:

a. The natural gas transportation price forecasts for fixed and variable costs are the actual contractual rates under FPL's natural gas transportation agreements with our pipeline counterparties. The current contractual rates as of the date of the fuel price forecast are used for the entire period of the forecast. For fuel oil, the transportation price forecast is based on historical data and market conditions. This data is updated periodically under no specific timetable.
b. As stated in subpart (a) above, FPL's methodology for forecasting natural gas transportation pricing is based on FPL's current contractual rates. Fuel oil primarily serves as a back-up fuel on FPL's system which results in sporadic consumption and resupply requirements. Therefore, FPL does not have long-term contracts in place for fuel oil transportation. Transportation for fuel oil is arranged based on each individual transaction. Transportation price forecasts are based on historical data and are adjusted periodically for market conditions.

AFFIDAVIT

Heather C. Stubblefield

State of Florida)

County of Palm Beach)

I hereby certify that on this 6th day of November, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Heather C. Stubblefield, who is personally known to me, and she acknowledged before me that she sponsored the answer(s) to Interrogatory No. 64 from Staff's 3rd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) is true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 6th day of November, 2015.

Notary Public, State of Florida

Notary Stamp:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

QUESTION:

Referring to Exhibit SRS-1, page 204 of 309, of Dr. Sim's direct testimony that discusses FPL's financial assumptions used in the Company's 2014 Ten-Year Site Plan, please list and discuss all financial and economic assumptions used in FPL's economic evaluation of OCEC Unit 1 including, but not limited to, capital structure, discount rate, general inflation rate, and tax assumptions.

RESPONSE:

The first stage of the OCEC Unit 1 analyses and steps 1 and 2 of the second stage of the analyses used the following financial assumptions: i) a capital structure of 40.38% debt and 59.62% equity; (ii) a 5.14% cost of debt; (iii) a 10.5% return on equity; and (iv) an after-tax discount rate of 7.54% while step 3 of the second stage of the analyses was based on the cost of debt and the after-tax discount rate that changed slightly to 5.05% and 7.51%, respectively. For both stages of the analyses, the OCEC Unit 1 book life is thirty years and tax life is twenty years.

The capital replacement escalation for the OCEC unit based on contract is approximately 2.0%, general capital escalation for other capital expenditures other than OCEC is 3.0% and escalation of O&M costs is 2.5%. This was consistent in both stages of the analyses.

QUESTION:
Referring to FPL's response to Staff's Second Set of Interrogatories No. 36, Attachment 1, Tab 1 of 1, please describe how FPL estimated the following plant specifications:

a. Planned Outage Factor
b. Forced Outage Factor
c. Equivalent Availability Factor
d. Annual Fixed O&M
e. Annual Variable O&M

RESPONSE:

a. Planned Outage Factor: estimated based on FPL historical performance per the North American Reliability Council ("NERC") – Generating Availability Data Systems ("GADS") codes.

b. Forced Outage Factor: based on FPL historical performance per the NERC GADS codes

c. Equivalent Availability Factor: based on FPL historical performance per the NERC GADS codes.

d. Annual Fixed O&M: consists of three areas of expenses: personnel, periodic maintenance, and capital replacement costs. Personnel expenses were developed using the extensive operating experience from the current FPL operating fleet, while periodic maintenance and capital replacement costs were estimated by utilizing manufacturer recommendations and the overhaul planning cycles. The annual stream of fixed O&M dollars described above is levelized in 2019 dollars. The value provided in Staff Table – 36 is the fixed O&M levelized dollars divided by the summer capacity.

e. Annual Variable O&M: was estimated by evaluating each site's need for water and chemicals to meet all environmental and emissions requirements. Water considerations assessed whether nearby sources of water could be utilized, and requirements for demineralized water for specific plant purposes. Annual cost of chemicals necessary to maintain proper water quality and to control emissions from NOx coming out of the combustion turbine are also part of the variable O&M expense. The annual variable O&M provided in Staff Table – 36 is the value, in $/MWh, for 2019. The annual variable O&M costs described above is divided by the product of the summer capacity of the unit (MW), 8760 hours and 85% capacity factor.

QUESTION:

Referring to FPL's response to Staff's Second Set of Interrogatories No. 39, FPL states "FPL relied on ICF International's National Emission Price forecasts developed in 2012."

a. Please state whether FPL has a more recent price forecast for emissions.
b. If yes, please provide the recent price forecast in a format similar to the format provided in FPL's response to Staff's Interrogatory No. 39(c).
c. If yes, please provide CPVRR first stage analyses, similar to that provided in Exhibit SRS-4 of FPL Witness Dr. Sim's direct testimony, based on FPL's most recent price forecast for emissions.
d. If yes, please provide CPVRR first stage analyses, similar to that provided in Exhibit SRS-5 of FPL Witness Dr. Sim's direct testimony, based on FPL's most recent price forecast for emissions.

RESPONSE:

a. FPL does not have a more recent price forecast for emissions.

b. Please see FPL's response to subpart (a) of this interrogatory.

c. Please see FPL's response to subpart (a) of this interrogatory.

d. Please see FPL's response to subpart (a) of this interrogatory.

QUESTION:
Referring to FPL's response to Staff's First Set of Interrogatories No. 42, Attachment 1, Tab 1 of 10, FPL's response states that: "Bill impact is calculated using the difference in revenue requirements of a particular option compared to the 1582 MW CC."

a. Please provide the estimated bill impact ($/1,000 kWh) associated with the OCEC Unit 1, for the years 2019 through 2028. Please do not provide this information as the difference in revenue requirements of a particular option compared to the OCEC Unit 1.
b. Please provide the estimated average bill impact ($/1,000 kWh) associated with the OCEC Unit 1 over the life of the unit. Please do not provide this information as the difference in revenue requirements of a particular option compared to the OCEC Unit 1.

RESPONSE:

a. Attachment No. 1 provides a bill impact projection of OCEC Unit 1 through 2043 compared to a scenario in which no other self-build generation option is assumed to be added in 2019 in place of OCEC Unit 1; *i.e.*, a "no build in 2019" scenario. Please see Attachment No. 1 for the requested information.

   FPL's prior response to Staff's Second Set of Interrogatories No. 42 provided a series of bill impact projections between OCEC Unit 1 and other self-build generation options that would also fully meet FPL's resource needs in 2019. Thus FPL's response provided a bill impact projection of scenarios that provide FPL's customers with a comparable level of system reliability. From a resource planning perspective, FPL believes that this "apples to apples" comparison in regard to system reliability is the more meaningful perspective with which to view projected bill impacts for FPL's customers.

   FPL notes that the projected bill impacts provided in Attachment No. 1 are based on scenarios that are projected to have significantly different levels of system reliability. The OCEC Unit 1 scenario will allow FPL to meet all three of its reliability criteria. The "no build in 2019" scenario will result in two of FPL's three reliability criteria being violated and, therefore, represents a much less reliable FPL system. From a resource planning perspective, this bill impact comparison is definitely not an "apples to apples" comparison. This bill impact comparison will be larger than those presented in FPL's response to Staff interrogatory 42 because the "no build in 2019" scenario does not incur expenses for adding new resources in 2019, thus resulting much lower system reliability for this scenario.

b. Please see FPL's response to subpart (a) of this interrogatory.

QUESTION:
Referring to FPL's response to Staff's Second Set of Interrogatories No. 45, Attachment 1, Tabs 1 through 5, FPL's response contained a note that FPL "Used 659 MW CC filler units for un-sited CC capacity from year 2023 through 2025 to facilitate optimization simulation convergence and reduce running time."

a. Please describe what FPL means by "optimization simulation convergence."
b. Please state whether FPL's use of filler units is consistent with previous FPL need determination filings.

RESPONSE:

a. Optimization simulation convergence refers to the simulation run time of the EGEAS model used in the referenced analysis. EGEAS is a dynamic optimization program used in resource planning that can optimize the resource plans given various planning alternatives. In EGEAS, unit additions are based on meeting the reliability criteria and either minimizing the levelized system average electric rate or minimizing the cumulative present value of revenue requirements. The number of resource plans created and the simulation run time depend on the number and type of available generation alternatives. The use of a 660 MW CC unit as a filler alternative (*i.e.*, unit that meets the reliability criteria after the NPGU need year) significantly reduced the simulation run time. In addition, the selection of this filler unit also ensured the development of a set of resource plans that included all the available technology choices being evaluated in 2019.

b. The use of filler units is consistent with previous FPL need determination filings.

AFFIDAVIT

Steven R. Sim

Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 12th day of November, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 65, 66, 68-70, 72, 73, 74, 77 - 83 from Staff's 4th Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of November, 2015.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC STATE OF FLORIDA

TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn.

AFFIDAVIT

Carlos Alves

Carlos Alves

State of Florida)

County of Palm Beach)

I hereby certify that on this 12th day of November, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Carlos Alves**, who is personally known to me, and he acknowledged before me that he co-sponsored the answer(s) to Interrogatory No(s). 77 from _Staff's 4th__Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of November, 2015.

Jayne Loring Davis

Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC STATE OF FLORIDA

JAYNE LORING DAVIS
Notary Public - State of Florida
My Comm. Expires Sep 14, 2017
Commission # FF 41751
Bonded Through National Notary Assn.

AFFIDAVIT

Roxane Kennedy

State of Florida)

County of Palm Beach)

I hereby certify that on this 12th day of November, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Roxane Kennedy**, who is personally known to me, and he acknowledged before me that she co-sponsored the answer(s) to Interrogatory No(s). 67 and 77 from Staff's 4th Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of November, 2015.

Notary Public, State of Florida

Notary Stamp:

BRENDA THEROFF
MY COMMISSION # FF905939
EXPIRES August 03, 2019
(407) 398-0153 FloridaNotaryService.com

QUESTION:
Referring to page 6, lines 11-13, of Witness Stubblefield's direct testimony, please provide documents containing the following documents that FPL used in support of its OCEC Unit 1 petition.

a. The model used to forecast natural gas and light fuel oil.

b. FPL's commodity, transportation, and delivered fuel price forecasts (exclusive of financial hedging impacts) for natural gas and light fuel oil used.

RESPONSE:

Please refer to the confidential document provided for the requested information to subpart (b). Florida Power & Light Company (FPL) utilizes a proprietary model from a vendor and does not have access to the model or inputs associated with the model; as a result, FPL has no responsive documents to subpart (a).

The confidential document will be provided to Staff with FPL's Request for Confidential Classification (RFCC). The confidential information will be made available to the other parties for inspection at FPL's Tallahassee Office at 215 South Monroe Street, Suite 810, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon completion of a Non-Disclosure Agreement and upon reasonable notice to FPL's counsel.

150196 – Staff's 2nd INT No. 39 – Att 1.xlsx

150196 – Staff's 4th POD No. 80 Attachment No. 1.xlsx

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FPL's Response to Staff's Interrogatories, Nos. 20, 21, 51, 55, 56, 70, 72. See also excel files contained on Staff Exhibit CD for Nos. 56, 70, 72

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI   EXHIBIT: 62
PARTY: STAFF
DESCRIPTION: FPL's Response to Staff's Interrogatories, Nos. 20, 21, 51, 55, 56, 70, 72. See also excel files co...

QUESTION:
On page 17, lines 14-16, of Dr. Sim's direct testimony, Dr. Sim states that, with regard to self-build generation options, "coal-fired technologies were removed from consideration due to current and prospective environmental concerns and regulations."

a. Please describe the prospective environmental concerns and regulations that are being referenced in Dr. Sim's testimony.
b. Please provide a hypothetical timeline for the construction of new integrated gasification combined cycle capacity sufficient to meet FPL's projected 2019 need.

RESPONSE:
a. The primary environmental reason for not considering coal fired electric generation technologies for future electric generation in Florida is the pending finalization of EPA's Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources for Electric Utility Generating Units (New Unit New Source Performance Standard (NSPS)) promulgated under the Clean Air Act Section 111(b), released on August 3rd, 2015). The requirements of this rule alone prevent the construction and operation of new coal fired electric generation. The new unit NSPS rule establishes a 1,400 lbs. CO2/MWh NSPS for newly constructed fossil fuel steam generating units, including efficient supercritical pulverized coal (SCPC) utility boilers implementing partial post-combustion carbon capture and storage technology to reduce CO2 emissions. This limit and expected partial capture and sequestration of carbon also applies to integrated gasification and combined cycle (IGCC) coal projects. Though EPA indicates there are projects that have achieved this rate of CO2 reduction throughout North America, the majority of these projects are research-related or DOE Demonstration Projects. FPL is unaware of any cost effective or commercially available options for building a SCPC generating facility with carbon capture capability. Further, there is not a carbon sequestration option currently available in Florida to use as storage/disposal of the captured CO2.

In addition, the costs of carbon capture and sequestration technology to meet the compliance limit imposed by the EPA's Standards of Performance for Greenhouse Gas Emissions rule for new units are prohibitive. In fact, the Department of Energy states that today's commercially available post-combustion capture technologies may increase the cost of electricity for a new pulverized coal plant by up to 80 percent and result in a 20 to 30 percent decrease in efficiency due to parasitic energy requirements. Additionally, many of today's commercially available post-combustion capture technologies have not been demonstrated at scales large enough for power plant applications. (Post Combustion Carbon Capture Research article from Office of Fossil Energy, U.S. Department of Energy, (See link http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research/carbon-capture-rd/post-combustion-carbon)

FPL also has determined that new coal fired generation in Florida is not practical due to the requirements that are imposed by the existing Mercury and Air Toxics Standards (MATS). The MATS rule imposes strict limits on Hazardous Air Pollutants (HAPS) regulated by the Clean Air Act. For coal fired generation, this rule requires several costly types of pollution control equipment that results in significant parasitic loads on the plant with increased water usage and requires significantly more land than other technologies. To remove particulates and HAPs metals including mercury from the flue gas, coal units would require electrostatic precipitators and fabric filters to capture many tons of ash that must then be recycled or managed in landfills. The coal combustion cycle also requires Flue Gas Desulferization Scrubbers (FGD) that need significant quantities of water and limestone storage to reduce SO2, mercury, hydrochloric acid, and particulate emissions. Following the scrubber treatment of the flue gas to reduce these pollutant emissions, the significant volumes of resulting by-product gypsum must be managed as a product or as a waste alongside the waste ash in landfills.

Finally, the resources required for the use of coal-fired generation are more imposing on the general population than those of other generation types. In Florida, coal fired generation would require increased train or truck traffic to haul limestone and coal and possibly backhaul gypsum and ash. The construction of a coal plant requires project specific landfills to manage the scrubber and ash waste.

b. FPL is not considering an integrated gasification combined cycle (IGCC) unit at this time. The development of IGCC units has been plagued with significant problems, including cost overruns, schedule delays and performance shortfalls. Based on recent, smaller capacity projects in Mississippi and Indiana (approximately 600 MW each), construction of an IGCC unit would take a minimum of five years. Prior to commencement of construction, it is anticipated that the regulatory approval process including determination of need and receipt of required construction and operating permits would take a minimum of two years. Thus the hypothetical timeline for the construction of new IGCC capacity sufficient to meet FPL's projected 2019 need would be at least seven years and could not be placed in service to meet FPL's 2019 resource need.

QUESTION:
On page 17, lines 16-18, of Dr. Sim's direct testimony, Dr. Sim states that "due to the 2019 need date, new nuclear capacity was removed from consideration because such capacity could not be added by that time." Please provide a hypothetical timeline for the construction of new nuclear capacity sufficient to meet FPL's projected 2019 need.

RESPONSE:
FPL is currently pursuing new nuclear capacity with its Turkey Point 6 & 7 project. Each of these two nuclear units is 1,100 MW. Therefore, each of these units would be capable of meeting FPL's 1,052 MW need in 2019 if the new nuclear units could be brought into service by mid-2019. However, as explained in the recently concluded 2015 nuclear cost recovery docket before the Florida Public Service Commission, FPL projects that 2027 and 2028 are the earliest practical deployment dates for these new nuclear units.

QUESTION:
On page 18, lines 10-12, of Witness Kingston's direct testimony, Witness Kingston testifies that the site design of OCEC Unit 1 allows for operation at full capacity for "72 hours of continuous operation using back-up fuel." Please discuss whether the proposed site can be supported to provide more than 72 hours of continuous operation (i.e. can fuel be transported to the site).

RESPONSE:

Liquid fuel (distillate oil) can be transported to the site by tanker truck, however, the number of tanker truck deliveries required to keep the proposed OCEC Unit 1 operating continuously at full capacity would be 215 trucks per day. This scenario is not logistically feasible. FPL's intent is to maintain inventory levels to ensure 72 hours of continuous, full load operation prior to an event that would necessitate the need for distillate oil consumption. If natural gas supply disruptions result in distillate oil consumption at OCEC Unit 1 and/or other FPL facilities, FPL will immediately take action to replenish the supply of distillate oil based on the system-wide status of its distillate oil inventory. The actual rate of replenishment at each specific site will vary depending on distillate oil availability, truck availability, projected unit dispatch and current inventory levels throughout FPL's distillate capable fleet.

QUESTION:
On page 7, lines 17-22, of witness Heather C. Stubblefield's direct testimony, Witness Stubblefield testifies that FPL has contracted with Sabal Trail for capacity sufficient to meet FPL's system gas requirements including the addition of OCEC Unit 1 in 2019. Please explain, in detail, how the delay or cancellation of the Sabal Trail natural gas pipeline would impact OCEC Unit 1.

RESPONSE:

Florida Power & Light Company (FPL) does not anticipate a delay or cancellation of the Sabal Trail or Florida Southeast Connection (FSC) pipeline projects. The Federal Energy Regulatory Commission (FERC) issued the draft Environmental Impact Statement (EIS) in September stating that the combined project will not have a significant environmental impact. The final EIS is expected by the end of the year. The final FERC certificate is expected in the first quarter of 2016. This is within the timeline required to complete construction and be in service by May 2017. OCEC is not expected to require gas for testing until September 2018; therefore, even if there was an unforeseen delay beyond May 2017, there is a "cushion" of 15 months before gas is required to be delivered to OCEC.

In the highly unlikely scenario the Sabal Trail project is cancelled, FPL would have to evaluate alternatives to try to connect one of the existing pipelines, FGT or Gulfstream, to OCEC. Unfortunately, FPL does not currently have excess capacity in either FGT or Gulfstream; therefore, even if OCEC could be connected to one of these pipelines, currently there is not sufficient capacity to serve this plant and all of FPL's existing facilities using natural gas if the Sabal Trail project is cancelled.

QUESTION:
Referring to page 7, lines 17-22, of witness Heather C. Stubblefield's direct testimony, Witness Stubblefield testifies that FPL has contracted with Sabal Trail Transmission, LLC and Florida Southeastern Connection, LLC for incremental gas transportation capacity. Please complete the table below summarizing FPL's gas transportation capacity service for the years 2015-2024. Please provide all requested data electronically in MS Excel format with all formulas intact.

Year	FGT (%)	Gulf Stream (%)	Sabal Trail (%)	Other (%)
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				

RESPONSE:

Please see below for table summarizing Florida Power & Light Company's gas transportation capacity service for the years 2015-2024. Attachment 1 to this response contains this table in Excel format with all formulas intact.

Totals may not add due to rounding	FGT (%)	Gulfstream (%)	Sabal Trail (%)	Upstream Pipelines [1] (%)
2015	42.4%	23.4%		34.2%
2016	42.4%	23.4%		34.1%
2017	38.4%	22.0%	8.5%	31.2%
2018	36.9%	21.1%	12.1%	29.9%
2019	36.9%	21.1%	12.1%	29.9%
2020	35.5%	20.3%	15.5%	28.7%
2021	34.8%	19.9%	17.2%	28.2%
2022	34.8%	19.9%	17.2%	28.2%
2023	34.8%	19.9%	17.2%	28.2%
2024	34.8%	19.9%	17.2%	28.2%

[1] Only FGT, Gulfstream and Sabal Trail deliver gas directly to FPL's plants. The Upstream Pipelines (Transcontinental Gas Pipeline, Gulf South, & Southeast Supply Header) provide diversified supply for FGT, Gulfstream and Sabal Trail. The annual totals assume FPL will extend all existing contracts beyond their initial term which is FPL's current intent.

AFFIDAVIT

Steven R. Sim

Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 20th day of October, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 17-31 and 33-47 from Staff's 2nd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20th day of October, 2015.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn.

AFFIDAVIT

Jacquelyn Kingston
Jacquelyn Kingston

State of Florida)

County of Palm Beach)

I hereby certify that on this 14th day of October 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Jacquelyn Kingston**, who is personally known to me, and she acknowledged before me that she sponsored the answer(s) to Interrogatory No(s). 48-54 from Staff's 2nd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 14th day of October, 2015.

Lisa A Fowler
Notary Public, State of Florida

Notary Stamp:

LISA A. FOWLER
Notary Public - State of Florida
My Comm. Expires Nov 14, 2018
Commission # FF 168308
Bonded through National Notary Assn.

AFFIDAVIT

Heather C. Stubblefield

State of Florida)

County of Palm Beach)

I hereby certify that on this 13 day of October, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Heather C. Stubblefield, who is personally known to me, and she acknowledged before me that she sponsored the answer(s) to Interrogatory No(s). 32, 55, 56, and 57 from Staff's 2nd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) is true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 13 day of October, 2015.

Notary Public, State of Florida

Notary Stamp:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

QUESTION:

On page 15, at lines 11-12, of Witness Kingston's direct testimony, Witness Kingston states that "OCEC Unit 1 will be dispatched ahead of other efficient FPL combined cycle units, resulting in significant fuel savings to FPL's customers." Please complete the table below summarizing FPL's estimated fuel consumption, through 2049, for each resource plan identified in Exhibit SRS-5, page 1 of 2, of Dr. Sim's direct testimony. Please provide all requested data electronically in MS Excel format with all formulas intact.

Natural Gas (MMBtu)	Oil (Bbl)

RESPONSE:

The requested data is provided on Table Staff-70, see Attachment No. 1.

QUESTION:

Referring to FPL's response to Staff's Second Set of Interrogatories No. 20, FPL states that "the development of IGCC units has been plagued with significant problems, including cost overruns, schedule delays and performance shortfalls." Please complete the table below summarizing the specifications of a hypothetical 600 MW IGCC power plant. Please provide all requested data electronically in MS Excel format with all formulas intact.

Net Generation MW (Summer)	
Installed Cost ($ Million)	
Fixed O&M ($/kw-yr) 2015$	
Variable O&M ($/MWh) 2015$	
Heat Rate (BTU/kwh)	
Equivalent Availability (%)	
Capacity Factor (%)	

RESPONSE:

FPL has not developed a self-build option for a hypothetical 600 MW IGCC power plant. FPL is providing the information in Table 72, see Attachment No. 1, for two recently licensed, approximately 600 MW, IGCC facilities in Mississippi and Indiana, based on publically available project information.

AFFIDAVIT

Steven R. Sim

Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 12th day of November, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 65, 66, 68-70, 72, 73, 74, 77 - 83 from Staff's 4th Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of November, 2015.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn

150196 – Staff's 2nd INT No. 56 – Att 1.xlsx

150196 – Staff's 4th POD No. 70 – Attachment No. 1.xlsx

150196 – Staff's 4th POD No. 72 – Attachment No. 1.xlsx

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FPL's Response to Staff's Interrogatories, Nos. 17, 18, 22, 23, 24, 27, 28, 29, 30, 31, 36 (including supplemental), 37, 38, 40, 42 (corrected), 43 (corrected & supplemental), 46, 47, 62, 79, 81, 83 (corrected). See also excel files contained on Staff Exhibit CD for Nos. 18, 24, 28, 30-31, 36, 42-43, 46-47, 62, 79, 81, 83.

&

FPL's Response to Staff's Request for Production of Documents, No. 7. See also pdf file contained on Staff Exhibit CD for No. 7

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 63
PARTY: STAFF
DESCRIPTION: FPL's Response to Staff's Interrogatories, Nos. 17, 18, 22, 23, 24, 27, 28, 29, 30, 31, 36 (includin...

QUESTION:
On page 8, lines 9-13, of Dr. Sim's direct testimony, Dr. Sim states that FPL evaluated three specific FPL-owned sites at which new generation could be built. Please describe, in detail, FPL's process for evaluating the three specific FPL-owned sites. Please also include a discussion regarding any factors considered in FPL's evaluation process.

RESPONSE:
FPL self-build generation analyses primarily focused on gas-fired generation options: combined cycle (CC) and combustion turbines (CT). The three sites that were evaluated are greenfield sites in Okeechobee and Hendry counties and a brownfield site in Putnam County. FPL's evaluation process consisted of three basic steps. First, each generation option to be considered at one of these sites was assumed to be in place at that site in 2019 and Turkey Point 6 & 7 were assumed to be added in their respective projected in-service years. Second, greenfield filler units (combined cycle units) were added as needed in all other years to meet FPL's projected remaining resource needs for the analysis period. Third, the system costs for this resource plan were projected for the analysis period to develop a cumulative present value of revenue requirements (CPVRR) value for this resource plan.

This process was repeated for all combinations of these three specific sites and generation technologies for 2019. The CPVRR values for all of the resource plans were then compared. The evaluation examined a number of system costs including: capital, fixed O&M, variable O&M, capital replacement, fuel, firm gas transportation, start up, transmission losses, and system emissions.

The evaluation of these technologies at these sites accounted for various site-specific considerations including:

- The likelihood of being able to obtain all permits and approvals that would be required to ensure a June 1, 2019 in-service date;
- Generation construction costs at the site;
- Transmission-related costs, including losses, at the site;
- The cost of getting sufficient firm gas to the site; and,
- The cost of sufficient water that would be used at the site.

QUESTION:
On page 9, lines 3-5, of Dr. Sim's direct testimony, Dr. Sim states that OCEC Unit 1 will enhance the efficiency of FPL's generating system.

a. Please provide the heat rate for each generating unit currently on FPL's system.
b. Please state whether FPL plans to negotiate a guarantee, regarding the heat rate, of OCEC Unit 1.
c. Please provide FPL's estimated system heat rate for the years 2015-2025.

RESPONSE:

a. Please see Attachment No. 1 for this information.
b. FPL plans to negotiate heat rate and other performance guarantees with its equipment suppliers and Engineering, Procurement and Construction (EPC) contractor for OCEC Unit 1.
c. Please see Attachment No. 2 for this information.

QUESTION:
On page 20, lines 1-17, of Dr. Sim's direct testimony, Dr. Sim testified that FPL utilized several computer models to perform its economic evaluation of its self-build generation options.

a. Please describe, in detail, each computer model used to evaluate the self-build generation options.
b. Please state whether or not FPL has used any of the computer models described above in any of its prior determinations of need cases.

RESPONSE:
a. The following models were used in FPL's evaluation of self-build generation options that occurred leading up to the designation of OCEC Unit 1 as FPL's Next Planned Generating Unit in FPL's capacity RFP for its 2019 need:

- PMArea: A commercially available production costing model designed to account for variable costs (such as fuel and variable O&M). (Note that beginning in early 2015, FPL switched to the UPLAN production costing model);
- Fixed Cost Spreadsheet: An FPL spreadsheet designed to account for and compare non-variable costs.
- EGEAS: A commercially available optimization model designed to account for both variable and non-variable costs.

b. Yes. The PMArea and Fixed Cost Spreadsheet models have been used in all of FPL's prior determination of need cases since the Martin 8 and Manatee 3 need filing. The EGEAS model, which was recently reactivated by FPL, was used in the Martin 8 and Manatee 3 determination of need filing.

QUESTION:
On page 20 (line 23) through 21 (line 2), of Dr. Sim's direct testimony, Dr. Sim states that FPL determined it was "unlikely that new capacity could be brought in-service at the Hendry site in time to address the 2019 need." Please provide an explanation as to why it is unlikely that new capacity could be brought in-service at the Hendry site in time to address the 2019 need.

RESPONSE:
During the time period in which FPL was evaluating its self-build generation options, the Hendry site was the subject of litigation regarding the land use designation for the site. FPL viewed it was unlikely that the litigation would be resolved in time to enable FPL to construct a new combined cycle unit and have it in-service by June 1, 2019. Therefore, FPL removed the Hendry site from consideration for addressing its 2019 need. In February 2015, FPL applied to Hendry County for a comprehensive plan amendment for the site. FPL expects the approval in November 2015 but the possibility exists that litigation could take several years before the property is available for construction. Therefore, Hendry remains a likely site for meeting FPL's resource needs after 2019, but is not a candidate to meet FPL's 2019 need.

QUESTION:
On page 21, lines 10-12, of Dr. Sim's direct testimony, Dr. Sim states that the best resources plan with a CC unit at the Okeechobee site was projected to be $65 million cumulative present value revenue requirements (CPVRR) more economic than the best resource plan with a CC unit sited at Putnam. Please complete the table below summarizing the CPVRR evaluation that resulted in the described $65 million in savings. Please provide all requested data electronically in MS Excel format with all formulas intact.

	$ millions, CPVRR
Capital (Generation)	
Capital (Transmission)	
O&M	
Fuel	
Environmental	
Other	
Total	

RESPONSE:
Please refer to Attachment No. 1 for the requested information.

QUESTION:
On page 26, lines 1-2, of Dr. Sim's direct testimony, Dr. Sim testifies that FPL examined "refinements to the GE 7HA.02 that included updated assumptions for heat rate, costs, and capacity (MW)." Please explain what prompted these "refinements" (i.e. GE provided new information).

RESPONSE:

Once the GE 7HA.02 combustion turbine was identified as the best GE combustion turbine model for a combined cycle (CC) unit to meet FPL's 2019 need, FPL examined different characteristics for the non-combustion turbine portion of the CC. Using information that had been previously provided by GE, FPL conducted analyses of variations regarding the remaining portions of the CC unit, including with and without duct firing, a higher pressure steam cycle with the same steam temperature, and higher steam cycle temperatures with the same steam pressure. The objective of examining these, and perhaps other, potential refinements of the GE 7HA.02 was to identify how each variation affected capacity, heat rates, and costs in order to select the variation that resulted in the lowest CPVRR cost for FPL's customers.

QUESTION:
On page 26, lines 7-10, of Dr. Sim's direct testimony, Dr. Sim testifies that the "GE 7HA.02 CT without duct firing, but with peak firing and wet compression, emerged as $42 million CPVRR more economic choice compared to the former leading candidate…." Please complete the table below summarizing the CPVRR evaluation that resulted in the described $42 million in savings. Please provide all requested data electronically in MS Excel format with all formulas intact.

	$ millions, CPVRR
Capital (Generation)	
Capital (Transmission)	
O&M	
Fuel	
Environmental	
Other	
Total	

RESPONSE:

Please refer to Attachment No. 1 for the requested information.

QUESTION:
On page 30, lines 11-13, of Dr. Sim's direct testimony, Dr. Sim states that a specific bidder refused to submit the required Bid Evaluation Fee. Please state whether the referenced bidder provide a reason or explanation for refusing to pay the Bid Evaluation Fee, and the explanation, if provided.

RESPONSE:
The party who offered an incomplete submittal to FPL's capacity RFP, which did not include the required Bid Evaluation Fee, was immediately contacted by FPL on the evening of May 15, 2015, which was the day on which the bids were due to FPL and the day this submission was received. FPL's May 15, 2015 e-mail to the submitting entity stated (the entity's name has been removed):

> *"This note confirms that FPL has received your bid in response to FPL's capacity RFP. However, one of the RFP's Minimum Requirements is that a check for the RFP Evaluation Fee of $25,000 accompany the bid materials. There was no such check included in the box containing (the party's) bid materials. If FPL is to consider (the party's) bid, we need to receive the RFP Evaluation Fee. FPL requests that (the party) submit the check by 5:00 p.m. next Tuesday, May 19th. (The mailing address is included in the RFP document.) Upon receipt of the evaluation fee, we will begin to review your bid's compliance with the RFP's other Minimum Requirements."*

On May 16 and 17, 2015, FPL reviewed the party's submittal and found numerous other deficiencies whereby the submission failed to meet the minimum requirements of the RFP, including incomplete and conflicting data as discussed in the direct testimony of FPL witness Sim. Consequently, the value of any analysis of this problematic information would have been questionable at best.

On May 18, 2015, the submitting party sent FPL a reply e-mail. Their reply is as follows:

> *"Thanks very much for the note. In regards to the bidder fee, as we read through the RFP, we were concerned that while we are a very large provider of competitively priced energy and capacity products in the market, as well as a company that is engaged in tolling/ppa arrangements throughout the US, that your strict RFP requirements were not commercially consistent with market expectations for a solicitation of this nature, therefore we are not comfortable providing a bid fee with our offer.*
>
> *If, upon review of our proposal, FPL sees value in what we have offered, we will certainly understand if our proposal is affected by the bid fee in your economic analysis of alternatives.*
>
> *We appreciate your review and would very much look forward to an opportunity to discuss a mutually beneficial arrangement in the event you think our offer is competitive.*
>
> *Thank you very much for your consideration."*

FPL interpreted this reply to indicate that the party had no intention of submitting an evaluation fee to enter into a competitive RFP process, but instead wished to move directly to discussions/negotiations regarding their project proposal. This response from the submitting party, plus the numerous problems with the information submitted, led FPL to take no further action regarding this incomplete submittal that failed to satisfy the minimum requirements of the RFP.

QUESTION:

On page 37, lines 11-16, of Dr. Sim's direct testimony, Dr. Sim states that if the Commission denies the need determination for the OCEC Unit 1 and no other self build option is allowed to replace the unit, FPL's generation only reserve margin (GRM) would fall to 5.8 percent. Please complete the table below assuming the in-service date of OCEC Unit 1 is delayed one year and no other generation or purchased power replaces the unit, assuming the same timeframe FPL used to evaluate the resource plans identified in Exhibit SRS-5 of Dr. Sim's direct testimony. Please provide all requested data electronically in MS Excel format with all formulas intact.

	Difference from resource plan with OCEC Unit 1 in 2019 ($ millions, CPVRR)
Capital (Generation)	
Capital (Transmission)	
O&M	
Fuel	
Environmental	
Other	
Total	

RESPONSE:

FPL notes that the requested comparison is not a comparison of comparable resource plans. The hypothetical resource plan in which no resource option is added in 2019 fails to meet two of FPL's reliability criteria and, therefore, is a plan with lower system reliability in 2019 compared to the resource plan in which the Okeechobee CC unit is added in 2019.

The requested information is presented in Attachment No. 1.

QUESTION:
On page 38, lines 14-17, of Dr. Sim's direct testimony, Dr. Sim states that FPL's system air emissions would increase if OCEC Unit 1 is not constructed. Please provide FPL's estimated SO2, NOX, and CO2 emissions for the years 2017-2026.

RESPONSE:

Dr. Sim's statement refers to the increase in FPL's projected system air emissions of a resource plan with simple cycle CTs instead of a resource plan that would have the more fuel-efficient Okeechobee combined cycle unit placed in-service. FPL is providing a projection of system SO2, NOX, and CO2 emissions for the years 2017 through 2026 for two of the resource plans provided in SRS-4: (1) Okeechobee 3x1 CC GE 7HA.02 and Summer capacity of 1,523 MW, and (2) Okeechobee 7x0 CT GE 7FA.05 and Summer capacity of 1,419. This information is presented in Attachment No. 1.

QUESTION:
For each generation option identified in Exhibit SRS-3, please provide plant specifications in a format similar to Exhibit JKK-8 of FPL Witness Jacquelyn K. Kingston's direct testimony.

RESPONSE:

The information requested is presented in Attachment No. 1.

QUESTION:

For each generation option identified in Exhibit SRS-3, please provide plant specifications in a format similar to Exhibit JKK-8 of FPL Witness Jacquelyn K. Kingston's direct testimony.

RESPONSE:

Please see Attachment No. 1 (Table Staff 36 Supplemental).

QUESTION:

Exhibit SRS-4 of Dr. Sim's direct testimony provides the CPVRR results of FPL's in the first stage of analyses.

a. Please state the time frame over which the CPVRR analyses were performed.
b. Please explain why FPL believes the timeframe identified in response to part 37(a) above, is appropriate for evaluating potential generating options.

RESPONSE:

a. The time frame over which FPL's first stage analyses were performed was from 2014 through 2049.

b. FPL believes the above-mentioned time frame is appropriate for evaluating potential self-build generation options because it allows FPL to fully account for the projected 30-year lives of both the combustion turbine and combined cycle units.

QUESTION:
Referring to Exhibit SRS-4 of Dr. Sim's direct testimony, please explain why the GE Model of CT units (7FA.05) considered in the CT generating options is different from the GE Model of CT units (7HA.02) considered in the CC generating options.

RESPONSE:

Either combustion turbine model is capable of operating in simple cycle mode as a stand-alone CT or as part of a combined cycle (CC). For example, versions of the 7FA CT have been utilized in earlier FPL CC units. However, the combustion turbine technology is continually advancing. At roughly the same time FPL commenced its evaluation of self-build generating options for meeting its 2019 need, FPL had decided that the GE 7FA.05 model was the most cost-effective choice for a simple cycle CT. Consequently, the new CTs in Broward and Lee counties that will replace older, existing gas turbines at those sites will be GE 7FA.05 units. Subsequent analyses for potentially meeting the 2019 need with CC units showed that the GE 7HA.02 model was a better, more cost-effective selection for a CC application.

QUESTION:
Referring to Exhibits SRS-4 and SRS-5 of Dr. Sim's direct testimony, please state whether FPL considered fuel cost sensitivities (i.e. high natural gas costs) in its CPVRR analyses.

a. If no, please explain the reasons.
b. If yes, please provide the fuel cost sensitivities in the same format as Exhibit HCS-1 of FPL Witness Heather C. Stubblefield's direct testimony.
c. If yes, please discuss FPL's methodology for developing its fuel cost sensitivities.
d. If yes, please provide the results of FPL's CPVRR analyses assuming the additional fuel cost sensitivities.

RESPONSE:

a. FPL did not include a high natural gas cost forecast in its analyses. The reason for this is that the results of FPL's first stage analyses showed that combined cycle (CC) options had a significant cost advantage over combustion turbine (CT) options based on use of a medium fuel cost forecast. If a sensitivity analysis had been performed that used a high gas cost forecast, the advantage of CC units over CT units would have only increased. Thus no such high gas cost sensitivity analysis was necessary in the first stage of the analyses. In the second stage of the analysis, only CC options were analyzed. Because all of the CC options had heat rates that were within a narrow range, no fuel cost sensitivities were warranted.

b. Please see FPL's response to subpart (a) of this interrogatory.

c. Please see FPL's response to subpart (a) of this interrogatory.

d. Please see FPL's response to subpart (a) of this interrogatory.

QUESTION:

For each self build option identified in Exhibit SRS-5 (page 1 of 2) of Dr. Sim's direct testimony, please provide the following information for each year of the analysis. Please provide all requested data electronically in MS Excel format with all formulas intact.

Annual Revenue Requirements (Generation Capital) ($millions, 2015 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2015 $)	Annual Revenue Requirements (O&M) ($millions, 2015 $)	Annual Revenue Requirements (Fuel) ($millions, 2015 $)	Annual Revenue Requirements (Environmental) ($millions, 2015 $)	Total ($millions, 2015 $)	Customer Bill Impact ($/1,000 kWh)

RESPONSE:

Please see Attachment No. 1 for the corrected Table #42.

QUESTION:

For each self build option identified in the table titled Third Step found in Exhibit SRS-5 (page 2 of 2) of Dr. Sim's direct testimony, please provide the following information for each year of the analysis. Please provide all requested data electronically in MS Excel format with all formulas intact.

Annual Revenue Requirements (Generation Capital) ($millions, 2015 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2015 $)	Annual Revenue Requirements (O&M) ($millions, 2015 $)	Annual Revenue Requirements (Fuel) ($millions, 2015 $)	Annual Revenue Requirements (Environmental) ($millions, 2015 $)	Total ($millions, 2015 $)	Customer Bill Impact ($/1,000 kWh)

RESPONSE:

Please see Attachment No. 1 for the corrected Table #43.

QUESTION:

For each self build option identified in the table titled Third Step found in Exhibit SRS-5 (page 2 of 2) of Dr. Sim's direct testimony, please provide the following information for each year of the analysis. Please provide all requested data electronically in MS Excel format with all formulas intact.

Annual Revenue Requirements (Generation Capital) ($millions, 2015 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2015 $)	Annual Revenue Requirements (O&M) ($millions, 2015 $)	Annual Revenue Requirements (Fuel) ($millions, 2015 $)	Annual Revenue Requirements (Environmental) ($millions, 2015 $)	Total ($millions, 2015 $)	Customer Bill Impact ($/1,000 kWh)

RESPONSE:

Please see Attachment No. 1 (Table Staff Supplemental-43). In this table, two sets of seven tables are provided. The first set provides annual nominal cost values for each resource plan that allow a bill impact projection to be performed. The second set of tables provides annual present value cost values discounted to 2015.

QUESTION:
For each self build option identified in Exhibit SRS-5 (page 1 of 2) of Dr. Sim's direct testimony, please provide the following information for the years 2017-2026:

a. The net generation for each generating unit on FPL's system.
b. The capacity for each generating unit on FPL's system.

RESPONSE:

Please see Attachment No. 1 for the requested information.

QUESTION:
For each self build option identified in the table titled Third Step found in Exhibit SRS-5 (page 2 of 2) of Dr. Sim's direct testimony, please provide the following information for the years 2017-2026:

a. The net generation for each generating unit on FPL's system.
b. The capacity for each generating unit on FPL's system.

RESPONSE:

Please see the Attachment No. 1 for the requested information.

AFFIDAVIT

Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 20th day of October, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 17-31 and 33-47 from Staff's 2nd Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20th day of October, 2015.

Notary Public/State of Florida

Notary Stamp:

TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn.

QUESTION:
Please refer to FPL's response to Staff's First Set of Interrogatories No. 13 for the following questions:

a. Please provide FPL's 7/27/2015 base case natural gas and light fuel oil short term and long term price forecasts (annualized and monthly).
b. Please provide FPL's 7/27/2015 high band natural gas and light fuel oil short term and long term price forecasts (annualized and monthly).
c. Please provide FPL's 7/27/2015 low band natural gas and light fuel oil short term and long term forecasts (annualized and monthly).
d. Please provide CPVRR first stage analyses, similar to that provided in Exhibit SRS-4 of FPL Witness Dr. Sim's Direct Testimony, based on FPL's 7/27/2015 base case, high band, and low band natural gas and light fuel oil price forecasts.
e. Please provide CPVRR second stage analyses, similar to that provided in Exhibit SRS-5 of FPL Witness Dr. Sim's Direct Testimony, based on FPL's 7/27/2015 base case, high band, and low band natural gas and light fuel oil price forecasts.

RESPONSE:

a. Please see Attachment No. 1 (Table Staff-62 (Part a), (Part b), and (Part c)).

b. Please see Attachment No. 1 (Table Staff-62 (Part a), (Part b), and (Part c)).

c. Please see Attachment No. 1 (Table Staff-62 (Part a), (Part b), and (Part c)).

d. Staff Interrogatory 62 d & e requested that FPL update two analyses that FPL had performed as part of its overall next planned generating unit (NPGU) analyses in 2014 and early 2015. The request was to update these analyses substituting FPL's July 27, 2015 fuel cost forecast for the fuel cost forecasts that were used at the time for each of the two analyses.

The updated analyses utilize this July 2015 fuel cost forecast (low, base, and high bands). However, FPL has also updated a number of other inputs to the analyses. These other updates include:

- A new October 2015 load forecast; and,
- Various other assumptions that were not then available and, therefore, had not been utilized during each stage/step in the NPGU analyses, but which were updated and incorporated into FPL's 2015 Ten-Year Site Plan, including: (i) the 2016 PV additions, (ii) the new schedule for GT replacements in Broward and Lee counties, (iii) the mutually agreed upon decision with Cedar Bay to sell that generating unit to FPL and FPL's plans to subsequently retire that unit, and (iv) the 2027/2028 in-service dates for Turkey Point 6 & 7.

Utilizing all of these updated assumptions and forecasts, FPL performed three scenario analyses. One scenario utilizes the July 2015 base case fuel cost forecast, another scenario utilizes the July 2015 low band fuel cost forecast, and the third scenario utilizes the July 2015 high band fuel cost forecast.

FPL has combined key generating options analyzed in the two previous, separate stages of analyses presented in Exhibits SRS-4 and SRS-5 into one set of analyses which examines the following self-build generating options. Please see Attachment No. 2 (Table Staff-62 (Parts d & e)):

- The 1,622 MW OCEC Unit 1 that was designated as FPL's NPGU in the capacity RFP;

- An enhanced 1,633 MW version of the OCEC Unit 1 (as referenced on page 36 of FPL witness Sim's direct testimony);
- Enhanced CT designs of 231 MW (Summer) capacity in 5 x 0, 6 x 0, and 7 x 0 configurations; and,
- The two most competitive non-GE CC units from the original analyses.

As shown in this response, the original 1,622 MW OCEC Unit 1 is still projected to be more economic than any of the CT and non-GE generation options; thus, the overall conclusions and recommendations reflected in the Petition for a determination of need and the supporting pre-filed testimony remain unchanged.

e. Please see the response to subpart (d) above.

AFFIDAVIT

Steven R. Sim

Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 4th day of November, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s).62 from _Staff's 3rd __Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 4th day of November, 2015.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn.

QUESTION:

Referring to FPL's response to Staff's Second Set of Interrogatories No. 42, Attachment 1, Tabs 1 through 10, FPL's response contained a note that states: "To capture 30 years of system cost for options with inservice dates in 2019, the model utilizes a five year extension period from 2044 through 2048. However the model only provides a CPVRR sum for this extension period." For each response (Tabs 1-10), please provide the CPVRR sum for the years 2044 through 2048.

RESPONSE:

The information requested is provided in Attachment No. 1.

QUESTION:

Referring to FPL's response to Staff's First Set of Interrogatories No. 43, Attachment 1, Tabs 1 through 5, FPL's response contained a note that states: "To capture 30 years of system cost for options with inservice dates in 2019, the model utilizes a five year extension period from 2044 through 2048. However the model only provides a CPVRR sum for this extension period." For each response (Tabs 1-5), please provide the CPVRR sum for the years 2044 through 2048.

RESPONSE:

The inclusion of an extension period in this analysis does not change the selection of the best technology choice. The information requested is provided in Attachment No. 1.

QUESTION:
Referring to FPL's response to Staff's Second Set of Interrogatories No. 45, Attachment 1, Tab 1 of 5:

a. Please provide the same information that was requested in Staff's Interrogatory No. 45, assuming each capacity addition identified in FPL's response is delayed one year, and no other generation or purchased power replaces the delayed capacity.
b. Please provide the following information in the table below based on the resource plan identified in part (a) above. Please provide all requested data electronically in MS Excel format with all formulas intact.

	Difference from resource plan identified in FPL's response to Staff's Interrogatory No. 45, Attachment 1, Tab 1 of 5. ($ millions, CPVRR)
Capital (Generation)	
Capital (Transmission)	
O&M	
Fuel	
Environmental	
Other	
Total	

RESPONSE:
a. Please see Staff Table 83(a)-Corrected, contained in Corrected Attachment No. 1.
b. Please see Staff Table 83(b)-Corrected, contained in Corrected Attachment No. 2.

AFFIDAVIT

Steven R. Sim

Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 12th day of November 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 65, 66, 68-70, 72, 73, 74, 77 - 83 from Staff's 4th Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of November, 2015.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
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FPL's Response to Staff's Request for Production of Documents, No. 7.

RESUME OF ALAN S. TAYLOR

AREAS OF QUALIFICATION

Independent evaluation services for competitive bidding resource selection, integrated resource planning, market analysis, risk assessment, and strategic planning

EMPLOYMENT HISTORY

- President, Sedway Consulting, Inc., Boulder, CO, 2001-present
- Senior Member of PA Consulting, Inc., Boulder, CO, 2001
- Vice President, Global Energy Business Sector, PHB Hagler Bailly, Inc., Boulder, CO, 2000
- From Senior Associate to Principal, Utility Services Group, Hagler Bailly Consulting, Inc., Boulder, CO, 1991-1999
- Senior Consultant, Energy Management Associates, Atlanta, GA, 1983-1988
- Internships at: Pacific Gas & Electric Company, San Francisco, CA (1990)
  Lawrence Berkeley National Laboratory, Berkeley, CA (1989-1991)
  MIT Resource Extraction Laboratory, Cambridge, MA (1982)
  Baltimore Gas and Electric Company, Baltimore, MD (1980)

EDUCATION

- Walter A. Haas School of Business, University of California at Berkeley, MBA, Valedictorian, Corporate Finance, 1991
- Massachusetts Institute of Technology, BS, Energy Engineering, 1983

PROFESSIONAL EXPERIENCE

- Conducted numerous competitive bidding project evaluations for conventional generating resources, renewable facilities, and off-system power purchases; analyzed thousands of such power supply proposals.
- Developed and/or reviewed dozens of requests for proposals for utility resource solicitations.
- Assisted in or monitored contract negotiations with hundreds of shortlisted bidders in utility resource solicitations.
- Testified on utility competitive bidding solicitation results, affiliate transactions, cost recovery procedures, rate case calculations, and incentive ratemaking proposals.
- Managed the development of market price forecasts of North American and European electricity markets under deregulation.
- Performed financial modeling of electric utility bankruptcy workout plans.
- Trained and assisted many of the nation's largest electric and gas utilities in their use of operational and strategic planning computer models.

SELECTED PROJECTS

2015 **California Solicitation for Capacity Resources**
Client: Southern California Edison

Currently serving as the Independent Evaluator (IE) in Southern California Edison's (SCE) annual Resource Adequacy (RA) Request for Offers (RFO). Mr. Taylor is managing a team that is conducting an independent analysis of all offers, monitoring the negotiations with shortlisted bidders, and preparing for the submission and analysis of final offers that will result in contracts that will help the utility fulfill some or all of its California RA capacity requirements for 2016-2019.

2015 **Minnesota Solicitation for New Solar PV Resources**
Client: Minnesota Power Company

Provided independent evaluation services in a focused solicitation for 10 MW of solar photovoltaic (PV) generation at a specific site in Minnesota. Power purchase agreement (PPA) bids were compared to the utility's selected engineering-procurement-construction (EPC) bid in which the utility would oversee the development of a project that it would ultimately own. The PPA bids were required to include buy-out provisions at various milestones during the terms of the PPAs. Mr. Taylor assisted with the development of the request for proposals (RFP), performed a parallel economic evaluation of the utility's EPC and all competing PPA proposals, monitored communications with bidders, and provided a report for filing with the Minnesota Public Utilities Commission regarding the results of the solicitation.

2014- **California Solicitation for Energy Storage Resources**
2015 Client: Southern California Edison

Currently serving as the IE in SCE's Energy Storage RFO that is seeking approximately 16 MW of energy storage resources to be developed in California as part of a regulatory requirement to promote the commercialization of utility-scale energy storage projects. Mr. Taylor is managing a team that has performed a parallel evaluation (to the utility's) of the initial indicative and final energy storage offers (using Sedway Consulting's proprietary model). The team also monitored all negotiations with shortlisted bidders to ensure fair and consistent treatment of counterparties.

2014 **Analysis of Ohio Hedging Transaction**
Client: Ohio Energy Group

Analyzed and provided expert testimony in AEP-Ohio's Energy Security Plan/Standard Service Offer proceeding regarding the hedging and price stabilizing benefits of a proposed rider for the net benefits associated with utility's entitlement to the Ohio Valley Electric Corporation's generating assets.

2013-2014 **California Solicitations for Resources and Energy Auctions**
Client: Southern California Edison

Served as the IE in SCE's Local Capacity Requirements (LCR) RFO for 1,900-2,500 MW of new local capacity resources from energy efficiency, demand response, energy storage and/or gas-fired facilities. Also served as the IE for all five of SCE's 2013 reverse energy auctions of the dispatch rights to facilities under power purchase agreements executed with developers of facilities selected in the utility's 2006 New Generation RFO.

2013-2014 **Florida Solicitation for Resources**
Client: Duke Energy Florida

Provided Independent Monitor/Evaluator services in a solicitation for over 1,600 MW of power supplies for Duke Energy Florida's supply portfolio that were needed by the end of 2018. Mr. Taylor participated in all bidder conferences, was copied on all emails between the utility and bidders, performed an independent evaluation of all proposals, and testified before the Florida Public Service Commission regarding the solicitation's results.

2013 **Minnesota Solicitation for New Resources**
Client: Minnesota Power Company

Provided independent evaluation services in a solicitation for 220 MW of wind generation in Minnesota; bids were compared to the utility's proposal to develop its own wind farm. Mr. Taylor assisted with the development of the request for proposals (RFP), performed a parallel economic evaluation of the utility's facility and all competing proposals, monitored communications and negotiations with shortlisted bidders, and provided a report for filing with the Minnesota Public Utilities Commission regarding the results of the solicitation.

2013 **Kentucky Renewable Resource Analysis**
Client: Kentucky Industrial Utility Customers

Provided expert analysis and testimony on behalf of customers of Kentucky Power regarding a renewable energy purchase agreement for output from a new 58 MW biomass facility that is expected on-line in 2017.

2006-2013 **California Solicitations for Conventional and Renewable Resources**
Client: Southern California Edison

Served as the IE in 23 solicitations for power or gas supplies in southern California – one, as noted above, for SCE's 2013 LCR RFO, an earlier one for over 2,500 MW of new conventional resources, four for renewable energy purchases to help SCE meet its state Renewables Portfolio Standard (RPS) requirements, five for near-term capacity resources, eight for reverse energy auctions of the dispatch rights to facilities under power purchase agreements, and four for gas financial hedging products. Mr. Taylor managed a Sedway Consulting team to perform a parallel evaluation of all proposals, monitor communications and negotiations with power suppliers, and support the review of the final selected proposals by the Procurement Review Group – a collection of non-market-participant stakeholders and regulators who are/were provided confidential access to the evaluation results at intermediate stages. He has filed IE reports and sponsored testimony before the California Public Utilities Commission concerning the results of most of these solicitations.

2012 **Florida Solicitation for New Resources**
Client: Tampa Electric Company

Served as an independent evaluator in a solicitation for 500 MW of power supplies in Florida. New capacity had to be on-line by 2017; bids were compared to the utility's proposal to repower four existing combustion turbines into a larger combined-cycle facility. Mr. Taylor assisted with the development of the RFP, performed a parallel evaluation of all proposals, monitored communications and negotiations with contracting counterparties, and testified before the Florida Public Service Commission regarding the solicitation's results.

2011 **Minnesota Solicitation for Wind Resources**
Client: Minnesota Power

Provided independent evaluation services in a solicitation for 100 MW of wind generation in Minnesota. Proposals competed with a utility proposal to develop its own wind farm. Mr. Taylor assisted with the development of the RFP and performed a parallel economic evaluation of the utility's facility and all competing proposals.

2005- **California Solicitations for Conventional and Renewable Resources**
2010 Client: Pacific Gas & Electric

Served as the Independent Evaluator in four solicitations for new power supplies in northern California – one for 2,200 MW of new conventional resources, another for up to 1,200 MW of new generating resources from any source, and two others for between 1,400 and 2,800 GWh/year of renewable energy purchases. Mr. Taylor managed a Sedway Consulting team to perform a parallel evaluation of all proposals, monitor communications and negotiations with power suppliers, and support the review of the final selected proposals by the Procurement Review Group – a collection of non-market-participant stakeholders and regulators who were provided confidential access to the evaluation results at intermediate stages. He has filed IE reports and sponsored testimony before the California Public Utilities Commission concerning the results of most of these solicitations.

2007- **Florida Solicitation for New Resources**
2008 Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,250 MW of new power supplies for 2011. Mr. Taylor performed a parallel economic evaluation to that which was undertaken by the utility. His work efforts allowed all proposal parameters to be cross-checked and corrected where necessary. He sponsored testimony before the Florida Public Service Commission concerning the results of the solicitation evaluation.

2007- **Avoided Cost Analysis for Interruptible Loads**
2008 Client: Public Service Company of Colorado

Provided an independent assessment of Public Service Company of Colorado's peaking resource avoided costs for use in the utility's development of customer credits for its interruptible service tariff.

2007- **Florida Solicitations for New Resources**
2008 Client: Tampa Electric Company

Provided independent evaluation services in two separate Tampa Electric Company solicitations for 600 MW of new power supplies for 2013, as a market test for the utility's proposals to develop initially an integrated gasification combined cycle (IGCC) facility and later a gas-fired combined cycle facility.

2004- **Regulatory Support of Commission Staff**
2005 Client: Utah Division of Public Utilities

Assisted staff for the Utah Division of Public Utilities in the division's efforts to analyze PacifiCorp's 2005 rate case. Mr. Taylor reviewed production cost modeling results and forecasts of system-wide fuel and purchase power costs.

2004- **Minnesota Solicitation for New Resources**
2005 Client: Minnesota Power

Provided independent evaluation services in a solicitation for 200 MW of firm power supplies. Mr. Taylor reviewed all proposals and performed a parallel economic evaluation among proposed turnkey facilities and power purchases.

2004 **Canadian Solicitations for Conventional and Renewable Resources**
Client: Ontario Energy Ministry

Participated in a broader consulting team and provided assistance in the development of RFPs for 2,500 MW of conventional resources and 300 MW of renewable resources. New long-term sources of power were sought to replace regional coal-fired generation.

2003- **Florida Solicitation for New Resources**

2004 Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,100 MW of new power supplies for 2007. Mr. Taylor performed a parallel economic evaluation of all proposals and reviewed, cross-checked, and corrected (where necessary) the utility's analyses. He sponsored testimony before the Florida Public Service Commission concerning the results of the solicitation evaluation.

2002- **Minnesota Solicitation for New Resources**
2003 Client: Northern States Power

Assisted in the evaluation of a large number of multi-option proposals for new power supplies in the 2005-2009 time frame. Mr. Taylor was the independent evaluator in two separate solicitations. He managed a team of individuals in the evaluation of responses for both Requests for Proposals (RFPs). In the first solicitation, contingent proposals were received that could serve as replacement contracts for 1,100 MW of nuclear capacity if NSP were forced to decommission its Prairie Island power plant in 2007. In the second solicitation, NSP sought approximately 1,000 MW of new supplies to supplement its existing supply portfolio. The evaluation included the review of over a dozen proposed wind projects.

2002 **Florida Revisions to Bidding Rule**
Client: Consortium of utilities

Provided the Florida Public Service Commission with recommendations concerning appropriate revisions to the state's bidding rule. Mr. Taylor participated in public workshops to provide the benefits of his extensive experience in performing competitive bidding solicitations and to convey what changes should or should not be made to Florida's existing bid rule to ensure the selection of the best resources for the state's electricity customers.

2002 **Arizona Testimony Concerning Competitive Bidding Solicitations**
Client: Harquahala Generating Company, LLC

Filed testimony before the Arizona Corporation Commission in the Generic Proceedings Concerning Electric Restructuring Issues and Associated Proceedings. Mr. Taylor's testimony provided the Commission with information about competitive bidding processes that he had seen work in other states. Also, his testimony addressed various concerns that were raised by Arizona Public Service as to the feasibility of implementing competitive bidding in Arizona.

2002 **Florida Solicitation for New Resources**
Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,750 MW of new power supplies in the 2005-2006 time frame. Mr. Taylor performed a parallel economic evaluation to that which was undertaken by the utility. His work efforts allowed all proposal parameters to be cross-checked and corrected where necessary. Also, he provided suggestions on resource optimization modeling approaches that ensured the most comprehensive examination of thousands of potential combinations of proposals.

2001 **Wisconsin Testimony Concerning Competitive Bidding Solicitations**
Client: MidWest Independent Power Suppliers

Provided testimony in a proceeding before the Wisconsin Public Service Commission on behalf of a consortium of independent power producers. Mr. Taylor testified on the benefits and timing of a competitive bidding solicitation that Wisconsin Electric Power Company (WEPCO) should be ordered to conduct prior to the utility's development of $2.8 billion in self-build generation facilities (embodied in a WEPCO proposal called Power the Future – 2). Without the benefits of a competitive solicitation, there would be no defensible means of ensuring that the utility's customers were being offered the best, most cost-effective resources.

150196 – Staff's 2nd INT No. 18 – Att 1.xlsx

150196 – Staff's 2nd INT No. 18 – Att 2.xlsx

150196 – Staff's 2nd INT No. 24 – Att 1.xlsx

150196 – Staff's 2nd INT No. 28 – Att 1.xlsx

150196 – Staff's 2nd INT No. 30 – Att 1.xlsx

150196 – Staff's 2nd INT No. 31 – Att 1.xlsx

150196 – Staff’s 2nd INT No. 36 – Att 1.xlsx

150196 – Staff’s 2nd INT No. 36 – Att 1 – Supplemental.xlsx

150196 – Staff's 2nd INT No. 42 – Att 1 - Corrected.xlsx

150196 – Staff's 2nd INT No. 46 – Att 1.xlsx

150196 – Staff's 2^{nd} INT No. 47 – Att 1.xlsx

150196 – Staff's 3rd INT No. 62 – Att 1.xlsx

150196 – Staff's 3rd INT No. 62 – Att 2 – Corrected.xlsx

150196 – Staff’s 4th POD No. 79 – Attachment No. 1. xlsx

150196 – Staff's 4th POD No. 81 – Attachment No. 1. xlsx

150196 – Staff’s 4th POD No. 83 – Corrected Att 1.xlsx

150196 – Staff’s 4th POD No. 83 – Corrected Att 2.xlsx

64

FPL's Response to ECOSWF's Interrogatories, Nos. 1, 3, 4, 15. See also excel files contained on Staff Exhibit CD for Nos. 1, 3, 4.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 64
PARTY: STAFF
DESCRIPTION: FPL's Response to ECOSWF's Interrogatories, Nos. 1, 3, 4, 15. See also excel files contained on Sta...

QUESTION:
For each month from 2015-2024, please provide the monthly Loss of Load Probability from the Loss of Load Probability calculation presented in Exhibit KRR 5-A for the plan without a 10% generation only reserve margin.

RESPONSE:

The requested information is presented in Attachment No. 1.

QUESTION:
For each month from 2015-2024, please provide the monthly Loss of Load Probability from the Loss of Load Probability calculation presented in Exhibit 6 to Dr. Sim's deposition in this docket.

RESPONSE:

The requested information is presented in Attachment No. 1.

QUESTION:
For each month from 2015-2024, please provide the monthly Loss of Load Probability for the base case load forecast without the addition of OCEC Unit 1.

RESPONSE:

FPL interprets this question to be asking for a revised LOLP projection that is based on Exhibit 6 of FPL witness Sim's deposition in this docket. Please see Attachment No. 1 for this projection.

QUESTION:
Please explain how FPL ensures that it does not pursue an uneconomically high level of reliability in its generation construction and operation planning.

RESPONSE:

FPL performs its reliability analyses using three reliability criteria: (i) a minimum 20% total reserve margin, (ii) a maximum of 0.1 day per year loss-of-load-probability (LOLP), and (iii) a minimum generation-only reserve margin (GRM). The minimum 20% total reserve margin criterion was approved by the FPSC for use by each of peninsular Florida's three IOUs. This criterion has reliability implications not only for each of the IOUs' individual systems, but also has implications for all of peninsular Florida's electric reliability. The LOLP criterion is commonly used in the electric utility industry. The GRM criterion is designed to guide the selection of resources with which FPL meets the 20% total reserve margin criterion.

When planning its system, FPL seeks to identify the resource plan with the lowest electric rate impact that meets all three of its reliability criteria. This is accomplished through the extensive planning analyses that FPL continually conducts.

AFFIDAVIT

Steven R. Sim

Dr. Steven Sim

State of Florida)

County of Palm Beach)

I hereby certify that on this 12 day of November, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Dr. Steven Sim**, who is personally known to me, and he acknowledged before me that he sponsored the answer(s) to Interrogatory No(s). 1-6, 8-9, 15-18, 20-21 from _ECOSWF's 1st__ Set of Interrogatories to Florida Power & Light Company in Docket No. 150196-EI, and that the response(s) are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of November, 2015.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC STATE OF FLORIDA

TRACI D. GOLDWIRE
Notary Public - State of Florida
Commission # FF 233425
My Comm. Expires Jul 31, 2019
Bonded through National Notary Assn.

150196 – ECOSWFT's 1st INT No. 1 Att 1.xlsx

150196 – ECOSWFT's 1st INT No. 3 Att 1.xlsx

150196 – ECOSWFT's 1st INT No. 4 Att 1.xlsx

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 65
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) – (REBUTTAL)
DESCRIPTION: Steven R. Sim SRS-6

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
1	Rábago	5/9	*"This significant increase in the already planned growth in generation stands in stark contrast to forecasted growth rates for customer population, load, and household income over the same period."* **(Misleading)**	Capacity needs are driven by a variety of factors including load growth, reserve margin requirements, unit retirements, and termination of power purchase agreements. Decisions on a unit's actual capacity are based on an economic decision-making process, once the capacity needs are known.
2	Rábago	6/5	*"How does the Company forecast LOLP? …It does not. As a result, the LOLP test really has no practical meaning in this application."* **(Incorrect)**	FPL provides a forecast of LOLP every year with its Ten Year Site Plan as part of FPL's response to Supplemental Data Requests. Also, the witness' testimony actually uses some of those forecasted LOLP values in his testimony.
3	Rábago	7/13	*"This number[LOLP] indicates that the proposed NPGU is not required in order to maintain system reliability or integrity."* **(Incorrect)**	The need for the NPGU is not based on LOLP, nor has FPL ever stated that it was. LOLP is merely one of three reliability criteria that FPL utilizes to determine the timing and magnitude of its resource needs. The other two reliability criteria are projected not to be met in 2019, thus indicating a need to add resources in that year.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
4	Rábago	9/6	*"In all, the factors suggesting a need to reexamine both the RM and GRM test include…the potential for increased reliance on other generation in the Eastern Interconnection."* **(Incorrect)**	FPL's reliance on the Eastern Interconnection is limited by transmission capacity access into Florida from Georgia as well as the high transmission losses that would be incurred bringing this energy to FPL's load centers.
5	Rábago	10/9	*"In short, the Company should conduct an objective and quantitative assessment of the ratepayer impact measure of its generation construction program over the past fifteen years in order to honestly claim customer benefits."* **(Incorrect and Misleading)**	It is incorrect to suggest that the FPSC has not been doing its job during these past 15 years as he alludes to here. The FPSC regularly holds evidentiary hearings in which power plant decisions are scrutinized before the FPSC grants a need determination and cost recovery for the new units. In other words, just this sort of analysis is regularly carried out by the FPSC.
6	Rábago	11/4	*"…the Company appears to have recently decided that they would like to have another generating unit operating by 2019, and they built a case to support that conclusion."* **(Incorrect and Misleading)**	The need for new capacity in 2019 is clearly demonstrated by FPL's filing in this docket that shows: (i) a projected need in 2019, (ii) OCEC Unit 1 is the most cost-effective self-build generating option, (iii) no viable market generation alternatives to OCEC Unit 1, and (iv) the continued trend of declining DSM cost-effectiveness.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
7	Rábago	15/12	*"The Company evaluates the DSM resource option solely for its ability to meet all of the increase in forecasted need. This approach is unrealistic, does not consider matching an increase in demand side resources coupled with a smaller NPGU."* **(Incorrect)**	FPL evaluates DSM options versus the planned generating unit on a per kW basis. This provides the best opportunity for DSM measures to pass economic screening analyses versus generation. Consequently, FPL does not evaluate DSM *"solely for its ability to meet all of the increase in forecasted need."* In addition, DSM is continuing its trend of declining cost-effectiveness.
8	Rábago	15/17	*"Options not considered include sufficient demand side resources to defer the NPGU for a single year, for example."* **(Incorrect)**	FPL has already accounted for all DSM found to be readily available and cost-effective in the 2013-2014 DSM Goals docket. Since that time, the trend of declining cost-effectiveness for DSM has continued. Therefore, there is no additional cost-effective DSM with which to partially address FPL's 2019 need. In fact, FPL's 2019 need would likely be larger if DSM's cost-effectiveness had been re-analyzed in 2015.
9	Rábago	15/18	*"Instead, the Company constructs a hyperbolic hypothetical in which 800MW of new DSM must be obtained solely through increases in the residential air-conditioning control program."* **(Incorrect and Misleading)**	This hypothetical was included merely to provide an example of the huge amount of additional, cost-effective DSM that would be required to fully meet the need. It was clearly hypothetical because there is no additional, readily available DSM that is cost-effective on FPL's system.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
10	Rábago	16/12	*"The Company does not evaluate the solar option from the perspective of the time frame required to develop that option."* **(Misleading)**	This statement ignores the uncertainties involved with meeting the 2019 need with solar and the fact that other, much more certain generation options would have to be bypassed if FPL were to wait several more years just to minimize the uncertainties surrounding solar. These issues were addressed in direct testimony.
11	Rábago	16/16	*"As detailed by Company witness Sim, the fact that the Company uses such a large, self-build NPGU size has a significant impact on dampening participation by non-utility bidders."* **(Misleading)**	The testimony referenced after this statement refers to the results of FPL's previous Bid process. These results were included to demonstrate that FPL's self-build option in that RFP prevailed over other bids because of economics, not simply because of its large size. Bidders were free to bid to provide all or a portion of FPL's 1,052 MW need. FPL believes that potential bidders were discouraged by the economic strength of OCEC Unit 1, primarily its cost and heat rate, not by its MW size.
12	Rábago	17/15	*"The Company reliance on the 10% generation-only reserve margin is also a significant factor in the Company's justifications for building new capacity."* **(Incorrect)**	The additional MW need required based on the 10% GRM over the 20% standard RM is only 64 MW, a very small amount compared to FPL's total system and, therefore, not a significant factor in this docket.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
13	Rábago	19/14	*"…the Commission should direct the Company to explore 'extreme' or 'fast response' demand response resources specifically designed to provide reliability support."* **(Incorrect and Misleading)**	FPL already has approximately 2,000 MW of fast response resources in its residential and commercial/industrial load management programs.
14	Wilson	7/5	*"…FPL witness Dr. Steven Sim testified during his telephonic deposition … that no such study or substantive analysis existed."* **(Incorrect and/or Misleading)**	In the deposition, FPL witness Sim interpreted the question to mean analyses which, starting from scratch, were designed to identify a specific RM value to use as a criterion. In has been many years since FPL did such a study, in large part due to the 20% stipulation reached in 1999. However, FPL has performed analyses that compared a 20% criterion versus a 15% criterion as discussed in the rebuttal testimony.
15	Wilson	7/20	*"…in 2010, the North Carolina Utilities Commission required Duke Energy Carolinas to conduct a reserve margin study… The result of Duke Energy Carolinas' reserve margin study (provided as Exhibit (JDW-2) was to reduce Duke's reserve margin from 17% to 15.5%, which had a material impact on Duke's resource plan."* **(Misleading)**	Mr. Wilson selectively chose to mention this 2010 study, but selectively decided not to mention the 2015 study in which Duke energy Carolinas decided not only to restore the 17% reserve margin criterion, but to consider for the first time a dual Summer/Winter reserve margin criterion.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
16	Wilson	11/2	*"I am not aware of any other utility that uses a GRM criterion."* **(Incorrect and/or Misleading)**	Although FPL has no way of knowing what Mr. Wilson may be aware of, he should be aware that TECO has utilized a similar supply-side reserve margin criterion for many years and continues to use it.
17	Wilson	12/17	*"…but those goals have been superseded by significantly lower goals adopted by the Commission in 2014 and are no longer in effect for FPL."* **(Misleading)**	This statement ignores the obvious possibility that FPL's DSM goals could be set again at very high levels. In fact, Mr. Wilson and SACE have been advocating - and continue to advocate - for just such very high DSM goals.
18	Wilson	15/4	*"But to the extent that peak events in June are driven by the same type of hot conditions that are more likely to occur in August, these programs should perform identically. I am unaware of evidence that energy efficiency or load control program technologies perform less effectively on a hot June or October day than on an equally hot August day."* **(Incorrect and Misleading)**	The probabilistic study referenced examines the effect of a DSM measure on reliability across all months, not just months reasonably close to Summer. Also, the statement ignores the possibility of a utility having generation problems on a mild weather day and the possibility of previously set DSM implementation levels being lowered due to lowered DSM cost-effectiveness cancelling the program or significantly reducing incentive payments.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
19	Wilson	15/9	*"FPL cites uncertainty about the performance of future EE programs, presenting a reliability risk in the form of load forecast uncertainty. This analysis is unreliable because it (1) is out of date (based on 2002 technology) and (2) is based on a simple average of program uncertainty without any evidence that averaging is the proper statistical technique, given the likelihood that there are relationships between the program outcomes.21 This type of analysis should be supported by a current evaluation, measurement and verification (EM&V) study conducted by an independent consultant and its novel application in this circumstance certainly requires greater scrutiny."* **(Misleading)**	Mr. Wilson misinterpreted the use of this data. It was never used in either the LOLP-based analyses or the system operations-based analyses. It was merely developed to get a ballpark idea of what the uncertainty range around DSM kW reductions per installation (and by program type) might be. Mr. Wilson's reference to EM&V confirms that there is uncertainty regarding the performance of DSM once it is installed. In addition, there is also uncertainty regarding the number of DSM installations that may occur in the future due to changes in DSM cost-effectiveness. However, FPL did not utilize either of these DSM uncertainty factors in its LOLP-based or system operations-based analyses.
20	Wilson	16/8	*"The GRM designed by FPL includes energy conservation programs, which are not subject to 'fatigue'. In fact, just the opposite as many of these programs involve the use of passive measures (e.g., insulation) or installation of lower power equipment."* **(Misleading and Irrelevant)**	Load management fatigue was not a factor in the LOLP-based and system operations-based analyses that led FPL to adopt the GRM criterion.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
21	Wilson	21/4	*"By adopting an unnecessary and wrongly designed criterion, FPL's customers will carry the cost of unnecessary power plant construction."* **(Incorrect and Misleading)**	The criterion is needed to ensure reliability on FPL's system and is correctly designed for the specific conditions of FPL's system. In addition, FPL's resource planning considers the electric rate impact of all resource options when considering resource additions to FPL's system.
22	Wilson	21/20	*"If FPL had made greater investments in energy efficiency and pursued opportunities to procure renewable energy in South Carolina, it might be possible for FPL to avoid adding any additional natural gas power plants - including the proposed OCEC Unit 1 - and the costs that they represent for customers."* **(Incorrect and Confusing)**	FPL neither operates in South Carolina nor adds renewable resource options in South Carolina. And there is no additional readily available, cost-effective DSM on FPL's system with which to meet FPL's 2019 resource needs. In addition, FPL is already tripling its solar generating resources in 2016 and is actively evaluating more solar resources.
23	Wilson	22/9	*"In other words, FPL's newest solar facilities are not the result of FPL's resource planning process as described in the ten-year site plan, but are the result of some other business development process that is not clearly described."* **(Incorrect)**	This statement appears to be a misinterpretation of FPL's Site Plan document. The process behind the selection of FPL's 3 new solar units is clearly described on Page 80 of FPL's 2015 Ten Year Site Plan which describes the activities carried out in FPL's 2014/early 2015 resource planning work. In addition, FPL's direct testimony describes how solar was evaluated as part of its resource planning process for the feasibility of addressing FPL's 2019 need.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
24	Wilson	23/11	*"...I cannot speculate as to the extent that solar technologies could substitute for any need that may exist (now or in the future) for a combined cycle natural gas plant. I would expect FPL to increase its plans to invest in solar resources if solar was included in the capacity optimization process."* **(Misleading)**	Solar is actively being evaluated in FPL's on-going resource planning work. As viable cost-effective solar applications are identified in this evaluation of resource options, FPL will likely incorporate them into its resource plan.
25	Mims	4/8	*"It would seem that if FPL is truly trying to diversify its fuel sources, at least one of these resources [solar or nuclear] would be increasing as a percent of total generation over time, not just natural gas."* **(Incorrect and Misleading)**	The statement ignores the fact that FPL's solar contribution will triple in 2016. Also, the discussion and associated table is very selective in regard to the years addressed. The years appear to have been carefully chosen to leave out recent fuel diversity additions such as: 110 MW of solar around 2010, more than 500 MW of additional nuclear capacity around 2012, and 2,200 MW of new nuclear capacity in 2027/2028. Furthermore, SACE actively opposed these nuclear additions which have enormous fuel diversity benefits as well as fuel hedge and environmental cost hedge benefits.

Commission Proceedings
Approving or Applying 20% Reserve Margin

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
981890 PSC-99-2507-S-EU	FPL, FPC, TECO	Generic Investigation	Commission approved 20% reserve margin stipulation for FPL, FPC and TECO. "During our reviews of the Ten Year Site Plans filed in 1997 and 1998, we expressed concerns about the adequacy of the reserve margins planned for Peninsular Florida. At the December 15, 1998, Internal Affairs meeting, we directed staff to open this docket to consider the reserve margins planned for Peninsular Florida electric utilities. … We approve the Stipulation agreed to by Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company. It addresses the basic concern about the adequacy of planned reserve margins for Peninsular Florida. Collectively, these three utilities plan for approximately 80 percent of the Peninsular Florida load. Thus, a twenty percent planning criterion adopted by these three utilities is a significant increase over the fifteen percent criterion currently employed."
991973 PSC-00-0504-PAA-EQ	FPC	Standard Offer	Commission granted rule waiver, in part because of 20% reserve margin standard. "If the waiver were not granted, FPC's efforts to meet the new 20% reserve margin would be frustrated."
001064 PSC-01-0029-FOF-EI	FPC	Need Determination	Commission granted a determination of need for Hines Unit 2. "We find that Florida Power Corporation has a need for additional capacity to maintain the reliability and integrity of its system, as contemplated by Section 403.519, Florida Statutes. The record shows that FPC has demonstrated **a** need for additional capacity to meet its 20 percent minimum reserve margin criteria. … In Order No. PSC-99-2507-S-EU, Docket No. 981890-EU, the Commission approved the stipulation reached by the peninsular Florida investor-owned utilities (IOUs). These IOUs agreed to implement a 20 percent minimum reserve margin criteria to be fully effective by the summer of 2004. P r i o r to t h i s stipulation, FPC utilized a 15 percent minimum reserve margin criteria. As shown in Exhibit 10, answers to staff's interrogatories, FPC's projected reserve margin in the winter of 2003/04 is 18.4 percent, if Hines 2 is not brought into service. FPC needs only

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			approximately 130 MW to precisely reach a 20 percent reserve margin in the winter of 2003/04. FPC will violate its 20 percent minimum reserve margin criterion, in the winter of 2004/05, if Hines 2 is delayed. FPC, therefore, is only accelerating the proposed capacity addition six months in order to meet the stipulation."
001437 PSC-00-2434-PAA-EI	FPL	Depreciation	Commission approved new depreciation rates for units added to meet the 20% reserve margin criterion. "Subsequently, by Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU, FPL agreed to a minimum reserve margin planning criterion of twenty percent reserve beginning with the Summer of 2004. To achieve this goal, FPL now plans to install six CTs at Ft. Myers, which will initially operate in a stand-alone mode until the overall completion of the repowering, currently projected for June 1, 2002."
010107 PSC-01-1337-PAA-EI	FPL	Depreciation	Commission approved new depreciation rates for units added to meet the 20% reserve margin criterion. "By Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU, FPL agreed to a minimum reserve margin planning criterion of twenty percent reserve beginning with the Summer of 2004. However, in an effort to achieve this goal by the Summer of 2001, FPL plans to install two combustion turbines (CTs) at the Martin Site in June, 2001. These units will initially operate in a stand-alone peaking mode with planned conversion to natural gas-fired, combined-cycle generators in the 2005-2006 time period to meet FPL's expected increased customer growth and usage."
	FPL, FPC, TECO	2001 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed *Ten-Year Site Plans* filed by twelve (12) reporting utilities and two (2) merchant plant companies. The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are ***suitable*** for planning purposes. Forecasted reserve margins for Peninsular Florida range from 20% to 23% during summer peak seasons, and from 23% to 26% during winter peak seasons. The Commission makes no determination on the suitability of the merchant plant filings."
020262 020263 PSC-02-1743-FOF-EI	FPL	Need Determination	Commission granted a determination of need for Martin Unit 8 and Manatee Unit 3. "We find that Florida Power & Light company has a need for additional capacity to maintain the reliability and integrity of its system, which will be provided by-

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			Manatee Unit 3 and Martin Unit 8. FPL has an estimated need for 1,122 MW of additional capacity for Summer, 2005, and an additional need for 600 MW of capacity for Summer, 2006. The 1,107 MW of summer capacity from Manatee Unit 3 will contribute to FPL's electric system reliability and integrity. With the addition of that capacity, FPL's projected reserve margin for Summer, 2005 is 19.92%. In order to precisely meet a planning reserve margin criterion of 20.0%' FPL needs only 15 MW of capacity with the addition of Manatee Unit *3* in Summer, 2005. Therefore, FPL does not have a pressing reliability need for the entire 789 MW of capacity from Martin Unit 8 until Summer, 2006. As discussed below, however, the record shows that it is more cost-effective for FPL to place Martin Unit 8 into commercial service in 2005 rather than 2006."
020295 PSC-02-0909-PAA-EQ	FPC	Standard Offer	Commission granted waiver of a Commission rule because of the need to meet the 20% reserve margin criterion. "We agree that if the waiver is not granted, FPC's efforts to meet the new 20% reserve margin would be frustrated. On November 30, 1999, we approved an agreement between FPC, FPL, and TECO adopting a 20% reserve margin planning criterion starting in the summer of 2004. A delay in the RFP process could seriously jeopardize FPC's ability to bring Hines 3 on line by the December, 2005, in-service date."
020332 PSC-02-1103-PAA-EI	FPL	Depreciation	Commission approved depreciation rates for units added by FPL to meet the 20% reserve margin criterion. "By Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU, FPL agreed to a minimum reserve margin planning criterion of twenty percent beginning with the Summer of 2004. To achieve this goal in a more timely fashion, FPL installed six CTs at Ft. Myers in *2000* and 2001, initially operating in a stand-alone mode. This provided immediate increases to the FPL system. With the recent addition of the six HRSGs, Ft. Myers became a combined cycle operating facility on May 31, 2022."
020953 PSC-03-0175-FOF-EI	FPC	Need Determination	Commission granted a determination of need for Hines Unit 3. "Reserve Margin PACE questioned whether there is a present need for the Hines Unit 3. PACE argues that FPC has done well over the past with a 15 percent reserve margin and if this margin is maintained, Hines Unit 3 is not needed. Regardless of past experience, however, Order No. PSC-99-2507-S-EU,issued December 22, 1999, in Docket No.

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			981890-EUf requires Florida's investor owned utilities (IOUs) to increase minimum planning reserve margins to a 20% reserve margin by the summer of 2004. By approving the stipulation proposed by the IOUs and issuing the above Order, we have already determined that 20% is the appropriate reserve margin criteria, and the IOUs are required to utilize this criteria, unless modified in a subsequent proceeding. To provide reliable service, utilities are required to maintain a margin of generating capacity above the firm demand of their customers (planned reserves). At any given time during the year, some generating plants will be out of service and unavailable due to forced outages, periodic maintenance, refueling of nuclear plants, etc. Therefore, adequate reserves must be available to provide for this unavailable capacity and for higher than projected peak demand due to forecast uncertainty and abnormal weather. The proper forum to address what minimum reserves are necessary should be in a generic docket, as was previously done, and not in a particular utility's power plant need determination docket. FPC has relied heavily in the past on demand side management (DSM) to meet its reserve requirements. FPC cannot use DSM as often or with the same duration as physical generation without eventually affecting customer participation levels, as was demonstrated by FPC's customer attrition from its DSM programs in 1998 and 1999. The record indicates FPC's DSM programs are becoming less cost-effective compared to the cost of generation. For these reasons, FPC is attempting to build up its physical reserve percentage." … "In summary, we find that FPC's load forecast is reasonable. FPC's projected reserve margin in the winter of 2005/2006 is 17 percent if Hines Unit 3 is not brought into service, and therefore FPC will violate its 20 percent minimum reserve margin in the winter of 2005/06 . FPC projects that the growth in winter peak demand will average approximately 159 MW a year from 2002/03 to 2006/07, with a projected peak in 2006/07 of 9,195 MW. FPC has projected a growth in winter peak demand of 416 MW for the period 2004/05 to 2006/07. Therefore, we find that Hines Unit 3 will be needed by December 2005 , to maintain FPC' s electric system reliability and integrity."
	FPL, PEF, TECO	2002 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes.

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			"The Commission has reviewed *Ten-Year Site Plans* filed by twelve (12) reporting utilities and two (2) merchant plant companies. The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are ***suitable*** for planning purposes. Forecasted statewide reserve margins range from 24% to 27% during summer peak seasons, and from 27% to 31% during winter peak seasons. The Commission makes no determination on the suitability of the merchant plant filings."
030866 PSC-03-1329-PAA-EQ	PEF	Standard Offer/ Bid Rule Waiver	Commission granted a waiver of the Bid Rule due to a likely inability to meet the 20% reserve margin criterion. "We believe that if the waiver is not granted, Progress's efforts to meet the 20% reserve margin would be frustrated. In 1999, an agreement was approved between Progress Energy Florida, Florida Power & Light Company, and Tampa Electric Company adopting a 20% reserve margin planning criterion, effective with the summer of 2004. See Order No. PSC-99-2507-S-EU, issued December 22, 1999, Docket No. 981890-EU, In Re: Generic Investigation into the Adequate Electric Utility Reserve Margins Planned f o r Peninsular Florida. A delay in the RFP process could seriously jeopardize Progress's ability to bring Hines 4 on line by the December 2007 in-service date, an action which is necessary to ensure that the Company maintains a 20% reserve margin. As a result, we agree with the Company that this potential impairment to the reliability of Progress's generation resources constitutes "substantial hardship" within the meaning of Section- 120.542, Florida Statutes."
	FPL, PEF, TECO	2003 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed *Ten-Year Site Plans* filed by eleven reporting utilities and one independent power producer (IPP). The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are ***suitable*** for planning purposes. Forecasted statewide reserve margins range from 23% to 26% during summer peak seasons, and from 26% to 30% during winter peak seasons. The Commission makes no determination on the suitability of the IPP filing."
040029 040031 040033 PSC-04-0763-PAA-EG	FPL PEF TECO	DSM Goals DSM Goals DSM Goals	Established DSM goals for FPL, PEF, and TECO using avoided costs calculated assuming a 20% reserve margin.

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PSC-04-0769-PAA-EG PSC-04-0765-PAA-EG			
040206 PSC-04-0609-FOF-EI	FPL	Need Determination	Commission granted a determination of need for Turkey Point Unit 5. “There is a need for the proposed Turkey Point Unit 5, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, Florida Statutes. Absent the timely addition of Turkey Point Unit 5, FPL’s summer reserve margins will fall to 14.7 percent in the summer of 2007, well below the Commission-approved 20 percent reserve margin planning criterion. Further, the addition of Turkey Point Unit 5 will enhance FPL’s operating flexibility and system reliability in Southeast Florida by reducing the growing imbalance between generation and load in this region.”
	FPL, PEF, TECO	2004 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. “The Commission has reviewed *Ten-Year Site Plans* filed by eleven reporting utilities and one independent power producer (IPP). The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. Forecasted statewide reserve margins range from 23% to 26% during summer peak seasons, and from 26% to 30% during winter peak seasons. The Commission makes no determination on the suitability of the IPP filing.”
	FPL, PEF, TECO	2005 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. “ Based on our review, the Commission finds the Ten-Year Site Plans filed by the eleven reporting utilities to be suitable.”
060225 PSC-06-0555-FOF-EI	FPL	Need Determination	Commission granted a determination of need for West County 1 & 2. “We find that there is a need for FPL’s proposed West County Units 1 and 2, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, Florida Statutes. Without completing West County Unit 1 by June 2009, FPL’s and Peninsular Florida’s electric system reliability and integrity would be significantly reduced. FPL would also fail to meet its 20 percent reserve margin planning criterion. Without the unit, FPL’s summer reserve margin for 2009 would decrease to 15.5% and decrease further in each following year.”
060387 PSC-06-0743-PAA-EQ	PEF	PPA Approval	Commission approved a PPA with a renewable resource, Florida Biomass. “By the terms of the negotiated contract, the Florida Biomass combined cycle

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			generator is to be operational no later than December 1, 2009, with net output projected to be 116 MW. PEF's 2006 Ten Year Site Plan shows projected growth of approximately 200 MW of demand each year. PEF asserts that it will need additional capacity by 2009 to maintain its 20% reserve margin. The next planned unit is the Bartow Repowering Project, currently scheduled to come on line in June 2009. There are six additional units planned through 2015 to meet PEF's demonstrated need for capacity in that period. While PEF has not included the Florida Biomass contract as a firm resource in its 2006 Ten Year Site Plan, if the contract is approved, PEF will include the projected committed capacity as a firm resource."
	FPL, PEF, TECO	2006 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "Pursuant to Section 186.801, Florida Statutes, the Florida Public Service Commission (Commission) has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities and finds them to be suitable."
070100 PSC-07-0456-PAA-EQ	FPL	Depreciation	Approved of Depreciation rates for Turkey Point Unit 5. "By Order No. PSC-99-2507-S-EU,2 FPL agreed to a minimum reserve margin planning criterion of 20 percent beginning in the summer of 2004. However, in 2003, FPL's integrated resource planning work determined that an additional 1,066 megawatts (MW) of capacity was needed by the summer of 2007. If the additional megawatts were not obtained, FPL and the Peninsular Florida's electric system reliability and integrity would be reduced and the required 20 percent reserve margin would not be met for 2007. Also, the balance between the amount of generating capacity located in southeast Florida and the electrical load would not be maintained. Pursuant to Order No. PSC-04-0609-FOF-EI,3 the Commission approved the construction of Turkey Point Unit 5 to meet FPL's needed capacity."
070602 PSC-08-0021-FOF-EI	FPL	Need Determination for Expansion	Commission granted a determination of need for expansion of Turkey Point and St. Lucie nuclear units. "There is a need for the Turkey Point nuclear power plant ("PTN") and St. Lucie nuclear power plant ("PSL") uprates, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519(4), Florida Statutes. Without the uprates, FPL's electric system reliability and integrity will be significantly reduced, and FPL will fail to meet its 20% reserve margin beginning in 2012 ….

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			FPL has future resource needs of 490 MW of incremental capacity in 2012. All demand side management ("DSM") that is known to be cost-effective through 2013 is already reflected in FPL's 2006/2007 resource planning work, which identified this capacity need. Consequently, to meet FPL's summer reserve margin criterion of 20% through 2013, FPL needs new capacity in the form of power plant construction and or purchases."
070650 PSC-08-0237-FOF-EI	FPL	Need Determination	Commission granted a determination of need for for Turkey Point units 6 and 7. "There is a need for Turkey Point 6 and 7, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519(4), F.S. FPL argues that there is a need for Turkey Point 6 and 7 because overall system demand is expected to grow by 40%. FPL further contends that without Turkey Point 6 and 7, the reserve margin would fall below 20% and FPL would have to rely more heavily on DSM, which would render FPL's system less reliable. … Based on the foregoing, we find that FPL's capacity need projections are reasonable. We note that no party took issue with the load forecast. FPL's need was determined after taking into account 1,899 MW of additional DSM, all other currently committed supply projects, 414 MW of recently approved nuclear capacity includes previously certified nuclear uprates in 2012 and 2013 as well as new uncertified gas CC units in 2011, 2015, 2016, and 2017, includes previously certified nuclear uprates in 2012 and 2013, but no new gas units and 287 MW of renewable generation, although none are yet contracted, from 2 biomass projects and 3 municipal waste-to-energy projects. FPL's need for additional capacity to meet rising electricity demands cannot be satisfied with additional purchased power from renewable generation. Additional DSM programs and renewables are not capable of deferring the need for additional capacity. In conclusion, the evidence shows that FPL has a need for 8,350 MW of additional capacity beginning in the 2011 through 2020 period. Turkey Point 6 and 7 will provide only a portion of FPL's need for capacity."
		2007 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "Pursuant to Section 186.801, Florida Statutes, the Commission has reviewed the

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			utilities' 2007 Ten-Year Site Plans and finds them to be suitable because the plans were responsive to the energy policies in place at the time of filing."
080407 080408 080409 PSC-09-0855-FOF-EG		DSM Goals	The Commission approved DSM Goals based on avoided cost calculation for FPL, FPC and TECO that employed a 20% reserve margin criterion.
080203 080245 080246 PSC-08-0591-FOF-EI	FPL	Need Determination	Commission granted a determination of need for West County Energy Center Unit 3, Conversion of Riviera Plant, and Conversion of Cape Canaveral Plant. "FPL has demonstrated a reliability need for additional resource capacity in 2013. Usually, when a company seeks to satisfy a need for additional resource capacity using natural gas facilities, a petition for need determination would be submitted approximately 3 years before the facility's in-service date. The company decided, however, that unique economic opportunities and site-specific circumstances made it more cost effective to build WCEC 3 for operation in 201 1 and perform the conversions at Cape Canaveral and Riviera by 2013 and 2014. FPL contends that it will not be able to perform the conversions of Cape Canaveral and Riviera without approval of the proposed WCEC 3. FPL chose gas-fired combined cycle units as its resource option to meet its capacity needs. This decision was made primarily because coal and nuclear generation have longer construction times and would not be able to provide the additional capacity in the time needed. This approach will maintain FPL's reserve margin above 20 percent throughout the period."
080512 PSC-08-0707-PAA-EQ	PEF	PPA Approval	Commission approved a PPA with Vision/FL, LLC. "The Facility is projected to have a maximum nominal generating capacity of 50 MW. After serving internal loads, the Facility will provide firm capacity of approximately 40 MW to PEF. The expected annual energy amounts to 3 11,853 MWh. As a renewable energy resource, Vision's projected committed capacity of 40 MW will be independent **of** the current fossil fuel infrastructure as it uses a separate, distinct supply mechanism for its biomass fuel. It is noted that the addition of 40 MW of firm capacity and energy from Vision in 2010 to PEF pursuant to the contract will not completely defer or avoid the need for additional capacity in order to meet a 20% reserve margin. However, the Facility will displace energy generated by fossil fuels, reducing the state's dependence on these resources and promoting fuel diversity."

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		2008 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. “The Commission has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities and finds that the projections of load growth appear reasonable and that the reporting utilities have identified additional generation facilities required in order to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2008 Ten-Year Site Plans filed by the eleven reporting utilities to be suitable for planning purposes.”
		2009 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. “The Commission has reviewed the Ten-Year Site Plans filed by the 11 reporting utilities and finds that the projections of load growth appear reasonable and that the reporting utilities have identified additional generation facilities required in order to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2009 Ten-Year Site Plans filed by the 11 reporting utilities to be suitable for planning purposes.”
		2010 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. “The Commission finds the 2010 Ten-Year Site Plans filed by the eleven reporting utilities to be suitable for planning purposes. While the plans are suitable for planning purposes, they are subject to modification due to factors such as changes to fuel cost, energy use projections, evolving technology, and shifting energy policy. Therefore, the Commission will continue to closely monitor the future rate of load growth in Florida and its effect on the need for additional generation and transmission facilities in the state.”
110018 PSC-11-0293-FOF-EI	FPL	Need Determination	Commission granted a determination of need for expansion of Solid Waste Authority of Palm Beach County unit. “FPL determines the magnitude and timing of its resource needs based on a minimum reserve margin. The reserve margin represents available generating capacity during peak demand periods. FPL has established a minimum reserve margin of 20 percent above peak demand for reliability purposes. FPL has identified a reliability need beginning in 2016. This projection is consistent with FPL's 2011 Ten Year Site Plan ("TYSP"). Commencing in 2015, SW A will provide the output

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			if the Expanded Facility as firm capacity and energy to FPL. … Upon review, we find that the Joint Petitioners are persuasive in their argument that the Expanded Facility will improve electric system reliability and integrity on FPL's system. FPL is currently projecting a need for additional capacity. The Expanded Facility, projected to provide between 70 and 80 MW of firm capacity by 2015, will satisfy a portion of FPL's projected need. Therefore, the SWA Expanded Facility will contribute to the reliability and integrity of FPL's electric system. In addition to providing additional capacity, the Expanded Facility, which will be located in Southeast Florida, has attributes that will address two system concerns for FPL: a) enhancing fuel diversity; and b) maintaining a regional balance between load and generating capacity, particularly in Southeastern Florida. We find that there is a need for the SWA Expanded Facility taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, F.S.
110309 PSC-12-0187-FOF-EI	FPL	Need Determination	Commission granted a determination of need for Port Everglades plant. "There is a need for Port Everglades Next Generation Energy Center, taking into account the need for electric system reliability and integrity. Based on the 20 percent reserve margin criterion adopted by FPL pursuant to a stipulation with this Commission, FPL projected in its filing that additional capacity to meet firm peak demand will be needed by the summer of 2016. If FPL did not construct PEEC until 2019, the Company's projected reserve margin would drop to 18.2 percent in 2017 and 2018 and would be primarily made up of Demand Side Management resources. After accounting for all projected DSM from cost-effective programs approved by this Commission, FPL' s projections at the time of the filing indicate that by 2016, the Company will have a capacity need of 284 MW in order to adhere to FPL's minimum reserve margin criterion of 20 percent. The timing of FPL's projected need was largely driven by the expiration of existing purchased power agreements totaling 1,306 MW of summer capacity and the decision to place certain units into inactive reserve mode. PEEC will provide 1,277 MW of capacity to help satisfy the Company's capacity needs through 2020."

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	FPL, DEF, TECO	2011 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. “The Commission has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities, as well as supplemental data provided through data requests, and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2011 Ten-Year Site Plans filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes.”
120234 PSC-13-0014-FOF-EI	TECO	Need Determination	Commission granted a determination of need for Polk unit 205 conversion. “We find that there is a need for Polk 2-5 as proposed by TECO to maintain electric system reliability and integrity as this criterion is used in Section 403.519(3), F.S. For planning purposes, TECO utilizes a 20 percent firm reserve margin reliability criteria above the system firm peak demand. After taking into account load growth, existing power plant unit capacity, firm purchased power agreements, and demand-side management (DSM), TECO's summer reserve margin is projected to fall below 20 percent in 2017. By providing up to approximately 459 MW of additional capacity, Polk 2-5 will help TECO meet its needs for additional capacity beginning in 2017.”
120314 PSC-13-0164-PAA-EQ	FPL	PPA Approval	Commission approved PPA agreements with U.S. EcoGen. “FPL maintains a planning reserve margin of 20 percent pursuant to a stipulation approved by this Commission.[1] FPL’s next major generating additions are the Cape Canaveral Modernization (1,210 MW) in 2013, the Riviera Modernization (1,212 MW) in 2014, and the Port Everglades Modernization (1,277 MW) in 2016, followed by Turkey Point Units 6 and 7 (1,100 MW each) in 2022 and 2023. … The firm capacity to be delivered under the terms of the Contracts, and the resulting potential to defer or delay a portion of FPL’s next generating unit, meets

[1] *See* Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU - In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.

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			the requirement of Rule 25-17.0832(3)(a), F.A.C. (which addresses the need for capacity by the purchasing utility and the state as a whole). Therefore, upon review, we find that approval of the proposed Contracts will enhance FPL's system reliability, encourage the use of renewable fuels in Florida, and promote fuel diversity for FPL's ratepayers."
	FPL, DEF, TECO	2012 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities, as well as supplemental data provided through data requests, and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2012 Ten-Year Site Plans filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes."
130199 130200 130201 PSC-14-0696-FOF-EU	FPL, DEF, TECO	DSM Goals	The Commission approved DSM Goals based on avoided cost calculation for FPL, FPC and TECO that employed a 20% reserve margin criterion.
	FPL, DEF, TECO	2013 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "Based on its review, the Commission finds the 2013 TYSPs filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes. Since the TYSP is not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's TYSP at a public hearing."
140110 PSC-14-0557-FOF-EI	DEF	Need Determination	Commission granted a determination of need for Citrus County plant. "As described by Witness Borsch, DEF employs two reliability criteria in its resource planning process: (1) a loss of load probability criterion, and (2) a reserve margin criterion. Witness Borsch stated that DEF's resource plans have been reviewed by this Commission each year since the early 1990s in the annual Ten-Year Site Plan review process. Witness Borsch asserted that the Company's need for the

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			proposed Citrus County Plant in the summer of 2018 is driven by the aforementioned reserve margin criterion. DEF's minimum reserve margin threshold is 20 percent and the Company calculates its reserve margin based on the relationship between peak load and total capacity available to serve that load. In addition to DEF's claimed need to satisfy its reserve margin criterion, Witness Borsch testified that the Citrus County Plant would provide reliability and stability to the Florida electric grid as determined by the Florida Reliability Coordinating Council, Inc. … There is no record evidence to indicate the recession has fundamentally altered DEF's expected forecast result for 2018 demand in a manner that casts doubt on the forecast. We find DEF's load forecast presented in this docket to be reasonable for the purposes of determining the need for DEF's proposed Citrus County Plant in 2018. Based on the evidence in the record, if DEF did not construct the proposed Citrus County Plant in 2018, the projected reserve margin could drop as low as 12.3 percent in 2018."
140111 PSC-14-0590-FOF-EI	DEF	Need Determination	Commission granted a determination of need for Hines unit Chiller project. "Based on the evidence in the record, we recalculated DEF's originally filed reserve margin to ensure that the Company still has a reliability need in 2017. Table 2, below, shows that DEF's reserve margin in 2017 would fall to 19 percent absent any new generation. This represents a 94 MW need. Although, the need is relatively small, Witness Borsch testified that the addition of the Hines Project is cost-effective even when the capacity of the project was not needed to meet the Company's reserve margin criteria. We also note that no party in this docket disputed the need for the Hines Project. … Given a 20 percent reserve margin criterion, we find that the evidence in the record demonstrates a need for the Hines Project beginning in 2017. Based on our calculations, if DEF did not construct the proposed Hines Project in 2017, the projected reserve margin could fall below the Company's 20 percent criterion."
	FPL, DEF, TECO	2014 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed the 2014 Ten-Year Site Plans and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of

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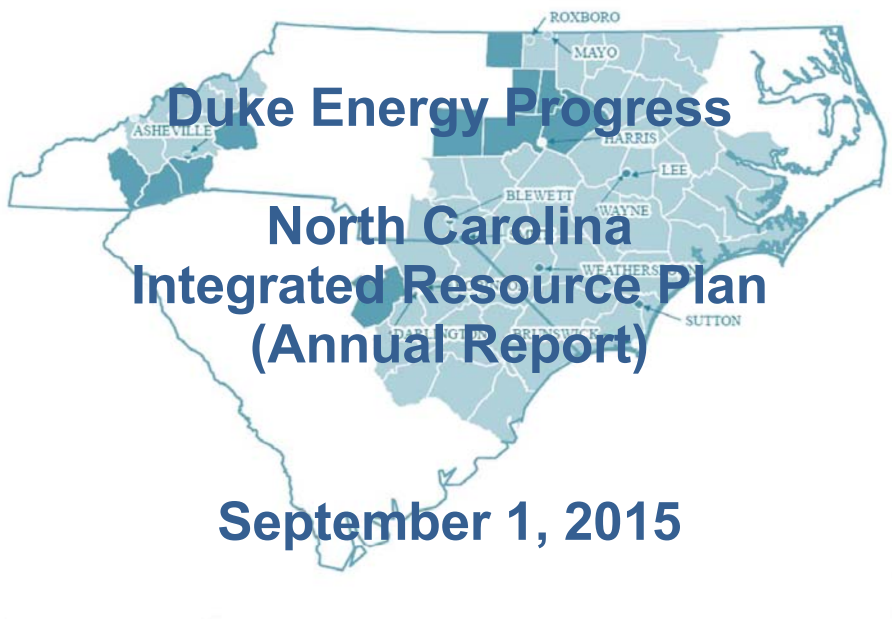
			electricity at a reasonable cost. The Commission will continue to monitor the impact of current and proposed EPA Rules and the state's dependence on natural gas for electricity production. Based on its review, the Commission finds the 2014 Ten-Year Site Plans to be suitable for planning purposes. Since the Plans are not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing."



Duke Energy Progress

North Carolina Integrated Resource Plan (Annual Report)

September 1, 2015

PUBLIC

FLORIDA PUBLIC SERVICE COMMISSION
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PARTY: FPL
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DEP NC 2015 IRP
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1. INTRODUCTION

For more than a century, Duke Energy Progress (DEP) has provided affordable and reliable electricity to customers in North Carolina (NC) and South Carolina (SC) now totaling more than 1.5 million in number. Each year, as required by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC), DEP submits a long-range planning document called the Integrated Resource Plan (IRP) detailing potential infrastructure needed to match the forecasted electricity requirements for our customers over the next 15 years.

The 2015 IRP is the best projection of how the Company's energy portfolio will look over the next 15 years, based on current data assumptions. This projection will change as variables such as projected load forecasts, fuel prices, new environmental regulations and other outside factors change.

On July 20, 2015, the NCUC ordered that the IRP process between biennial IRPs be significantly streamlined. As such, the remainder of this document provides the information ordered by the NCUC for this update (odd year) IRP.

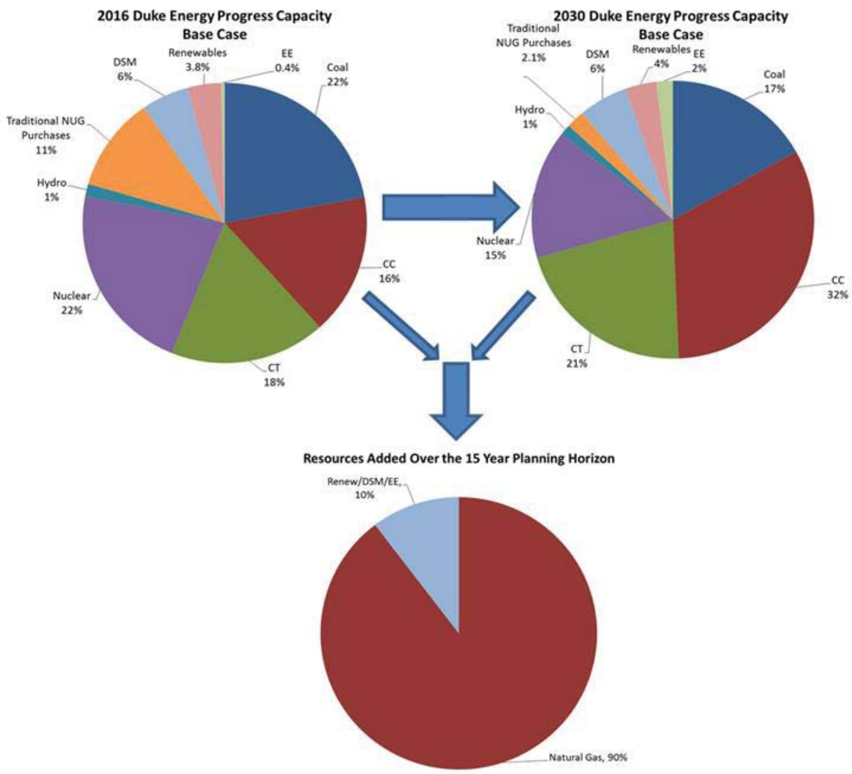
The Company files separate 2015 IRPs for North Carolina and South Carolina. However, the IRP analyzes the system as one DEP utility across both states including customer demand, energy efficiency (EE), demand side management (DSM), renewable resources and traditional supply-side resources. As such, the quantitative analysis contained in both the North Carolina and South Carolina filings is identical, while certain sections dealing with state-specific issues such as state renewable standards or environmental standards may be specific to that state's IRP.

2. 2015 IRP SUMMARY

As 2015 is an update year for the IRP, DEP developed two cases based on the results of the 2014 IRP. The first case, or the "Base Case" is an update to the presented Base Case in the 2014 IRP which includes the expectation of carbon legislation beginning in 2020. Additionally, a "No Carbon Sensitivity" was developed in which no carbon legislation is considered. All results presented in this IRP represent the Base Case, except where otherwise noted.

As shown in the 2015 IRP Base Case, projected incremental needs are driven by load growth and the retirement of aging combustion turbine (CT) and coal-fired resources. The 2015 IRP seeks to achieve a reliable, economic long term power supply through a balance of incremental renewable resources, EE, DSM, nuclear, and traditional supply-side resources planned over the coming years. In order to reliably and affordably meet our customers' needs into the future, the Company projects the need for incremental investments in these resources as depicted in the charts below.

Chart 2-A 2016 and 2030 Base Case Summer Capacity Mix and Sources of Incremental Capacity



The additional assets included over the 15 year planning horizon were selected as the most reliable and affordable resource mix to meet customer demand into the future. Furthermore, the selected mix of renewable resources, EE programs, DSM programs, nuclear generation, and state-of-the-art natural gas facilities also help the Company maintain a diversified resource mix while reducing the environmental footprint associated with each unit of energy production.

3. IRP PROCESS OVERVIEW

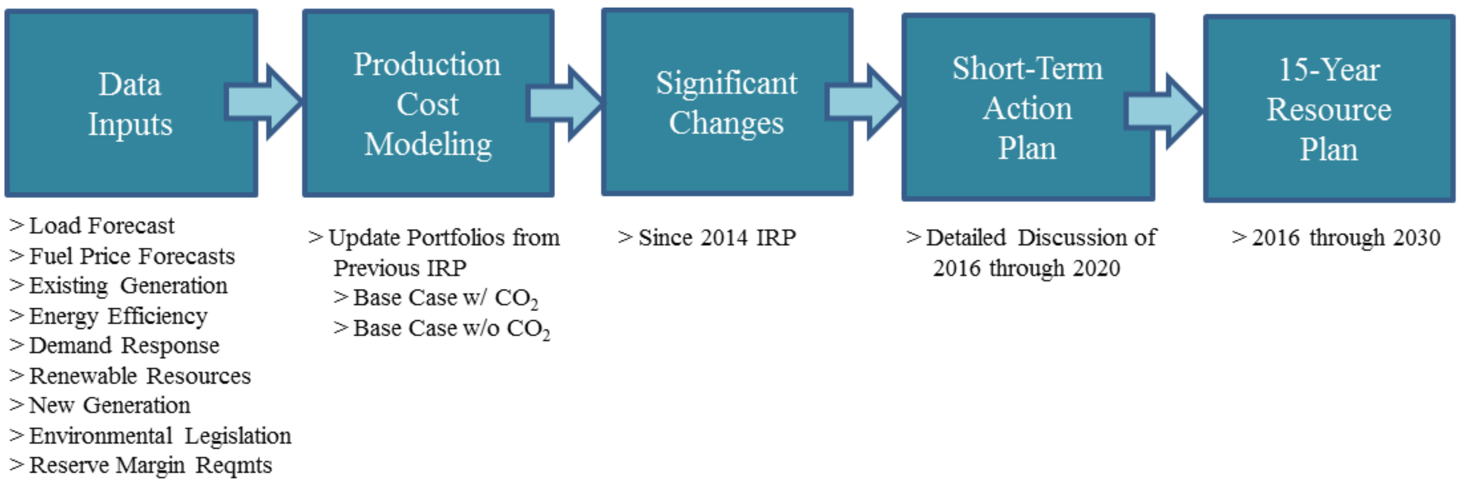
To meet the future needs of DEP's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, the Company develops a load forecast of cumulative energy sales and hourly peak demand. To determine total resources needed, the Company considers the peak demand load obligation plus a 17% minimum planning reserve margin. The projected capability of existing resources, including generating units, EE and DSM, renewable resources and purchased power contracts, is measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meet the load obligation and planning reserve margin while complying with all environmental and regulatory requirements. It should be noted that DEP considers the non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with Duke Energy Carolinas (DEC) in the development of its independent Base Case. To accomplish this, DEP and DEC plans are determined simultaneously to minimize revenue requirements of the combined jointly-dispatched system while maintaining independent reserve margins for each company.

The use of a 17% reserve margin represents an increase over last year's IRP that is discussed in more detail in Chapter 4. As discussed in Chapter 4, this increase does not materially impact the near-term resource needs of the Company as projected in the Short-Term Action Plan but rather influences the subsequent years of the plan.

For the 2015 Update IRP, the Company presents a Base Case with a CO_2 tax beginning in 2020. The current assumption of a CO_2 tax is intended to serve as a placeholder for future carbon regulation. Consistent with this assumption, the final Environmental Protection Agency (EPA) Clean Power Plan (CPP) was released in mid-August and each state is in the process of developing individual state plans to comply with the rule as discussed in Chapter 4. Furthermore, a primary focus of this update IRP is the Short-Term Action Plan (STAP) which runs from 2016 to 2020. It was determined that the inclusion of the CO_2 tax did not have a significant impact on the STAP, and therefore the majority of the data presented in this report is taken from the CO_2 case (Base Case).

Figure 3-A represents a simplified overview of the resource planning process in the update years (odd years) of the IRP cycle.

Figure 3-A Simplified IRP Process



4. SIGNIFICANT CHANGES FROM THE 2014 IRP

As an initial step in the IRP process, all production cost modeling data is updated to include the most current and relative data. Throughout the year, best practices are implemented to ensure the IRP best represents the Company's generation system, conservation programs, renewable energy and fuel costs. The data and methodologies are regularly updated and reviewed to determine if adjustments can be made to further improve the IRP process and results.

As part of the review process, certain data elements, with varying impacts on the IRP, inevitably change. A discussion of newly included or updated data elements that had the most substantial impact on the 2015 IRP is provided below.

a) Load Forecast

The 2015 DEP Spring Load Forecast is updated to include the most current data available at this time. The process and models for the load forecast remain the same, however the method by which utility energy efficiency (UEE) [1] impacts are incorporated into the load forecast has changed since the 2014 IRP. UEE programs are energy efficiency programs that were developed and offered to customers by the Company The impacts of UEE on the load forecast do not include load reductions from free-riders. Free-riders are those customers who would have adopted the energy efficiency program regardless of incentives provided by the Company.

Program lives of UEE programs were previously considered indefinite in the IRP process, but in this year's IRP, are more clearly incorporated in the load forecast. Many UEE programs have a finite program life, much like the useful life of any generating resource. By including the useful life of the programs, the Company is better able to account for the UEE programs available to the DEP system, and as such represent a more realistic and accurate representation of these programs. A numerical representation of the impacts of these changes and impacts to the load forecast are included in Chapter 5.

In the development of the load forecast, many variables may cause the load forecast projection to change. A brief comparison of the growth of the DEP load forecast is presented in Table 4-A and a more detailed discussion can be found in Chapter 5.

[1] The term UEE is utilized in the load forecasting sections which represents utility-sponsored EE impacts net of free riders. The term "Gross EE" represents UEE plus naturally occurring energy efficiency in the marketplace.

Table 4-A 2015 DEP Load Forecast Growth Rates vs. 2014 Load Forecast Growth Rates (Retail and Wholesale Customers)

	2015 Forecast (2016 – 2030)			**2014 Forecast (2015 – 2029)**		
	Summer Peak Demand	**Winter Peak Demand**	**Energy**	**Summer Peak Demand**	**Winter Peak Demand**	**Energy**
Excludes impact of new EE programs	1.5%	1.3%	1.2%	1.6%	1.5%	1.3%
Includes impact of new EE programs	1.3%	1.2%	1.2%	1.4%	1.3%	1.0%

b) Renewable Energy

The Company is committed to full compliance with the North Carolina Renewable Energy Portfolio Standard (NC REPS). Currently signed projects and additional resources needed to fully comply with NC REPS are included in the 2015 IRP. There is currently a large influx of solar resources in the interconnection queue in the DEP system. With this influx, more solar projects are utilized to meet the NC REPS general compliance requirement, replacing biomass and wind resources that were represented in the 2014 IRP.

Additionally, the newly approved South Carolina Distributed Energy Resource Program (SC DERP) has been included. The SC DERP was approved by the PSCSC on July 15, 2015. The Company's commitment to meet the increasing goals of this program through 2020 is included in the 2015 IRP.

Finally, growing customer demand for renewable generation is driving the need for additional solar resources. These resources are included as Utility-owned projects and are projected in the IRP. Such projects are incremental to NC REPS or SC DERP compliance renewables. Utility-owned projects include the expected projects procured by the Company that will increase the capacity of renewable generation on the DEP system.

As mentioned above, DEP has seen a large influx of solar resources in the interconnection queue. A summary of the projects currently in the interconnection queue is represented in Table 4-B. The table shows not only the amount of resources, but also the type of resources.

Table 4-B DEP QF Interconnection Queue

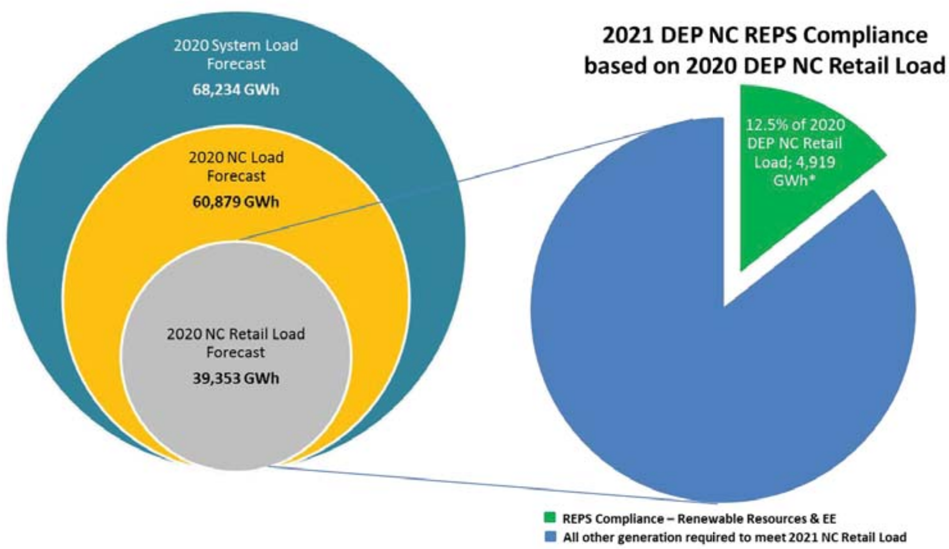
Utility	Facility State	Energy Source Type	Number of Pending Projects	Pending Capacity MW AC
DEP	**NC**	Biogas	2	7
		Biomass	3	53
		Landfill Gas	2	16
		Other	2	1
		Solar	436	3244
		Wood Waste	1	5
DEP	**NC Total**		**446**	**3326**
	SC	Solar	37	605
	SC Total		**37**	**605**
DEP Total			**483**	**3931**

Renewables Compliance

A large portion of the renewable resources added over the planning horizon are a result of complying with NC REPS. The pie charts presented in Chapter 2 above represent the capacity of each asset by fuel type. However, the NC REPS compliance plan sets compliance targets based upon retail energy sales. As such, the renewable *capacity* percentage detailed above is not adequate for determining the Company's compliance with the NC REPS *energy* target.

In an effort to explain NC REPS compliance needs, Chart 4-A shows the energy forecasts and the ultimate NC REPS compliance need for DEP.

Chart 4-A DEP - Meeting NC REPS Compliance



*** 4,919 GWh represents the projected amount of Renewables and EE required to meet REPS compliance in 2021 based on the NC Retail load forecast for the year 2020. The cumulative EE and renewables energy on the DEP system is expected to be greater than what is represented here. Additionally, NC REPS allows 65% of the 2021 target to be met by EE and Out of State Renewable Energy Certificates (RECs).**

c) Addition of Combined Heat & Power (CHP) to the IRP

Combined Heat and Power (CHP) systems, also known as cogeneration, generate electricity and useful thermal energy in a single, integrated system. CHP is not a new technology, but an approach to applying existing technologies. Heat that is normally wasted in conventional power generation is recovered as useful energy, which avoids the losses that would otherwise be incurred from separate generation of heat and power. CHP incorporating a CT and heat recovery steam generator (HRSG) is more efficient than the conventional method of producing usable heat and power separately via a gas package boiler.

Duke Energy is exploring and working with potential customers with good base thermal loads on a regulated Combined Heat and Power offer. The CHP asset will be included as part of Duke Energy's IRP as a placeholder for future projects as described below. The steam sales are credited back to the revenue requirement of the projects to reduce the total cost of this generation grid resource. Along with the potential to be a competitive cost generation resource, CHP can result in CO_2 emission reductions, and present economic development opportunities for the state.

Projections for CHP have been included in the following quantities in the 2015 IRP:

2019: 20 MW
2021: 20 MW

As CHP continues to be pursued, future IRP processes will incorporate additional CHP as appropriate.

Additional technologies evaluated as part of the 2015 IRP are discussed in Chapter 6.

d) Reserve Margin

In 2012, DEP and DEC hired Astrape Consulting to conduct a reserve margin study for each utility. Astrape conducted a detailed resource adequacy assessment that incorporated the uncertainty of weather, economic load growth, unit availability and transmission availability for emergency tie assistance. Astrape analyzed the optimal planning reserve margin based on providing an acceptable level of physical reliability and minimizing economic costs to customers. The most common physical metric used in the industry is to target a system reserve margin that satisfies the one day in 10 years Loss of Load Expectation (LOLE) standard. This standard is interpreted as one firm load shed event every 10 years due to a shortage of generating capacity. From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. Similarly, as planning reserve margin decreases, the cost of reserves decreases while the costs related to reliability events increase, including the costs to customers of loss of power. Thus, there is an economic optimum point where the cost of additional reserves plus the cost of reliability events to customers is minimized. Based on past reliability assessments, results of the Astrape analysis, and to enhance consistency and communication regarding reserve targets, both DEP and DEC had adopted a 14.5% minimum summer planning reserve margin for scheduling new resource additions.

In 2015, DEP and DEC contracted again with Astrape Consulting to perform an updated resource adequacy study. The Companies believe that the study was warranted at this time due to several factors. First, the severe, extreme weather experienced in the service territory the last two winter periods was so impactful to the systems that additional review with the inclusion of recent years' weather history was warranted. Second, since the last reliability study the system has added, and projects to add, a large amount of resources that provide meaningful capacity benefits in the summer only. From a peak reduction perspective such summer oriented resources include solar generation, HVAC load control and chiller uprates to existing natural gas combined cycle units. The interconnection queue for solar facilities shows potential to add significantly to the solar resources already incorporated in the system.

Initial results of this updated study indicate that a 17% summer planning reserve margin is required to maintain the one day in 10 year LOLE standard. As such, DEP has utilized a 17% planning reserve margin in the 2015 IRP as opposed to the 14.5% reserve margin used in the 2014 IRP. However, preliminary findings also indicate that a summer-only reserve margin target may not be adequate for providing long term reliability given the increasing levels of summer-only resources. Additional study is needed to determine whether dual summer/winter planning reserve margin targets are required in the future. Once the final results are determined, any changes will be included in the 2016 IRP.

Adequacy of Projected Reserves

DEP's resource plan reflects reserve margins ranging from 17.0% to 21.9%. Reserves projected in DEP's IRP meet the minimum planning reserve margin target and thus satisfy the one day in 10 years LOLE criterion. The projected reserve margin exceeds the minimum 17% target by 3% or more in 2016-2018 primarily due to a decrease in the load forecast compared to earlier projections. The projected reserve margin exceeds the target by 3% or more in 2022 as a result of the economic addition of a large combined-cycle facility.

A significant increase in projected solar capacity causes reserves to exceed 3% of the target in 2023. The projected reserve margin also exceeds the target by 3% or more in 2027 as a result of the economic addition of a large block of combustion turbine capacity.

The IRP provides general guidance in the type and timing of resource additions. Since capacity is generally added in large blocks to take advantage of economies of scale, it should be noted that projected planning reserve margins in years immediately following new generation additions will often be somewhat higher than the minimum target. Large resource additions are deemed economic only if they have a lower Present Value Revenue Requirement (PVRR) over the life of the asset as compared to smaller resources that better fit the short-term reserve margin need. Development of detailed self-build projects and utilization of the Request for Proposals (RFP) process to consider purchased power alternatives will ensure the Company selects the most cost-effective resource additions. Reserves projected in DEP's IRP are appropriate for providing an economic and reliable power supply.

e) <u>Fuel Costs</u>

In the 2014 IRP, the first 5 years of natural gas prices were based on market data and the remaining years were based off of fundamental pricing. Market prices represent liquid, tradable gas prices offered at the present time, also called "future or forward prices." These prices represent an actual contractually agreed upon price that willing buyers and sellers agree to transact upon at a specified future date. As such, assuming market liquidity, they represent the markets view of spot prices for a given point in the future. Fundamental prices developed through external econometric models, on the other hand, represent a projection of fuel prices into the future taking into account changing supply and demand assumptions of the changing dynamics of the external marketplace. The natural gas market has become more liquid, and there are now multiple buyers and sellers of natural gas in the marketplace that are willing to transact at longer transaction terms. Due to the evolving natural gas market, DEP and DEC are using market based prices for the first 10 years of the planning period (2016 – 2025). Following the 10 years of market prices, the Companies transition to fundamental pricing over a 5 year period with 100% fundamental pricing in 2030 and beyond.

As in the 2014 IRP, coal prices continue to be based on 5 years of market data in the 2015 IRP. In order to account for the impact on coal prices by using a longer market based natural gas price, the companies are transitioning to fundamental coal pricing over a 10 year period (2021 to 2030), using the same growth rate as natural gas through that time period. Previously the Companies moved to fundamental coal prices once market prices were unavailable, but the

Companies believe this creates an unrealistic disconnect between coal and natural gas prices in the medium term.

f) New Resource Retirements/Additions

Asheville Plant

As part of the Western Carolinas Modernization Project (WCMP) announced in the spring of 2015, the combined 376 MW Asheville 1 & 2 coal units are planned to be retired no later than January 31, 2020. The retired units are expected to be replaced with a 663 MW natural gas combined cycle unit on site in November 2019, along with necessary and associated natural gas delivery and electric transmission infrastructure projects. Additionally, an undetermined amount of solar generation is planned for installation at the same site shortly after the retirement of the coal plants. The Certificate of Public Convenience and Necessity (CPCN) for the new combined cycle unit is expected to be filed with the NCUC in the fourth quarter of 2015. As part of the WCMP, the three fuel oil combustion turbine units totaling 126 MW that were planned for Asheville in 2019, as included in the 2014 DEP IRP Short-Term Action Plan, are no longer necessary and have been removed from the 2015 IRP.

This retirement date for the Asheville coal units represents an acceleration of approximately 10 years from previous planning assumptions. The retirements of the units, and the corresponding investments in the required infrastructure to replace those units, are being accelerated due to a culmination of several factors. These factors include continued declines in natural gas prices, the unique opportunity to take advantage of an economic gas delivery project by the local gas distribution company, and the opportunity to avoid significant investment in additional environmental controls at the coal units that would be required by 2020.

In summary, benefits from the WCMP include, but are not limited to:

- Significant fuel cost reductions through the construction of new transmission infrastructure and combined cycle plant coupled with eliminating the uneconomic utilization of the coal units.
- Avoidance of significant capital expenditures for further environmental controls on the coal units.
- Avoidance of costs associated with three fuel oil combustion turbine units that would be required in the absence of the WCMP.
- Engagement in a unique opportunity to partner with the local gas distribution company to bring cost-effective natural gas supply to the western Carolinas.
- Enhanced reliability following multiple polar vortex events.

Sutton and Lee Inlet Air Chillers

The 2014 IRP called for installation of 137 MW of inlet air chiller technology at Sutton and Lee combined cycle plants prior to the summer of 2018. The most recent analysis of summer reserves shows that these chillers can be delayed until at least the summer of 2019. The 2015 IRP shows installation in May 2019, and a slight downward adjustment of capacity to 135 MW (77 MW at Lee CC and 58 MW at Sutton CC). The benefits to winter capacity from these chillers is not included in the plan as the chiller technology only provides summer peaking capability.

Purchase of NCEMPA Portion of Assets

The North Carolina Eastern Municipal Power Agency (NCEMPA) previously owned partial interest in several Duke Energy Progress plants, including Brunswick Nuclear Plant Units 1 and 2, Mayo Plant, Roxboro Plant Unit 4 and the Harris Nuclear Plant. The Power Agency's ownership interest in these plants represented approximately 700 megawatts of generating capacity. DEP's prior IRPs included NCEMPA's ownership share of the jointly owned assets along with the associated load obligation.

Boards of directors of Duke Energy and the NCEMPA approved an agreement for Duke Energy Progress to purchase the Power Agency's ownership in these generating assets. All required regulatory approvals have been completed and the agreement closed on July 31, 2015. DEP is now 100% owner of these previously jointly owned assets. Under the agreement, Duke Energy Progress will continue meeting the needs of NCEMPA customers previously served by the Power Agency's interest in Duke Energy Progress' plants.

g) EPA Clean Power Plan (CPP)

On August 3, 2015, the EPA signed the final CO_2 emission limits rule for existing fossil-fuel power plants, known as the "Clean Power Plan". The regulation is promulgated under Section 111(d) of the Clean Air Act and is sometimes referred to as "111(d)". The rule is both lengthy (over 1550 pages) and complex. There have been considerable legal questions raised since the initial proposal and the rule remains controversial both at the state and federal levels.

EPA has made substantial changes from the proposed rule it released in June 2014 and a complete analysis will take time. The rule maintains a building block approach and preserves the first three building blocks of heat rate improvement, re-dispatch to natural gas and construction of renewables. Building block 4, which in the proposal established energy efficiency targets, has been eliminated from the final rule. There are new elements in the final rule including additional compliance options, a model trading program and a "clean energy incentive program" to encourage early investments in renewable generation and demand-side energy efficiency.

Regulation under Section 111(d) of the Clean Air Act requires EPA to set the program requirements in a guideline document it issues to the states. The document must include:

"An emission guideline that reflects the application of the best system of emission reduction … that has been adequately demonstrated for designated facilities," taking into account both the "cost of achieving such emission reductions" as well as the "remaining useful life of sources."

States use the EPA guidance document to develop their own regulations – often referred to as a state implementation plan (SIP). States have primary implementation and enforcement authority and responsibility for the regulation.

State emission reduction goals were calculated based on EPA's determination of the "Best System of Emission Reduction" (BSER) for existing plants. Since no technology is commercially available to reduce CO_2 emissions at fossil fueled power plants, EPA proposed that the application of building blocks across the entire electric generation system was appropriate for determining the degree of emission reduction that would be achievable.

States have until September 6, 2016 to submit a complete plan or a partial plan with an extension request. States receiving an extension must submit a final state implementation plan (SIP) by September 6, 2018. EPA plans to take one year to review state plans (this could be a significant challenge for the Agency to accomplish). Duke Energy's compliance obligations will be finalized once a state compliance plan has been approved. If a state chooses not to submit a plan or a plan is deemed to be inadequate, EPA will impose a federal plan on the state.

North Carolina

The North Carolina 2030 rate target increased from 992 lbs. CO_2/MWh (proposed rule) to 1,136 lbs./MWh (final rule). In addition, the final rule includes a 2030 mass cap for North Carolina of 51,266,234 tons of CO_2. It remains unclear if the increased rate will make it easier or more difficult to comply given the uncertainty surrounding the treatment of new natural gas combined cycle (NGCC) units. Early indications are that the NC Department of Environment and Natural Resources (NC DENR) will pursue submittal of a final plan based on what utilities can achieve at the individual affected unit, referred to as 'Building Block 1', to the EPA by the September 2016 deadline. With seven operational coal-fired stations and a growing fleet of NGCC units, the final rule and implementation plan will certainly impact generation in North Carolina, but the extent of these impacts remains unclear.

South Carolina

The South Carolina 2030 rate target increased from 772 lbs. CO_2/MWh (proposed rule) to 1,156 lbs./MWh (final rule). In addition, the final rule includes a 2030 mass cap for South Carolina of 25,998,968 tons of CO_2. The SC Department of Health and Environmental Control has a robust stakeholder group evaluating options and intends to apply for the two year extension, pushing back the date for submittal of a final rule to September 2018. Duke Energy operates no coal-fired generation in South Carolina, so the impact of the rule is anticipated to be minimal.

h) Transmission Planned or Under Construction

This section contains the planned transmission line and substation additions since the 2014 IRP. Only those projects added since the 2014 IRP are included. A discussion of the adequacy of DEP's transmission system is also included. Table 4-C lists the transmission projects that are planned to meet reliability needs. This section also provides information pursuant to the North Carolina Utilities Commission Rule R8-62.

Table 4-C: DEP Transmission Line and Substation Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2016	Falls	-	336	230/115	New
2016	Selma	-	336	230/115	Upgrade
2018[2]	Vanderbilt	West Asheville	307	115	Upgrade
2018[3]	Richmond	Raeford	1195	230	Relocate, new
2018[4]	Ft. Bragg Woodruff St.	Raeford	1195	230	Relocate, new
2019	Craggy	Enka	799	230	New
2019	Asheville Plant	-	448	230/115	New
2020	Jacksonville	Grants Creek	1195	230	New
2020	Newport	Harlowe	681	230	New

[2] The date for this project in the 2014 IRP was 2016. The project has been re-scheduled for 2018.
[3] This project was included in the 2014 IRP, however some parameters have been made and are represented on the following pages.
[4] This project was included in the 2014 IRP, however some parameters have been made and are represented on the following pages.

Rule R8-62: Certificates of environmental compatibility and public convenience and necessity for the construction of electric transmission lines in North Carolina.

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(1) For existing lines, the information required on FERC Form 1, pages 422, 423, 424, and 425, except that the information reported on pages 422 and 423 may be reported every five years.

Please refer to the Company's FERC Form No. 1 filed with NCUC in April, 2015.

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(2) For lines under construction, the following:

- *a. Commission docket number;*
- *b. Location of end point(s);*
- *c. Length;*
- *d. Range of right-of-way width;*
- *e. Range of tower heights;*
- *f. Number of circuits;*
- *g. Operating voltage;*
- *h. Design capacity;*
- *i. Date construction started;*
- *j. Projected in-service date;*

The following pages represent those projects in response to Rule R8-62 parts (1) and (2).

DEP has no transmission line projects currently under construction.

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(3) For all other proposed lines, as the information becomes available, the following:

a. County location of end point(s);
b. Approximate length;
c. Typical right-of-way width for proposed type of line;
d. Typical tower height for proposed type of line;
e. Number of circuits;
f. Operating voltage;
g. Design capacity;
h. Estimated date for starting construction (if more than 6 month delay from last report, explain); and
i. Estimated in-service date (if more than 6-month delay from last report, explain). (NCUC docket no. E-100, sub 62, 12/4/92; NCUC docket no. E-100, sub 78a, 4/29/98.)

The following pages represent those projects in response to Rule R8-62 part (3).

Richmond – Raeford 230 kV Line Loop-In

Project Description: Loop-In the existing 230 kV transmission line from the Richmond 230 kV Substation in Richmond County to the Ft. Bragg Woodruff St 230 kV Substation in Cumberland County at Raeford 230 kV Substation in Hoke County.

a. County location of end point(s); Hoke County
b. Approximate length; 5 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 -120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 1195 MVA
h. Estimated date for starting construction; September 2015
i. Estimated in-service date; June 2018

Ft. Bragg Woodruff St – Raeford 230 kV Line loop-in

Project Description: Loop-In the existing 230 kV transmission line from the Richmond 230 kV Substation in Richmond County to the Ft. Bragg Woodruff St 230 kV Substation in Cumberland County at Raeford 230 kV Substation in Hoke County.

a. County location of end point(s); Hoke County
b. Approximate length; 5 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 1195 MVA
h. Estimated date for starting construction; September 2015
i. Estimated in-service date; June 2018

Craggy – Enka 230 kV Line

Project Description: Construct new 230 kV transmission line from the Craggy 230 kV Substation in Buncombe County to the Enka 230 kV Substation also in Buncombe County.

a. County location of end point(s); Buncombe County
b. Approximate length; 10 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 799 MVA
h. Estimated date for starting construction; September 2016
i. Estimated in-service date; December 2019

Jacksonville – Grants Creek 230 kV Line

Project Description: Construct new 230 kV transmission line from the Jacksonville 230 kV Substation in Onslow County to the Grants Creek 230 kV Substation in Onslow County.

a. County location of end point(s); Onslow County
b. Approximate length; 15 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 1195 MVA
h. Estimated date for starting construction; September 2016
i. Estimated in-service date; June 2020

Newport – Harlowe 230 kV Line

Project Description: Construct new 230 kV transmission line from the Newport 230 kV Substation in Carteret County to the Harlowe 230 kV Substation in Carteret County.

a. County location of end point(s); Carteret County
b. Approximate length; 8 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 681 MVA
h. Estimated date for starting construction; September 2016
i. Estimated in-service date; June 2020

DEP Transmission System Adequacy

DEP monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The DEP transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEP works with DEC, NCEMC and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEP and DEC systems in both North and South Carolina. In addition, transmission planning is coordinated with neighboring systems including South Carolina Electric & Gas (SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between SCE&G, Santee Cooper, DEP, and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEP's Transmission Planning Summary guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC policy and NERC Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades. The transmission system is planned to ensure that no equipment overloads and adequate voltage is maintained to provide reliable service. The most stressful scenario is typically at peak load with certain equipment out of service. A thorough screening process is used to analyze the impact of potential equipment failures or other disturbances. As problems are identified, solutions are developed and evaluated.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEP currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Summary guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the Large and Small Generator Interconnection Procedures in the OATT and the North Carolina Interconnection Procedures.

Southeastern Reliability Corporation (SERC) audits DEP every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEP to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the

Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEP in the fall of 2014. DEP received "No Findings" from the audit team.

DEP participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-balancing authority area transfer capability and interconnection reliability. Each reliability group's purpose is to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;

- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and

- Ensure interconnected system compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

Application of the practices and procedures described above have ensured DEP's transmission system is expected to continue to provide reliable service to its native load and firm transmission customers.

5. LOAD FORECAST

The Duke Energy Progress Spring 2015 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2016 – 2030 and represents the needs of the following customer classes:

- Residential
- Commercial
- Industrial
- Other Retail
- Wholesale

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather and appliance efficiency trends. Population is also used in the Residential customer model. While regression analysis has consistently yielded reasonable results over the years, processes are continually reviewed and compared between jurisdictions in an effort to improve upon the forecasting process. Large unforeseen events however, such as the "great recession" or the loss of large wholesale customers, will cause forecasts to differ from actual results.

The economic projections used in the Spring 2015 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North Carolina and South Carolina.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial.

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electric price and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The projected growth rate of Residential in the Spring 2015 Forecast after all adjustments for Utility EE programs, Solar and Electric Vehicles from 2016-2030 is 1.3%.

The Commercial forecast also uses a SAE model in an effort to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the Commercial class are Offices, Education and Retail. Commercial is expected to be the fastest growing class, with a projected growth rate of 1.5%, after adjustments.

The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output, textile output, and the price of electricity. Overall, Industrial sales are expected to grow 0.9% over the forecast horizon, after all adjustments.

County population projections are obtained from the North Carolina Office of State Budget and Management as well as the South Carolina Budget and Control Board. These are then used to derive the total population forecast for the counties that comprise the DEP service area.

Weather impacts are incorporated into the models by using Heating Degree Days and Cooling Degree Days with a base temperature of 65. The forecast of degree days is based on a 10 year average.

The appliance saturation and efficiency trends are developed by Itron using data from the EIA. Itron is a recognized firm providing forecasting services to the electric utility industry. These appliance trends are used in the residential and commercial sales models.

Peak demands were projected using the SAE approach in the Spring 2015 Forecast. The peak forecast was developed using a monthly SAE model, similar to the sales SAE models, which includes monthly appliance saturations and efficiencies, interacted with weather and the fraction of each appliance type that is in use at the time of monthly peak.

Assumptions

Below are the projected average annual growth rates of several key drivers from DEP's Spring 2015 Forecast.

	2016 - 2030
Real Income	2.7%
Mfg. IPI	2.1%
Population	1.0%

In addition to economic, demographic, and efficiency trends, the forecast also incorporates the expected impacts of utility-sponsored energy efficient programs, as well as projected effects of electric vehicles and behind the meter solar technology.

Wholesale

The wholesale contracts that are included in the load forecast are listed in Table 10-A in Chapter 10.

Historical Values

It should be noted that the long-term structural decline of the Textile industry and the recession of 2008-2009 have had an adverse impact on DEP sales. The worst of the Textile decline appears to be over, and Moody's Analytics expects the Carolina's economy to show solid growth going forward.

In tables 5-A & 5-B below the history of DEP customers and sales are given. As a note, the values in Table 5-B are not weather adjusted.

Table 5-A Retail Customers (Thousands, Annual Average)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Residential	1,123	1,149	1,174	1,195	1,207	1,216	1,221	1,231	1,242	1,257
Commercial	205	210	214	216	215	216	217	219	222	222
Industrial	4	4	4	4	5	5	4	4	4	4
Total	1,332	1,363	1,392	1,415	1,426	1,437	1,443	1,455	1,468	1,484

Table 5-B Electricity Sales (GWh Sold - Years Ended December 31)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Residential	16,003	16,664	16,259	17,200	17,000	17,117	19,108	17,764	16,663	18,201
Commercial	13,019	13,314	13,358	14,033	13,940	13,639	14,184	13,709	13,581	13,887
Industrial	13,036	12,741	12,416	11,883	11,216	10,375	10,677	10,573	10,508	10,321
Military &Other	1,431	1,410	1,419	1,438	1,467	1,497	1,574	1,591	1,602	1,614
Total Retail	43,490	44,129	43,451	44,553	43,622	42,628	45,544	43,637	42,355	44,023
Wholesale	12,439	12,210	12,231	12,656	12,868	12,772	12,772	12,267	12,676	13,578
Total System	55,928	56,340	55,682	57,209	56,489	55,400	58,316	55,903	55,031	57,601

Utility Energy Efficiency

A new process for reflecting the impacts of UEE on the forecast was introduced in Spring 2015. In the latest forecast, the concept of 'Program Life' for a program was included in the calculations. For example, if the accelerated benefit of a residential UEE program is expected to have occurred 7 years before the energy reduction program would have been otherwise adopted, then the UEE effects after year 7 are subtracted ("rolled off") from the total cumulative UEE. With the SAE models framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption.

The table below illustrates this process.

- Column A: Total energy demand for DEP before any reduction for UEE
- Column B: Total incremental cumulative UEE
- Column C: Roll-off amount of the historical UEE programs
- Column D: Roll-off amount of the incremental future UEE programs
- Column E: Total net UEE benefits (column B less columns C & D)
- Column F: Total DEP energy demand after incorporating UEE (column A less column E)

Table 5-C UEE Program Life Process (MWh)

	A	B	C	D	E	F
	Forecast Before EE	Total Cumulative EE	Roll-Off Historical UEE	Roll-Off Forecasted UEE	UEE to Subtract From Forecast	Forecast After UEE
2016	66,805,005	1,611,837	37,998	0	1,573,839	65,231,166
2017	67,539,168	1,789,279	104,966	0	1,684,313	65,854,855
2018	68,364,378	1,968,176	206,527	0	1,761,649	66,602,728
2019	69,176,185	2,144,881	351,978	0	1,792,903	67,383,282
2020	70,004,351	2,321,586	533,731	17,605	1,770,249	68,234,102
2021	70,639,854	2,498,291	733,010	65,593	1,699,688	68,940,166
2022	71,379,803	2,674,996	882,119	172,724	1,620,152	69,759,651
2023	72,151,810	2,851,701	999,141	298,876	1,553,685	70,598,125
2024	73,065,309	3,028,406	1,068,137	438,547	1,521,722	71,543,587
2025	73,863,360	3,205,111	1,098,140	595,656	1,511,315	72,352,045
2026	74,748,903	3,381,816	1,106,441	765,119	1,510,256	73,238,647
2027	75,636,152	3,558,521	1,106,441	948,224	1,503,856	74,132,296
2028	76,674,488	3,735,226	1,106,441	1,139,861	1,488,924	75,185,564
2029	77,495,104	3,911,931	1,106,441	1,338,884	1,466,606	76,028,497
2030	78,426,888	4,088,636	1,106,441	1,540,020	1,442,175	76,984,713

Note: UEE Data is net of free riders

Results

Tabulations of class forecasts and sales are given in Table 5-D and Table 5-E. The sales forecasts are after all adjustments for UEE, Solar and Electric Vehicles.

Table 5-D Retail Customers (Thousands, Annual Average)

	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2016	1,292	225	4	1	1,523
2017	1,309	227	4	2	1,542
2018	1,325	229	4	2	1,560
2019	1,342	231	4	2	1,578
2020	1,358	233	4	2	1,596
2021	1,373	235	4	2	1,614
2022	1,389	237	4	2	1,632
2023	1,404	239	5	2	1,649
2024	1,419	241	5	2	1,667
2025	1,434	244	5	2	1,683
2026	1,448	246	5	2	1,700
2027	1,463	248	5	2	1,717
2028	1,478	250	5	2	1,734
2029	1,492	252	5	2	1,751
2030	1,507	255	5	2	1,767

Table 5-E Electricity Sales (GWh Sold - Years Ended December 31)

	Residential Gwh	Commercial Gwh	Industrial Gwh	Other Gwh	Retail Gwh
2016	17,967	14,043	10,412	1,620	44,042
2017	18,166	14,207	10,497	1,618	44,487
2018	18,383	14,418	10,574	1,615	44,990
2019	18,620	14,635	10,658	1,612	45,525
2020	18,878	14,863	10,758	1,610	46,107
2021	19,095	15,048	10,836	1,607	46,587
2022	19,354	15,252	10,920	1,605	47,130
2023	19,615	15,476	11,020	1,602	47,713
2024	19,897	15,734	11,120	1,600	48,351
2025	20,125	15,952	11,219	1,597	48,894
2026	20,402	16,201	11,316	1,595	49,514
2027	20,681	16,460	11,416	1,593	50,150
2028	21,042	16,756	11,514	1,591	50,904
2029	21,304	17,008	11,611	1,589	51,511
2030	21,616	17,311	11,723	1,587	52,236

Tabulations of the utility's forecasts, including peak loads for summer and winter seasons of each year and annual energy forecasts, both with and without the impact of UEE programs, are shown below in Tables 5-G and 5-H.

Load duration curves, with and without UEE programs, follow Tables 5-G and 5-H, and are shown as Charts 5-A and 5-B.

The values in these tables reflect the loads that Duke Energy Progress is contractually obligated to provide and cover the period from 2016 to 2030.

For the period 2016-2030, the Spring 2015 Forecast resulted in the following growth rates:

Table 5-F Growth Rates of Retail and Wholesale Customers (2016-2030)

	2015 Forecast (2016 – 2030)		
	Summer Peak Demand	**Winter Peak Demand**	**Energy**
Excludes impact of new EE programs	1.5%	1.3%	1.2%
Includes impact of new EE programs	1.3%	1.2%	1.2%

The peaks and sales in the tables and charts below are at the generator, except for the Class sales forecast, which is at meter.

Table 5-G Load Forecast without Energy Efficiency Programs & Before Demand Reduction Program

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2016	13,048	12,767	66,805
2017	13,224	12,938	67,539
2018	13,402	13,133	68,364
2019	13,595	13,342	69,176
2020	13,949	13,531	70,004
2021	14,208	13,703	70,640
2022	14,444	13,882	71,380
2023	14,709	14,062	72,152
2024	14,901	14,278	73,065
2025	15,082	14,437	73,863
2026	15,264	14,621	74,749
2027	15,440	14,797	75,636
2028	15,636	15,022	76,674
2029	15,814	15,183	77,495
2030	15,981	15,352	78,427

Chart 5-A Load Duration Curve without Energy Efficiency Programs & Before Demand Reduction Programs

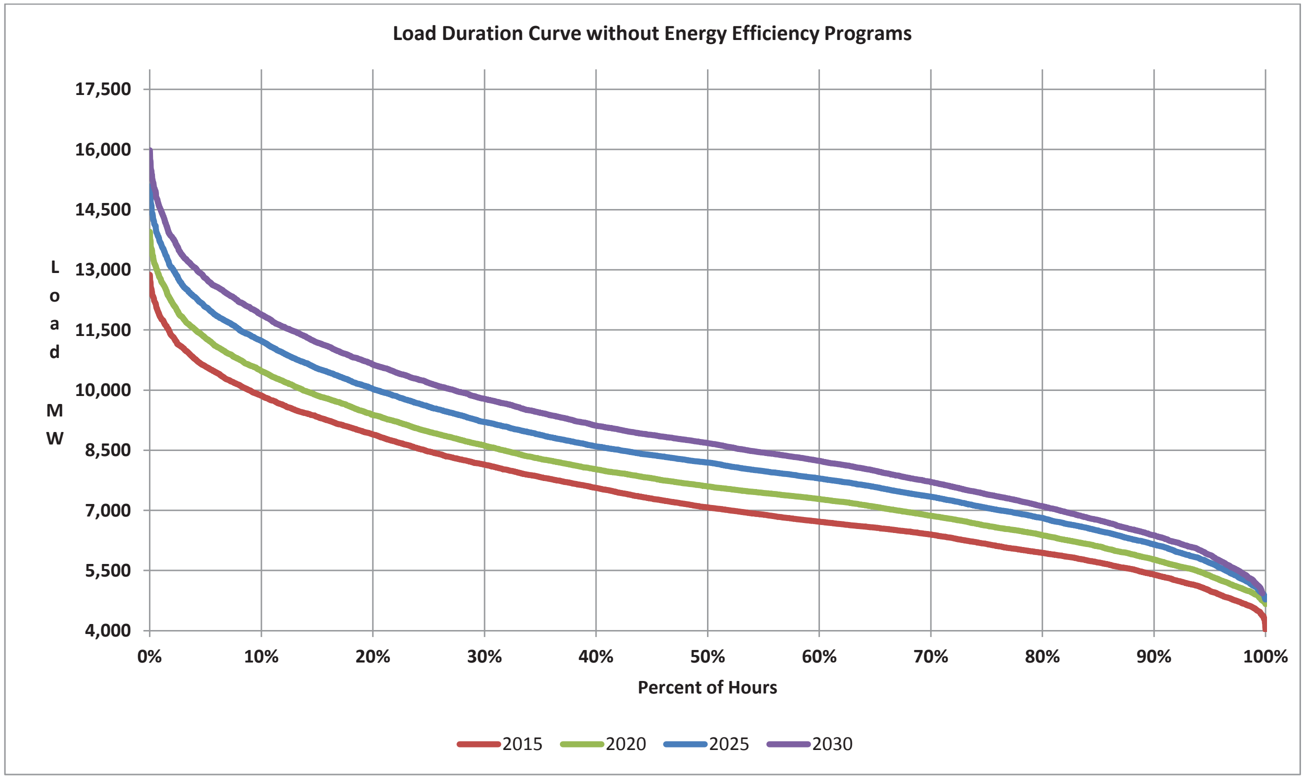
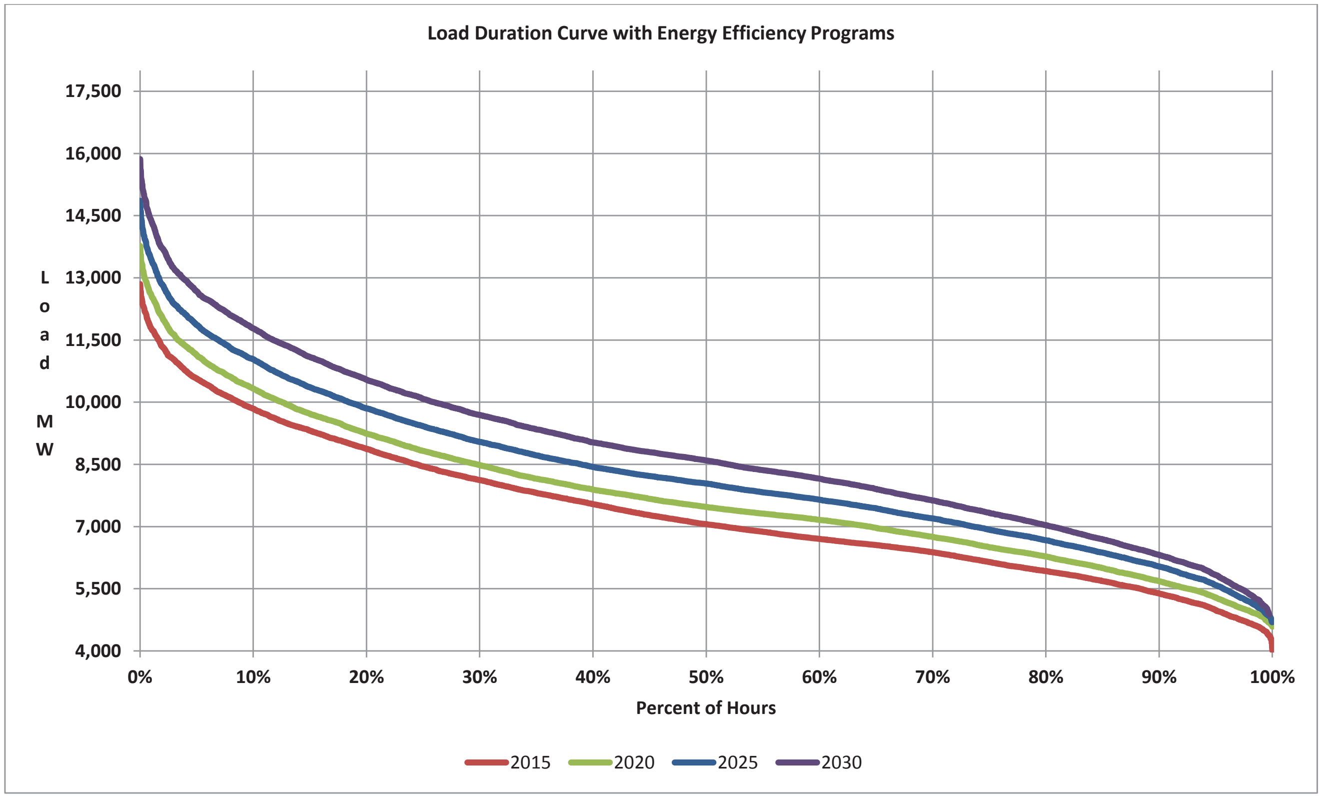


Table 5-H Load Forecast with Energy Efficiency Programs & Before Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2016	12,981	12,727	65,231
2017	13,127	12,877	65,855
2018	13,277	13,050	66,603
2019	13,440	13,236	67,383
2020	13,766	13,403	68,234
2021	13,996	13,552	68,940
2022	14,205	13,711	69,760
2023	14,445	13,872	70,598
2024	14,611	14,070	71,544
2025	14,770	14,211	72,352
2026	14,934	14,381	73,239
2027	15,098	14,548	74,132
2028	15,292	14,772	75,186
2029	15,465	14,930	76,028
2030	15,629	15,096	76,985

Chart 5-B Load Duration Curve with Energy Efficiency Programs & Before Demand Reduction Programs



6. DEVELOPMENT OF RESOURCE PLAN

The following section details the Company's expansion plan and resource mix that is required to meet the needs of DEP's customers over the next 15 years. The section also includes a discussion of the various technologies considered during the development of the IRP, as well as, a summary of the resources required in the "No Carbon" sensitivity case.

Table 6-A Load, Capacity and Reserves Table – Summer

**Summer Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2015 Annual Plan**

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Forecast															
1 Duke System Peak	13,048	13,224	13,402	13,595	13,949	14,208	14,444	14,709	14,901	15,082	15,264	15,440	15,636	15,814	15,981
2 Firm Sale	150	150	150	150	150	150	150	150	150	0	0	0	0	0	0
3 Cumulative New EE Programs	(67)	(96)	(125)	(155)	(183)	(212)	(239)	(265)	(290)	(313)	(330)	(342)	(344)	(349)	(352)
4 Adjusted Duke System Peak	**13,131**	**13,277**	**13,427**	**13,590**	**13,916**	**14,146**	**14,355**	**14,595**	**14,761**	**14,770**	**14,934**	**15,098**	**15,292**	**15,465**	**15,629**
Existing and Designated Resources															
5 Generating Capacity	12,776	12,776	12,813	12,828	12,963	13,194	12,844	12,844	12,844	12,844	12,844	12,844	12,664	12,664	12,664
6 Designated Additions / Uprates	0	98	15	135	1,013	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	(61)	0	0	(782)	(350)	0	0	0	0	0	(180)	0	0	(741)
8 Cumulative Generating Capacity	**12,776**	**12,813**	**12,828**	**12,963**	**13,194**	**12,844**	**12,844**	**12,844**	**12,844**	**12,844**	**12,844**	**12,664**	**12,664**	**12,664**	**11,923**
Purchase Contracts															
9 Cumulative Purchase Contracts	**1,919**	**1,930**	**1,930**	**1,761**	**1,616**	**861**	**528**	**528**	**528**	**528**	**478**	**477**	**452**	**419**	**407**
Non-Compliance Renewable Purchases	177	188	188	188	188	132	131	130	130	130	80	80	58	25	12
Non-Renewables Purchases	1,742	1,742	1,742	1,574	1,429	729	397	397	397	397	397	397	394	394	394
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Combined Cycle	0	0	0	0	0	895	895	0	0	0	0	0	0	0	895
12 Combustion Turbine	0	0	0	0	0	828	0	0	0	0	0	828	0	0	0
13 CHP	0	0	0	20	0	20	0	0	0	0	0	0	0	0	0
Renewables															
14 Cumulative Renewables Capacity	437	473	433	434	437	348	347	619	637	645	639	653	667	677	666
15 Cumulative Production Capacity	**15,132**	**15,217**	**15,191**	**15,179**	**15,268**	**15,816**	**16,378**	**16,648**	**16,666**	**16,674**	**16,618**	**17,280**	**17,269**	**17,246**	**17,377**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**871**	**923**	**967**	**1,004**	**1,021**	**1,029**	**1,032**	**1,034**	**1,037**	**1,040**	**1,043**	**1,046**	**1,049**	**1,052**	**1,055**
17 Cumulative Capacity w/ DSM	**16,003**	**16,140**	**16,159**	**16,183**	**16,288**	**16,845**	**17,409**	**17,683**	**17,703**	**17,715**	**17,662**	**18,326**	**18,319**	**18,298**	**18,432**
Reserves w/ DSM															
18 Generating Reserves	2,872	2,862	2,732	2,593	2,372	2,698	3,054	3,088	2,942	2,945	2,728	3,228	3,027	2,832	2,803
19 % Reserve Margin	**21.9%**	**21.6%**	**20.3%**	**19.1%**	**17.0%**	**19.1%**	**21.3%**	**21.2%**	**19.9%**	**19.9%**	**18.3%**	**21.4%**	**19.8%**	**18.3%**	**17.9%**

Table 6-B Load, Capacity and Reserves Table – Winter

**Winter Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2015 Annual Plan**

	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Load Forecast														
1 Duke System Peak	12,767	12,938	13,133	13,342	13,531	13,703	13,882	14,062	14,278	14,437	14,621	14,797	15,022	15,183
2 Firm Sale	150	150	150	150	150	150	150	150	150	0	0	0	0	0
3 Cumulative New EE Programs	(40)	(62)	(84)	(105)	(129)	(151)	(171)	(190)	(209)	(226)	(240)	(249)	(250)	(253)
4 Adjusted Duke System Peak	**12,877**	**13,027**	**13,200**	**13,386**	**13,553**	**13,702**	**13,861**	**14,022**	**14,220**	**14,211**	**14,381**	**14,548**	**14,772**	**14,930**
Existing and Designated Resources														
5 Generating Capacity	13,895	13,899	13,917	13,935	14,289	13,772	13,772	13,772	13,772	13,772	13,772	13,772	13,540	13,540
6 Designated Additions / Uprates	4	94	18	733	350	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	(76)	0	(379)	(867)	0	0	0	0	0	0	(232)	0	0
8 Cumulative Generating Capacity	**13,899**	**13,917**	**13,935**	**14,289**	**13,772**	**13,772**	**13,772**	**13,772**	**13,772**	**13,772**	**13,772**	**13,540**	**13,540**	**13,540**
Purchase Contracts														
9 Cumulative Purchase Contracts	**2,006**	**2,017**	**2,017**	**2,017**	**1,704**	**1,148**	**502**	**502**	**502**	**502**	**452**	**452**	**441**	**434**
Non-Compliance Renewable Purchas	126	137	137	137	137	81	80	80	80	80	30	30	22	15
Non-Renewables Purchases	1,880	1,880	1,880	1,880	1,567	1,066	422	422	422	422	422	422	419	419
Undesignated Future Resources														
10 Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Combined Cycle	0	0	0	0	0	935	935	0	0	0	0	0	0	0
12 Combustion Turbine	0	0	0	0	0	878	0	0	0	0	0	878	0	0
13 CHP	0	0	0	20	0	20	0	0	0	0	0	0	0	0
Renewables														
13 **Cumulative Renewables Capacity**	222	257	216	216	218	129	129	178	174	177	176	179	178	183
14 Cumulative Production Capacity	**16,127**	**16,191**	**16,168**	**16,542**	**15,714**	**16,901**	**17,191**	**17,240**	**17,236**	**17,239**	**17,188**	**17,837**	**17,826**	**17,823**
Demand Side Management (DSM)														
15 Cumulative DSM Capacity	**531**	**552**	**569**	**583**	**595**	**606**	**610**	**613**	**617**	**621**	**624**	**628**	**631**	**634**
16 Cumulative Capacity w/ DSM	**16,658**	**16,743**	**16,737**	**17,125**	**16,310**	**17,508**	**17,800**	**17,853**	**17,853**	**17,860**	**17,813**	**18,464**	**18,456**	**18,457**
Reserves w/ DSM														
17 Generating Reserves	3,781	3,716	3,537	3,739	2,757	3,806	3,940	3,831	3,633	3,648	3,432	3,916	3,684	3,527
18 % Reserve Margin	**29.4%**	**28.5%**	**26.8%**	**27.9%**	**20.3%**	**27.8%**	**28.4%**	**27.3%**	**25.6%**	**25.7%**	**23.9%**	**26.9%**	**24.9%**	**23.6%**

DEP - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer Projections of Load, Capacity, and Reserves table. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke Energy Progress System.

2. Firm sale of 150 MW through 2024.

3. Cumulative energy efficiency and conservation programs (does not include demand response programs).

4. Peak load adjusted for firm sales and cumulative energy efficiency.

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of January 1, 2015.

   Includes total unit capacity of jointly owned units.

6. Capacity Additions include:

   Planned nuclear uprates totaling 29 MW in the 2017-2018 timeframe.

   Planned combined cycle uprates totaling 135 MW in 2019.

   84 MW Sutton Blackstart combustion turbine addition in 2017.

   A short-term 350 MW PPA is included in 2017, and removed in the fall of 2017.

   This PPA is a placeholder to ensure compliance with the minimum planning reserve margin and will be re-evaluated in the coming months.

7. Planned Retirements include:

   Sutton CT Units 1, 2A and 2B in 2017 (61 MW).

   Darlington CT Units 1-11 by 2020 (553 MW).

   Blewett CT Units 1-4 and Weatherspoon CT units 1-4 in 2027 (180 MW).

   Robinson 2 in 2030 (741 MW).

8. Sum of lines 5 through 7.

DEP - Assumptions of Load, Capacity, and Reserves Table (cont.)

9. Cumulative Purchase Contracts have several components:

   Purchased capacity from PURPA Qualifying Facilities, Anson and Hamlet CT tolling, Butler Warner purchase, Southern CC purchase, and Broad River CT purchase.

   Additional line items are shown under the total line item to show the amounts of renewable and traditional resource purchases. Renewables in these line items are not used for NC REPS compliance.

10. New nuclear resources economically selected to meet load and minimum planning reserve margin Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

    No new nuclear resources were selected in the Base Case in the 15 year study period.

11. New combined cycle resources economically selected to meet load and minimum planning reserve margin.

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

    Addition of 895 MW of combined cycle capacity in 2021, 2022 and 2030.

12. New combustion turbine resources economically selected to meet load and minimum planning reserve margin.

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

    Addition of 828 MW of combustion turbine capacity in 2021 and 2027.

13. New CHP resources. 20 MW in 2019 and 20 MW in 2021.

14. Cumulative solar, biomass, hydro and wind resources to meet NC REPS and SC DERP compliance.

    Also includes utility-owned solar.

DEP - Assumptions of Load, Capacity, and Reserves Table (cont.)

15. Sum of lines 8 through 14.

16. Cumulative Demand Side Management programs including load control and DSDR.

17. Sum of lines 15 and 16.

18. The difference between lines 17 and 4.

19. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

    Line 18 divided by Line 4.

    Minimum target planning reserve margin is 17%.

Technologies Considered

Similar to the 2014 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels in order to meet future generation needs in the 2015 IRP.

As in the 2014 IRP, the Company conducted an economic screening analysis of various technologies. Through the screening process the following technologies were considered as part of the more detailed quantitative analysis phase of the planning process in the 2015 IRP, with changes from the 2014 IRP highlighted and explained in further detail below.

- Base load – 723 MW Supercritical Pulverized Coal with CCS
- Base load – 525 MW IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear units (AP1000)
- Base load – **895 MW** – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Duct Fired)
- **Base load – 20 MW – CHP** (CT with HRSG)
- Peaking/Intermediate – **828 MW** 4-7FA CTs
- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Landfill Gas
- Renewable – 25 MW Solar Photovoltaic (PV)

Combined Cycle base capacities and technologies: Based on proprietary third party engineering studies, the 2x2x1 Advanced CC saw an increase in base load of 29 MWs. The older version base 2x1 CC and the 3x1 Advanced CC were not considered in the updated IRP. However, as the Company begins the process of evaluating particular technologies for future undesignated generation needs, these technologies, along with other new technologies, may be considered based on factors such as generation requirements, plot size, new environmental regulations, etc.

Combustion Turbine base capacities and technologies: Based on proprietary third party engineering studies, the F-Frame CT technology saw an increase in base load of 36 MWs. The LM6000 CTs were not considered in the updated IRP. However, as the Company begins the process of evaluating particular technologies for future undesignated generation needs, these technologies, along with other new technologies, may be considered based on factors such as generation requirements, plot size, new environmental regulations, etc.

CHP: As mentioned previously, two 20-MW Combined Heat & Power units are considered in the 2015 IRP and are included as resources for meeting future generation needs. Duke Energy is exploring and working with potential customers with good base thermal loads on a regulated CHP offer and, as CHP continues to be implemented, future IRP processes will incorporate additional CHP as appropriate.

In addition to the technologies listed above, Li-ion batteries with off-peak charging were considered in the screening process as an energy storage option. Energy Storage in the form or battery storage is becoming more feasible with the advances in battery technology and the reduction in battery cost; however, their uses have been concentrated on frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e. solar and wind applications).

Centralized generation will likely remain the backbone of the grid for Duke Energy in the long term; however, in addition to centralized generation it is possible that distributed generation will begin to share more and more grid responsibilities over time as technologies such as energy storage increase our grid's flexibility. At this point however, the screening analysis shows that costs are still prohibitive for large scale battery technologies to be considered in the IRP.

<u>Expansion Plan and Resource Mix</u>

A tabular presentation of the 2015 Base Case resource plan represented in the above LCR table is shown below:

Table 6-C DEP Base Case Resources– Summer (with CO_2)

Duke Energy Progress Resource Plan (1) Base Case - Summer					
Year	**Resource**			**MW**	
2016	-			-	
2017	Sutton Blackstart CTs	Nuclear Uprates		84	14
2018	Nuclear Uprates			15	
2019	CC Uprates	CHP		135	20
2020	Asheville CC			663	
2021	New CC	New CT	CHP	895	828	20
2022	New CC			895	
2023	-			-	
2024	-			-	
2025	-			-	
2026	-			-	
2027	New CT			828	
2028	-			-	
2029	-			-	
2030	New CC			895	

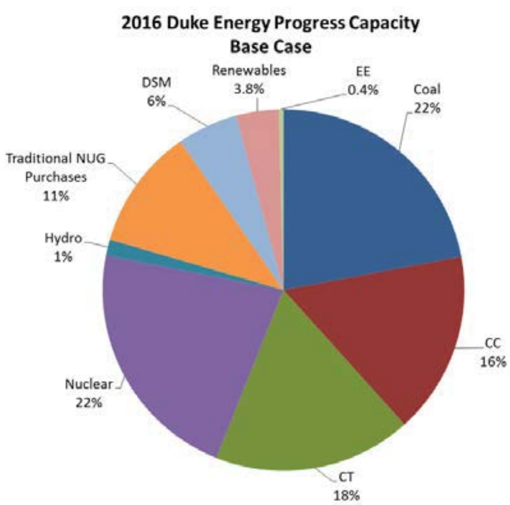
Notes: (1) Table includes both designated and undesignated capacity additions

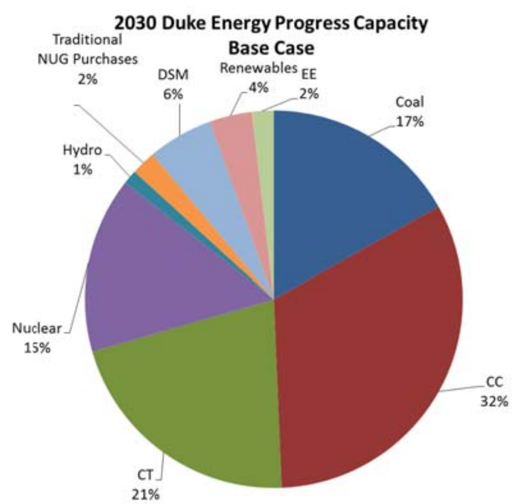
Table 6-D DEP Base Case Resources (with CO_2) Cumulative Summer Totals

DEP Base Case Resources Cumulative Summer Totals - 2016 - 2030	
Nuclear	29
CC	3483
CT	1740
CHP	40
Total	5292

The following charts illustrate both the current and forecasted capacity by fuel type for the DEP system, as projected in the Base Case. As demonstrated in Chart 6-A, the capacity mix for the DEP system changes with the passage of time. In 2030, the Base Case projects that DEP will have a smaller reliance on coal and a higher reliance on gas-fired resources, nuclear, renewable resources and EE as compared to the current state.

Chart 6-A 2016 & 2030 Base Case Summer Capacity Mix





As a sensitivity, the Company developed a No Carbon Price scenario (No Carbon Sensitivity). The expansion plan for this case is shown below in Table 6-E. Table 6-F summarizes the capacity additions for the No Carbon Sensitivity case by technology type.

Table 6-E No Carbon Sensitivity – Summer

Duke Energy Progress Resource Plan (1) No Carbon Sensitivity - Summer						
Year	**Resource**			**MW**		
2016	-			-		
2017	Sutton Blackstart CTs	Nuclear Uprates		84	14	
2018	Nuclear Uprates			15		
2019	CC Uprates	CHP		135	20	
2020	Asheville CC			663		
2021	New CT	New CC	CHP	828	895	20
2022	New CT			414		
2023	-			-		
2024	New CT			414		
2025	-			-		
2026	-			-		
2027	New CT			414		
2028	New CT			414		
2029	-			-		
2030	New CT			1242		

Notes: (1) Table includes both designated and undesignated capacity additions

Table 6-F No Carbon Sensitivity Cumulative Summer Totals

DEP No Carbon Sensitivity Resources Cumulative Summer Totals - 2016 - 2030	
Nuclear	29
CC	1693
CT	3810
CHP	40
Total	5572

7. SHORT-TERM ACTION PLAN

The Company's Short-Term Action Plan, which identifies accomplishments in the past year and actions to be taken over the next five years, is summarized below:

Continued Reliance on EE and DSM Resources

The Company is committed to continuing to grow the amount of EE and DSM resources utilized to meet customer growth. The following are the ways in which DEP will increase these resources:

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of EE and DSM programs spanning the residential, commercial, and industrial classes.

- Continue on-going work to develop and implement additional cost-effective EE and DSM products and services. Since the last biennial IRP, DEP has implemented the following new program offerings: Residential New Construction Program, Energy Efficient Lighting Program and Small Business Energy Saver Program.

- Continue to seek enhancements to the Company's EE/DSM portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results and (3) other EE research & development pilots.

- Over the 5 year period represented in the Short-Term Action Plan, DEP projects to add an incremental 115 MW of EE and 149 MW of DSM.

Continued Focus on Renewable Energy Resources

- DEP is committed to full compliance with NC REPS in North Carolina and SC DERP in South Carolina. Due to pending expiries of Federal and State tax subsidies for solar development, the Company has experienced a substantial increase in solar QFs in the interconnection queue. With this significant level of interest in solar development, DEP continues to procure renewable purchase power resources, when economically viable, as part of its Compliance Plans. DEP is also pursuing the addition of new utility-owned solar on the DEP system.

- DEP continues to evaluate market options for renewable generation and procure capacity, as appropriate. PPAs have been signed with developers of solar PV and landfill gas resources. Additionally, REC purchase agreements have been executed for purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities.

- DEP continues to pursue CHP opportunities, as appropriate.

Addition of Clean Natural Gas Resources

- Begin construction on the Sutton Blackstart CTs in 2016 to be available for the summer peak of 2017. The Company's petition for a Certificate of Public Convenience and Necessity (CPCN) was approved by the NCUC with an order issued on August 3, 2015.

- Pursue the addition of a new combined cycle at the Asheville facility in the 2019 timeframe as part of the WCMP.

- Continue to evaluate older CTs on the DEP system. The Company is evaluating the condition and economic viability of the older CTs on the system. In doing so, DEP is preparing for the potential retirement of these units. This includes determining the type of resources needed to reliably replace these units to maintain a minimum planning reserve margin.

- Take actions to ensure capacity needs beginning in 2021 are met. In addition to seeking to meet the Company's EE and DSM goals and meeting the Company's NC REPS and SC DERP requirements, actions to secure additional capacity may include purchased power, short-term PPAs or Company-owned generation. The 2015 IRP projects that the best resources to meet this 2021 demand are combined cycle units.

- Placeholder for a short-term PPA of 350 MW is included in 2017 to meet 17% reserve margin. This will continue to be reviewed in future IRPs.

Expiration of Wholesale Purchase Contracts (CONFIDENTIAL)

In the 2016-2020 timeframe, DEP has [redacted] of wholesale purchase contracts that are scheduled to expire. At this time, DEP is not relying on contract extensions on these contracts. As such, these contract expirations are included in the IRP and Short-Term Action Plan. A summary of those expirations is shown in Table 7-A below. In addition to the expirations shown in this five year period, additional contracts expire during the 15 year IRP study period.

Table 7-A Wholesale Purchase Contract Expirations (CONFIDENTIAL)

[redacted]

Continued Focus on System Reliability and Resource Adequacy for DEP System

As previously stated, DEP has retained Astrape Consulting to conduct a reserve margin study to examine the resource adequacy of the DEP system. Based upon the recent extreme winter weather, the potential for continued extreme weather, and the large amount of expected solar resource additions, the Company felt that new examination of the reliability of the system and the adequacy of the resources was warranted.

Initial results of this updated study indicate that a 17% summer planning reserve margin is required to maintain the one day in 10 year loss of load expectation (LOLE). As such, DEP has utilized a 17% planning reserve margin in the 2015 IRP as opposed to the 14.5% reserve margin used in the 2014 IRP. However, preliminary findings also indicate that a summer-only reserve margin target may not be adequate for providing long term reliability given the increasing levels of summer-only resources. Additional study is needed to determine whether dual summer/winter planning reserve margin targets are required in the future. Once the final results are determined, any changes will be included in the 2016 IRP.

The 2015 IRP includes a placeholder for a short-term 350 MW purchased power agreement (PPA) in 2020 to satisfy the increase in the planning reserve margin to 17%. The need for this short-term PPA will be reevaluated after the reserve margin study is completed and there is greater certainty regarding reserve margin target(s), load and resource needs.

Continued Focus on Regulatory, Environmental Compliance & Wholesale Activities

- Retired older coal generation. As of December 2013, all of DEP's older, un-scrubbed coal units have been retired. DEP has retired 1,600 MW of older coal units in total since 2011.

- Retire Asheville coal units. The Company expects to retire the existing Asheville coal units no later than January 31, 2020 and replace with new combined cycle generation as part of the WCMP. The Asheville units have a combined capacity of 376 MW.

- Continue to prepare for the final rule of EPA's Clean Power Plan.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with existing and potential environmental regulations such as MATS, the Coal Combustion Residuals rule, the Cross State Air Pollution Rule (CSAPR), and the new Ozone National Ambient Air Quality Standard (NAAQS).

- Aggressively pursue compliance in North Carolina and South Carolina in addressing coal ash management and ash pond remediation. Ensure timely compliance plans and their associated costs are contemplated within the planning process and future integrated resource plans, as appropriate.

- Continue to pursue existing and potential opportunities for wholesale power sales agreements within the Duke Energy balancing authority area.

- Continue to monitor energy-related statutory and regulatory activities.

- Continue to examine the benefits of joint capacity planning and pursue appropriate regulatory actions.

A summarization of the capacity resources for the reference plan in the 2015 IRP is shown in Table 7-B below. Capacity retirements and additions are presented as incremental values in the year in which the change is projected to occur. The values shown for renewable resources, EE and DSM represent cumulative totals.

Table 7-B DEP Short-Term Action Plan

Duke Energy Progress Short-Term Action Plan								
			Compliance Renewable Resources (Cumulative Nameplate MW)			Other Non-Compliance Renewables (Cumulative Nameplate MW) (4)		
Year	Retirements	Additions	Wind (1)	Solar (1)	Biomass/Hydro (3)	Solar/Biomass/Hydro	EE	DSM (2)
2016			0	459	171	397	67	871
2017	61 MW Sutton CTs (Units 1, 2A, 2B)	84 MW Sutton Blackstart CTs 14 MW Nuc Uprate	0	462	206	409	96	923
2018		15 MW Nuc Uprate	0	465	164	408	125	967
2019		20 MW CHP 135 MW CC Uprate	0	467	164	407	155	1004
2020	406 MW Darlington CT (Units 1-3, 5, 7-10) 376 MW Asheville Coal	663 MW Asheville CC 350 MW CT PPA (5)	0	468	167	407	183	1021

Notes:

(1) Capacity is shown in nameplate ratings. For planning purposes, wind presents a 13% contribution to peak and solar has a 44% contribution to peak.

(2) Includes impacts of grid modernization.

(3) Biomass includes swine and poultry contracts.

(4) Other renewables includes NUGs and utility-owned projects.

(4) This is a placeholder PPA for 2020, and removed in 2021.

8. OWNED GENERATION

DUKE ENERGY PROGRESS OWNED GENERATION

Duke Energy Progress' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Progress-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2014, Duke Energy Progress' nuclear and coal-fired generating units met the vast majority of customer needs by providing 46% and 26%, respectively, of Duke Energy Progress' energy from generation. Hydroelectric generation, Combustion Turbine generation, Combined Cycle generation, solar generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

The tables below list the Duke Energy Progress' plants in service in North Carolina (NC) and South Carolina (SC) with plant statistics, and the system's total generating capability.

Existing Generating Units and Ratings [1, 3]
All Generating Unit Ratings are as of December 31, 2014 unless otherwise noted.

Coal						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Asheville	1	192	191	Arden, NC	Coal	Base
Asheville	2	187	185	Arden, NC	Coal	Base
Mayo [2]	1	746	727	Roxboro, NC	Coal	Base
Roxboro	1	380	379	Semora, NC	Coal	Base
Roxboro	2	673	671	Semora, NC	Coal	Base
Roxboro	3	698	691	Semora, NC	Coal	Base
Roxboro [2]	4	711	698	Semora, NC	Coal	Base
Total Coal		3,587	3,542			

Combustion Turbines						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Asheville	3	185	164	Arden, NC	Natural Gas/Oil	Peaking
Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking
Blewett	1	17	13	Lilesville, NC	Oil	Peaking
Blewett	2	17	13	Lilesville, NC	Oil	Peaking
Blewett	3	17	13	Lilesville, NC	Oil	Peaking
Blewett	4	17	13	Lilesville, NC	Oil	Peaking
Darlington	1	63	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	2	64	48	Hartsville, SC	Oil	Peaking
Darlington	3	63	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	4	66	50	Hartsville, SC	Oil	Peaking
Darlington	5	66	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	6	62	45	Hartsville, SC	Oil	Peaking
Darlington	7	65	51	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	8	66	48	Hartsville, SC	Oil	Peaking
Darlington	9	65	52	Hartsville, SC	Oil	Peaking
Darlington	10	65	51	Hartsville, SC	Oil	Peaking
Darlington	11	67	52	Hartsville, SC	Oil	Peaking
Darlington	12	133	118	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking
Smith [4]	1	183	157	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	2	183	156	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	3	185	155	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	4	186	159	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	6	187	153	Hamlet, NC	Natural Gas/Oil	Peaking
Sutton	1	12	11	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2A	31	24	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2B	33	26	Wilmington, NC	Oil/Natural Gas	Peaking
Wayne	1/10	192	177	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	2/11	192	174	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	3/12	193	173	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	4/13	185	170	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	5/14	197	169	Goldsboro, NC	Oil/Natural Gas	Peaking
Weatherspoon	1	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	2	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	3	41	33	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	4	41	31	Lumberton, NC	Natural Gas/Oil	Peaking
Total NC		2,561	2,208			
Total SC		978	787			
Total CT		3,539	2,995			

Combined Cycle

	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	CT1A	223	177	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1B	222	176	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1C	223	179	Goldsboro, NC	Natural Gas/Oil	Base
Lee	ST1	379	378	Goldsboro, NC	Natural Gas/Oil	Base
Smith [4]	CT7	189	160	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT8	189	157	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST4	175	165	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT9	214	178	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT10	214	178	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST5	246	250	Hamlet, NC	Natural Gas/Oil	Base
Sutton	CT1A	225	179	Wilmington, NC	Natural Gas/Oil	Base
Sutton	CT1B	225	179	Wilmington, NC	Natural Gas/Oil	Base
Sutton	ST1	267	264	Wilmington, NC	Natural Gas/Oil	Base
Total CC		2,991	2,620			

Hydro

	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Blewett	1	4	4	Lilesville, NC	Water	Intermediate
Blewett	2	4	4	Lilesville, NC	Water	Intermediate
Blewett	3	4	4	Lilesville, NC	Water	Intermediate
Blewett	4	5	5	Lilesville, NC	Water	Intermediate
Blewett	5	5	5	Lilesville, NC	Water	Intermediate
Blewett	6	5	5	Lilesville, NC	Water	Intermediate
Marshall	1	2	2	Marshall, NC	Water	Intermediate
Marshall	2	2	2	Marshall, NC	Water	Intermediate
Tillery	1	21	21	Mt. Gilead, NC	Water	Intermediate
Tillery	2	18	18	Mt. Gilead, NC	Water	Intermediate
Tillery	3	21	21	Mt. Gilead, NC	Water	Intermediate
Tillery	4	24	24	Mt. Gilead, NC	Water	Intermediate
Walters	1	36	36	Waterville, NC	Water	Intermediate
Walters	2	40	40	Waterville, NC	Water	Intermediate
Walters	3	36	36	Waterville, NC	Water	Intermediate
Total Hydro		227	227			

Nuclear						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Brunswick [2]	1	975	938	Southport, NC	Uranium	Base
Brunswick[2]	2	953	932	Southport, NC	Uranium	Base
Harris [2]	1	973	928	New Hill, NC	Uranium	Base
Robinson	2	797	741	Hartsville, SC	Uranium	Base
Total NC		2,901	2,798			
Total SC		797	741			
Total Nuclear		3,698	3,539			

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
TOTAL DEP SYSTEM - N.C.	12,267	11,395
TOTAL DEP SYSTEM - S.C.	1,775	1,528
TOTAL DEP SYSTEM	14,042	12,923

Note 1: Ratings reflect compliance with NERC reliability standards and are gross of co-ownership interest as of 12/31/14.
Note 2: DEP's purchase of NCEMPA's interest in these power plants was closed on July 31, 2015. DEP is now 100% owner of these previously jointly owned assets.
Note 3: Resource type based on NERC capacity factor classifications which may alternate over the forecast period.
Note 4: Richmond County Plant renamed to Sherwood H. Smith Jr. Energy Complex.

Planned Uprates			
Unit	**Date**	**Winter MW**	**Summer MW**
Brunswick 2 [1]	June 2017	10	10
Harris 1 [1]	June 2017	4	4
Harris 1[1]	June 2019	15	15
Lee CC CT1A [1]	May 2019	25.7	25.7
Lee CC CT1B [1]	May 2019	25.7	25.7
Lee CC CT1C [1]	May 2019	25.7	25.7
Sutton CC CT1A [1]	May 2019	29.0	29.0
Sutton CC CT1B [1]	May 2019	29.0	29.0

Note 1: Capacity not reflected in Existing Generating Units and Ratings section.

Retirements

Unit & Plant Name	Location	Capacity (MW) Winter / Summer	Fuel Type	Retirement Date
Cape Fear 5	Moncure, NC	148 / 144	Coal	10/1/12
Cape Fear 6	Moncure, NC	175 / 172	Coal	10/1/12
Cape Fear 1A	Moncure, NC	14 / 11	Combustion Turbine	3/31/13
Cape Fear 1B	Moncure, NC	14 / 12	Combustion Turbine	3/31/13
Cape Fear 2A	Moncure, NC	15 / 12	Combustion Turbine	3/31/13
Cape Fear 2B	Moncure, NC	14 / 11	Combustion Turbine	10/1/12
Cape Fear 1	Moncure, NC	12 / 11	Steam Turbine	3/31/11
Cape Fear 2	Moncure, NC	12 / 7	Steam Turbine	3/31/11
Lee 1	Goldsboro, NC	80 / 74	Coal	9/15/12
Lee 2	Goldsboro, NC	80 / 68	Coal	9/15/12
Lee 3	Goldsboro, NC	252 / 240	Coal	9/15/12
Lee 1	Goldsboro, NC	15 / 12	Combustion Turbine	10/1/12
Lee 2	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Lee 3	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Lee 4	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Morehead 1	Morehead City, NC	15 / 12	Combustion Turbine	10/1/12
Robinson 1	Hartsville, NC	179 / 177	Coal	10/1/12
Robinson 1	Hartsville, NC	15 / 11	Combustion Turbine	3/31/13
Weatherspoon 1	Lumberton, NC	49 / 48	Coal	9/30/11
Weatherspoon 2	Lumberton, NC	49 / 48	Coal	9/30/11
Weatherspoon 3	Lumberton, NC	79 / 74	Coal	9/30/11
Sutton 1	Wilmington, NC	98 / 97	Coal	11/27/13
Sutton 2	Wilmington, NC	95 / 90	Coal	11/27/13
Sutton 3	Wilmington, NC	389 / 366	Coal	11/4/13
Total		1,880 MW / 1,760 MW		

Planning Assumptions – Unit Retirements[a]

Unit & Plant Name	Location	Capacity (MW)	Fuel Type	Expected Retirement
Asheville 1	Arden, N.C.	191	Coal	1/2020
Asheville 2	Arden, N.C.	185	Coal	1/2020
Mayo 1	Roxboro, N.C.	727	Coal	6/2035
Roxboro 1	Semora, N.C.	379	Coal	6/2032
Roxboro 2	Semora, N.C.	665	Coal	6/2032
Roxboro 3	Semora, N.C.	691	Coal	6/2035
Roxboro 4	Semora, N.C.	698	Coal	6/2035
Robinson 2 [b]	Hartsville, S.C.	741	Nuclear	6/2030
Darlington 1	Hartsville, S.C.	52	Natural Gas/Oil	6/2020
Darlington 2	Hartsville, S.C.	48	Oil	6/2020
Darlington 3	Hartsville, S.C.	52	Natural Gas/Oil	6/2020
Darlington 4	Hartsville, S.C.	50	Oil	1/2014
Darlington 5	Hartsville, S.C.	52	Natural Gas/Oil	6/2020
Darlington 6	Hartsville, S.C.	45	Oil	1/2014
Darlington 7	Hartsville, S.C.	51	Natural Gas/Oil	6/2020
Darlington 8	Hartsville, S.C.	48	Oil	6/2020
Darlington 9	Hartsville, S.C.	52	Oil	6/2020
Darlington 10	Hartsville, S.C.	51	Oil	6/2020
Darlington 11	Hartsville, S.C.	52	Oil	1/2014
Sutton 1	Wilmington, N.C.	11	Natural Gas/Oil	6/2017
Sutton 2A	Wilmington, N.C.	24	Natural Gas/Oil	6/2017
Sutton 2B	Wilmington, N.C.	26	Natural Gas/Oil	6/2017
Blewett 1	Lilesville, N.C.	13	Oil	6/2027
Blewett 2	Lilesville, N.C.	13	Oil	6/2027
Blewett 3	Lilesville, N.C.	13	Oil	6/2027
Blewett 4	Lilesville, N.C.	13	Oil	6/2027
Weatherspoon 1	Lumberton, N.C.	32	Natural Gas/Oil	6/2027
Weatherspoon 2	Lumberton, N.C.	32	Natural Gas/Oil	6/2027
Weatherspoon 3	Lumberton, N.C.	33	Natural Gas/Oil	6/2027
Weatherspoon 4	Lumberton, N.C.	31	Natural Gas/Oil	6/2027
Total		5071		

Note a: Retirement assumptions are for planning purposes only; dates are based on useful life expectations of the unit
Note b: Nuclear retirements for planning purposes are based on the end of current operating license

Planned Operating License Renewal

Unit & Plant Name	Location	Original Operating License Expiration	Date of Approval	Extended Operating License Expiration
Blewett #1-6 [1]	Lilesville, NC	04/30/08	*Pending*	2058 [2]
Tillery #1-4 [1]	Mr. Gilead, NC	04/30/08	*Pending*	2058 [2]
Robinson #2	Hartsville, SC	07/31/10	04/19/2004	07/31/2030
Brunswick #2	Southport , NC	12/27/14	06/26/2006	12/27/2034
Brunswick #1	Southport, NC	09/08/16	06/26/2006	09/08/2036
Harris #1	New Hill, NC	10/24/26	12/12/2008	10/24/2046

Note 1: The license renewal application for the Blewett and Tillery Plants was filed with the FERC on 04/26/06; the Company is awaiting issuance of the new license from FERC. Pending receipt of a new license, these plants are currently operating under a renewable one-year license extension which has been in effect since May 2008. Although Progress Energy has requested a 50-year license, FERC may not grant this term.

Note 2: Estimated - New license expiration date will be determined by FERC license issuance date and term of granted license.

9. CONCLUSIONS

DEP continues to focus on the needs of customers by meeting the growing demand in the most economical and reliable manner possible. The Company continues to improve the IRP process by determining best practices and making changes to more accurately and realistically represent the DEP System in its planning practices. The 2015 IRP represents a 15 year projection of the Company's plan to balance future customer demand and supply resources to meet this demand plus a 17% minimum planning reserve margin. Over the 15-year planning horizon, DEP expects to require 5,292 MW of additional generating resources in addition to the incremental renewable resources, EE and DSM already in the resource plan.

The Company focuses on the needs of the short-term, while keeping a close watch on market trends and technology advancements to meet the demands of customers in the long-term. The Company's short-term and long-term plans are summarized below:

Short-Term

Over the next 5 years, DEP's 2015 IRP focuses on the following:

- Begin construction on the Sutton Blackstart CTs in 2016 to be available for the summer peak of 2017.
- Pursue the addition of a new combined cycle at the Asheville facility in the 2019 timeframe as part of the WCMP.
- Take actions to ensure capacity needs beginning in 2021 are met.
- Complete the resource adequacy study currently underway with Astrape Consulting.
- Procure CHP resources as cost-effective and diverse generation sources, as appropriate.
- Continue to meet NC REPS and SC DERP compliance plans and invest in additional cost-effective renewable resources.
- Continue to invest in EE and DSM in the Carolinas region.

Long-Term

Beyond the next 5 years, DEP's 2015 IRP focuses on the following:

- Continue to seek the most cost-effective, reliable resources to meet the growing customer demand in the service territory. Currently, those are new combined cycle units and combustion turbine units in the 15 year planning horizon.
- Procure CHP resources as cost-effective and diverse generation sources, as appropriate.

- Continue to meet NC REPS and SC DERP compliance plans by investing in additional renewable resources and EE on the DEP system.
- Continue to invest in DSM in the Carolinas region.

DEP's goal is to continue to diversify the DEP system by adding a variety of cost-effective, reliable, clean resources to meet customer demand. Over the next 15 years, the Company projects filling the increasing demand with investments in natural gas, renewables, and EE and DSM.

10. NON-UTILITY GENERATION AND WHOLESALE

The following information describes the tables included in this chapter.

Wholesale Sales Contracts
This table includes wholesale sales contracts that are included in the 2015 Load Forecast. This information is **CONFIDENTIAL**.

Wholesale Purchase Contracts
This table includes all wholesale purchase contracts that are included as resources in the 2015 IRP. This information is **CONFIDENTIAL**.

Non-Utility Generation Contracts
This table includes all Non-Utility Generation contracts that have been signed since the 2014 IRP. This list includes contracts signed since June 1, 2014, as this was the date utilized in the tables in Appendix H in the 2014 IRP. This list is up to date as of June 30, 2015. This information is **CONFIDENTIAL**, so the customer names have been redacted.

Table 10-A Wholesale Sales Contracts **CONFIDENTIAL**

[redacted]

Duke Energy Progress
North Carolina
2015 IRP Update Report
Integrated Resource Plan
September 1, 2015

Table 10-B Firm Wholesale Purchased Power Contracts **CONFIDENTIAL**

[redacted]

[redacted]

Table 10-C Non-Utility Generation

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
			North Carolina Generators:			
Facility 1	Wilmington	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 2	Raleigh	NC	Solar	4.9	Intermediate/Peaking	Yes
Facility 3	Leland	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 4	Raleigh	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 5	Jacksonville	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 6	Cary	NC	Solar	9.9	Intermediate/Peaking	Yes
Facility 7	Raleigh	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 8	New Hill	NC	Solar	6.2	Intermediate/Peaking	Yes
Facility 9	Selma	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 10	Apex	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 11	Raleigh	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 12	Knightdale	NC	Solar	6.4	Intermediate/Peaking	Yes
Facility 13	Cary	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 14	Pittsboro	NC	Solar	7.0	Intermediate/Peaking	Yes
Facility 15	Raleigh	NC	Solar	5.3	Intermediate/Peaking	Yes
Facility 16	Cary	NC	Solar	2.8	Intermediate/Peaking	Yes
Facility 17	Biltmore Lakes	NC	Solar	5.5	Intermediate/Peaking	Yes
Facility 18	Asheville	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 19	Raleigh	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 20	Wilmington	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 21	Cary	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 22	Cary	NC	Solar	5.6	Intermediate/Peaking	Yes
Facility 23	Clayton	NC	Solar	5.3	Intermediate/Peaking	Yes
Facility 24	Pittsboro	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 25	Raleigh	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 26	Wilmington	NC	Solar	4.5	Intermediate/Peaking	Yes
Facility 27	Pinehurst	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 28	Weaverville	NC	Solar	3.5	Intermediate/Peaking	Yes
Facility 29	Chapel Hill	NC	Solar	5.1	Intermediate/Peaking	Yes
Facility 30	Asheville	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 31	Leicester	NC	Solar	4.9	Intermediate/Peaking	Yes
Facility 32	Asheville	NC	Solar	5.1	Intermediate/Peaking	Yes
Facility 33	Pittsboro	NC	Solar	2.4	Intermediate/Peaking	Yes
Facility 34	Apex	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 35	New Hill	NC	Solar	8.0	Intermediate/Peaking	Yes
Facility 36	Cary	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 37	Raleigh	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 38	Cary	NC	Solar	4.1	Intermediate/Peaking	Yes
Facility 39	Fuquay Varina	NC	Solar	4.6	Intermediate/Peaking	Yes
Facility 40	Apex	NC	Solar	2.6	Intermediate/Peaking	Yes
Facility 41	Pittsboro	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 42	Raleigh	NC	Solar	2.3	Intermediate/Peaking	Yes
Facility 43	Wilmington	NC	Solar	2.6	Intermediate/Peaking	Yes
Facility 44	New Bern	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 45	Raleigh	NC	Solar	6.1	Intermediate/Peaking	Yes
Facility 46	Pittsboro	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 47	Holly Springs	NC	Solar	9.2	Intermediate/Peaking	Yes
Facility 48	Chapel Hill	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 49	Raleigh	NC	Solar	3.2	Intermediate/Peaking	Yes
Facility 50	Raleigh	NC	Solar	5.5	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 51	Cary	NC	Solar	5.6	Intermediate/Peaking	Yes
Facility 52	Pittsboro	NC	Solar	2.2	Intermediate/Peaking	Yes
Facility 53	Pittsboro	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 54	Pittsboro	NC	Solar	3.6	Intermediate/Peaking	Yes
Facility 55	Pittsboro	NC	Solar	4.1	Intermediate/Peaking	Yes
Facility 56	Siler City	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 57	Clayton	NC	Solar	7.3	Intermediate/Peaking	Yes
Facility 58	Raleigh	NC	Solar	3.2	Intermediate/Peaking	Yes
Facility 59	Fayetteville	NC	Solar	3.5	Intermediate/Peaking	Yes
Facility 60	Pittsboro	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 61	Pittsboro	NC	Solar	3.9	Intermediate/Peaking	Yes
Facility 62	Pittsboro	NC	Solar	4.5	Intermediate/Peaking	Yes
Facility 63	Holly Springs	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 64	Raleigh	NC	Solar	6.3	Intermediate/Peaking	Yes
Facility 65	Pittsboro	NC	Solar	5.7	Intermediate/Peaking	Yes
Facility 66	Chapel Hill	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 67	Pittsboro	NC	Solar	4.9	Intermediate/Peaking	Yes
Facility 68	Pittsboro	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 69	Pittsboro	NC	Solar	3.2	Intermediate/Peaking	Yes
Facility 70	Pittsboro	NC	Solar	7.6	Intermediate/Peaking	Yes
Facility 71	Pittsboro	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 72	Asheville	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 73	Wilmington	NC	Solar	2.3	Intermediate/Peaking	Yes
Facility 74	Cary	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 75	Raleigh	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 76	Pittsboro	NC	Solar	2.7	Intermediate/Peaking	Yes
Facility 77	Raeford	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 78	Pittsboro	NC	Solar	6.9	Intermediate/Peaking	Yes
Facility 79	Pittsboro	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 80	Pittsboro	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 81	Siler City	NC	Solar	3.9	Intermediate/Peaking	Yes
Facility 82	Raleigh	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 83	Chapel Hill	NC	Solar	2.4	Intermediate/Peaking	Yes
Facility 84	Cary	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 85	Pittsboro	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 86	Pittsboro	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 87	Chapel Hill	NC	Solar	8.5	Intermediate/Peaking	Yes
Facility 88	Apex	NC	Solar	6.9	Intermediate/Peaking	Yes
Facility 89	Raleigh	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 90	Apex	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 91	Asheville	NC	Solar	3.6	Intermediate/Peaking	Yes
Facility 92	Swannanoa	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 93	Raleigh	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 94	Zebulon	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 95	Black Mountain	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 96	Pittsboro	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 97	Fuquay Varina	NC	Solar	4.1	Intermediate/Peaking	Yes
Facility 98	Siler City	NC	Solar	9.8	Intermediate/Peaking	Yes
Facility 99	Pittsboro	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 100	Fuquay Varina	NC	Solar	5.6	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 101	Cary	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 102	Raleigh	NC	Solar	2.7	Intermediate/Peaking	Yes
Facility 103	Raleigh	NC	Solar	2.4	Intermediate/Peaking	Yes
Facility 104	Raleigh	NC	Solar	4.1	Intermediate/Peaking	Yes
Facility 105	Fuquay Varina	NC	Solar	5.4	Intermediate/Peaking	Yes
Facility 106	Pittsboro	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 107	Cary	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 108	Willow Spring	NC	Solar	5.5	Intermediate/Peaking	Yes
Facility 109	Pittsboro	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 110	Wilmington	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 111	Chapel Hill	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 112	Cary	NC	Solar	5.7	Intermediate/Peaking	Yes
Facility 113	Raleigh	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 114	Chapel Hill	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 115	Alexander	NC	Solar	6.6	Intermediate/Peaking	Yes
Facility 116	Raleigh	NC	Solar	5.7	Intermediate/Peaking	Yes
Facility 117	Chapel Hill	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 118	Chapel Hill	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 119	Holly Springs	NC	Solar	5.9	Intermediate/Peaking	Yes
Facility 120	Carolina Beach	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 121	Chapel Hill	NC	Solar	9.5	Intermediate/Peaking	Yes
Facility 122	Raleigh	NC	Solar	4.5	Intermediate/Peaking	Yes
Facility 123	Pittsboro	NC	Solar	2.2	Intermediate/Peaking	Yes
Facility 124	Chapel Hill	NC	Solar	5.8	Intermediate/Peaking	Yes
Facility 125	Raleigh	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 126	Raleigh	NC	Solar	2.0	Intermediate/Peaking	Yes
Facility 127	Knightdale	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 128	Clayton	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 129	Raleigh	NC	Solar	3.5	Intermediate/Peaking	Yes
Facility 130	Robbins	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 131	Raleigh	NC	Solar	3.9	Intermediate/Peaking	Yes
Facility 132	Apex	NC	Solar	3.9	Intermediate/Peaking	Yes
Facility 133	Wilmington	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 134	Pittsboro	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 135	Zebulon	NC	Solar	8.1	Intermediate/Peaking	Yes
Facility 136	Leland	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 137	Chapel Hill	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 138	Chapel Hill	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 139	Angier	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 140	Pittsboro	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 141	Raleigh	NC	Solar	6.6	Intermediate/Peaking	Yes
Facility 142	Pittsboro	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 143	Benson	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 144	Pittsboro	NC	Solar	2.7	Intermediate/Peaking	Yes
Facility 145	Raleigh	NC	Solar	2.4	Intermediate/Peaking	Yes
Facility 146	Pittsboro	NC	Solar	2.3	Intermediate/Peaking	Yes
Facility 147	Cary	NC	Solar	6.7	Intermediate/Peaking	Yes
Facility 148	Chapel Hill	NC	Solar	5.1	Intermediate/Peaking	Yes
Facility 149	Raleigh	NC	Solar	6.4	Intermediate/Peaking	Yes
Facility 150	Pittsboro	NC	Solar	2.1	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 151	Raleigh	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 152	Pittsboro	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 153	Wilmington	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 154	Southern Pines	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 155	Siler City	NC	Solar	8.8	Intermediate/Peaking	Yes
Facility 156	Raleigh	NC	Solar	4.5	Intermediate/Peaking	Yes
Facility 157	Wilmington	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 158	Cary	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 159	Wilmington	NC	Solar	4.6	Intermediate/Peaking	Yes
Facility 160	Raleigh	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 161	Pittsboro	NC	Solar	6.6	Intermediate/Peaking	Yes
Facility 162	Morrisville	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 163	Raleigh	NC	Solar	3.6	Intermediate/Peaking	Yes
Facility 164	Raleigh	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 165	Raleigh	NC	Solar	6.3	Intermediate/Peaking	Yes
Facility 166	Goldsboro	NC	Solar	4.6	Intermediate/Peaking	Yes
Facility 167	Biltmore Lake	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 168	Lillington	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 169	Raleigh	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 170	Raleigh	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 171	Apex	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 172	Cary	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 173	Cary	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 174	Apex	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 175	Raleigh	NC	Solar	4.6	Intermediate/Peaking	Yes
Facility 176	Raleigh	NC	Solar	9.3	Intermediate/Peaking	Yes
Facility 177	Raleigh	NC	Solar	3.5	Intermediate/Peaking	Yes
Facility 178	Black Mountain	NC	Solar	8.0	Intermediate/Peaking	Yes
Facility 179	Apex	NC	Solar	6.6	Intermediate/Peaking	Yes
Facility 180	Raleigh	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 181	Pittsboro	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 182	Raleigh	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 183	Spring Hope	NC	Solar	7.8	Intermediate/Peaking	Yes
Facility 184	Raleigh	NC	Solar	5.9	Intermediate/Peaking	Yes
Facility 185	Raleigh	NC	Solar	5.4	Intermediate/Peaking	Yes
Facility 186	Zebulon	NC	Solar	2.0	Intermediate/Peaking	Yes
Facility 187	Henderson	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 188	New Bern	NC	Solar	3.5	Intermediate/Peaking	Yes
Facility 189	Willow Spring	NC	Solar	4.6	Intermediate/Peaking	Yes
Facility 190	Pittsboro	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 191	Raleigh	NC	Solar	2.0	Intermediate/Peaking	Yes
Facility 192	Weaverville	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 193	Cary	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 194	Fuquay Varina	NC	Solar	2.1	Intermediate/Peaking	Yes
Facility 195	Raleigh	NC	Solar	4.6	Intermediate/Peaking	Yes
Facility 196	Raleigh	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 197	Asheville	NC	Solar	7.7	Intermediate/Peaking	Yes
Facility 198	Durham	NC	Solar	34.2	Intermediate/Peaking	Yes
Facility 199	Asheville	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 200	Wilmington	NC	Solar	1.0	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 201	Asheville	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 202	Leasburg	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 203	Fairview	NC	Solar	8.0	Intermediate/Peaking	Yes
Facility 204	Asheville	NC	Solar	14.6	Intermediate/Peaking	Yes
Facility 205	Willow Spring	NC	Solar	2,000.0	Intermediate/Peaking	Yes
Facility 206	Raleigh	NC	Solar	1.8	Intermediate/Peaking	Yes
Facility 207	Asheville	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 208	Wake Forest	NC	Solar	5.9	Intermediate/Peaking	Yes
Facility 209	Asheboro	NC	Solar	2.0	Intermediate/Peaking	Yes
Facility 210	Apex	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 211	Pittsboro	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 212	Candler	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 213	Pinehurst	NC	Solar	8.0	Intermediate/Peaking	Yes
Facility 214	Asheville	NC	Solar	7.6	Intermediate/Peaking	Yes
Facility 215	Raleigh	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 216	Asheville	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 217	Asheville	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 218	Louisburg	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 219	Asheville	NC	Solar	2.1	Intermediate/Peaking	Yes
Facility 220	Raleigh	NC	Solar	9.6	Intermediate/Peaking	Yes
Facility 221	Vass	NC	Solar	6.2	Intermediate/Peaking	Yes
Facility 222	Pittsboro	NC	Solar	6.1	Intermediate/Peaking	Yes
Facility 223	Fairview	NC	Solar	7.7	Intermediate/Peaking	Yes
Facility 224	Cary	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 225	Henderson	NC	Solar	4,998.0	Intermediate/Peaking	Yes
Facility 226	Nashville	NC	Solar	2,000.0	Intermediate/Peaking	Yes
Facility 227	Cary	NC	Solar	15.0	Intermediate/Peaking	Yes
Facility 228	Clayton	NC	Solar	407.0	Intermediate/Peaking	Yes
Facility 229	Hurdle Mills	NC	Solar	20.0	Intermediate/Peaking	Yes
Facility 230	Angier	NC	Solar	2.6	Intermediate/Peaking	Yes
Facility 231	Fletcher	NC	Solar	3.2	Intermediate/Peaking	Yes
Facility 232	Waynesville	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 233	Raleigh	NC	Solar	2.6	Intermediate/Peaking	Yes
Facility 234	Asheboro	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 235	Black Mountain	NC	Solar	5.1	Intermediate/Peaking	Yes
Facility 236	Louisburg	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 237	Asheville	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 238	Cary	NC	Solar	4.5	Intermediate/Peaking	Yes
Facility 239	Candler	NC	Solar	7.6	Intermediate/Peaking	Yes
Facility 240	Weaverville	NC	Solar	10.1	Intermediate/Peaking	Yes
Facility 241	Candler	NC	Solar	0.9	Intermediate/Peaking	Yes
Facility 242	Fairview	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 243	Asheville	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 244	Southern Pines	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 245	Leicester	NC	Solar	5.9	Intermediate/Peaking	Yes
Facility 246	Fairview	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 247	Asheville	NC	Solar	7.7	Intermediate/Peaking	Yes
Facility 248	Ashville	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 249	Cary	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 250	Pittsboro	NC	Solar	6.0	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 251	Weaverville	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 252	Black Mountain	NC	Solar	5.3	Intermediate/Peaking	Yes
Facility 253	Raeford	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 254	Asheville	NC	Solar	8.6	Intermediate/Peaking	Yes
Facility 255	Wilmington	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 256	Durham	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 257	Wilmington	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 258	Angier	NC	Solar	5.8	Intermediate/Peaking	Yes
Facility 259	Asheville	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 260	Coats	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 261	Montreat	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 262	Pittsboro	NC	Solar	1.6	Intermediate/Peaking	Yes
Facility 263	Rocky Point	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 264	Pittsboro	NC	Solar	2.0	Intermediate/Peaking	Yes
Facility 265	Chapel Hill	NC	Solar	16.0	Intermediate/Peaking	Yes
Facility 266	Pittsboro	NC	Solar	8.0	Intermediate/Peaking	Yes
Facility 267	Hampstead	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 268	Raleigh	NC	Solar	8.0	Intermediate/Peaking	Yes
Facility 269	Asheville	NC	Solar	5.5	Intermediate/Peaking	Yes
Facility 270	Raleigh	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 271	Asheville	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 272	Clayton	NC	Solar	2.6	Intermediate/Peaking	Yes
Facility 273	Apex	NC	Solar	6.2	Intermediate/Peaking	Yes
Facility 274	Apex	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 275	Apex	NC	Solar	6.3	Intermediate/Peaking	Yes
Facility 276	Pittsboro	NC	Solar	2.2	Intermediate/Peaking	Yes
Facility 277	Leland	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 278	Weaverville	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 279	Raleigh	NC	Solar	7.8	Intermediate/Peaking	Yes
Facility 280	Asheville	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 281	Apex	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 282	Southern Pines	NC	Solar	1.6	Intermediate/Peaking	Yes
Facility 283	Raleigh	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 284	Asheville	NC	Solar	1.9	Intermediate/Peaking	Yes
Facility 285	Candler	NC	Solar	10.1	Intermediate/Peaking	Yes
Facility 286	Pittsboro	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 287	Fairview	NC	Solar	7.1	Intermediate/Peaking	Yes
Facility 288	Chapel Hill	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 289	Fairview	NC	Solar	2.8	Intermediate/Peaking	Yes
Facility 290	Raleigh	NC	Solar	7.7	Intermediate/Peaking	Yes
Facility 291	Asheville	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 292	Raleigh	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 293	Wilmington	NC	Solar	7.2	Intermediate/Peaking	Yes
Facility 294	Pittsboro	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 295	Raleigh	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 296	Swannanoa	NC	Solar	1.5	Intermediate/Peaking	Yes
Facility 297	Barnardsville	NC	Solar	4.4	Intermediate/Peaking	Yes
Facility 298	Wilmington	NC	Solar	8.8	Intermediate/Peaking	Yes
Facility 299	Asheville	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 300	Pittsboro	NC	Solar	2.6	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 301	Apex	NC	Solar	96.0	Intermediate/Peaking	Yes
Facility 302	Apex	NC	Solar	15.0	Intermediate/Peaking	Yes
Facility 303	Asheville	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 304	Wilmington	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 305	Candler	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 306	Asheville	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 307	Garner	NC	Solar	7.3	Intermediate/Peaking	Yes
Facility 308	Chapel Hill	NC	Solar	7.0	Intermediate/Peaking	Yes
Facility 309	Raleigh	NC	Solar	1.6	Intermediate/Peaking	Yes
Facility 310	Wilmington	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 311	Asheville	NC	Solar	4.1	Intermediate/Peaking	Yes
Facility 312	Asheville	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 313	Fletcher	NC	Solar	6.1	Intermediate/Peaking	Yes
Facility 314	Angier	NC	Solar	2.6	Intermediate/Peaking	Yes
Facility 315	Lillington	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 316	Asheville	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 317	Asheville	NC	Solar	6.5	Intermediate/Peaking	Yes
Facility 318	Asheville	NC	Solar	2.3	Intermediate/Peaking	Yes
Facility 319	Asheville	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 320	Morrisville	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 321	Sanford	NC	Solar	5.8	Intermediate/Peaking	Yes
Facility 322	Raleigh	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 323	Wilmington	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 324	Morrisville	NC	Solar	1.3	Intermediate/Peaking	Yes
Facility 325	Fuquay-Varina	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 326	Raleigh	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 327	Kinston	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 328	Asheville	NC	Solar		Intermediate/Peaking	Yes
Facility 329	Fairview	NC	Solar	5.39	Intermediate/Peaking	Yes
Facility 330	Cary	NC	Solar	7	Intermediate/Peaking	Yes
Facility 331	Fuquay Varnia	NC	Solar	2.49	Intermediate/Peaking	Yes
Facility 332	Newport	NC	Solar	7.6	Intermediate/Peaking	Yes
Facility 333	Fuquay Varina	NC	Solar	0.82	Intermediate/Peaking	Yes
Facility 334	Fletcher	NC	Solar	2.75	Intermediate/Peaking	Yes
Facility 335	Siler City	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 336	Asheville	NC	Solar	5	Intermediate/Peaking	Yes
Facility 337	Cary	NC	Solar	1.84	Intermediate/Peaking	Yes
Facility 338	Candler	NC	Solar	7.975	Intermediate/Peaking	Yes
Facility 339	Star	NC	Solar	2.3	Intermediate/Peaking	Yes
Facility 340	Fayetville	NC	Solar	5.71	Intermediate/Peaking	Yes
Facility 341	Fayetteville	NC	Solar	5	Intermediate/Peaking	Yes
Facility 342	Asheville	NC	Solar	3.9	Intermediate/Peaking	Yes
Facility 343	Asheville	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 344	Asheville	NC	Solar	3.2	Intermediate/Peaking	Yes
Facility 345	Asheboro	NC	Solar	6.88	Intermediate/Peaking	Yes
Facility 346	Wilmington	NC	Solar	1.63	Intermediate/Peaking	Yes
Facility 347	Asheville	NC	Solar	7.1	Intermediate/Peaking	Yes
Facility 348	Vass	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 349	Waynesville	NC	Solar	3.62	Intermediate/Peaking	Yes
Facility 350	Asheville	NC	Solar	7	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 351	Raleigh	NC	Solar	3	Intermediate/Peaking	Yes
Facility 352	Alexander	NC	Solar	2.91	Intermediate/Peaking	Yes
Facility 353	Pittsboro	NC	Solar	6	Intermediate/Peaking	Yes
Facility 354	Raleigh	NC	Solar	2.49	Intermediate/Peaking	Yes
Facility 355	Pittsboro	NC	Solar	5	Intermediate/Peaking	Yes
Facility 356	Chapel Hill	NC	Solar	4.158	Intermediate/Peaking	Yes
Facility 357	Asheville	NC	Solar	3	Intermediate/Peaking	Yes
Facility 358	Asheville	NC	Solar	3.12	Intermediate/Peaking	Yes
Facility 359	Angier	NC	Solar	5	Intermediate/Peaking	Yes
Facility 360	Asheville	NC	Solar	3	Intermediate/Peaking	Yes
Facility 361	Clayton	NC	Solar	2000	Intermediate/Peaking	Yes
Facility 362	Raleigh	NC	Solar	4	Intermediate/Peaking	Yes
Facility 363	Holly Springs	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 364	Canton	NC	Solar	2	Intermediate/Peaking	Yes
Facility 365	Godwin	NC	Solar	5	Intermediate/Peaking	Yes
Facility 366	Raleigh	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 367	Asheville	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 368	Coats	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 369	Pittsboro	NC	Solar	8	Intermediate/Peaking	Yes
Facility 370	Raleigh	NC	Solar	7.54	Intermediate/Peaking	Yes
Facility 371	Raleigh	NC	Solar	8.64	Intermediate/Peaking	Yes
Facility 372	Climax	NC	Solar	7.68	Intermediate/Peaking	Yes
Facility 373	Aberdeen	NC	Solar	4.14	Intermediate/Peaking	Yes
Facility 374	Smyrna	NC	Wind	10	Intermediate/Peaking	Yes
Facility 375	Castalia	NC	Solar	3	Intermediate/Peaking	Yes
Facility 376	Weaverville	NC	Solar	7.5	Intermediate/Peaking	Yes
Facility 377	Benson	NC	Solar	3	Intermediate/Peaking	Yes
Facility 378	Broadway	NC	Solar	8.55	Intermediate/Peaking	Yes
Facility 379	Raleigh	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 380	Goldsboro	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 381	Weaverville	NC	Solar	6	Intermediate/Peaking	Yes
Facility 382	Pittsboro	NC	Solar	1.632	Intermediate/Peaking	Yes
Facility 383	CAMERON	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 384	Waynesville	NC	Solar	5	Intermediate/Peaking	Yes
Facility 385	Asheville	NC	Solar	4.92	Intermediate/Peaking	Yes
Facility 386	Hollister	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 387	Weaverville	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 388	Fletcher	NC	Solar	424	Intermediate/Peaking	Yes
Facility Name	**City/County**	**State**	**Primary Fuel Type**	**Capacity (AC KW)**	**Designation**	**Inclusion in Utility's Resources**
South Carolina Generators:						
Facility 1	Sumter	SC	Biogas		Intermediate/Peaking	Yes

11. CROSS-REFERENCE TABLE

	Requirement	Location
1	Summary of significant amendments or revisions to most recently filed biennial report (including amendments to type and size of resources identified	Chapter 4
2	Short-term action plan	Chapter 7
3	REPS Compliance Plan	Attachment: NC REPS Compliance Plan
4	Most recent 10-year history and forecast of: - customers by each customer class, - energy sales (MWh) by each customer class, - utilities summer and winter peak load	Chapter 5
5	15 year table (w/ and w/o projected supply or demand side resources) of: -Peak loads for summer and winter seasons of each year - annual energy forecasts - Reserve margins - Load duration curves - Effects of DR and EE programs on forecasted annual energy and peak loads	Chapter 5
6	Description of future supply-side resources including type of capacity / resource (MW rating, fuel source, base, intermediate, or peaking)	Chapter 6
7	List of existing units in service with: - type of fuel(s) used - Type of unit (base, int, peak) - Location of existing unit - List of units to be retired with location and date - List of units for which there are specific plans for life extension, refurbishment, or upgrading - Other changes to existing generating units that are expected to impact gen capability by 10% or 10 MW	Chapter 8
8	Planned Generation Additions with: - Type of fuel used - Type of unit (MW rating, base, int, peak) - Location if determined - Summaries of analyses supporting any new gen additions included in its 15-year forecast	Chapter 6
9	List of all NUG facilities - facility name - location - primary fuel type - capacity (base, int, peak) - which are included in its total supply of resources	Chapter 10
10	Cumulative resource additions necessary to meet load obligation & reserve margins	Chapter 6

The Duke Energy Progress

NC Renewable Energy & Energy Efficiency Portfolio Standard (NC REPS) Compliance Plan

September 1, 2015

NC REPS Compliance Plan
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INTRODUCTION:

Duke Energy Progress, LLC (DEP or the Company) submits its annual Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS or REPS) Compliance Plan (Compliance Plan) in accordance with NC Gen. Stat. § 62-133.8 and North Carolina Utilities Commission (the Commission) Rule R8-67(b). This Compliance Plan, set forth in detail in Section II and Section III, provides the required information and outlines the Company's projected plans to comply with NC REPS for the period 2015 to 2017 (the Planning Period). Section IV addresses the cost implications of the Company's REPS Compliance Plan.

In 2007, the North Carolina General Assembly enacted Session Law 2007-397 (Senate Bill 3), codified in relevant part as NC Gen. Stat. § 62-133.8, in order to:

- Diversify the resources used to reliably meet the energy needs of consumers in the State;
- Provide greater energy security through the use of indigenous energy resources available within the State;
- Encourage private investment in renewable energy and energy efficiency; and
- Provide improved air quality and other benefits to energy consumers and citizens of the State.

As part of the broad policy initiatives listed above, Senate Bill 3 established the NC REPS, which requires the investor-owned utilities, electric membership corporations or co-operatives, and municipalities to procure or produce renewable energy, or achieve energy efficiency savings, in amounts equivalent to specified percentages of their respective retail megawatt-hour (MWh) sales from the prior calendar year.

Duke Energy Progress seeks to advance these State policies and comply with its REPS obligations through a diverse portfolio of cost-effective renewable energy and energy efficiency resources. Specifically, the key components of Duke Energy Progress' 2015 Compliance Plan include: (1) energy efficiency programs that will generate savings that can be counted towards the Company's REPS obligation; (2) purchases of renewable energy certificates (RECs); (3) operations of company-owned renewable facilities; and (4) research studies to enhance the Company's ability to comply with its REPS obligations in the future. The Company believes that these actions yield a diverse portfolio of qualifying resources and allow a flexible mechanism for compliance with the requirements of NC Gen. Stat. § 62-133.8.

In addition, the Company has undertaken, and will continue to undertake, specific regulatory and operational initiatives to support REPS compliance, including: (1) submission of regulatory applications to pursue reasonable and appropriate renewable energy and energy efficiency initiatives in support of the Company's REPS compliance needs; (2) solicitation, review, and analysis of proposals from renewable energy suppliers offering RECs and diligent pursuit of the most attractive opportunities, as appropriate;

and (3) development and implementation of administrative processes to manage the Company's REPS compliance operations, such as procuring and managing renewable resource contracts, accounting for RECs, safely interconnecting renewable energy suppliers, reporting renewable generation to the North Carolina Renewable Energy Tracking System (NC-RETS), and forecasting renewable resource availability and cost in the future.

The Company believes these actions collectively constitute a thorough and prudent plan for compliance with NC REPS and demonstrate the Company's commitment to pursue its renewable energy and energy efficiency strategies for the benefit of its customers.

I. REPS COMPLIANCE OBLIGATION:

Duke Energy Progress calculates its NC REPS Compliance Obligations[5] for 2015, 2016, and 2017 based on interpretation of the statute (NC Gen. Stat. § 62-133.8), the Commission's rules implementing Senate Bill 3 (Rule R8-67), and subsequent Commission orders, as applied to the Company's actual or forecasted retail sales in the Planning Period, as well as the actual and forecasted retail sales of those wholesale customers for whom the Company is supplying REPS compliance services. The Company's wholesale customers for whom it supplies REPS compliance services are the Town of Sharpsburg, the Town of Stantonsburg, the Town of Lucama, the Town of Black Creek, Town of Winterville and the City of Waynesville (Waynesville compliance provided for 2015 only, as DEP's contract with Waynesville expires 12/31/2015) (collectively referred to as Wholesale or Wholesale Customers)[6]. Table 1 below shows the Company's retail and Wholesale customers' REPS Compliance Obligation.

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[5] For the purposes of this Compliance Plan, Compliance Obligation is more specifically defined as the sum of Duke Energy Progress' native load obligations for both the Company's retail sales and for wholesale native load priority customers' retail sales for whom the Company is supplying REPS compliance. All references to the respective Set-Aside requirements, the General Requirements, and REPS Compliance Obligation of the Company include the aggregate obligations of both Duke Energy Progress and the Wholesale Customers. Also, for purposes of this Compliance Plan, all references to the compliance activities and plans of the Company shall encompass such activities and plans being undertaken by Duke Energy Progress on behalf of the Wholesale Customers.

[6] For purposes of this Compliance Plan, Retail Sales is defined as the sum of Duke Energy Progress' retail sales and the retail sales of the wholesale customers for whom the company is supplying REPS compliance.

Table 1: Duke Energy Progress' NC REPS Compliance Obligation

Compliance Year	Previous Year DEP Retail Sales (MWhs)	Previous Year Wholesale Retail Sales (MWhs)	Total Retail sales for REPS Compliance (MWhs)	Solar Set-Aside (RECs)	Swine Set-Aside (RECs)	Poultry Set-Aside (RECs)	REPS Requirement (%)	Total REPS Compliance Obligation (RECs)
2015	37,490,737	212,347	37,703,084	52,784	26,392	202,536	6%	2,262,185
2016	37,084,787	120,748	37,205,535	52,088	26,044	255,925	6%	2,232,332
2017	37,500,664	121,215	37,621,879	52,671	52,671	257,740	6%	2,257,313

Note: Obligation is determined by prior-year MWh sales. Thus, retail sales figures for compliance years 2015 and 2016 are estimates.

As shown in Table 1, the Company's requirements in the Planning Period include the solar energy resource requirement (Solar Set-Aside), swine waste resource requirement (Swine Set-Aside), and poultry waste resource requirement (Poultry Set-Aside). In addition, the Company must also ensure that, in total, the RECs that it produces or procures, combined with energy efficiency savings, is an amount equivalent to 6% of its prior-year retail sales in compliance years 2015, 2016 and 2017. The Company refers to this as its Total Obligation. For clarification, the Company refers to its Total Obligation, net of the Solar, Swine, and Poultry Set-Aside requirements, as its General Requirement.

II. REPS COMPLIANCE PLAN:

In accordance with Commission Rule R8-67b(1)(i), the Company describes its planned actions to comply with the Solar, Swine, and Poultry Set-Asides, as well as the General Requirement below. The discussion first addresses the Company's efforts to meet the Set-Aside requirements and then outlines the Company's efforts to meet its General Requirement in the Planning Period.

A. SOLAR ENERGY RESOURCES:

Pursuant to NC Gen. Stat. § 62-133.8(d), the Company must produce or procure solar RECs equal to a minimum of 0.14% of the prior year's total electric energy in megawatt-hours (MWh) sold to retail customers in North Carolina in 2015, 2016 and 2017.

Based on the Company's actual retail sales in 2014, the Solar Set-Aside is 52,784 RECs in 2015. Based on forecasted retail sales, the Solar Set-Aside is projected to be approximately 52,088 RECs and 52,671 RECs in 2016 and 2017, respectively.

The Company's plan for meeting the Solar Set-Aside in the Planning Period is described in further detail below.

1. Company-Owned Solar Facilities

As the result of a solar RFP issued in February 2014, DEP announced plans to acquire and construct three solar facilities in North Carolina, totaling 128 MW of capacity: a 65MW facility in Duplin County; a 40MW facility in Wilson County and a 23MW facility in Bladen County. In addition, the Camp Lejeune Solar Facility will add approximately 13 MW of solar PV capacity to DEP's system and is the Company's first solar facility at a military base. All of these Company-owned projects are anticipated to be online by the end of 2015.

2. Solar PPAs and Solar REC Purchase Agreements

DEP has executed multiple solar REC purchase agreements with third parties. These agreements include contracts with multiple counterparties to procure solar RECs from both solar photovoltaic (PV) and solar water heating installations. Also as part of the 2014 solar RFP, DEP signed power purchase agreements with five new solar projects, totaling 150 MW of capacity. Additional details with respect to the REC purchase agreements are set forth in Exhibit A.

3. Residential Solar PV Program

The Company also maintains a residential solar PV program, which offers incentives to customers who install solar. In exchange, the Company receives RECs created by the systems for 5 years. By year-end 2015, the Company expects total program participation of approximately 4MW of solar PV from around 900 program participants.

4. Review of Company's Solar Set-Aside Plan

The Company has made and continues to make reasonable efforts to meet the Solar Set-Aside requirement in the Planning Period, and remains confident that it will be able to comply with this requirement. Therefore, the Company sees minimal risk in meeting the Solar Set-Aside and will continue to monitor the development and progress of solar initiatives and take appropriate actions as necessary.

B. SWINE WASTE-TO-ENERGY RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8(e), as amended by the NCUC *Final Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief,* Docket No. E-100, Sub 113 (November 2014), for calendar years 2015 and 2016, at least 0.07%, and in 2017, at least 0.14% of prior-year total retail electric energy sold in aggregate by utilities in North Carolina must be supplied by energy derived from swine waste. The Company's Swine Set-Aside is estimated to be 26,392 RECs in 2015, 26,044 RECs in 2016, and 52,671 RECs in 2017.

Swine waste-to-energy compliance challenges have been numerous and varied. Three paths to the creation of swine waste-to-energy RECs have been identified, although each faces unique challenges.

1. On-farm generation

Projects consisting of digestion and generation on a single farm or tight cluster of farms often face gas production and feedstock agreement challenges, as well as interconnection difficulties. The Company understands that many farms in NC are contract growers and have only limited term agreements with the integrators. Accordingly, many contract growers are not in a position to provide a firm supply of waste sufficient to support project financing. The Company is exploring ways to overcome such risks.

2. Centralized digestion

This type of system would benefit farmers that cannot individually construct and operate an anaerobic digester manure handling system on their own due to the capital expense or just don't have the number of animals required to operate a digester successfully or cost effectively. Farms located close to each other could share the cost of the centrally located digester system. The centralized digester operated by an individual or private company would carry out the operation and maintenance of the digester and its mechanical systems. It would have the same advantages as on-farm digesters of odor reduction, pathogen and weed seed destruction, biogas production and a stable effluent ready to fertilize fields and crops.

The Company recognizes that NIMBY ("Not In My Back Yard") issues may scuttle some developers' plans for overcoming fuel supply and interconnection problems faced by more rural, on-farm projects.

3. Injected/Directed biogas

In theory, injected biogas reduces costs by using large, efficient centralized generation in the place of smaller, less-efficient reciprocating engines typical of other projects. However, practically, the Company has found such solutions in North Carolina to be economically challenged, in part due to additional gas clean-up requirements prior to injection and the general lack of physical proximity between clusters of farms and pipeline infrastructure.

The Company continues to explore directed biogas opportunities, including promising opportunities outside of North Carolina where the gas would be transported on interstate pipelines used for fuel in one of the Company's combined cycles.

In spite of Duke Energy Progress' active and diligent efforts to secure resources to comply with its Swine Waste Set-Aside requirements, the Company will not be able to procure sufficient volumes of RECs to meet its pro-rata share of the swine waste set-aside requirements in 2015. The Company remains actively engaged in seeking additional resources and continues to make every reasonable effort to comply with the swine waste set-aside requirements.

The Company's ability to comply in 2016 and 2017 remains highly uncertain and subject to multiple variables, particularly relating to counterparty achievement of projected delivery requirements and commercial operation milestones. Additional details with respect to the Company's compliance efforts and REC purchase agreements are set forth in Exhibit A and the Company's tri-annual progress reports, filed confidentially in Docket E-100 Sub113A.

Due to its expected non-compliance in 2015, the Company has submitted a motion to the Commission for approval of a request to relieve the Company from compliance with the swine-waste requirements until calendar year 2016 by delaying the compliance obligation for a one year period.

C. POULTRY WASTE-TO-ENERGY RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8(f), as amended by NCUC *Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief*, Docket No. E-100, Sub 113 (March 2014), for calendar year 2015, at least 700,000 MWhs, and for 2016 and 2017, at least 900,000 MWhs, of the prior year's total electric energy sold to retail electric customers in the State or an equivalent amount of energy shall be produced or procured each year from poultry waste, as defined per the Statute and additional clarifying Orders. As the Company's retail sales share of the State's total retail megawatt-hour sales is approximately 29%, the Company's Poultry Set-Aside is estimated to be 202,536 RECs in 2015, 255,925 RECs in 2016, and 257,740 in 2017.

In spite of Duke Energy Progress' active and diligent efforts to secure resources to comply with its Poultry Waste Set-Aside requirements, the Company will not be able to procure sufficient volumes of RECs to meet its pro-rata share of the poultry set-aside requirements in 2015. The Company remains actively engaged in seeking additional resources and continues to make every reasonable effort to comply with the poultry waste set-aside requirements.

Several near-term challenges remain to the Company's meeting the poultry set-aside targets in the future. To date, only a handful of poultry projects are operating and online in North Carolina. Ramping up to meet the increased compliance targets for 2015 - 2017 has been problematic because other suppliers have either delayed projects or lowered the volume of RECs to be produced. The Company is, nevertheless, encouraged by the growing use of thermal poultry RECs and the proposals that it has recently received from developers.

The Company's ability to comply in 2016 and 2017 remains uncertain and largely subject to counterparty performance. Additional details with respect to the Company's compliance efforts and REC purchase agreements are set forth in Exhibit A and the Company's tri-annual progress reports, filed confidentially in Docket E-100 Sub113A.

Due to its expected non-compliance in 2015, the Company has submitted a motion to the Commission for approval of a request to relieve the Company from compliance with the poultry-waste requirements until calendar year 2016 by delaying the compliance obligation for a one year period.

D. GENERAL REQUIREMENT RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8, Duke Energy Progress is required to comply with its Total Obligation in 2015, 2016, and 2017 by submitting for retirement a total volume of RECs equivalent to 6% of retail sales in North Carolina in the prior year: approximately 2,262,185 RECs in 2015, 2,232,332 RECs in 2016, and 2,257,313 RECs in 2017. This requirement, net of the Solar, Swine, and Poultry Set-Aside requirements, is estimated to be 1,980,473 RECs in 2015, 1,898,275 RECs in 2016, and 1,894,231 in 2017. The various resource options available to the Company to meet the General Requirement are discussed below, as well as the Company's plan to meet the General Requirement with these resources.

1. Energy Efficiency

During the Planning Period, the Company plans to meet 25% of the Total Obligation with Energy Efficiency (EE) savings, which is the maximum allowable amount under NC Gen. Stat. § 62-133.7(b)(2)c. The Company continues to develop and offer its customers new and innovative EE programs that will deliver savings and count towards its future NC REPS requirements. The Company has attached a list of those EE measures that it plans to use toward REPS compliance, including projected impacts, as Exhibit B.

2. Hydroelectric Power

Duke Energy Progress plans to use hydroelectric power from two sources to meet the General Requirement in the Planning Period: (1) Wholesale Customers' Southeastern Power Administration (SEPA) allocations; and (2) hydroelectric generation suppliers whose facilities have received Qualifying Facility (QF or QF Hydro) status. Wholesale Customers may also bank and utilize hydroelectric resources arising from their full allocations of SEPA. When supplying compliance for the Wholesale Customers, the Company will ensure that hydroelectric resources do not comprise more than 30% of each Wholesale Customers' respective compliance portfolio, pursuant to NC Gen. Stat. § 62-133.8(c)(2)c. In addition, RECs from QF Hydro facilities will be used towards the General Requirements of Duke Energy Progress' retail customers. Please see Exhibit A for more information.

3. Biomass Resources

Duke Energy Progress plans to meet a portion of the General Requirement through a variety of biomass resources, including landfill gas to energy, combined heat and power, and direct combustion of biomass fuels. The Company is purchasing RECs from multiple biomass facilities in the Carolinas, including landfill gas to energy facilities and biomass-fueled combined heat and power facilities, all of which qualify as renewable energy facilities. Please see Exhibit A for more information on each of these contracts.

Duke Energy Progress notes, however, that reliance on direct-combustion biomass remains limited in long-term planning horizons, in part due to continued uncertainties around the developable potential of such resources in the Carolinas and the projected availability of other forms of renewable resources to offset the need for biomass.

4. Wind

Duke Energy Progress plans to meet a portion of the General Requirement with RECs from wind facilities. While the Company expects to rely upon wind resources for REPS compliance, the extent and timing of that reliance will likely vary commensurately with changes to supporting policies and prevailing market prices. The Company recognizes that some land-based wind developers are presently pursuing projects of significant size in North Carolina. While successful projects have to navigate a litany of obstacles, these obstacles are not insurmountable. The Company also has observed that opportunities may exist to transmit land-based wind energy resources into the Carolinas from other regions, which could supplement the amount of wind that could be developed within the Carolinas.

5. Use of Solar Resources for General Requirement

Duke Energy Progress plans to meet a portion of the General Requirement with RECs from solar facilities. The Company views the downward trend in solar equipment and installation costs over the past several years as a positive development. Additionally, new solar facilities also benefit from generous supportive Federal and State policies that are expected to be in place beyond 2015. While uncertainty remains around possible alterations or extensions of policy support, as well as the pace of future cost declines, the Company fully expects solar resources to contribute to our compliance efforts beyond the solar set-aside minimum threshold for NC REPS during the Planning Period.

6. Review of Company's General Requirement Plan

The Company has contracted for or otherwise procured sufficient resources to meet its General Requirement in the Planning Period. Based on the known information available at the time of this filing, the Company is confident that it will meet this General Requirement during the Planning Period and submits that the actions and plans described herein represent a reasonable and prudent plan for meeting the General Requirement.

E. SUMMARY OF RENEWABLE RESOURCES

The Company has evaluated, procured, and/or developed a variety of types of renewable and energy efficiency resources to meet its NC REPS requirements within the compliance Planning Period. As noted above, several risks and uncertainties exist across the various types of resources and the associated parameters of the NC REPS requirements. The Company continues to carefully monitor opportunities and unexpected developments across all facets of its compliance requirements. Duke Energy Progress submits that it has crafted a prudent, reasonable plan with a diversified balance of renewable resources that will allow the Company to comply with its NC REPS obligation over the Planning Period.

III. COST IMPLICATIONS OF REPS COMPLIANCE PLAN

A. CURRENT AND PROJECTED AVOIDED COST RATES

The current variable rate represents the avoided cost rate in Schedule CSP-29 (NC), Distribution Interconnection, approved in the Commission's *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, issued in Docket No. E-100, Sub 127 (July 27, 2011). The current long-term rates represent the annualized avoided cost rates approved in the Commission's *Order on Motion to Suspend Avoided Cost Rates*, issued in Docket No. E-100, Sub 136 (December 21, 2012). The projected avoided cost rates represent the annualized avoided cost rates proposed by the Company in Docket No. E-100, Sub 140.

The projected avoided costs rates contained herein are subject to change, particularly as the underlying assumptions change and as the methodology for determining the avoided cost is addressed by the North Carolina Utilities Commission in pending Docket No. E-100, Sub 140. Primary assumptions that impact avoided cost rates are turbine costs, fuel price projections, and the expansion plans. Changes to these assumptions are addressed in greater detail in the current Integrated Resource Plan.

Table 2: Current and Projected Avoided Cost Rates Table

[BEGIN CONFIDENTIAL]

CURRENT AVOIDED ENERGY AND CAPACITY COST (from E-100 Sub 136)			
	On-Peak Energy[1] ($/MWh)	**Off-Peak Energy[1] ($/MWh)**	[redacted]
2016	47.44	38.53	
2017	47.05	40.20	
2018	54.14	42.60	

PROJECTED AVOIDED ENERGY AND CAPACITY COST			
	On-Peak Energy[5] ($/MWh)	**Off-Peak Energy[5] ($/MWh)**	[redacted]
2016	36.99	32.89	
2017	38.60	34.46	
2018	37.04	34.13	

Notes: (1) On-peak and off-peak energy rates based on Option B hours and information and assumptions available concurrent with the 2014 IRP and derived using methodology approved in Docket No. E-100, Sub 136
(2) Capacity Cost column provides the installed CT cost with AFUDC
(3) Turbine cost agreed upon in E-100 Sub 136 settlement
(4) Turbine cost proposed in E-100, Sub 140 divided by summer capacity rating
(5) On-peak and off-peak energy rates based on Option B hours and information and assumptions available concurrent with the methodology proposed in Docket No. E-100, Sub 140
(6) Does not incorporate additional considerations used in rate calculation and is subject to change

[END CONFIDENTIAL]

B. PROJECTED TOTAL NORTH CAROLINA RETAIL AND WHOLESALE SALES AND YEAR-END NUMBER OF CUSTOMER ACCOUNTS BY CLASS

The tables below reflect the inclusion of the Wholesale Customers in the Compliance Plan.

Table 3: Retail Sales for Retail and Wholesale Customers

		2014 Actual	2015 Forecast	2016 Forcast	2017 Forecast
Retail MWh Sales		37,490,737	37,084,787	37,500,664	37,909,134
Whoesale MWh Sales		212,347	120,748	121,215	121,684
Total MWh Sales		37,703,084	37,205,535	37,621,879	38,030,818

Note: The MWh sales reported above are those applicable to REPS compliance years 2015 – 2017, and represent actual MWh sales for 2014, and projected MWh sales for 2015 and 2017.

Table 4: Retail and Wholesale Year-end Number of Customer Accounts

		2014 (Actual)	2015 (Projected)	2016 (Projected)	2017 (Projected)
Residential Accts		1,215,618	1,232,841	1,247,894	1,265,529
General Accts		198,063	199,849	200,952	202,759
Industrial Accts		2,123	2,109	2,099	2,090

Note: The number of accounts reported above are those applicable to the cost caps for compliance years 2015 – 2017, and represent the actual number of accounts for year-end 2014, and the projected number of accounts for year-end 2015 through 2017.

C. PROJECTED ANNUAL COST CAP COMPARISON OF TOTAL AND INCREMENTAL COSTS, REPS RIDER AND FUEL COST IMPACT

Projected compliance costs for the Planning Period are presented in the cost tables below by calendar year. The cost cap data is based on the number of accounts as reported above.

Table 5: Projected Annual Cost Caps and Fuel Related Cost Impact

	2015	2016	2017
Total projected REPS compliance costs	$175,742,700	$238,968,551	$ 251,665,511
Recovered through the Fuel Rider	$150,405,592	$206,151,650	$ 214,179,630
Total incremental costs (REPS Rider)	$ 25,337,108	$ 32,816,901	$ 37,485,881
Total including Regulatory Fee	$ 25,370,140	$ 32,859,684	$ 37,534,751
Projected Annual Cost Caps (REPS Rider)	$ 46,419,866	$ 74,002,944	$ 74,670,196

EXHIBIT A

Duke Energy Progress, LLC's 2014 REPS Compliance Plan
Duke Energy Progress' Renewable Resource Procurement from 3rd Parties
(signed contracts as of July 1, 2015)

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

EXHIBIT B

Duke Energy Progress, LLC's 2014 REPS Compliance Plan
Duke Energy Progress, LLC's EE Programs and Projected REPS Impacts

Forecast Annual Energy Efficiency Impacts for the REPS Compliance Planning Period 2015-2017 (MWhs)

Residential Programs	2015	2016	2017
Appliance Recycling	6,435	6,425	6,425
K-12	1,704	1,701	1,701
MultiFamily	14,229	9,976	10,931
MyHER	100,290	-	-
Neighborhood Energy Saver	1,546	1,543	1,543
Residential Home Energy Improvement	3,322	2,138	2,138
Residential Lighting	50,546	56,166	55,896
Residential New Construction	8,076	9,963	11,355
New Products*			
Sub Total	**186,149**	**87,912**	**89,989**
Non Residential Programs	2015	2016	2017
EEB	70,188	75,098	79,255
SBES	50,138	38,504	30,803
New Products*			
Sub Total	**120,326**	**113,602**	**110,059**
Total	**306,475**	**201,514**	**200,048**

been explained in FPL's testimony presented in support of its request for a determination of need for WCEC 3, because, whether with or without the proposed plant conversions, adding WCEC 3 in 2011 is the most economic resource available to FPL in 2011 through 2013, it would not be beneficial to FPL's customers to implement any other alternative. Therefore, adding WCEC 3 in 2011 is necessary and appropriate if FPL is to proceed with the cleaner, high efficiency conversion of Canaveral and Riviera and continue to ensure system reliability.

Q. Is the 20% reserve margin planning criterions appropriate for use in FPL's IRP process?

A. Yes. The 20% reserve margin reliability criterion utilized by FPL in its integrated resource planning process has been reviewed and approved by the Commission and it is appropriate and necessary to ensure reliable service for FPL's customers.

Q. Could FPL lower the planning reserve margin reliability criterion to 15% and still provide reliable service to its customers?

A. No. A 15% reserve margin is not adequate to ensure reliable service in FPL's system.

Q. How was FPL's current reserve margin criterion of 20% established?

A. Prior to 1999 FPL used a reserve margin criterion of 15%. It should be noted that FPL's reserves at that time consisted more heavily of generation reserves, with load management contributing less than half of what it will provide in 2014. However, the Commission initiated in the late 1990s a proceeding to determine what the appropriate reserve margin criterion should be to ensure reliability of electric service in the future, recognizing rapid increases in electric loads, the introduction and expansion of new technologies, and recognition that fuel supply interruptions could occur. After audits were performed by the Commission Staff, and after several stakeholders, including Florida's investor-owned utilities, presented their analyses and conclusions, all parties agreed that a 20% reserve margin for the investor-owned utilities was the appropriate level that would ensure reliability of service in the utilities' systems, as well as in peninsular Florida. These investor-owned utilities stipulated that they would agree to use a 20% reserve margin as one of the reliability criteria for resource planning, in addition to a probabilistic criterion such as LOLP, beginning in the summer of 2004. This stipulation was approved by the Commission.

Q. Why is a 15% reserve margin not adequate to ensure reliability in FPL's system?

A. Because a 15% reserve margin, as used in the resource planning process, would provide a level of generation reserves that would be too low to offset the consequences of commonly occurring differences between the assumptions used in FPL's long term plan and actual operating conditions, especially if those differences occur at times when FPL has scheduled planned maintenance outages for one or more generating units.

Q. What differences are you referring to?

A. There are a number of such differences, as one would expect when recognizing that six or more years can separate forecasts that are used to make resource decisions from actual conditions at the time the resource plan is implemented. To illustrate my point I will provide a numerical example that addresses two differences: one is the point in time during the year in which the peak load actually occurs, and the other is the difference between the actual magnitude of the peak load in a future year (2014) and the projected magnitude of the peak for that year that would have been forecasted six years earlier (2008).

Q. How will you present this illustration?

A. I will first use a calculation very similar to that presented in Exhibit SRS-2 attached to the testimony of FPL witness Sim to show, pursuant to the resource planning process FPL follows to determine future needs, how a projected reserve margin of 15% would be achieved for the summer of 2014. This calculation is presented in my Exhibit RS-3. The only difference between this calculation and that presented in SRS-2 is that the former includes sufficient firm generating capacity in FPL's portfolio to reach a reserve margin of 15%. The forecasted load for 2014 was developed in 2008 as part of FPL's IRP process. Column 3 shows the total projected capacity available in FPL's system in the summer of 2014 (27,502 MW). Column 4 shows the projected peak load in the summer of 2014 (26,576 MW). Column 5 shows the quantity of projected DSM available in the summer of 2014 (2,651 MW).

Column 6 shows the projected "firm" peak load; that is, that portion of the projected peak load that cannot be mitigated through the exercise of DSM. This projected "firm" peak load is equal to the projected peak load less the projected DSM, or 23,925 MW. It should be noted that this demonstrates that in its resource planning process FPL first considers all the cost-effective DSM as a resource before determining what additional supply-side resources are required.

Column 7 shows the projected generation reserves compared to the projected "firm" load. This projected generation reserve compared to projected "firm" peak load is equal to projected capacity available less projected "firm" peak load, or 3,577 MW. Column 8 shows the projected reserve margin that this projected generation reserve provides compared to the "firm" peak load; it is equal to the projected generation reserve against "firm" peak load divided by "firm" peak load, expressed as a percent. This is the reserve margin that is used in FPL's resource planning process to develop and compare plans that will provide a 20% reserve margin relative to "firm" peak load. In this case, however, the projected reserve margin against the projected "firm" peak load, after all the DSM is utilized is 15% in the summer of 2014. As column 9 shows, FPL would need to add 1,208 MW of additional firm capacity in order to meet the 20% reserve margin criterion.

Q. You indicated that the calculation above is consistent with FPL's resource planning process. How does FPL allocate resources to meet actual electric load?

A. In actual daily operations FPL dispatches its generation resources in economic order, with lowest cost generation first, to produce all the electricity its customers need. It is only if generation resources are insufficient to meet actual load that the load management portion of DSM is utilized. I am providing an example of the effect of having only 15% reserve margin in my Exhibit RS-4, page 1 of 2. For simplicity, my example assumes that all the DSM consists of load management. First, it is assumed that actual conditions in 2014 are the same as shown on Exhibit RS-3. In other words, the peak load is 26,576 MW and total capacity available is 27,502 MW. Therefore, FPL would be able to meet the load and have 926 MW of unused generation. It would also have 2,651 MW of unused DSM for total reserves of 3,577 MW. This is the same total of reserves as shown on column 7 of Exhibit RS-3, but note that only 926 MW are generation reserves. In other words, in actual operations, generation reserves are only about one fourth of total reserves, with DSM providing three fourths of the reserve. Another way to look at these results is that, in effect, accepting a 15% reserve margin criterion would result in generation reserves that actually provide less than 4% operational reserve margin. Applying the rest of the reserve margin, which is provided by DSM, requires partial curtailment of service to customers who subscribe to load control. This is the situation that would exist in 2014 if all happens as was forecasted six years earlier, in 2008.

Q. **How would a difference between the projected and actual date of a year's peak load affect FPL's ability to meet its customer's needs?**

A. FPL's forecast typically projects that the summer peak load will occur in August and, at present, no plant outages for inspection and maintenance are planned during that month. However, the peak load can occur in June and July when such plant outages are planned. In fact, in the last 16 years the actual peak load day has occurred in August only 9 times. Therefore, it has been a fairly common occurrence that the peak day has occurred in June or July, instead of August.

Q. **How would the actual peak day occurring in June of 2014 instead of August affect the results presented above, assuming FPL were to plan for a 15% reserve margin in 2014?**

A. Typically, about 800 MW of generation capacity will be out of service for planned maintenance in the month of June. Therefore, if the projected peak for 2014 were to occur in June, instead of having 926 MW of generation reserves on the peak load day FPL would have only 126 MW of generation reserves. In other words, the operational reserve margin provided by generation resources in this situation would be not 4%, but only 0.5%.

Q. How would a difference between the actual and projected magnitude in the peak load affect FPL's ability to meet its customer's needs?

A. If the actual peak load in a particular year is significantly greater than had been projected at the time the resource plan was developed for that year as much as six years earlier, unless the reserves are adequate FPL would not be able to meet its customers' needs.

Q. What has been the average percent difference between the actual peak load and the peak load forecast developed six years earlier?

A. On average in the last four years the actual peak load has been 7.3% higher than had been projected six years before. As stated previously, FPL's resource plan that includes the proposed addition of WCEC in 2011 and the conversions of Canaveral and Riviera by 2013 and 2014, respectively utilizes FPL's most recent peak load forecast developed in 2008.

Q. How would your results above change if instead of the actual peak in 2014 occurring in August it occurred in June, and if the actual magnitude of the peak load were 7.3% higher than the forecast, consistent with the three-year average percent variance, and assuming that FPL plans for a 15% reserve margin in 2014?

A. The actual peak load in June of 2014 would be 28,516 MW, which would exceed by 1,814 MW the amount of generation capability of 26,702 MW. In other words, if "average" differences were to occur in only these two areas that affect FPL's ability to meet its customers' needs, based on a 15% reserve margin criterion FPL would be short of generation resources to serve its customers and would be forced to exercise 1,814 MW of the DSM capability, or almost 70% of all DSM. In fact, FPL would then have zero generation reserves and would have only 821 MW of DSM left to address all other possible unexpected occurrences.

Q. Under these circumstances wouldn't FPL return to service all generation facilities that are scheduled for planned maintenance to meet the higher than projected peak load?

A. FPL would indeed try to bring as many of the resources as possible back in service. However, depending on the type of technology scheduled for planned maintenance, the type of maintenance activity to be performed or the stage at which the maintenance work is when there are indications that a significant peak load is likely, FPL may not be able to return generation to service quickly enough to meet the peak load requirement. It should be noted that as FPL continues to add advanced gas turbines to its system, there will be less and less flexibility regarding scheduling planned outages. For advanced gas turbine technology, inspections and maintenance must be performed on a strict schedule to avoid the risk of catastrophic technical failure.

Q. In your calculations above have you assumed that any unplanned generation or transmission outages would occur on the peak day?

A. No. The results provided above assume that all generation that is scheduled to operate on the peak day is operating at maximum capacity and that there are no transmission interruptions. Similarly, this calculation assumes that there are no fuel interruptions and that FPL is not providing emergency assistance to other utilities. In other words, the calculations represented in these examples reflect perfect performance of all systems, with only commonly recurring differences between actual operating conditions and the forecast on which the resource plan is based. The results above indicate that even if everything in 2014 were to occur exactly as projected, generation reserves would only be adequate to mitigate the effect of a combination of unplanned outages and interruptions totaling up to 926 MW. To put this in perspective, FPL has more than 20 generating units with generating capacity greater than 400 MW, of which 9 have a generating capacity greater than 630 MW. Therefore, unplanned outages that could exceed 926 MW are not rare.

If the only deviation from the forecast is that the peak occurs in June when 800 MW of capacity is out of service for a planned maintenance outage, the resulting generation reserves of 126 MW would not be adequate to mitigate the effect of any unplanned outage except for one occurring in FPL's smallest peaking units. As can be seen, the 15% reserve margin criterion is not adequate to ensure reliable service.

Q. How would the results with the higher adjusted peak load occurring in June of 2014 change when FPL maintains a 20% reserve margin?

A. As shown in Exhibit RS-3, maintaining a 20% reserve margin would require total generation capacity to be 28,711 MW in 2014. As shown in Exhibit RS-4, page 2 of 2, this plan would result in available generating capacity of 27,911 MW (after accounting for the 800 MW out for planned maintenance in

June 2014) plus 2,635 MW of DSM for a total of 30,546 MW of resources against the higher adjusted total peak of 28,516 MW. In this situation FPL would be able to meet load demand, provided that it exercises 605 MW of DSM, leaving a DSM reserve of 2,030 MW to meet any other unexpected circumstance. It is important to note that even with a 20% reserve margin in 2014, the occurrence of ordinary differences between planned and actual peak load conditions such as those presented in this example could use up all generation reserves and about 23% of available DSM would have to be utilized. That leaves only 77% of the DSM reserves, and no generation reserves to offset all other unplanned occurrences, against which the reserve margin is intended to protect FPL's customers. For this reason FPL believes that maintaining a 20% reserve margin criterion for resource planning purposes is in the best interest of its customers.

Q. Is this example intended to demonstrate that FPL's 20% reserve margin criterion will always be the correct level of reserve margin to apply to resource planning?

A. No. This example shows that the Commission should dismiss any suggestion that a 15% reserve margin planning criterion would be adequate. The results above show that a 15% reserve margin reliability criterion is totally inadequate to ensure that FPL could provide reliable service to its customers. Furthermore, these analysis results demonstrate that the additional reliability provided by a 20% reserve margin planning criterion compared to what it would be with a 15% reserve margin is very valuable to FPL's customers.

The question regarding the proper level of reserve margin for future resource planning processes would need to be addressed in an independent proceeding and the implementation date of any change should be far enough into the future to allow utilities to incorporate it into their strategic and operational planning processes, especially because it could well be determined that a reserve margin greater than 20% would be appropriate in the future. It is important to note that the reserve margin criterion is a critical starting point in a utility's multi-year process of identifying need for new resources, obtaining data on the various alternatives, evaluating those alternatives, selecting the best alternative to meet that need, negotiating contract for equipment and construction services or purchased power, and presenting a petition to the Commission to obtain a determination of need. If this basic foundation of the process were to be changed as part of the need determination proceeding, there would be no basis on which a utility could begin the planning process. This view is consistent with the Commission's own views, expressed in Commission Order No. PSC-03-0175-FOF-EI regarding a need determination petition for Progress Energy Florida's Hines Unit 3 in which the Commission stated that it is inappropriate to consider a change to the reserve margin planning criterion in a particular utility's need determination proceeding.

Calculation of FPL's Reserve Margin in Summer of 2014

Maintaining a 15% Reserve Margin

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast ** (MW)	Summer DSM Forecast *** (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2014	25,002	2,500	27,502	26,576	2,651	23,925	3,577	**15.0%**	**1,208**

Maintaining a 20% Reserve Margin

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast ** (MW)	Summer DSM Forecast *** (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2014	26,536	2,175	28,711	26,576	2,651	23,925	4,785	**20.0%**	**(0)**

* The Peak Load Forecast is FPL's Feb 2008 load forecast that includes Lee County load.

* * DSM values shown represent cumulative load management and incremental conservation capability.

EXAMPLE WHY 15% RESERVE MARGIN IS INADEQUATE
OPERATIONS WITH NO WCEC 3 NOR PLANT CONVERSIONS

ADDED 325 MW PPA TO MEET 15% RESERVE MARGIN IN 2014

Year	Month	Week	Total Generating Capacity (MW)	Planned Maintenance (MW)	Available Generating Capacity (MW)	Peak Load (MW)	Generating Capacity Reserves (MW)	DSM Available for Use (MW)	DSM Reserves (MW)	Total Reserves (MW)
2014	August	4	27,502	0	27,502	26,576	926	2,651	2,651	3,577

The above outcome assumes everything occurs in 2014 exactly as forecasted six years earlier, in 2008.

Year	Month	Week	Total Generating Capacity (MW)	Planned Maintenance (MW)	Available Generating Capacity (MW)	Peak Load (MW)	Generating Capacity Reserves (MW)	DSM Available for Use (MW)	DSM Reserves (MW)	Total Reserves (MW)
2014	June	1	27,502	(800)	26,702	26,576	126	2,635	2,635	2,761

The above outcome assumes that the forecasted peak occurs in June; otherwise, there is no change.

Year	Month	Week	Total Generating Capacity (MW)	Planned Maintenance (MW)	Available Generating Capacity (MW)	Peak Load (MW)	Generating Capacity Reserves (MW)	DSM Available for Use (MW)	DSM Reserves (MW)	Total Reserves (MW)
2014	June	1	27,502	(800)	26,702	28,516	**(1,814)**	2,635	**821**	**821**

The above outcome assumes that the peak occurs in June, and that the actual peak is higher than forecasted, and the variance is equal to the average percent variance observed in 2004 - 2007.

Note:

The results above assume that all generating capacity except that explicitly scheduled for maintenance is operating at maximum capacity (i.e., no forced outages), that there are no fuel supply interruptions or transmission interruptions, and that FPL is not providing assistance to any other utility.

EXAMPLE WHY 15% RESERVE MARGIN IS INADEQUATE

OPERATIONS WITH WCEC 3 AND CONVERSIONS OF CANAVERAL AND RIVIERA

Year	Month	Week	Total Generating Capacity (MW)	Planned Maintenance (MW)	Available Generating Capacity (MW)	Peak Load (MW)	Generating Capacity Reserves (MW)	DSM Available for Use (MW)	DSM Reserves (MW)	Total Reserves (MW)
2014	August	4	28,711	0	28,711	26,576	2,135	2,651	2,651	4,786

The above outcome assumes everything occurs in 2014 exactly as forecasted seven years earlier.

Year	Month	Week	Total Generating Capacity (MW)	Planned Maintenance (MW)	Available Generating Capacity (MW)	Peak Load (MW)	Generating Capacity Reserves (MW)	DSM Available for Use (MW)	DSM Reserves (MW)	Total Reserves (MW)
2014	June	1	28,711	(800)	27,911	26,576	1,335	2,635	2,635	3,970

The above outcome assumes that the forecasted peak occurs in June; otherwise, there is no change.

Year	Month	Week	Total Generating Capacity (MW)	Planned Maintenance (MW)	Available Generating Capacity (MW)	Peak Load (MW)	Generating Capacity Reserves (MW)	DSM Available for Use (MW)	DSM Reserves (MW)	Total Reserves (MW)
2014	June	1	28,711	(800)	27,911	28,516	**(605)**	2,635	2,030	2,030

The above outcome assumes that the peak occurs in June, and that the actual peak is higher than forecasted, and the variance is equal to the average percent variance observed in 2004 - 2007.

Note:

The results above assume that all generating capacity except that explicitly scheduled for maintenance is operating at maximum capacity (i.e., no forced outages), that there are no fuel supply interruptions or transmission interruptions, and that FPL is not providing assistance to any other utility.

A Look at January 11, 2010 If FPL Had Planned to a 15% Total Reserve Margin Criterion

I. What Actually Occurred with FPL Planning to a 20% Total Reserve Margin Criterion

		(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (7) - (5) - (3)
		Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted or Remaining LM	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves
		(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)
(1)	2009 TYSP resource plan projection for Summer 2010	22,916	21,147	220	20,927	1,899	19,028	3,888	20.4%	1,769
(2)	2009 TYSP resource plan projection for Winter 2010	26,852	18,790	114	18,676	1,705	16,971	9,881	58.2%	8,062
	Note that all subsequent rows present adjustments to show how Jan 2010 peak day actual conditions differed from planned conditions shown on row (2)									
	Load Adjustments on Jan 2010 peak day									
(3)	Adjustment				6,196					
(4)	Resulting operating conditions on 2010 Winter peak hour	26,852			24,872	1,705	23,167	3,685	15.9%	1,980
	Generation / Load Management Adjustments on Jan 2010 peak day									
(5)	Adjustments	(1,980)			(561)	(561)				
(6)	Operating conditions on 2010 Winter peak hour	24,872			24,311	1,144	23,167	1,705	7.4%	561
	Emergency Sales adjustments on Jan 2010 peak day resulted in 24,346MW of FPL load and 561MW of emergency sales. Total load (FPL and 3rd parties) served is 24,872MW									
(7)	Adjustment				561					
(8)	Operating conditions on 2010 Winter peak hour	24,872			24,872	1,144	23,728	1,144	4.8%	0
	TP Unit 4 Adjustment (if occurred at peak hour)									
(9)	Adjustment	(750)			(750)	(750)				
(10)	Operating conditions on 2010 Winter peak hour	24,122			24,122	394	23,728	394	1.7%	0

Docket No. 150196-EI
A Look at January 11, 2010 If FPL Had Planned to a 15% Total Reserve Margin Criterion
Exhibit SRS-10, Page 1 of 2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 69
PARTY: FPL
DESCRIPTION: Steven R. Sim SRS-10

A Look at January 11, 2010 If FPL Had Planned to a 15% Total Reserve Margin Criterion

II. What Is Projected to Have Occurred If FPL Had Planned to a 15% Total Reserve Margin Criterion

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					= (2) - (3)		= (4) - (5)	= (1) - (6)	= (7) / (6)	= (7) - (5) - (3)
		Total Projected Capacity	**Forecasted Peak Load**	**Forecasted Utility EE**	**Peak Load After EE**	**Forecasted or Remaining LM**	**Forecasted Firm Load After EE and LM**	**Total Reserves**	**Total Reserve Margin as % of Firm Load**	**Generation Reserves**
		(MW)	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(%)**	**(MW)**
(1)	**2009 TYSP resource plan projection for Summer 2010**	22,916	21,147	220	20,927	1,899	19,028	3,888	20.4%	1,769
(2)	**2009 TYSP resource plan projection for Winter 2010**	26,852	18,790	114	18,676	1,705	16,971	9,881	58.2%	8,062
(1a)	**Adjusted resource plan for Summer 2010 assuming 15% RM criterion**	21,882	21,147	220	20,927	1,899	19,028	2,854	15.0%	735
(1b)	**Adjusted resource plan for Winter 2010 assuming the same Summer/Winter ratio for total projected capacity**	25,640	18,790	114	18,676	1,705	16,971	8,669	51.1%	6,850
	Note that all subsequent rows present adjustments to show how Jan 2010 peak day actual conditions would have differed from planned conditions shown on row (2b) if FPL had planned to a 15% total reserve margin									
	Load Adjustments on Jan 2010 peak day									
(3)	**Adjustment**				6,196					
(4)	**Resulting operating conditions on 2010 Winter peak hour**	25,640			24,872	1,705	23,167	2,473	10.7%	768
	Generation / Load Management Adjustments on Jan 2010 peak day									
(5)	**Adjustments**	(1,980)			(561)	(561)				
(6)	**Operating conditions on 2010 Winter peak hour**	23,660			24,311	1,144	23,167	493	2.1%	(651)
	Emergency Sales adjustments on Jan 2010 peak day resulted in 24,346MW of FPL load and 561MW of emergency sales. Total load (FPL and 3rd parties) served is 24,872MW									
(7)	**Adjustment**				561					
(8)	**Operating conditions on 2010 Winter peak hour**	23,660			24,872	1,144	23,728	(68)	-0.3%	(1,212)
	TP Unit 4 Adjustment (if occurred at peak hour)									
(9)	**Adjustment**	(750)			(750)	(750)				
(10)	**Operating conditions on 2010 Winter peak hour**	22,910			24,122	394	23,728	(818)	-3.4%	(1,212)

Note: An inability to serve 68 MW would impact ~39,000 customers. An inability to serve 818 MW would impact ~471,000 customers.

The Need for a 3rd Reliability Criterion for FPL: a Generation-Only Reserve Margin (GRM) Criterion

Bob Barrett
VP Finance
February 28, 2014

A Note Regarding this New Presentation

- **This presentation first addresses 4 "carry over" topics from the Dec. 6th meeting:**
  1. What does a projected LOLP value really mean?
  2. LM customer "fatigue" benchmarking results.
  3. Benefits of generation reserves during pre-hurricane periods.
  4. Emergency declarations and regulatory scrutiny.

- **The presentation then discusses FPL's need for a new reliability criterion from 3 perspectives:**

1. A "looking back" analysis of the Winter peak day of 2010 and what might have occurred if FPL had entered that January having a Summer GRM of 10% or 5%*
2. A "looking forward" analysis using the year 2021
3. Why 10% is a reasonable value for the new GRM criterion

- **The presentation concludes with a summary of "next steps"**

* Unless otherwise noted, all GRM values are Summer GRM values (because the Summer GRM values will have the most impact on resource planning)

Executive Summary

- A generation-only reserve margin (GRM) reliability criterion is desirable from an operational perspective for several reasons:

    - If two resource plans have an identical total reserve margin value, but one plan has a 10% GRM and the other a 5% GRM, the 10% GRM plan can provide operators with hundreds of additional MW of reserves (generating and/or load management) during severe peaks

    - A higher GRM plan can also provide operators with significant additional reserves when hurricanes force early shut downs of nuclear units

- A GRM reliability criterion is also desirable from a resource planning perspective because it can lower LOLP projections

- A GRM criterion of a minimum of 10% matches well with Operation's projected need for 2,650 MW of "operational generation reserves" (i.e., generation above forecasted load)

The 1st topic, "what does an LOLP value mean?", is addressed both by looking at the calculation and providing an interpretation

How is an LOLP Value Calculated?

- LOLP calculations project the probability that a utility will not be able to serve 100% of its firm load (i.e., at least 1 MW of firm load cannot be served) during the time period analyzed after all available generation and LM have been used
- LOLP calculations do not provide information regarding: (1) the MW amount that cannot be served; and (2) the duration of the event
- The probability of not being able to serve all firm load is calculated for the peak hour for each day in the year
- These daily probabilities are then summed to derive a monthly probability of not being able to meet firm load on a peak hour during the month
- Then the monthly probabilities are summed to derive an annual probability of not being able to meet firm load on a peak hour during the year
- Thus an LOLP value is a sum of daily probabilities (which can exceed 1.00) and the LOLP value is commonly expressed in terms of "days per year"

A monthly breakdown of previously provided annual LOLP projections is provided below

Monthly Breakdown of Previous LOLP Values

- **In the 12/06/2013 presentation, two LOLP values were presented for the year 2021: 0.0358 days/year for a 5% GRM plan and 0.0257 days/year for a 10% GRM plan**
- **The following table shows a monthly breakdown of these values:**

Month	w/ 5% GRM ---------------- Projected Days per Individual Month	w/ 5% GRM Projected Cumulative Days per Year	w/ 10% GRM ------------------- Projected Days per Individual Month	w/ 10% GRM Projected Cumulative Days per Year
January	0.000018	0.0000	0.000003	0.0000
February	0.000000	0.0000	0.000000	0.0000
March	0.000030	0.0000	0.000004	0.0000
April	0.000002	0.0001	0.000001	0.0000
May	0.000065	0.0001	0.000022	0.0000
June	0.001522	0.0016	0.000819	0.0008
July	0.000436	0.0021	0.000351	0.0012
August	0.001456	0.0035	0.001203	0.0024
September	0.031795	0.0353	0.023089	0.0255
October	0.000506	0.0358	0.000210	0.0257
November	0.000000	0.0358	0.000000	0.0257
December	0.000000	0.0358	0.000000	0.0257
Annual Days per Year =		**0.0358**		**0.0257**

LOLP discussion may be "flipped" from "days per year" to "years per day" terms to provide an easier-to-use interpretation

A Useful Interpretation of LOLP Values

- **If one assumes that a projected LOLP value for a given year remains constant for each year in an LOLP analysis, one can project how many years will pass before the utility will not be able to meet firm load (i.e., before the sum of the annual LOLP values = 1.0) by dividing the annual LOLP into 1.0**

- **Some utilities, such as Hawaiian Electric Company, use this "years per day" format when reporting results of LOLP analyses**

- **The 5% GRM plan had an annual LOLP value of 0.0358 which converts to 27.9 years, and the 10% GRM plan had an annual LOLP value of 0.0257 or 38.9 years, before LOLP sums to 1.0**

In this analysis, the 10% GRM plan is projected to allow FPL to meet firm load for 11 more years without an interruption than with the 5% GRM plan

Docket No. 150196-EI
The Need for a 3rd Reliability Criterion for FPL:
A Generation-Only Reserve Margin (GRM) Criterion
Exhibit SRS-11, Page 6 of 33

Regarding the 2nd topic of LM "fatigue", benchmarking data was sought from multiple sources

Benchmarking Results

- **The DSM group contracted with Esource to canvas various industry leaders (utilities / consultants)**
- **No empirical data exists on customer fatigue due to over use of LM, but opinions received are in-line with FPL's view regarding avoiding LM fatigue:**
  - No greater than 10 events/year
  - Events should be spread out throughout the year (e.g., not all in summer or extreme winter events)
  - Events should not be prolonged (e.g., greater than 2-3 hours)
- **Ahmad Faruqui, Ph.D., an industry expert, stated this is a question "for which I have not been able to find any good data"**
  - He implied a range for which fatigue may occur: "Survey results indicate that the maximum realistic call duration for ERCOT is 4 hrs. and frequency should be no greater than 10 events/year."

LM benchmarking on customer fatigue is inconclusive

FPL

The 3rd topic is the relevance of generation reserves to address generation needed prior to hurricane landfall

Generation Margins Needed Pre-Hurricane

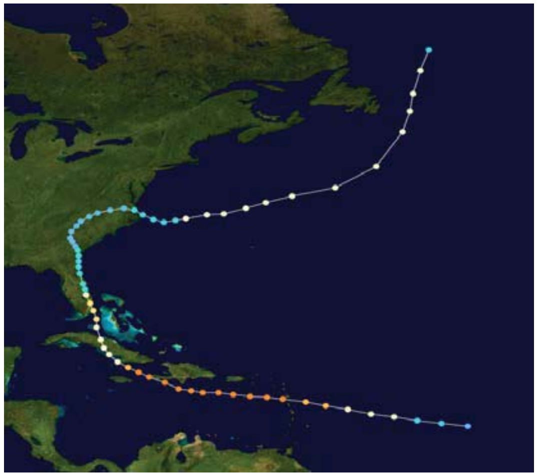
- **Prior to land fall, loads are high due to customers cooling their homes and lowering refrigerator temperatures**
- **High loads prior to land fall occur while FPL is shutting down specific units**
  - For example, a hurricane impacting the St. Lucie units (almost 2,000 MW of generation/gross output), must go to 60% output as early as 24 hours prior to land fall, and complete shut down at 18 hours prior to hurricane winds at the site.
- **Activation of LM due to a capacity shortfall prior to landfall would have an impact on our customers' preparations including efforts to pre-cool their homes**
- **A generation reserve of approximately 2,650 MW (as discussed on slide 20 – Operational generation reserves) provides additional reliability, allowing service for our customers prior to hurricane impact**

Operations prior to hurricane landfall must consider the unavailability of specific generation and impact to customers

If a hurricane impacts both PTN and PSL, there is high potential to shut down both units

PTN and PSL Impact and Generation Reserves

- Over the past 100 years, multiple hurricanes have impacted the PTN and PSL areas
- In 1960, Hurricane Cleo (Category 2) may have resulted in sustained hurricane force winds at both PTN and PSL (no anemometers in area)
- Both plants, with output of approx. 3,600 MW, would need to shut down if affected



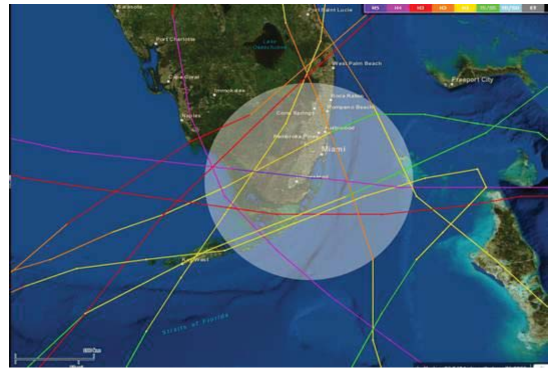
- The operational generation reserves provide additional reliability to mitigate the unavailability of generation prior to hurricane impact

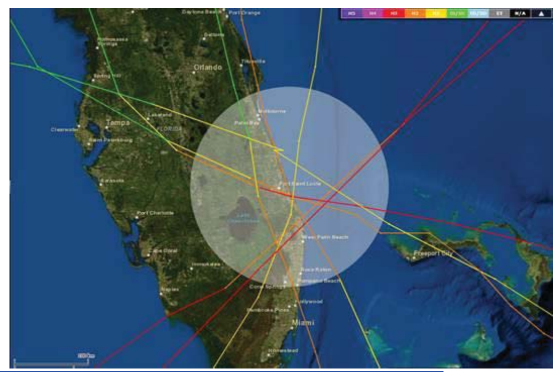
The impact of a hurricane affecting PTN and PSL would require the use of large amounts of LM. Shedding of firm customers is not expected.

Generation reserves are needed to account for generation during periods prior to hurricane landfall

Generation Reserves Needed Pre-Hurricane

- **From the period of 1960-2013 eleven hurricanes tracked within 65 nautical miles of Turkey Point and another 8 hurricanes tracked within 65 nautical miles of St. Lucie**
  - Turkey Point hurricanes would reduce the total reserve margin from 21.0% (year 2021) to 13.9%
  - St. Lucie hurricanes would reduce the total reserve margin from 21.0% (year 2021) to 12.2%





The impact from a hurricane to one of the nuclear sites is significant, resulting in the loss of most of the generation

The 4th topic is that the potential for regulatory implications due to emergency operations declarations

North American Electric Reliability Corporation (NERC) Standards

- **EOP-002 NERC Reliability Standard: Declaration of Energy Emergency Alert (EEA)**
  - FPL's plan based on its interpretation of EOP-002 which is to declare an EEA-2 when LC capability is less (or close to less) than the required reserves necessary to cover the loss of largest FPL unit (FM2 at 1,515 MW by 2021)
    - -- Note: EEA-3 is when load shedding is eminent or underway
  - FPL plan will not result in a declaration for limited (e.g., less than 400 MW) use of LC
    - -- FPL has not declared an EEA under EOP-002
  - From discussions with peers in the Southeast and limited information on NERC website, FPL's practice appears to be consistent with historical declarations in other regions

FPL.

The 4th topic is that the potential for regulatory implications also influences FPL's operating philosophy (Cont'd)

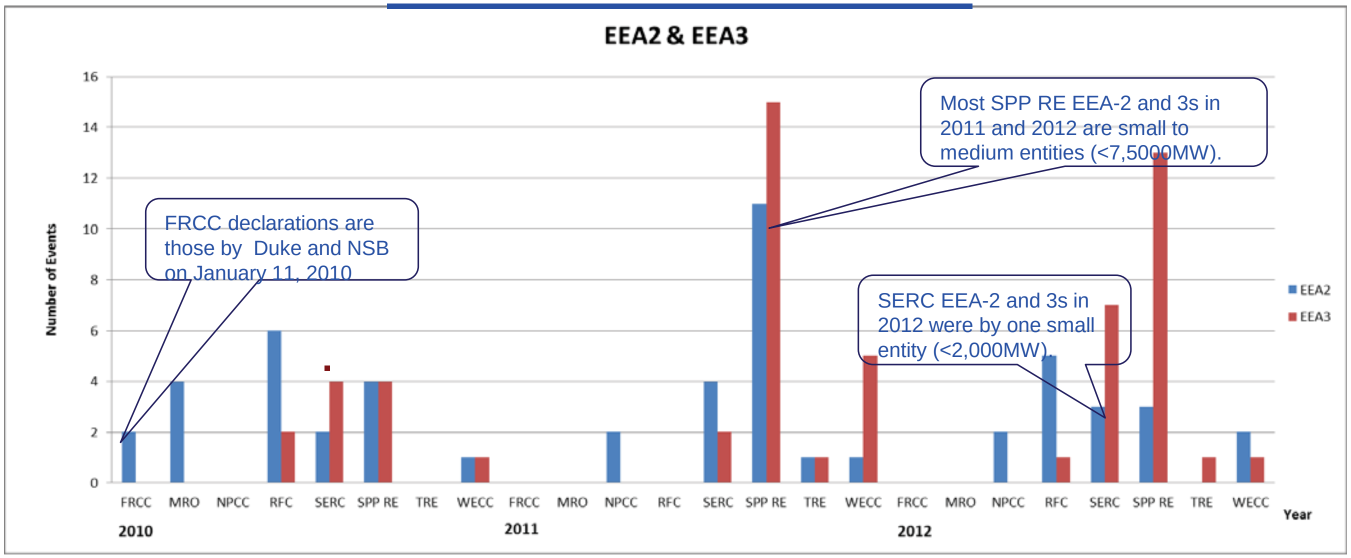
North American Electric Reliability Corporation (NERC) Standards

- **EOP-002 triggers for EEA-2s is not clear, and recognized as such industry-wide**
  - Standard implies that a declaration of an EEA-2 is linked to LC deployment
  - FRCC procedure linking the FRCC Emergency Capacity Plan with EOP-002 does clarify triggers for EEA-2
- **NERC tracks EEA-2s and EEA-3s under EOP-002 to measure the number of events declared during peak load periods, this may serve as leading indicator of capacity shortfall**

FPL

NERC historical tracking of alert declarations varies by region

EEA-2 and EEA-3 Events



- **Legitimate emergencies will be tracked by NERC**
  - NERC states that EEA-2 events calling solely for activation of DSM or interruption of non-firm load will be excluded from the metric in the future as demand response is a legitimate resource and are not of direct concern regarding reliability.

The potential, form, and results of regulatory scrutiny based on what NERC considers too many legitimate emergencies is unclear

The need for a new GRM reliability criterion can be supported by 3 points

FPL's Need for a New Reliability Criterion

- **These 3 points (presented in decreasing order of importance) are:**
  1. "All resource plans with identical total reserve margins are not created equal" from an operational perspective (a higher GRM plan will result in significantly more total resources - generation and load management - available for system operators than a lower GRM plan in severe peak conditions)
  2. A resource plan with a higher GRM value is projected to be more reliable from an LOLP perspective (slides 3 through 5)
  3. A resource plan with a higher GRM value is projected to have to use its LM resources less frequently (from 12/06/13 presentation)
- **In regard to point 1 above:**
  – This point can be demonstrated by a "look backwards" analysis of Winter 2010 (slides 15 – 17 and Appendix slides 24 - 27)
  – This point can also be demonstrated by a "looking forward" analysis for Summer and Winter for the year 2021 (slides 18 & 19 and Appendix slides 28 -33)

In the "look backwards" analysis, several perspectives were taken of the Winter peak day in 2010

Regarding the January 2010 Peak Day

- **The first perspective was of what actually happened on that day (the 2009 Site Plan's projections for the year 2010 were used as the starting point for this analysis)**
- **The second perspective was to see how FPL's system would have fared if the resource plan had been different with a GRM of 10% in 2010 (but an identical Summer total RM of 20.4%)**
- **The third perspective was to see how FPL's system would have fared if the resource plan had been different with a GRM of 5% in 2010 (but an identical Summer total RM of 20.4%)**

Sufficient generation reserves are needed for peak load periods

January 11, 2010 (7- 8 AM) – All Time FPL Peak Load

- **Relative to the 2009 Ten Year Site Plan (TYSP), the total reserves for the Winter were 58.2% with a Generation Reserve Margin (GRM) of 42.9%. The Summer reserve margin was 20.4% with an 8.4% GRM**
  - FPL's load was 24,872 MW, 6,196 MW higher than forecasted
  - FPL entered day with 7.4% reserves, all in load management (LM)
  - 24,872 MW of generation was available
  - FPL implemented C/I LM and voltage reduction (561 MW)
  - FPL sold 526 MW of emergency power
  - 1,144 MW of LM remained available during the peak hour
  - No firm load was curtailed by FPL or any other Florida utility
  - Several hours after the peak hour Turkey Point 4 (PTN4) tripped with 750 MW of generation

In Winter 2010, the generation reserves were just sufficient to provide reliable operations with no curtailment of firm load in Florida

FPL.

Analyses of Winter 2010, using different GRM values, provide a couple of key "takeaways"*

Takeaways from the January 2010 Peak Day Analyses

	Firm Load is Shed?		
Scenario	**W/ TP4**	**W/O TP4**	**Comments**
Actual: 8.4% GRM	No	No	If PTN4 would have tripped prior to the peak, FPL would have implemented additional LM
w/ 10% GRM	No	No	A 10% GRM (as compared to a 5%) would have resulted in a 659 MW increase in LM reserves, and no utilities would have had to shed firm load Similar to the 8.4% GRM scenario, if PTN4 would have tripped prior to the peak, FPL would have implemented additional LM
w/ 5% GRM	No	Yes	W/O TP4 either FPL or another utility in Florida would have had to shed 52 MW of firm load impacting over 30,000 customers

* The actual analyses are presented in Appendix slides 24 - 27

On 1/11/10, a 5% GRM would have resulted in 30,000 firm load customers being shed, but a 10% GRM would have provided 659 MW of additional reserves

A "looking forward" analysis of 2021 addressed both Summer and Winter with 5% and 10% GRM-based resource plans

<u>How the Analyses of 2021 Were Conducted</u>

- The 2013 Site Plan's resource plan for the year 2021 was the starting point: 6.9% GRM, 21.0% Summer total RM, and 34.5% Winter total RM
- Then two alternate resource plans with the same 21.0% Summer total RM, but either 5% or 10% Summer GRM were "constructed" for Summer (comparable alternate resource plans for Winter 2021 were also constructed)
- To simplify the analysis, the alternate plans <u>differed in regard to EE and generation only</u> (similar results would occur if LM instead of EE had been varied in the plans)
- Identical changes of 9% were made to forecasted load, EE, and available generation (the percentage change chosen is arbitrary, but reasonable and consistent)
- The resulting available generation and total resources remaining after these changes were made are compared (note that EE's impact has already "happened" at the peak)

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The "looking forward" analyses of resource plans for 2021 provides additional support for a 10% GRM-based resource plan compared to a 5% GRM-based plan

Key Points from the "Looking Forward" Analyses

- Only the 10% GRM-based resource plan is projected to allow FPL to meet firm load in both Summer and Winter of 2021
- Furthermore, when comparing the two GRM-based resource plans, the 10% GRM-based plan provides significantly more MW of resources for both Summer and Winter

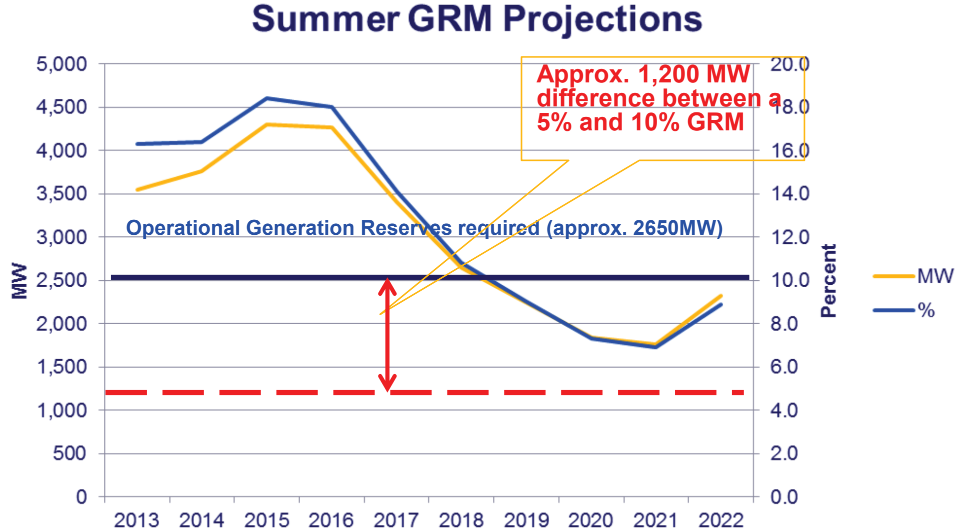
	Summer of 2021			Winter of 2021		
	w/ 10% GRM	w/ 5% GRM	Increased Total Reserves w/ 10% GRM	w/ 10% GRM	w/ 5% GRM	Increased Total Reserves w/ 10% GRM
Total Reserves Remaining after Load, EE, and Generation Adjustments	34	(169)	202	2,921	2,193	728

This "looking forward" analysis again shows system operators will have more resources for their use with a 10% GRM, rather than a 5% GRM, resource plan

Docket No. 150196-EI
The Need for a 3rd Reliability Criterion for FPL:
A Generation-Only Reserve Margin (GRM) Criterion
Exhibit SRS-11, Page 19 of 33

A 10% GRM criterion is a reasonable, easy-to-articulate proxy for FPL's operational generation reserves need

GRM Projections from FPL's 2013 Site Plan



- **FPL's goal is to maintain ~ 2,650 MW of Operational Generation Reserves to cover the following operational situations:**
  - Expected unavailable generation (687 MW)
  - The generation loss of the largest the largest unit (1,515 MW)
  - Real time operating reserves deployable within 15 minutes as part of the Florida Reserve Sharing Group (450 MW by 2021)

A 10% GRM is consistent with FPL's required operational reserves

FPL has begun using the new GRM criterion in its resource planning process and in 2014 analyses to be filed w/ the FPSC

Next Steps regarding the GRM Criterion

- Text explaining why FPL is using the new criterion will be included in the 2014 TYSP filing and as part of the DSM Goals testimony
- The explanation focuses on analyses comparing resource plans with 10% GRM vs. 5% GRM and include these key points :
  - A 10% GRM results in hundreds of MW of additional operational reserves on severe peak days
  - A 10% GRM results in lower LOLP projections
  - A 10% GRM criterion matches well with the approximately 2,650 MW of generation reserves necessary for operations
- Analyses supporting the 2014 TYSP and DSM Goals filings in April, and the 2014 NCRC filing in early May, all are using the 10% GRM criterion
- These analyses all assume that the 10% GRM criterion must be met beginning in the Summer of 2019

FPL is not making a separate filing seeking official FPSC approval for FPL's GRM criterion

Next Steps regarding the GRM Criterion (Continued)

- No separate filing/request seeking official FPSC approval for the new GRM criterion will be made
- The only time the FPSC has officially approved a reliability criterion is in the late 1990s when it approved the voluntary stipulation by FPL, TECO, and DEF to move from a 15% to a 20% total reserve margin criterion to close an FPSC docket examining Florida reserves
- TECO did not request approval for its similar supply side reserve margin which it has been using for approximately 10 years
- It is anticipated that discovery requests focused on the new GRM criterion will be received in regard to both the TYSP and DSM Goals filings

FPL

Appendix

FPL and others utilities in Florida were marginally able to serve their entire firm load and FPL met its operational reserve requirements with an 8.4% GRM

January 11, 2010 (7-8 AM) – All Time FPL Peak Load

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (7) - (5) - (3)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
2009 TYSP resource plan projection for Summer 2010	22,916	21,147	220	20,927	1,899	19,028	3,888	20.4%	1,769	8.4%	---
2009 TYSP resource plan projection for Winter 2010	26,852	18,790	114	18,676	1,705	16,971	9,881	58.2%	8,062	42.9%	---
Note that all subsequent rows present adjustments to show how Jan 2010 peak day actual conditions differed from planned conditions shown on row (2)											
Load Adjustments on Jan 2010 peak day											
Increase in FPL load served after EE (w/o DSM)				6,196							---
Resulting operating conditions on 2010 Winter peak hour	26,852			24,872	1,705	23,167	3,685	15.9%	1,980	8.0%	**Yes**

FPL and other utilities in Florida were marginally able to serve entire firm load and meet operational reserve requirements with 8.4% GRM (additional adjustments)

January 11, 2010 (7-8AM) – All Time FPL Peak Load

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
				= (2) - (3)		= (4) - (5)	= (1) - (6)	= (7) / (6)	= (7) - (5) - (3)	= (9) / (2)	
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
Generation / Load Management (CILC and Voltage reduction) Adjustments of on Jan 2010 peak day											
	(1,980)			(561)	(561)						---
Operating conditions on 2010 Winter peak hour	24,872			24,311	1,144	23,167	1,705	7.4%	561	2.3%	**Yes**
Emergency Sales adjustments on Jan 2010 peak day resulted in 24,346MW of FPL load and 526MW of emergency sales. Total load (FPL and 3rd parties) served is 24,872MW											
Emergency sales (recallable)				526							---
Operating conditions on 2010 Winter peak hour	24,872			24,872	1,144	23,728	1,144	4.8%	0	0.0%	**Yes**
TP Unit 4 Nuclear Trip on Jan 2010 prior to peak day											
TP Nuclear Adjustment	(750)			(750)	(750)						---
Operating conditions on 2010 Winter peak hour	24,122			24,122	394	23,728	394	1.7%	**0**	0.0%	**Yes**

Two “what if” analyses examined how FPL would have fared if it had entered Winter 2010 with a higher (10%) or lower (5%) GRM

“What If”for January 2010 Peak Day w/ 10% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
Creation of Revised 10% GRM Summer Plan and Corresponding Winter Plan											---
Modify the 2009 TYSP resource plan for Summer 2010 to achieve a 10% GRM	23,262	21,147	(72)	21,219	1,899	19,320	3,941	20.4%	2,115	10.0%	---
Using Winter vs Summer differentials, and the modified Summer resource plan, create a comparable resource plan for Winter 2010	27,216	18,790	(37)	18,827	1,705	17,122	10,094	59.0%	8,426	44.8%	Yes
Load Adjustments on Jan 2010 peak day											
Increase in FPL load served after EE but prior to LM utilization				6,231							
Resulting operating conditions on 2010 Winter peak hour due to load	27,216		(37)	25,058	1,705	23,353	3,863	16.5%	2,158	8.6%	Yes
Generation / Load Management / Further FPL Load Adjustments of on Jan 2010 peak day											
	(1,980)			(561)	(561)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments	25,236			24,497	1,144	23,353	1,883	8.1%	739	3.0%	Yes
Emergency Sales Adjustments on Jan 2010 peak day											
Emergency sales				526							
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments+Em. Sales	25,236			25,023	1,144	23,879	1,357	5.7%	213	0.9%	Yes
TP Unit 4 Nuclear Trip on Jan 2010 prior to peak day											
TP Nuclear Adjustment	(750)			(750)	(750)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, generation & TP adjustments	24,486			24,273	394	23,879	607	2.5%	213	0.9%	Yes

* The 2010 Tony letter showed FPL unit capability as 23,333 MW for Winter 2010 & 22,142 MW for Summer. The Winter/Summer ratio is 1.054.

FPL’s generation and LM resources would have been greater with a 10% GRM than with 8.4% GRM

FPL

The second "what if" analysis examined how FPL would have fared if it had entered Winter 2010 with a lower (5%) GRM

"What If"for January 2010 Peak Day w/ 5% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
Creation of Revised 5% GRM Summer Plan and Corresponding Winter Plan											---
Modify the 2009 TYSP resource plan for Summer 2010 to achieve a 5% GRM	22,204	21,147	806	20,341	1,899	18,442	3,762	20.4%	1,057	5.0%	---
Using Winter vs Summer differentials, and the modified Summer resource plan, create a comparable resource plan for Winter 2010	26,102	18,790	418	18,372	1,705	16,667	9,435	56.6%	7,312	38.9%	**Yes**
Load Adjustments on Jan 2010 peak day											
Increase in FPL load served after EE but prior to LM utilization				6,231							
Resulting operating conditions on 2010 Winter peak hour due to load	26,102		418	24,603	1,705	22,898	3,204	14.0%	1,499	6.1%	**Yes**
Generation / Load Management / Further FPL Load Adjustments of on Jan 2010 peak day											
	(1,980)			(561)	(561)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments	24,122			24,042	1,144	22,898	1,224	5.3%	80	0.3%	**Yes**
Emergency Sales Adjustments on Jan 2010 peak day											
Emergency sales				526							
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments+Em. Sales	24,122			24,568	1,144	23,424	698	3.0%	(446)	-1.8%	**No**
TP Unit 4 Nuclear Trip on Jan 2010 prior to peak day											
TP Nuclear Adjustment	(750)			(750)	(750)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, generation & TP adjustments	23,372			23,818	394	23,424	(52)	-0.2%	(446)	-1.9%	**No**

* The 2010 Tony letter showed FPL unit capability as 23,333 MW for Winter 2010 & 22,142 MW for Summer. The Winter/Summer ratio is 1.054.

Even after exhausting FPL's generation and LM resources, FPL would not have been able to meet its firm load with a 5% GRM

FPL

Regarding a "look forward" to 2021, the 5% Summer GRM-based resource plan was examined first in regard to Summer peak

"What If" Summer 2021 Peak Day w/ 5% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
Summer	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
5% GRM resource plan	26,838	25,560	1,230	24,330	2,150	22,180	4,658	21.0%	1,278	5.0%
Higher-than-Projected Peak Load *		2,300								
Lower-than-projected EE Reduction *			(111)							
Resulting actual operating conditions on 2021 peak hour	26,838	27,860	1,119	26,741	2,150	24,591	2,247	9.1%	97	0.3%
Unavailable Generation *	(2,415)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	24,423	27,860	1,119	26,741	2,150	24,591	(169)	-0.7%	(2,319)	-8.3%

* A 9% adjustment was made to the starting point value in the first row.

With the 5% GRM plan, FPL would not be able to meet Summer firm load (as seen by the negative 169 MW) of Total Reserves in Col. 7)

FPL

The 10% Summer GRM-based resource plan was examined next in regard to Summer peak

"What If" Summer 2021 Peak Day w/ 10% GRM

Summer	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
10% GRM resource plan	28,116	25,560	174	25,386	2,150	23,236	4,880	21.0%	2,556	10.0%
Higher-than-Projected Peak Load *		2,300								
Lower-than-projected EE Reduction *			(16)							
Resulting actual operating conditions on 2021 peak hour	28,116	27,860	158	27,702	2,150	25,552	2,564	10.0%	414	1.5%
Unavailable Generation *	(2,530)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	25,586	27,860	158	27,702	2,150	25,552	34	0.1%	(2,117)	-7.6%

* A 9% adjustment was made to the starting point value in the first row.

With the 10% GRM plan, FPL would be able to meet Summer firm load (as seen by the positive 34 MW of Total Reserves)

The 5% Summer GRM-based resource plan was examined next in regard to Winter peak

"What If" Winter 2021 Peak Day w/ 5% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
Winter	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
Winter resource plan corresponding to the Summer plan w/ 5% GRM	28,287	23,601	637	22,964	1,597	21,367	6,920	32.4%	4,686	19.9%
Higher-than-Projected Peak Load *		2,124								
Lower-than-projected EE Reduction *			(57)							
Resulting actual operating conditions on 2021 peak hour	28,287	25,725	580	25,145	1,597	23,548	4,739	20.1%	3,142	12.2%
Unavailable Generation *	(2,546)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	25,741	25,725	580	25,145	1,597	23,548	2,193	9.3%	596	2.3%

* A 9% adjustment was made to the starting point value in the first row.

With the 5% GRM resource plan, FPL would be able to meet Winter firm load with 2,193 MW of Total Reserves to spare

FPL

The 10% Summer GRM-based resource plan was then examined in regard to Winter peak

"What If" Winter 2021 Peak Day w/ 10% GRM

Winter	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or	(10) = (9) / (2)
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
Winter resource plan corresponding to the Summer plan w/ 10% GRM	29,634	23,601	90	23,511	1,597	21,914	7,720	35.2%	6,033	25.6%
Higher-than-Projected Peak Load *		2,124								
Lower-than-projected EE Reduction *			(8)							
Resulting actual operating conditions on 2021 peak hour	29,634	25,725	82	25,643	1,597	24,046	5,588	23.2%	3,991	15.5%
Unavailable Generation *	(2,667)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	26,967	25,725	82	25,643	1,597	24,046	2,921	12.1%	1,324	5.1%

* A 9% adjustment was made to the starting point value in the first row.

With the 10% GRM resource plan, FPL would be able to meet Winter firm load with 2,921 MW of Total Reserves to spare

FPL

Another "look forward to 2021" case was analyzed in which LM, not EE, was allowed to vary

"What If" Summer 2021 Peak Day w/ 5% GRM & LM Varying

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
Summer	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
5% GRM resource plan	26,838	25,560	830	24,730	2,550	22,180	4,658	21.0%	1,278	5.0%
Higher-than-Projected Peak Load *		2,300								
Lower-than-projected EE and LM Reduction *					(230)					
Resulting actual operating conditions on 2021 peak hour	26,838	27,860	830	27,030	2,321	24,710	2,128	8.6%	-192	-0.7%
Unavailable Generation *	(2,415)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	24,423	27,860	830	27,030	2,321	24,710	(287)	-1.2%	(2,608)	-9.4%

* A 9% adjustment was made to the starting point value in the first row.

With the 5% GRM plan, FPL would not be able to meet Summer firm load (as seen by the negative 287 MW of Total Reserves in Col. 7)

Another “look forward to 2021” case was analyzed in which LM, not EE, was allowed to vary - continued

“What If” Summer 2021 Peak Day w/ 10% GRM & LM Varying

Summer	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
10% GRM resource plan	28,116	25,560	830	24,730	1,494	23,236	4,880	21.0%	2,556	10.0%
Lower-than-projected EE and LM Reduction *		2,300								
Lower-than-projected EE Reduction *					(134)					
Resulting actual operating conditions on 2021 peak hour	28,116	27,860	830	27,030	1,360	25,671	2,445	9.5%	1,086	3.9%
Unavailable Generation *	(2,530)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	25,586	27,860	830	27,030	1,360	25,671	(85)	-0.3%	(1,445)	-5.2%

* A 9% adjustment was made to the starting point value in the first row.

With the 10% GRM plan, FPL comes closer to meeting Summer firm load (as seen by the negative 85 MW of Total Reserves in Col. 7)

FPL

	Winter Peak	
Year	**Weather Impact (MW)**	**Cold Buildup (Heating Degree Hours)****
2009-2010	**4,410**	**919**
2010-2011	**2,479**	**815**
1989-1990*	**3,497**	**789**
1996-1997	**1,727**	**743**
1988-1989	**1,428**	**738**
2002-2003	**2,164**	**669**
1995-1996	**1,764**	**669**
2007-2008	**1,223**	**654**
2000-2001	**1,125**	**653**
2008-2009	**1,190**	**575**

*1989 Christmas experience

** Heating Degree Hours are the number of degrees that the hourly temperature is below 66 °F

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 72
PARTY: FPL
DESCRIPTION: Richard Feldman RF-9

EXHIBIT NO. 73

DOCKET NO: 150196-EI

WITNESS: Steven R. Sim

PARTY: FPL

DESCRIPTION: Excerpt of FPL's 2015 Status/Update Report on Storm Hardening/Preparedness and Distribution Reliability

DOCUMENTS:

PROFFERED BY: ECOSWF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 73
PARTY: ECOSWR
DESCRIPTION: Sim/Excerpt of FPL's 2015 update Report on Storm Hardening Preparedness and Distribution Reliability

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March 2, 2015

- VIA HAND DELIVERY -

Thomas Ballinger
Division of Engineering
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: **Florida Power & Light Company's 2015 Status/Update report on Storm Hardening/Preparedness and Distribution Reliability**

Dear Mr. Ballinger:

Pursuant to Order No. PSC-06-0781-PAA-EI, I am enclosing for filing in the above docket the original and seven copies of Florida Power & Light Company's ("FPL's") status report and update of its *Storm Preparedness Initiatives,* which was filed in Docket No. 060198-EI on June 1, 2006. Consistent with Staff's request at its October 30, 2006 workshop, FPL has consolidated into the enclosed document the following additional information:

(1) Wood Pole Inspection Report required by Order No. PSC-06-0144-PAAEI, issued in Docket No. 060078-EI on February 27, 2006;

(2) Distribution Reliability Report required by rule 25-6.0455, F.A.C.; and,

(3) A discussion of FPL's 2012 results for storm hardening facilities;

If there are any questions regarding this transmittal, please contact me at 561-304-5633.

Sincerely,

Scott A. Goorland

Enclosures

cc: Jim Dean, Director, Division of Economic Regulation

Florida Power & Light Company
Annual Filing to the Florida Public Service Commission
March 2, 2015

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EXECUTIVE SUMMARY – FPL's MARCH 2, 2015 FILING

In 2014, FPL continued to invest in and take significant steps to strengthen its electrical infrastructure and enhance its emergency response capabilities. Included in this ongoing work were pole inspections, system infrastructure hardening, vegetation management, as well as other storm preparedness initiatives. Additionally, FPL continued to deliver excellent overall reliable service for its customers.

In 2015, FPL plans to continue its efforts to accelerate the strengthening of its electric infrastructure against severe weather and maintain its strong everyday reliability for customers.

This filing provides details about these efforts and is organized into two major sections: (1) Storm Preparedness/Infrastructure Hardening; and (2) Reliability. The first section concentrates on FPL's efforts to strengthen its distribution and transmission systems and enhance storm response capabilities. Initiatives addressed in this section include: Pole Inspections; System Hardening; 10 Storm Preparedness Initiatives; and 2015 Storm Season Readiness. The second section of this report includes information about FPL's service reliability, including 2014 results and 2015 plans for the distribution and transmission systems.

The following are brief overviews of each of these two sections:

Section 1: STORM PREPAREDNESS/INFRASTRUCTURE HARDENING

Pole Inspections

Distribution – In 2014, consistent with its FPSC-approved plan, FPL initiated its second eight-year pole inspection cycle.

- In 2014, FPL inspected approximately 1/8 of its pole population and completed all remaining follow-up work resulting from the 2013 pole inspections.
- In 2015, FPL plans to complete inspections on approximately 1/8 of its pole population, as well as complete all remaining follow-up work resulting from the 2014 pole inspections.

Transmission – In 2014, FPL completed all transmission pole/structure inspections consistent with its FPSC-approved plan.

- In 2014, FPL performed ground level visual inspections on 100% of its transmission poles/structures. Additionally, FPL performed climbing or bucket truck inspections on approximately 1/6 of its wood poles/structures, 1/6 of all 500kV structures, 1/10 of its other concrete and steel poles/structures and conducted storm and pre-construction mitigation patrols on all concrete and steel poles/structures. Also, FPL completed all follow-up work resulting from the 2013 inspections.

- In 2015, FPL plans to conduct ground level visual inspections on 100% of its transmission poles/structures; perform climbing or bucket truck inspections on approximately 1/6 of its wood poles/structures, 1/6 of all 500kV structures and 1/10 of its concrete and steel poles/structures; and complete all follow-up work identified from the 2014 inspections.

System Hardening

Distribution

Consistent with FPL's FPSC-approved 2013–2015 Electric Infrastructure Storm Hardening Plan (see Order PSC-13-0639-PAA-EI in Docket No. 130132-EI), FPL continued to implement its three-prong approach in 2014 by applying: (1) extreme wind loading criteria (EWL) to critical infrastructure facilities (CIF); (2) incremental hardening, up to and including EWL, to "Community Project" feeders; and (3) construction design guidelines that require EWL for the design and construction of all new overhead facilities, major planned work, relocation projects, and daily work activities.

- In 2014, FPL applied EWL on 75 feeder projects serving various CIF, e.g., police/fire stations and water treatment plants, one highway crossing and 16 "01" switches. FPL also applied incremental hardening to 21 "Community Projects", i.e., feeders that serve essential community needs such as grocery stores, gas stations and pharmacies. Additionally, FPL's Design Guidelines were applied to all new construction and other construction activities described above. Finally, FPL installed submersible equipment to mitigate the impact of significant water intrusion in six of the 12 vaults in the Miami downtown electric network that are located just at or within the FEMA 100-year flood elevation levels.

- FPL also continued to promote overhead-to-underground conversions in 2014, completing one project that qualified under its Governmental Adjustment Factor (GAF) tariff.

- In 2015, FPL plans to apply EWL on 65 CIF feeder projects, one highway crossing and 16 "01" switches. FPL will also incrementally harden, up to and including EWL, 38 Community Project feeders. FPL's Design Guidelines will again be used for all new construction activities. Finally, FPL will complete its efforts to install submersible equipment to mitigate the impact of significant water intrusion in the remaining six vaults in the Miami downtown electric network that are located just at or within the FEMA 100-year flood elevation levels.

Transmission
Storm hardening details for Transmission are provided in Storm Preparedness Initiative No. 4

Storm Preparedness Initiatives

(1) Vegetation Trim Cycles – In 2014, FPL continued its three-year average cycle and mid-cycle programs for feeders and its six-year average trim cycle for laterals.

(2) Joint Use Audits – Approximately 20 percent of FPL's jointly used poles are audited annually through its joint use surveys. Additionally, joint use poles are inspected through FPL's pole inspection program. Survey and inspection results continue to show that through FPL's joint use processes and procedures, along with cooperation from joint pole owners and third-party attachers, FPL has properly identified and accounted for joint use facilities.

(3) Six-year Transmission Structure Inspection Cycle – In 2014, FPL performed ground level visual inspections on 100% of its transmission poles/structures. Additionally, FPL performed climbing or bucket truck inspections on approximately 1/6 of its wood transmission system poles/structures, 1/6 of its 500 kV structures, 1/10 of its other concrete and steel poles/structures and conducted storm and pre-construction mitigation patrols on all concrete and steel poles/structures.

(4) Hardening the Transmission System – In 2014, FPL continued executing its plan to replace all wood transmission structures in its system, completed the replacement of all ceramic post insulators with polymer insulators within its system and continued with its installation of flood monitoring equipment in substations that are more susceptible to flooding.

(5) Distribution Geographic Information System (GIS) – FPL completed its five originally approved key Distribution GIS improvement initiatives in 2011. These initiatives included developing a post-hurricane forensic analysis tool and the addition of poles, streetlights, joint use survey and hardening level data to the GIS. Updates to the GIS continue as data is collected through inspection cycles and other normal daily work activities.

(6) Post-Storm Forensic Collection/Analysis – FPL has post-storm forensic data collection and analysis plans, systems and processes in place and available for use. No major storms affected FPL's service territory in 2014; therefore, no forensic collection or analysis was required.

(7) Overhead (OH) and Underground (UG) Storm Performance – FPL has plans, systems and processes in place to capture OH and UG storm performance. No major storms affected FPL's service territory in 2014; therefore, no data collection or analysis was required.

(8) Increased Coordination with Local Governments – In 2014, FPL continued its efforts to improve local government coordination. Activities included: (1) meetings with county emergency operations managers to discuss critical infrastructure locations in each jurisdiction; (2) inviting federal, state, county and municipal emergency management personnel to participate in FPL's annual company-wide storm preparedness dry run and; (3) FPL External Affairs managers conducted 483 community presentations, providing information on storm readiness and other topics of community interest.

(9) Collaborative Research on Hurricanes/Storm Surge – Collaborative research efforts led by the Public Utility Research Center (PURC) have resulted in greater knowledge of appropriate vegetation management practices during storm and non-storm periods, wind during storm and non-storm events, and hurricane and damage modeling to further understand the costs and benefits of undergrounding.

(10) Natural Disaster Preparedness/Recovery Plans – FPL's Storm Emergency Plan identifies emergency conditions and the responsibilities and duties of the FPL emergency response organization for severe weather and fires. The plan covers the emergency organization, roles and responsibilities and FPL's overall severe storm emergency processes. These processes describe the planning activities, restoration practices, public communications, and coordination with government, training, practice exercises and lessons-learned evaluation systems. The plan is reviewed annually and revised as necessary.

2015 Storm Season Readiness

FPL's comprehensive storm plan focuses on readiness, restoration and recovery in order to respond safely and as quickly as possible in the event the electrical infrastructure is damaged by a storm. FPL is well-prepared for the 2015 storm season and continues to train and hone its storm preparedness and response capabilities.

In addition to the initiatives to strengthen its system and improve storm preparedness discussed previously, FPL will complete the following additional storm preparedness activities prior to the start of storm season:

- Extensive storm restoration training based on employees' storm roles;
- Annual company-wide hurricane dry run in late April/early May;
- Management workshops throughout the storm season to keep focus on key storm restoration policies/processes;
- Plan for and review of mutual assistance agreements to ensure they are adequate and ready;
- Continue to focus on improving outage communications and estimated restoration times to customers;
- Clear vegetation from all feeder circuits serving top critical infrastructure (e.g. top CIF hospitals, 911 centers, special needs shelters, police and fire stations, etc.) prior to the peak of hurricane season; and

- Implement new technology to be utilized by storm damage assessors to improve damage assessment collection/analysis capabilities.

Section 2: RELIABILITY

Total FPL System (Distribution and Transmission) – Overall reliability is best gauged by SAIDI (System Average Interruption Duration Index), considered the most relevant and best overall reliability indicator because it encompasses two other standard industry performance metrics for reliability: SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index). In 2014, FPL continued to provide strong overall reliability for its customers, achieving an overall adjusted SAIDI of 66.6 minutes (2013 – 65.6 minutes).

Distribution – FPL's 2014 overall adjusted distribution reliability, as measured by SAIDI was 63.8 (2013 – 61.4). 2014 adjusted results for SAIFI were 0.99 interruptions per customer (2013 – 0.89 interruptions). Adjusted 2014 results for CAIDI were 64.5 minutes (2013 – 68.7 minutes) and adjusted MAIFIe for 2014 was 8.7 momentary events (2013 – 9.1 momentary events).

Transmission – In 2014, FPL's Transmission/Substation adjusted SAIDI was 2.8 minutes (2013 – 4.2 minutes), adjusted SAIFI was 0.21 interruptions per customer (2013 – 0.22 interruptions) and adjusted MAIFI was 0.7 momentary events (2013 – 0.7 momentary events).

EXHIBIT NO. 74

DOCKET NO: 150196-EI

WITNESS: Steven R. Sim

PARTY: FPL

DESCRIPTION: Excerpt of FPL's 2015 Petition for Approval of Demand-Side Management Plan

DOCUMENTS:

PROFFERED BY: ECOSWF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 74
PARTY: ECOSWF
DESCRIPTION: Sim/Excerpt of FPL's 2015 Petition for approval of DMS Plan

FPL

Jessica A. Cano
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Florida Power & Light Company
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(561) 691-7135 (Facsimile)

March 16, 2015

-VIA ELECTRONIC FILING-

Carlotta Stauffer, Director
Division of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. ___________; Petition for Approval of Florida Power & Light Company's Demand-Side Management Plan

Dear Ms. Stauffer:

Please find enclosed for filing the Petition for Approval of Florida Power & Light Company's ("FPL's") Demand-Side Management ("DSM") Plan, including Attachment 1 (FPL's proposed DSM Plan with Appendix A and Appendix B) and Attachment 2 (tariff sheets proposed for cancellation in both legislative and final format).

Consistent with direction received from FPSC staff, FPL will also be submitting 5 hard copies and 3 compact discs containing FPL's filing in electronic format.

If there are any questions regarding this filing, please contact me at 561-304-5226.

Sincerely,

s/ Jessica A. Cano
Jessica A. Cano
Fla. Bar No. 0037372

Enclosures
cc: Theresa Tan, Esq., Division of Legal Services

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Approval of) Florida Power & Light Company's) Demand-Side Management Plan)	Docket No. __ Filed: March 16, 2015

PETITION FOR APPROVAL OF FLORIDA POWER & LIGHT COMPANY'S DEMAND-SIDE MANAGEMENT PLAN AND REQUEST TO CANCEL CLOSED ON CALL TARIFF SHEETS

Florida Power & Light Company ("FPL" or "the Company"), pursuant to Section 366.82, Florida Statutes; Rules 25-9.001(3), 25-17.0021, and 28-106.201, Florida Administrative Code; and Order No. PSC-14-0696-FOF-EU (issued Dec. 16, 2014), petitions the Florida Public Service Commission ("Commission") to approve FPL's Demand-Side Management ("DSM") Plan ("DSM Plan" or "Plan") filed herewith, including the cancellation of the closed On Call tariff sheets and consolidation of customers into the open Residential Load Control tariff, and to authorize FPL to recover through the Energy Conservation Cost Recovery ("ECCR") clause the reasonable and prudent expenditures associated with the implementation of this DSM Plan. In support of this petition FPL states as follows:

1. FPL is a corporation with headquarters at 700 Universe Boulevard, Juno Beach, Florida 33408. FPL is an investor-owned utility operating under the jurisdiction of this Commission pursuant to the provisions of Chapter 366, Florida Statutes. Any pleading, motion, notice, order or other document required to be served upon FPL or filed by any party to this proceeding should be served upon the following individuals:

Kenneth A. Hoffman
Vice President Regulatory Affairs
Florida Power & Light Company
215 S. Monroe Street, Ste 810
Tallahassee, FL 32301
(850) 521-3919
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Ken.Hoffman@fpl.com

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Jessica.Cano@fpl.com

2. This Petition is being filed consistent with Rule 28-106.201, Fla. Admin. Code. The agency affected is the Florida Public Service Commission, located at 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399. This case does not involve reversal or modification of an agency decision or an agency's proposed action. Therefore, subparagraph (c) and portions of subparagraphs (e), (f) and (g) of Rule 28-106.201(2) are not applicable to this Petition. In compliance with subparagraph (d), FPL states that it is not known which, if any, of the issues of material fact set forth in the body of this Petition, or the DSM Plan and attachments filed herewith, may be disputed by others.

3. FPL is subject to the Florida Energy Efficiency and Conservation Act ("FEECA"), Sections 366.80-366.85 and 403.519, Florida Statutes. Pursuant to FEECA and the Commission rules implementing FEECA, FPL is required to file a DSM Plan for Commission approval to meet the new DSM Goals established for FPL by Order No. PSC-14-0696-FOF-EU. *See* §366.82(7), Fla. Stat. (2014); Rule 25-17.0021(4), Fla. Admin. Code. FPL also is entitled to seek recovery of associated expenditures through the ECCR clause. *See* §366.82(11), Fla. Stat. (2014); Rule 25-17.015, Fla. Admin. Code. FPL has a substantial interest in whether the Commission approves its DSM Plan and authorizes cost recovery for Plan implementation expenditures and customer incentives.

FPL's Proposed DSM Plan

4. FPL's proposed DSM Plan consists of six residential programs (including one specifically targeted at low income residential customers), seven business programs, a Conservation Research and Development ("CRD") program for evaluating new technologies, a Cogeneration and Small Power Production program, and seven Solar Pilots that expire at the end of 2015.[1] FPL's low income program, while itself not cost-effective, will enhance low income customer awareness of and access to (i) energy efficiency education, (ii) low-cost and quick-payback measures, and (iii) other DSM programs that are cost-effective, consistent with the direction provided by the Commission in Order No. PSC-14-0696-FOF-EU.

5. FPL's proposed DSM Plan is included as Attachment 1, which is incorporated herein by reference. The subparts of Rule 25-17.0021(4), Fla. Admin. Code, setting forth the required information for each proposed program, are satisfied therein. FPL's DSM Plan includes Appendix A, which shows the individual program cost-effectiveness screening test results, using the Commission's approved cost-effectiveness methodology. FPL's DSM Plan also includes Appendix B, which shows the specific changes to FPL's existing DSM programs that are reflected in its proposed Plan. The development of FPL's proposed Plan relied upon the same cost-effectiveness-related inputs and assumptions that were utilized and accepted by the Commission in FPL's recent DSM Goals docket (Docket No. 130199-EI). The resulting Plan reflects related impacts to the number of measures and levels of rebates that can be offered cost-effectively at this time.

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[1] FPL's Solar Pilots were approved by Order No. PSC-11-0079-PAA-EG. None of the Solar Pilots is currently cost-effective. Pursuant to stipulation approved by Order No. PSC-14-0632-FOF-EG, these pilots will expire at the end of 2015. FPL is not proposing any changes to its Solar Pilots and does not intend to seek any changes to the pilots' Program Standards previously approved by Commission Staff.

Cancellation of FPL's Closed Residential On Call Tariff Sheets

6. For almost three decades, FPL's DSM Plan has included some form of residential load management. Within FPL's current Residential Load Management DSM program there are customers participating under two different tariffs: the "Residential On Call" tariff ("On Call Tariff") which has been closed to new participants since 2003, and the "Residential Load Control" tariff ("Load Control Tariff"), which was approved as a pilot in 2003 and as a permanent program in 2007. Both the On Call Tariff and the Load Control Tariff provide residential customers who volunteer to participate in the program a monthly bill credit in exchange for permitting FPL to interrupt the power to certain appliances (i.e., central electric air conditioning, electric space heating, electric water heaters, and swimming pool pumps.) Credits vary depending upon the type and control cycle of appliances selected by the customer. The only difference between the closed and open tariffs is the bill credit amount for two of the appliance control options: central electric air conditioning cycling and electric water heating. These load management tariffs enable the Company to reduce demand at times of system emergencies, allowing the Company to defer or avoid capacity additions that would otherwise be needed.

7. As a result of normal program attrition, participation in the closed On Call Tariff has been declining since its closure. Today, only about 30% of the total participants in the overall Residential Load Management program remain on the closed On Call Tariff. As part of this DSM Plan, FPL is proposing to transfer the remaining customers participating under the closed On Call Tariff to the open Load Control Tariff and cancel all tariff sheets associated with the closed On Call Tariff. Specifically, FPL requests cancellation of FPL's Third Revised Tariff Sheet No. 8.207, Fourth Revised Tariff Sheet No. 8.208, and Second Revised Tariff Sheet No.

8.209. Those tariff sheets, in both legislative and proposed final format, are attached to this petition as Attachment 2. Customers transferred from the closed to the open tariff would be notified after issuance of the consummating order in this docket, and would begin seeing the new bill credits consistent with the currently-approved Load Control Tariff thereafter, consistent with each customer's billing cycle.[2]

8. After cancellation of the closed On Call Tariff sheets and transfer of remaining customers to the Load Control Tariff, all participating residential customers will receive the same bill credits for the same type of participation. This addresses a price disparity that currently exists between the two groups of participating customers, who provide identical benefits to the general body of customers. As demonstrated in Attachment A to the DSM Plan, the open tariff (that will continue for all participants) is highly beneficial from a participant's perspective.[3] Moreover, this consolidation will lower both administrative and incentive ECCR costs to the general body of customers, while maintaining more than sufficient program participation for FPL to meet its new DSM Goals.

Conclusion

9. FPL's DSM Plan is designed to achieve the annual DSM Goals established by the Commission in Order No. PSC-14-0696-FOF-EU. FPL's DSM Plan will reduce the growth rate of weather-sensitive peak demand, reduce and control the growth rate of energy consumption, increase the conservation of expensive resources, and increase the efficiency of the electrical system, as demonstrated by the data included in Attachment 1. Additionally, FPL's DSM Plan

[2] Regardless of the fact that the program remains cost-effective for participants, customers who are transferred from the closed On Call Tariff to the open Load Control Tariff would be free to terminate their participation in the program at any time with seven days' notice (including prior to the transfer), consistent with the current tariffs.

[3] Consistent with Attachment A, the program will continue to be referred to as the "Residential Load Management (On Call) Program."

can be reasonably monitored. FPL's monitoring efforts for each of its DSM programs and research projects are set forth in the program summaries in FPL's DSM Plan. For all the foregoing reasons, FPL's DSM Plan, including the transfer of customers from the closed to the open Residential Load Control Tariff and cancellation of associated tariff sheets, should be approved.

WHEREFORE, FPL respectfully requests that the Commission: (i) approve FPL's DSM Plan, as provided in Attachment 1; (ii) approve the cancellation of FPL's Residential On Call Tariff, the transfer of remaining customers on that tariff to the open Residential Load Control Tariff, and the revised tariff sheets provided in Attachment 2; (iii) authorize FPL to recover reasonable and prudent expenditures associated with the implementation of this DSM Plan through the ECCR clause; and (iv) grant such other relief as may be appropriate.

Respectfully submitted,

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By: *s/ Jessica A. Cano*
Jessica A. Cano
Florida Bar No. 37372

ATTACHMENT 2

~~RESIDENTIAL LOAD MANAGEMENT PROGRAM~~
~~(FPL "ON CALL" PROGRAM)~~
~~(CLOSED SCHEDULE)~~

~~RATE SCHEDULE: RSL~~

~~AVAILABLE:~~

~~Available only within the geographic areas served by the Company's Load Management System.~~

~~APPLICATION:~~

~~To Customers receiving service under Rate Schedule RS-1 who were active participants in this program as of April 1, 2003 and who utilized at least one of the following installed electrical appliances on the premises that was designated as of April 1, 2003:~~

~~1. Conventional electric water heater~~
~~2. Central electric air conditioning~~
~~3. Swimming pool pump (including pool sweeps as appropriate)~~
~~4. Central electric space heating*~~

~~*Central electric space heating systems alone are ineligible for program participation. These systems are eligible for program participation only when one or more of the other 3 appliances listed above is signed up for participation.~~

~~This Rate Schedule is not applicable for service to commonly owned facilities of condominium, cooperative, or homeowners' associations. Service under this Rate Schedule is not transferable to either new Customers requesting service at any premises that were designated by a Customer participating in this program prior to April 1, 2003 OR to the Customers participating in this program as of April 1, 2003 who discontinue service at the premises designated prior to April 1, 2003.~~

~~SERVICE:~~

~~The same as specified in Rate Schedule RS-1.~~

~~LIMITATION OF SERVICE:~~

~~The same as specified in Rate Schedule RS-1. The specified electrical appliances shall be interrupted at the option of the Company by means of load management equipment installed at the Customer's premises.~~

~~MONTHLY CREDIT:~~

~~Customers receiving service under this schedule will receive a credit on the monthly bill as follows:~~

~~DEVICE (OPTION)~~	~~APPLICABILITY~~	~~CREDIT~~
~~1. Conventional electric water heater~~	~~Year-round~~	~~$ 3.50~~
~~2. Central electric air conditioning (Option C)~~	~~April-October~~	~~$ 6.00~~
~~3. Central electric air conditioning (Option S)~~	~~April-October~~	~~$ 9.00~~
~~4. Swimming pool pump~~	~~Year-round~~	~~$ 3.00~~
~~5. Central electric space heating (Option C)~~	~~November-March~~	~~$ 2.00~~
~~6. Central electric space heating (Option S)~~	~~November-March~~	~~$ 4.00~~

~~Total monthly credit shall not exceed 40 percent of the Rate Schedule RS-1 "Base Energy Charge" actually incurred for the month (if the Budget Billing Plan is selected, actual energy charges will be utilized in the calculations, not the levelized charges) and no credit will be applied to reduce the Minimum bill specified on Rate Schedule RS-1.~~

~~Note: Option C or Option S (listed below) may be selected for either central air conditioning or heating systems. If both appliance types are participating in the program, the same option must be selected.~~

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

~~(Continued from Sheet No. 8.207)~~

~~INTERRUPTION SCHEDULES FOR ELECTRICAL APPLIANCES~~

~~The Customer's participating electrical appliances will be interrupted only during the following periods except as noted below:~~

~~April 1 through October 31: 3 p.m. to 10 p.m.~~

~~November 1 through March 31: 5 a.m. to 11 a.m.~~
~~4 p.m. to 10 p.m.~~

~~The interruption schedules available for each appliance are as follows:~~

~~1. Conventional electric water heating equipment may be interrupted up to, but not to exceed, 240 minutes per day.~~

~~2. Central electric air conditioning equipment may be interrupted under one of the following options selected by the Customer:~~

~~Option C equipment may be interrupted an accumulated total of 15 minutes during any 30 minute period with a cumulative interruption time of up to 180 minutes per day. If normal operation of the Program is not able to provide sufficient demand reduction to divert an emergency situation, central electric air conditioners may be interrupted for 17.5 minutes during any 30 minute period with a cumulative interruption time of up to 210 minutes per day.~~

~~Option S equipment may be interrupted up to, but not to exceed, 180 minutes per day.~~

~~3. Swimming pool pump equipment may be interrupted up to, but not to exceed, 240 minutes per day.~~

~~4. Central electric space heating equipment may be interrupted under one of the following options selected by the Customer:~~

~~Option C equipment may be interrupted an accumulated total of 15 minutes during any 30 minute period with a cumulative interruption time of up to 180 minutes per day.~~

~~Option S equipment may be interrupted up to, but not to exceed, 180 minutes per day.~~

~~The limitations on interruptions of electrical equipment shall not apply during emergencies on the Company's system or to interruptions caused by force majeure or other causes beyond the control of the Company.~~

~~TERM OF SERVICE:~~

~~During service under this Rate Schedule, a Customer may discontinue service by giving the Company seven (7) days advance notice. If, upon seven (7) days advance notice, the Customer requests to change interruption options, the selection of electrical appliances connected to the load management equipment, or have one or more appliances removed from participation in the program on or subsequent to April 1, 2003, then the Customer will be ineligible to participate further in the program.~~

~~SPECIAL PROVISIONS~~

~~1. The Company shall not be required to install load management equipment if the installation cannot be economically justified for reasons such as: excessive installation costs, oversized/undersized heating or cooling equipment or abnormal utilization of equipment, including vacation or other limited occupancy residences.~~

~~2. Billing under this Rate Schedule will commence upon the installation and completion of required inspections of the load management equipment.~~

~~3. Multiple units of any particular appliance type must all be connected with load management equipment to qualify for the credit attributable to that appliance type. In such circumstances, only a single credit for that appliance type will be applied. Pool sweeps, when coupled with pool pumps, are included in this category.~~

~~(Continued on Sheet No. 8.209)~~

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

~~(Continued from Sheet No. 8.208)~~

~~4. Installation of the load management equipment at the Customer's home is to be the sole responsibility of a licensed, independent contractor. The Customer agrees that the Company shall not be liable for any damages or injuries that may occur as a result of the interruption or restoration of electric service pursuant to the terms of this schedule.~~

~~5. The following types of electric water heaters are ineligible for participation in the program: solar water heaters, heat recovery units and heat pump water heaters.~~

~~6. If the Company determines that the Customer no longer uses one or more of the appliances signed up for program participation, then the Company has the right to remove the appropriate load management equipment and to discontinue the appropriate credits.~~

~~7. The Customer shall give the Company and the licensed, independent contractor reasonable access for installing, maintaining, testing and removing the Company's load management equipment, and for verifying that the equipment effectively controls the Customer's appliances as intended by this schedule.~~

~~8. If the Company determines that the effect of equipment interruptions has been offset by the Customer's use of supplementary or alternative electrical equipment, then service under this schedule may be discontinued and the Customer billed for all prior Monthly Credits received under this Rate Schedule over a period not to exceed six (6) months.~~

~~9. If the Company determines that its load management equipment on the Customer's premises has been rendered ineffective by mechanical, electrical or other devices or actions ("tampering"), then the Company may discontinue the Customer's participation in the program and bill for all expenses involved in removal of the load management equipment, plus applicable investigative charges. The Company may rebill all prior Monthly Credits received by the Customer from an established tampering date. If such a date cannot be established, then rebilling of the Monthly Credits shall be for the lesser of the number of months receiving service under this Rate Schedule or the previous twelve (12) months.~~

~~10. Service under this Rate Schedule is applicable only to eligible electrical equipment that was installed at the designated premises as of April 1, 2003. Installation of any new (but not replacement) electrical appliances on or subsequent to April 1, 2003 will not be eligible for service under this Rate Schedule.~~

~~11. Service under this Rate Schedule may not be combined with any other Residential Load Management Program or any other program with a provision for crediting on the Customer's monthly bill for eligible electrical appliances connected to load management equipment which may be offered by FPL in the future.~~

<u>RESERVED FOR FUTURE USE</u>

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: ~~April 1, 2003~~

RESERVED FOR FUTURE USE

EXHIBIT NO. 75

DOCKET NO: 150196-EI

WITNESS: Steven R. Sim

PARTY: FPL

DESCRIPTION: FPL Residential Load Control Program Rate Sheets 8.217, 8.218, & 8.219

DOCUMENTS:

PROFFERED BY: ECOSWF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 75
PARTY: ECOSWF
DESCRIPTION: Sim/FPL Residential Load Program Rate Sheets

RESIDENTIAL LOAD CONTROL PROGRAM

RATE SCHEDULE: RLP

AVAILABLE:

Available only within the geographic areas served by the Company's Load Management System.

APPLICATION:

To Customers receiving service under Rate Schedule RS-1 who elect to participate in this Residential Load Control Program ("Program") on or after April 1, 2003 and who utilize at least one of the following installed electrical appliances at the Customer's premise:

1. Conventional electric water heater
2. Central electric air conditioning
3. Swimming pool pump (including pool sweeps as appropriate)
4. Central electric space heating*

*Central electric space heating systems alone are ineligible for Program participation. These systems are eligible for Program participation only when one (or more) of the other 3 appliances listed above is (are) signed up for participation.

This Rate Schedule is not applicable for service to commonly-owned facilities of condominium, cooperative, or homeowners' associations.

SERVICE:

The same as specified in Rate Schedule RS-1

LIMITATION OF SERVICE:

The same as specified in Rate Schedule RS-1. The specified electrical appliances shall be interrupted at the option of the Company by means of load management equipment installed at the Customer's premise.

MONTHLY CREDIT:

Customers receiving service under this Rate Schedule will receive a credit on the monthly bill as follows:

	DEVICE (OPTION)	APPLICABILITY	CREDIT
1.	Conventional electric water heater	Year-round	$ 1.50
2.	Central electric air conditioning (Option C)	April-October	$ 3.00
3.	Central electric air conditioning (Option S)	April-October	$ 9.00
4.	Swimming pool pump	Year-round	$ 3.00
5.	Central electric space heating (Option C)	November-March	$ 2.00
6.	Central electric space heating (Option S)	November-March	$ 4.00

Total monthly credit shall not exceed 40 percent of the Rate Schedule RS-1 "Base Energy Charge" actually incurred for the month (if the Budget Billing Plan is selected, actual energy charges will be utilized in the calculations, not the levelized charges) and no credit will be applied to reduce the Minimum bill specified on Rate Schedule RS-1.

Note: Option C or Option S (listed below) may be selected for either central air conditioning or heating systems. If both appliance types are participating in the Program, the same option must be selected.

(Continued on Sheet No. 8.218)

(Continued from Sheet No. 8.217)

INTERRUPTION SCHEDULES FOR ELECTRICAL APPLIANCES

The Customer's participating electrical appliances will be interrupted only during the following periods except as noted below:

April 1 through October 31:	2 p.m. to 10 p.m.
November 1 through March 31:	5 a.m. to 11 a.m. 4 p.m. to 10 p.m.

The interruption schedules available for each appliance are as follows:

1. Conventional electric water heating equipment may be interrupted up to, but not to exceed, 240 minutes per day.

2. Central electric air conditioning equipment may be interrupted under one of the following options selected by the Customer:

   Option C equipment may be interrupted an accumulated total of 15 minutes during any 30 minute period with a cumulative interruption time of up to 180 minutes per day. If normal operation of the Program is not able to provide sufficient demand reduction to divert an emergency situation, central electric air conditioners may be interrupted for 17.5 minutes during any 30 minute period with a cumulative interruption time of up to 210 minutes per day.

   Option S equipment may be interrupted up to, but not to exceed, 180 minutes per day.

3. Swimming pool pump equipment may be interrupted up to, but not to exceed, 240 minutes per day.

4. Central electric space heating equipment may be interrupted under one of the following options selected by the Customer:

   Option C equipment may be interrupted an accumulated total of 15 minutes during any 30 minute period with a cumulative interruption time of up to 180 minutes per day.

   Option S equipment may be interrupted up to, but not to exceed, 180 minutes per day.

The limitations on interruptions of electrical equipment shall not apply during emergencies on the Company's system or to interruptions caused by force majeure or other causes beyond the control of the Company.

TERM OF SERVICE:

During service under this Rate Schedule, a Customer may change interruption options or the selection of electrical appliances connected to the load management equipment or discontinue service under this Rate Schedule by giving the Company 7 days advance notice. If the Customer requests to have one or more appliances removed from participation in the Program, the Customer will be ineligible to participate with such appliance(s) again in the Program for one year (12 months) from the time participation ended.

SPECIAL PROVISIONS

1. The Company shall not be required to install load management equipment if the installation cannot be economically justified for reasons such as: excessive installation costs, oversized/undersized heating or cooling equipment or abnormal utilization of equipment, including vacation or other limited occupancy residences.

2. Billing under this Rate Schedule will commence upon the installation and completion of required inspections of the load management equipment.

3. Multiple units of any particular appliance type must all be connected with load management equipment to qualify for the credit attributable to that appliance type. In such circumstances, only a single credit for that appliance type will be applied. Pool sweeps, when coupled with pool pumps, are included in this category.

(Continued on Sheet No. 8.219)

(Continued from Sheet No. 8.218)

4. Installation of the load management equipment at the Customer's premise is to be the sole responsibility of a licensed, independent contractor. The Customer agrees that the Company shall not be liable for any damages or injuries that may occur as a result of the interruption or restoration of electric service pursuant to the terms of this Rate Schedule.

5. The following types of electric water heaters are ineligible for participation in the Program: solar water heaters, heat recovery units and heat pump water heaters

6. If the Company determines that the Customer no longer uses one or more of the appliances signed up for Program participation, then the Company has the right to remove the appropriate load management equipment and to discontinue the appropriate credits.

7. The Customer shall give the Company and the licensed, independent contractor reasonable access for installing, maintaining, testing and removing the Company's load management equipment, and for verifying that the equipment effectively controls the Customer's appliances as intended by this Rate Schedule.

8. If the Company determines that the effect of equipment interruptions has been offset by the Customer's use of supplementary or alternative electrical equipment, then service under this Rate Schedule may be discontinued and the Customer billed for all prior Monthly Credits received under this Rate Schedule over a period not to exceed six (6) months.

9. If the Company determines that its load management equipment at the Customer's premise has been rendered ineffective by mechanical, electrical or other devices or actions ("tampering"), then the Company may discontinue the Customer's participation in the Program and bill for all expenses involved in removal of the load management equipment, plus applicable investigative charges. The Company may rebill all prior Monthly Credits received by the Customer from an established tampering date. If such a date cannot be established, then rebilling of the Monthly Credits shall be for the lesser of the number of months receiving service under this Rate Schedule or the previous twelve (12) months.

EXHIBIT NO. 76

DOCKET NO: 150196-EI

WITNESS: Steven R. Sim

PARTY: FPL

DESCRIPTION: FPL's 2014 Demand-Side Management Annual Report

DOCUMENTS:

PROFFERED BY: ECOSWF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 76
PARTY: ECOSWF
DESCRIPTION: Sim/FPL 2014 Demand-Side Management Annual Report

March 2, 2015

Shevie Brown
Division of Economics
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: 2014 Demand-Side Management (DSM) Annual Report

Dear Mr. Brown:

In accordance with Rule 25-17.0021(5), Florida Administrative Code, Florida Power & Light Company ("FPL") is submitting its 2014 DSM Annual Report. The Report includes the results of FPL's DSM Plan as approved by Order No. PSC-11-0346-PAA-EG (consummated by Order No. PSC-11-0590-FOF-EG). FPL's DSM Plan consists of the DSM programs approved by the Commission in 2004 and subsequent modifications approved by the Commission in 2006.

FPL developed internal demand and energy targets ("FPL Targets") following the Commission's approval of its current DSM Plan. The FPL Targets are based on the incentive levels and a similar program mix contained in FPL's approved DSM Plan as well as adjustments for 2012 Florida Building Code changes. Below is a table comparing FPL's 2014 performance to the FPL Targets:

	Residential and Business Combined			Residential			Business		
	Actual Total Achieved	FPL Target	% Variance	Actual Total Achieved	FPL Target	% Variance	Actual Total Achieved	FPL Target	% Variance
Summer Peak MW	142.1	131.1	8%	99.1	80.3	23%	43.0	50.8	-15%
Winter Peak MW	66.6	79.0	-16%	51.1	56.0	-9%	15.5	23.1	-33%
GWh Energy	222.1	156.4	42%	162.6	101.1	61%	59.4	55.3	7%

On a combined basis, FPL achieved the Summer MW and GWh targets. The value of demand and energy savings for FPL's general body of customers is unrelated to whether the savings occur in the residential or business sector.

In the enclosed report, FPL's performance is compared to the demand and energy goals established by Order No. PSC-09-0855-FOF-EG, issued December 30, 2009, in Docket No. 080407-EG ("2009 Goals"). The results are summarized on page one of the attached report. In

2014, FPL achieved DSM savings within 15% of the residential Summer MW and business Winter MW goals. On a combined basis, FPL's 2014 achievements exceeded 2013. FPL's 2014 residential and business sector-level achievements also exceeded 2013, with the exception of business GWh. Achievement in the business sector continues to be affected by customers deferring projects due to budget constraints as a result of the slow economic recovery. As indicated in the transmittal letter accompanying last year's DSM Annual Report, variances from the 2009 DSM Goals are expected because FPL's approved DSM Plan was not designed to meet the 2009 Goals.

Please do not hesitate to contact me should you have any questions.

Sincerely,

for Wayne Besley
Director, Demand-Side Management Programs

Enclosures

FLORIDA POWER & LIGHT COMPANY 2014 DEMAND-SIDE MANAGEMENT ANNUAL REPORT

March 2, 2015

FLORIDA POWER & LIGHT COMPANY
2014 DEMAND-SIDE MANAGEMENT ANNUAL REPORT

FLORIDA POWER & LIGHT COMPANY
Comparison of Achieved MW and GWh Reductions
v. Annual Commission Goals Established December 30, 2009
Reporting Period: 2014

Residential and Business Combined (@ Generator)

	Summer Peak MW Reduction			Winter Peak MW Reduction			GWh Energy Reduction		
Year	Annual Total Achieved	Annual Commission Established Goal	% Variance	Annual Total Achieved	Annual Commission Established Goal	% Variance	Annual Total Achieved	Annual Commission Established Goal	% Variance
2010	129.2	110.4	17%	59.4	41.3	44%	204.1	204.3	0%
2011	146.2	142.2	3%	64.2	52.3	23%	261.1	295.2	-12%
2012	139.9	166.5	-16%	70.9	61.9	15%	211.0	360.3	-41%
2013	127.0	179.8	-29%	55.6	69.4	-20%	214.2	389.4	-45%
2014	142.1	183.6	-23%	66.6	74.6	-11%	222.1	394.1	-44%
2015		172.2			71.0			360.5	
2016		155.9			66.3			317.6	
2017		140.1			61.1			279.0	
2018		128.7			56.4			253.3	
2019		118.3			51.4			228.5	

Residential (@ Generator)

	Summer Peak MW Reduction			Winter Peak MW Reduction			GWh Energy Reduction		
Year	Annual Total Achieved	Annual Commission Established Goal	% Variance	Annual Total Achieved	Annual Commission Established Goal	% Variance	Annual Total Achieved	Annual Commission Established Goal	% Variance
2010	92.9	67.7	37%	38.2	33.2	15%	141.3	119.6	18%
2011	109.5	79.7	37%	46.2	42.4	9%	196.1	145.8	35%
2012	88.5	90.2	-2%	40.7	50.3	-19%	140.9	168.8	-17%
2013	84.7	98.5	-14%	40.7	56.3	-28%	138.7	186.7	-26%
2014	99.1	104.3	-5%	51.1	60.2	-15%	162.6	200.0	-19%
2015		100.7			55.9			193.0	
2016		95.9			51.3			183.4	
2017		91.4			47.0			174.2	
2018		87.4			43.2			166.4	
2019		83.3			39.4			157.5	

Business (@ Generator)

	Summer Peak MW Reduction			Winter Peak MW Reduction			GWh Energy Reduction		
Year	Annual Total Achieved	Annual Commission Established Goal	% Variance	Annual Total Achieved	Annual Commission Established Goal	% Variance	Annual Total Achieved	Annual Commission Established Goal	% Variance
2010	36.2	42.7	-15%	21.3	8.1	162%	62.8	84.7	-26%
2011	36.8	62.5	-41%	18.0	9.9	82%	64.9	149.4	-57%
2012	51.4	76.3	-33%	30.3	11.6	161%	70.1	191.5	-63%
2013	42.3	81.3	-48%	14.9	13.1	14%	75.5	202.7	-63%
2014	43.0	79.3	-46%	15.5	14.4	8%	59.4	194.1	-69%
2015		71.5			15.1			167.5	
2016		60.0			15.0			134.2	
2017		48.7			14.1			104.8	
2018		41.3			13.2			86.9	
2019		35.0			12.0			71.0	

Utility: Florida Power & Light Company
Program Name: **Residential Building Envelope**
Program Start Date: January 1981
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[1]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	4,010,837	2,483,638	18,159	0.7%	14,041	14,041	0.6%	(4,118)
2011	4,056,428	2,493,710	36,448	1.5%	13,675	27,716	1.1%	(8,732)
2012	4,141,910	2,528,354	54,891	2.2%	11,639	39,355	1.6%	(15,536)
2013	4,226,978	2,562,588	73,508	2.9%	8,420	47,775	1.9%	(25,733)
2014	4,311,223	2,596,138	92,321	3.6%	8,752	56,527	2.2%	(35,794)
2015	4,394,802	2,629,080	111,135	4.2%				
2016	4,477,937	2,661,746	129,948	4.9%				
2017	4,560,569	2,694,101	148,761	5.5%				
2018	4,642,575	2,726,069	167,575	6.1%				
2019	4,720,827	2,755,712	186,388	6.8%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	0.27	0.29	2,391	2,577
Winter kW Reduction	0.37	0.40	3,217	3,467
kWh Reduction	663	703	5,801,116	6,155,390

2014	
Utility Cost per Installation	$377
Total Utility Program Cost ($000)	$3,299
Net Benefits ($000)	$98

[1] Cumulative participants prior to 2010 = 502,577

Utility: Florida Power & Light Company
Program Name: **Residential Duct System Testing and Repair**
Program Start Date: August 1991
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[1]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	4,010,837	1,708,376	17,741	1.0%	16,348	16,348	1.0%	(1,393)
2011	4,056,428	1,710,053	35,772	2.1%	3,575	19,923	1.2%	(15,849)
2012	4,141,910	1,728,433	54,093	3.1%	1,277	21,200	1.2%	(32,893)
2013	4,226,978	1,746,346	72,704	4.2%	1,294	22,494	1.3%	(50,210)
2014	4,311,223	1,763,618	91,608	5.2%	2,032	24,526	1.4%	(67,082)
2015	4,394,802	1,780,313	110,513	6.2%				
2016	4,477,937	1,796,819	129,418	7.2%				
2017	4,560,569	1,813,111	148,323	8.2%				
2018	4,642,575	1,829,136	167,227	9.1%				
2019	4,720,827	1,843,562	186,132	10.1%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	0.17	0.19	355	383
Winter kW Reduction	0.19	0.21	394	424
kWh Reduction	378	401	768,520	815,454

2014	
Utility Cost per Installation	$449
Total Utility Program Cost ($000)	$913
Net Benefits ($000)	$1

[1] Cumulative participants prior to 2010 = 478,515

Utility: Florida Power & Light Company
Program Name: **Residential Air Conditioning**
Program Start Date: October 1990
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		Actual			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[1]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	4,010,837	3,172,427	106,731	3.4%	99,897	99,897	3.1%	(6,834)
2011	4,056,428	3,180,593	221,154	7.0%	113,907	213,804	6.7%	(7,350)
2012	4,141,910	3,206,087	343,459	10.7%	101,156	314,960	9.8%	(28,499)
2013	4,226,978	3,227,951	473,914	14.7%	105,164	420,124	13.0%	(53,790)
2014	4,311,223	3,225,622	612,872	19.0%	121,349	541,473	16.8%	(71,399)
2015	4,394,802	3,219,715	751,830	23.4%				
2016	4,477,937	3,212,539	890,787	27.7%				
2017	4,560,569	3,205,241	1,029,745	32.1%				
2018	4,642,575	3,176,065	1,168,703	36.8%				
2019	4,720,827	3,158,213	1,307,661	41.4%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	0.53	0.57	64,568	69,593
Winter kW Reduction	0.19	0.20	22,523	24,276
kWh Reduction	1,131	1,200	137,258,649	145,641,035

2014	
Utility Cost per Installation	$630
Total Utility Program Cost ($000)	$76,399
Net Benefits ($000)	$353

[1] Cumulative participants prior to 2010 = 1,239,291

Utility: Florida Power & Light Company
Program Name: **Residential Load Management (On Call)**
Program Start Date: July 1986
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[1]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	4,010,837	3,225,872	15,900	0.5%	6,826	6,826	0.2%	(9,074)
2011	4,056,428	3,255,563	33,100	1.0%	8,021	14,847	0.5%	(18,253)
2012	4,141,910	3,323,845	51,600	1.6%	13,910	28,757	0.9%	(22,843)
2013	4,226,978	3,390,413	71,400	2.1%	15,370	44,127	1.3%	(27,273)
2014	4,311,223	3,454,858	94,700	2.7%	10,395	54,522	1.6%	(40,178)
2015	4,394,802	3,515,137	118,000	3.4%				
2016	4,477,937	3,574,972	141,300	4.0%				
2017	4,560,569	3,634,304	164,600	4.5%				
2018	4,642,575	3,693,010	187,900	5.1%				
2019	4,720,827	3,747,962	211,200	5.6%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	1.98	2.14	20,604	22,207
Winter kW Reduction	1.88	2.03	19,548	21,069
kWh Reduction	2	2	17,100	18,144

2014	
Utility Cost per Installation [2]	$68
Total Utility Program Cost ($000) [3]	$55,462
Net Benefits ($000)	$473

[1] Cumulative participants prior to 2010 = 784,965
[2] Based on cumulative active participants at year-end = 810,074
[3] Includes depreciation, return & rebates paid in 2014 to active participants who signed up in 2014 & prior years

Utility: Florida Power & Light Company
Program Name: **Residential New Construction (BuildSmart®)**
Program Start Date: February 1996
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants(1)	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	4,010,837	18,505	1,612	8.7%	2,089	2,089	11.3%	477
2011	4,056,428	30,508	3,282	6.7%	2,317	4,406	9.0%	1,124
2012	4,141,910	36,750	5,431	6.3%	2,943	7,349	8.6%	1,918
2013	4,226,978	39,597	7,582	6.0%	2,600	9,949	7.9%	2,367
2014	4,311,223	41,313	9,635	5.8%	3,503	13,452	8.1%	3,817
2015	4,394,802	43,189	11,581	5.5%				
2016	4,477,937	43,800	13,528	5.3%				
2017	4,560,569	44,274	15,474	5.2%				
2018	4,642,575	45,278	17,421	5.1%				
2019	4,720,827	46,918	19,368	5.0%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	0.78	0.85	2,750	2,964
Winter kW Reduction	0.28	0.30	982	1,059
kWh Reduction	1,273	1,351	4,459,000	4,731,311

2014	
Utility Cost per Installation	$209
Total Utility Program Cost ($000)	$732
Net Benefits ($000)	$199

(1) Cumulative participants prior to 2010 = 22,515

Utility: Florida Power & Light Company
Program Name: **Residential Low Income Weatherization**
Program Start Date: April 2004
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[(1)]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	4,010,837	693,875	581	0.1%	837	837	0.1%	256
2011	4,056,428	701,181	1,190	0.2%	1,666	2,503	0.4%	1,313
2012	4,141,910	715,361	1,828	0.3%	2,505	5,008	0.7%	3,180
2013	4,226,978	729,439	2,496	0.3%	844	5,852	0.8%	3,356
2014	4,311,223	743,345	3,197	0.4%	884	6,736	0.9%	3,539
2015	4,394,802	757,104	3,897	0.5%				
2016	4,477,937	770,786	4,598	0.6%				
2017	4,560,569	784,380	5,299	0.7%				
2018	4,642,575	797,867	5,999	0.8%				
2019	4,720,827	810,704	6,700	0.8%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	0.22	0.23	192	206
Winter kW Reduction	0.07	0.08	66	71
kWh Reduction	474	503	418,808	444,385

2014	
Utility Cost per Installation	$142
Total Utility Program Cost ($000)	$126
Net Benefits ($000)	$5

(1) Cumulative participants prior to 2010 = 1,961

Utility: Florida Power & Light Company
Program Name: **Residential Home Energy Surveys**
Program Start Date: January 1981
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[1]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	4,010,837	4,010,837	75,000 - 100,000	1.9% - 2.5%	139,837	139,837	3.5%	64,837 - 39,837
2011	4,056,428	4,056,428	150,000 - 200,000	3.7% - 4.9%	159,620	299,457	7.4%	149,457 - 99,457
2012	4,141,910	4,141,910	225,000 - 300,000	5.4% - 7.2%	145,069	444,526	10.7%	219,526 - 144,526
2013	4,226,978	4,226,978	300,000 - 400,000	7.1% - 9.5%	147,012	591,538	14.0%	291,820 - 191,820
2014	4,311,223	4,311,223	375,000 - 500,000	8.7% - 11.6%	197,794	789,332	18.3%	414,332 - 289,332
2015	4,394,802	4,394,802	450,000 - 600,000	10.2% - 13.6%				
2016	4,477,937	4,477,937	525,000 - 700,000	11.7% - 15.6%				
2017	4,560,569	4,560,569	600,000 - 800,000	13.2% - 17.5%				
2018	4,642,575	4,642,575	675,000 - 900,000	14.5% - 19.4%				
2019	4,720,827	4,720,827	750,000 - 1,000,000	15.9% - 21.2%				

2014	
Utility Cost per Installation	$60
Total Utility Program Cost ($000)	$11,919
Net Benefits ($000)	N/A

- No kW or kWh reductions attributed to this program

(1) Cumulative participants prior to 2010 = 2,751,350

Utility: Florida Power & Light Company
Program Name: **Business Heating, Ventilating & Air Conditioning**
Program Start Date: February 1990
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants(1)	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	605,498	378,692	18,668	4.9%	10,611	10,611	2.8%	(8,057)
2011	620,548	369,436	38,212	10.3%	8,789	19,400	5.3%	(18,812)
2012	635,972	340,406	57,831	17.0%	12,224	31,625	9.3%	(26,207)
2013	651,779	349,806	77,380	22.1%	12,936	44,561	12.7%	(32,819)
2014	667,980	340,390	97,364	28.6%	12,932	57,493	16.9%	(39,871)
2015	684,583	330,789	117,349	35.5%				
2016	701,598	321,447	137,333	42.7%				
2017	719,037	312,369	157,318	50.4%				
2018	736,909	303,562	177,302	58.4%				
2019	755,226	295,033	197,286	66.9%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	1.00	1.08	12,932	13,939
Winter kW Reduction	0.38	0.41	4,930	5,313
kWh Reduction	1,343	1,425	17,369,491	18,430,245

2014	
Utility Cost per Installation	$494
Total Utility Program Cost ($000)	$6,386
Net Benefits ($000)	$299

(1) Cumulative participants prior to 2010 (@ Generator) = 325,170
Note: One Customer, Participant or Installation equals one Summer kW

Utility: Florida Power & Light Company
Program Name: **Business Efficient Lighting**
Program Start Date: June 1984
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		Actual			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[1]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	842,587	449,346	1,489	0.3%	3,810	3,810	0.8%	2,321
2011	863,530	459,025	3,104	0.7%	3,509	7,320	1.6%	4,216
2012	884,994	468,857	4,837	1.0%	4,397	11,716	2.5%	6,880
2013	906,991	478,855	6,681	1.4%	2,742	14,458	3.0%	7,777
2014	929,535	489,033	8,630	1.8%	1,411	15,869	3.2%	7,239
2015	952,639	499,405	10,579	2.1%				
2016	976,317	510,084	12,528	2.5%				
2017	1,000,584	521,076	14,477	2.8%				
2018	1,025,454	532,390	16,427	3.1%				
2019	1,050,943	544,034	18,376	3.4%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	1.00	1.08	1,411	1,521
Winter kW Reduction	0.63	0.68	892	961
kWh Reduction	5,033	5,340	7,102,339	7,536,079

2014	
Utility Cost per Installation	$364
Total Utility Program Cost ($000)	$513
Net Benefits ($000)	$65

[1] Cumulative participants prior to 2010 (@ Generator) = 270,713

Note: One Customer, Participant or Installation equals one Summer kW

Utility: Florida Power & Light Company
Program Name: **Business Building Envelope**
Program Start Date: June 1995
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		Actual			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants(1)	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	455,771	455,771	8,602	1.9%	6,358	6,358	1.4%	(2,244)
2011	467,099	458,497	17,720	3.9%	5,864	12,222	2.7%	(5,498)
2012	478,709	460,989	27,329	5.9%	6,765	18,987	4.1%	(8,342)
2013	490,608	463,279	37,404	8.1%	6,760	25,747	5.6%	(11,657)
2014	502,802	465,398	47,922	10.3%	7,466	33,213	7.1%	(14,709)
2015	515,300	467,377	58,440	12.5%				
2016	528,108	469,667	68,958	14.7%				
2017	541,234	472,276	79,476	16.8%				
2018	554,687	475,210	89,994	18.9%				
2019	568,474	478,479	100,512	21.0%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	1.00	1.08	7,466	8,047
Winter kW Reduction (2)	0.00	0.00	-16.59	-17.88
kWh Reduction	1,951	2,070	14,563,373	15,452,758

2014	
Utility Cost per Installation	$1,013
Total Utility Program Cost ($000)	$7,563
Net Benefits ($000)	$219

(1) Cumulative participants prior to 2010 (@ Generator) = 80,192

(2) The negative value is the result of the proportionately large participation in the Window Treatment measure

Note: One Customer, Participant or Installation equals one Summer kW

Utility: Florida Power & Light Company
Program Name: **Business Custom Incentive**
Program Start Date: April 1993
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[1]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	139,467	90,912	282	0.3%	2,586	2,586	2.8%	2,304
2011	142,934	92,890	564	0.6%	2,098	4,684	5.0%	4,120
2012	146,487	94,924	846	0.9%	2,335	7,019	7.4%	6,173
2013	150,128	97,015	1,128	1.2%	3,795	10,814	11.1%	9,686
2014	153,859	99,165	1,410	1.4%	1,220	12,034	12.1%	10,624
2015	157,683	101,376	1,692	1.7%				
2016	161,603	103,649	1,974	1.9%				
2017	165,619	105,985	2,256	2.1%				
2018	169,736	108,387	2,538	2.3%				
2019	173,955	110,855	2,820	2.5%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	1.00	1.08	1,220	1,315
Winter kW Reduction	1.07	1.16	1,311	1,413
kWh Reduction	7,766	8,241	9,477,099	10,055,865

2014	
Utility Cost per Installation	$237
Total Utility Program Cost ($000)	$289
Net Benefits ($000)	$106

[1] Cumulative participants prior to 2010 (@ Generator) = 34,162
Note: One Customer, Participant or Installation equals one Summer kW

Utility: Florida Power & Light Company
Program Name: **Business Water Heating**
Program Start Date: May 2006
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		Actual			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[1]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	80,321	73,863	187	0.3%	25	25	0.0%	(162)
2011	82,317	75,512	383	0.5%	6	31	0.0%	(352)
2012	84,363	77,197	589	0.8%	23	54	0.1%	(535)
2013	86,460	78,920	802	1.0%	34	88	0.1%	(713)
2014	88,609	80,683	1,021	1.3%	3	92	0.1%	(930)
2015	90,812	82,488	1,241	1.5%				
2016	93,069	84,344	1,461	1.7%				
2017	95,382	86,252	1,681	1.9%				
2018	97,753	88,212	1,900	2.2%				
2019	100,182	90,227	2,120	2.3%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	1.00	1.08	3	3
Winter kW Reduction	0.62	0.67	2	2
kWh Reduction	4,304	4,566	13,341	14,156

2014	
Utility Cost per Installation	$3,517
Total Utility Program Cost ($000)	$11
Net Benefits ($000)	$0

[1] Cumulative participants prior to 2010 (@ Generator) = 180
Note: One Customer, Participant or Installation equals one Summer kW

Utility: Florida Power & Light Company
Program Name: **Business Refrigeration**
Program Start Date: May 2006
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[1]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	87,601	45,200	304	0.7%	40	40	0.1%	(263)
2011	89,778	46,020	607	1.3%	141	181	0.4%	(426)
2012	92,010	46,868	906	1.9%	60	242	0.5%	(665)
2013	94,297	47,749	1,196	2.5%	66	308	0.6%	(889)
2014	96,641	48,668	1,474	3.0%	958	1,266	2.6%	(208)
2015	99,043	49,630	1,751	3.5%				
2016	101,505	50,623	2,029	4.0%				
2017	104,028	51,647	2,307	4.5%				
2018	106,613	52,703	2,584	4.9%				
2019	109,263	53,793	2,862	5.3%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	1.00	1.08	958	1,033
Winter kW Reduction	0.86	0.93	824	888
kWh Reduction	4,871	5,169	4,667,858	4,952,924

2014	
Utility Cost per Installation	$125
Total Utility Program Cost ($000)	$120
Net Benefits ($000)	$67

[1] Cumulative participants prior to 2010 (@ Generator) = 546
Note: One Customer, Participant or Installation equals one Summer kW

Utility: Florida Power & Light Company
Program Name: **Business On Call**
Program Start Date: June 1995
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		Actual			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[1]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	1,723,593	1,632,987	6,524	0.4%	1,901	1,901	0.1%	(4,623)
2011	1,766,434	1,667,052	13,048	0.8%	5,662	7,562	0.5%	(5,486)
2012	1,810,340	1,702,125	19,572	1.1%	4,473	12,035	0.7%	(7,537)
2013	1,855,337	1,738,233	26,096	1.5%	6,073	18,108	1.0%	(7,988)
2014	1,901,452	1,775,401	32,620	1.8%	4,914	23,023	1.3%	(9,597)
2015	1,948,714	1,813,654	39,144	2.2%				
2016	1,997,150	1,853,020	45,668	2.5%				
2017	2,046,791	1,893,527	52,192	2.8%				
2018	2,097,665	1,935,203	58,716	3.0%				
2019	2,149,804	1,978,077	65,240	3.3%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	1.00	1.08	4,914	5,297
Winter kW Reduction	0.00	0.00	0	0
kWh Reduction	1.0	1.2	4,963	5,676

2014	
Utility Cost per Installation [2]	$38
Total Utility Program Cost ($000) [3]	$3,965
Net Benefits ($000)	$164

[1] Cumulative participants prior to 2010 (@ Generator) = 90.6
[2] Based on cumulative active participants at year-end = 104.0
[3] Includes depreciation, return & rebates paid in 2014 to active participants who signed up in 2014 & prior years
Note: One Customer, Participant or Installation equals one Summer kW

Utility: Florida Power & Light Company
Program Name: **Commercial/Industrial Demand Reduction**
Program Start Date: May 2000
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[1]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	4,895,780	3,780,346	6,333	0.2%	7,786	7,786	0.2%	1,453
2011	5,017,468	3,867,976	12,666	0.3%	7,038	14,825	0.4%	2,159
2012	5,142,180	3,957,941	18,999	0.5%	16,255	31,080	0.8%	12,081
2013	5,269,992	4,050,300	25,332	0.6%	5,657	36,737	0.9%	11,405
2014	5,400,981	4,145,112	31,665	0.8%	10,129	46,866	1.1%	15,201
2015	5,535,225	4,242,438	37,998	0.9%				
2016	5,672,807	4,342,340	44,331	1.0%				
2017	5,813,808	4,444,883	50,664	1.1%				
2018	5,958,314	4,550,133	56,997	1.3%				
2019	6,106,411	4,658,155	63,330	1.4%				

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	1.00	1.08	10,129	10,917
Winter kW Reduction	0.64	0.69	6,457	6,960
kWh Reduction	10.93	11.60	110,710	117,471

2014	
Utility Cost per Installation [2]	$74
Total Utility Program Cost ($000) [3]	$17,633
Net Benefits ($000)	$65

[1] Cumulative participants prior to 2010 (@ Generator) = 210.5

[2] Based on cumulative active participants at year-end = 238.8

[3] Includes rebates paid in 2014 to active participants who signed up in 2014 & prior years

Note: One Customer, Participant or Installation equals one Summer kW

Utility: Florida Power & Light Company
Program Name: **Business Energy Evaluation**
Program Start Date: October 1990
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		Actual			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants[1]	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	534,490	534,490	6,000	1.1%	13,228	13,228	2.5%	7,228
2011	547,697	541,775	12,000	2.2%	11,690	24,918	4.6%	12,918
2012	561,576	549,390	18,000	3.3%	12,089	37,007	6.7%	19,007
2013	575,598	557,344	24,000	4.3%	12,101	49,108	8.8%	25,108
2014	590,087	565,645	30,000	5.3%	12,822	61,930	10.9%	31,930
2015	604,956	574,301	36,000	6.3%				
2016	620,071	583,321	42,000	7.2%				
2017	635,559	592,714	48,000	8.1%				
2018	651,590	602,491	54,000	9.0%				
2019	667,785	612,659	60,000	9.8%				

2014	
Utility Cost per Installation	$592
Total Utility Program Cost ($000)	$7,588
Net Benefits ($000)	N/A

- No kW or kWh reductions attributed to this program

[1] Cumulative participants prior to 2010 = 141,194

Utility: Florida Power & Light Company
Program Name: **Residential Solar Water Heating Pilot**
Program Start Date: May 2011
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants (1)	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	4,010,837	4,010,837	0	0.0%	0	0	0.0%	0
2011	4,056,428	4,056,428	4,588	0.1%	523	523	0.0%	(4,065)
2012	4,141,910	4,137,322	9,470	0.2%	1,145	1,668	0.0%	(7,802)
2013	4,226,978	4,217,507	14,444	0.3%	1,084	2,752	0.1%	(11,692)
2014	4,311,223	4,296,778	15,344	0.4%	1,118	3,870	0.1%	(11,474)
2015	4,394,802	4,379,458	16,244	0.4%				
2016								
2017								
2018								
2019								

	Per Installation (2)		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	0.22	0.24	242	261
Winter kW Reduction	0.45	0.49	495	533
kWh Reduction	1,482	1,573	1,628,718	1,728,184

2014	
Utility Cost per Installation	$1,306
Total Utility Program Cost ($000)	$1,460
Net Benefits ($000)	($108)

(1) Original Dec. 2014 expiration (Order No. PSC-11-0079-PAA-EG) extended through year-end 2015 (Order No. PSC-14-0632-FOF-EG)

(2) Reflects only the 1,099 electric water heaters replaced (gas = 19 replacements)

Utility: Florida Power & Light Company
Program Name: **Residential Solar Water Heating (Low Income New Construction) Pilot**
Program Start Date: May 2011
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants [1]	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	4,010,837	404	0	0.0%	0	0	0.0%	0
2011	4,056,428	404	200	24.8%	0	0	0.0%	(200)
2012	4,141,910	404	400	33.0%	113	113	9.3%	(287)
2013	4,226,978	404	600	37.1%	103	216	13.4%	(384)
2014	4,311,223	404	800	39.6%	266	482	23.9%	(318)
2015	4,394,802	404	920	38.0%				
2016								
2017								
2018								
2019								

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	0.22	0.24	59	63
Winter kW Reduction	0.45	0.49	120	129
kWh Reduction	1,482	1,573	394,212	418,287

2014	
Utility Cost per Installation	$4,022
Total Utility Program Cost ($000)	$1,070
Net Benefits ($000)	($108)

[1] Original Dec. 2014 expiration (Order No. PSC-11-0079-PAA-EG) extended through year-end 2015 (Order No. PSC-14-0632-FOF-EG)

Utility: Florida Power & Light Company
Program Name: **Business Solar Water Heating Pilot**
Program Start Date: May 2011
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants [1]	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	534,490	534,490	0	0.0%	0	0	0.0%	0
2011	547,697	547,697	43	0.0%	9	9	0.0%	(34)
2012	561,576	561,533	94	0.0%	22	31	0.0%	(63)
2013	575,598	575,503	157	0.0%	7	38	0.0%	(119)
2014	590,087	589,930	233	0.0%	3	41	0.0%	(192)
2015	604,956	604,724	243	0.0%				
2016								
2017								
2018								
2019								

	Per Installation[2]		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	0.90	0.97	3	3
Winter kW Reduction	0.06	0.07	0	0
kWh Reduction	3,301	3,502	9,902	10,507

2014	
Utility Cost per Installation	$22,969
Total Utility Program Cost ($000)	$69
Net Benefits ($000)	($1)

[1] Original Dec. 2014 expiration (Order No. PSC-11-0079-PAA-EG) extended through year-end 2015 (Order No. PSC-14-0632-FOF-EG)

[2] Reflects only the 3 electric water heaters replaced (gas = 0 replacements)

Utility: Florida Power & Light Company
Program Name: **Residential Photovoltaic Pilot**
Program Start Date: May 2011
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants [1]	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	4,010,837	4,010,837	0	0.0%	0	0	0.0%	0
2011	4,056,428	4,056,428	340	0.0%	271	271	0.0%	(69)
2012	4,141,910	4,141,570	680	0.0%	225	496	0.0%	(184)
2013	4,226,978	4,226,298	1,020	0.0%	278	774	0.0%	(246)
2014	4,311,223	4,310,203	1,360	0.0%	257	1,031	0.0%	(329)
2015	4,394,802	4,393,442	1,760	0.0%				
2016								
2017								
2018								
2019								

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	3.01	3.24	773	833
Winter kW Reduction	0.11	0.12	28	30
kWh Reduction	9,854	10,456	2,532,499	2,687,159

2014	
Utility Cost per Installation	$18,006
Total Utility Program Cost ($000)	$4,628
Net Benefits ($000)	($144)

[1] Original Dec. 2014 expiration (Order No. PSC-11-0079-PAA-EG) extended through year-end 2015 (Order No. PSC-14-0632-FOF-EG)

Utility: Florida Power & Light Company
Program Name: **Business Photovoltaic Pilot**
Program Start Date: May 2011
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants [1]	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	534,490	534,490	0	0.0%	0	0	0.0%	0
2011	547,697	547,697	63	0.0%	31	31	0.0%	(32)
2012	561,576	561,512	130	0.0%	66	97	0.0%	(33)
2013	575,598	575,468	201	0.0%	56	153	0.0%	(48)
2014	590,087	589,886	281	0.0%	51	204	0.0%	(77)
2015	604,956	604,676	361	0.1%				
2016								
2017								
2018								
2019								

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	11.96	12.89	610	657
Winter kW Reduction	0.36	0.38	18	20
kWh Reduction	37,798	40,107	1,927,722	2,045,448

2014	
Utility Cost per Installation	$40,242
Total Utility Program Cost ($000)	$2,052
Net Benefits ($000)	($77)

[1] Original Dec. 2014 expiration (Order No. PSC-11-0079-PAA-EG) extended through year-end 2015 (Order No. PSC-14-0632-FOF-EG)

Utility: Florida Power & Light Company
Program Name: **Business Photovoltaic for Schools Pilot**
Program Start Date: May 2011
Reporting Period: 2014

a	b	c	d	e (d/c)	f	g	h (g/c)	i (g-d)
			Projected		**Actual**			
Year	Total Number of Customers	Total Number of Eligible Customers	Cumulative Number of Program Participants [1]	Cumulative Penetration Level %	Annual Number of Program Participants	Cumulative Number of Program Participants	Cumulative Penetration Level %	Cumulative Participation Over (Under) Projected Participants
2010	534,490	1,334	0	0.0%	0	0	0.0%	0
2011	547,697	1,334	18	1.3%	0	0	0.0%	(18)
2012	561,576	1,334	40	3.0%	0	0	0.0%	(40)
2013	575,598	1,334	61	4.6%	29	29	2.2%	(32)
2014	590,087	1,334	79	5.9%	63	92	6.9%	13
2015	604,956	1,334	107	8.0%				
2016								
2017								
2018								
2019								

	Per Installation		Program Total	
2014	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	3.88	4.18	245	264
Winter kW Reduction	0.12	0.12	7	8
kWh Reduction	12,268	13,017	772,863	820,062

2014	
Utility Cost per Installation	$21,537
Total Utility Program Cost ($000) [2]	$1,357
Net Benefits ($000)	($376)

[1] Original Dec. 2014 expiration (Order No. PSC-11-0079-PAA-EG) extended through year-end 2015 (Order No. PSC-14-0632-FOF-EG)
[2] Includes depreciation & return in 2014 for participants who signed up since inception

RESEARCH & DEVELOPMENT

Conservation Research & Development ("CRD") Program: CRD is an umbrella program under which FPL researches a wide variety of new technologies to evaluate their potential for reductions in peak load and energy as well as customer bill savings. Florida's climatic conditions are unique so the studies must incorporate the effects of our hot humid environment. Favorable evaluation results can lead to incorporation in FPL's DSM programs. Examples of technologies that have been included are: Energy Recovery Ventilators; Demand Control Ventilation; and Residential Air Conditioning Duct Plenum Seal. Examples of other potentially viable candidates currently being considered are: variable speed pool pumps; hotel occupancy sensors; and residential heat pump water heaters.

FPL partners in its research projects with the Florida Solar Energy Center and engineering departments of several Florida universities. In 2014, FPL had active research projects with five universities. In addition, FPL participates in relevant co-funded projects through the U.S. Department of Energy ("DOE"). This co-funding enables FPL to participate in larger research projects at a fraction of the total cost.

In 2014, two CRD projects were completed. The first was field testing of a water misting system for the condenser coils of air-cooled large HVAC and refrigeration equipment at a supermarket. The second was Phase I of the co-funded DOE Building America Deep Retrofit project which is aimed at improving energy efficiency of existing homes with low-cost ("shallow") and higher-cost ("deep") retrofits.

Two projects began in 2014 which will be completed in 2015. First is Phase II of the DOE project which is focusing on a new set of deep retrofit measures. Equipment was installed in 2014 and data collection and analysis will be conducted in 2015. Second is a field research project at a supermarket to quantify the savings of a control system which varies the speed of the evaporator fan and the position of the supply air damper on a large rooftop HVAC unit.

Renewable Research & Demonstration ("RRD"): RRD's overall objectives are to: (a) increase awareness of mainstream solar technologies; and (b) evaluate emerging renewable technologies and their applications. The three strategies to meet these objectives are:

1. Demonstrate commercially-available photovoltaic ("PV") or solar water heating ("SWH") systems in real-world field installations.
2. Conduct specific research projects to quantify the performance of renewable products which are less well known, but worthy of closer examination.
3. Educate contractors and the public about the proper way to install solar systems for best performance.

To achieve these, FPL has: installed PV systems and educational displays at public facilities with large numbers of visitors, funding scientific research conducted by Florida universities or other qualified laboratories to test emerging renewable energy technologies, and partnering with universities and technical centers to increase access for solar contractors' training and providing education to FPL's residential and business customers.

In 2014, FPL completed four renewable demonstration installations – the Central Florida Zoo in Sanford, Equine Assisted Therapies at Tradewinds Park in Coconut Creek, Florida Gateway College in Lake City, and the Palm Beach Zoo. FPL also completed four renewable research projects – a solar tracker, hybrid thin film PV, hybrid solar thermal panels, and a solar thermal assisted residential HVAC. Data will continue to be collected on several of the sites for longer term analysis.

OTHER CONSERVATION ACTIVITIES

Cogeneration & Small Power Production: The objective of this program is to facilitate cogeneration and small power production facilities. In 2014, there were purchases from thirteen facilities. These facilities produced 2,503 GWh, summer demand of 748 MW and winter demand of 214 MW

EXHIBIT NO. 77

DOCKET NO: 150196-EI

WITNESS: **SIM**

PARTY: **FPL**

DESCRIPTION: **Exhibit No. 1 to Steve Sim Deposition (10-8-2015)**
Order No. PSC-99-2507-S-EU (Docket No. 981890-EU)

DOCUMENTS: **Order Approving Stipulation**

PROFFERED BY: **SACE**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 77
PARTY: SACE
DESCRIPTION: Sim/Exhibit 1 to Steven Sim Deposition 10/8/15

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.	DOCKET NO. 981890-EU ORDER NO. PSC-99-2507-S-EU ISSUED: December 22, 1999

The following Commissioners participated in the disposition of this matter:

JOE GARCIA, Chairman
J. TERRY DEASON
SUSAN F. CLARK
E. LEON JACOBS, JR.

APPEARANCES:

JAMES D. BEASLEY and LEE WILLIS, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

JOSEPH A. McGLOTHLIN, McWhirter, Reeves, McGlothlin, Davidson, Dekker, Kaufman, Arnold & Steen, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Reliant Energy Power Generation.

VICKI GORDON KAUFMAN and JOHN MCWHIRTER, McWhirter, Reeves, McGlothlin, Davidson, Dekker, Kaufman, Arnold & Steen, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of the Florida Industrial Power Users Group.

GARY L. SASSO, Carlton, Fields, Ward, Emmanuel, Smith & Cutler, P.A., Post Office Box 2861, St. Petersburg, Florida 33731, appearing on behalf of Florida Power Corporation.

MATTHEW M. CHILDS, Steel, Hector & Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, appearing on behalf of Florida Power & Light Company.

DEBRA SWIM, Legal Environmental Assistance Foundation, 1115 North Gadsden Street Tallahassee, Florida 32301, appearing on behalf of Legal Environmental Assistance Foundation (LEAF).

EXHIBIT
SIM #1
WH 10.8.15

ROY YOUNG, Young, van Assenderp and Varnadoe, P. A., P. O. Box 1833, Tallahassee, Florida 32302-1833, appearing on behalf of the City of Lakeland and Kissimmee Utility Authority.

PAUL SEXTON, Thornton Williams & Associates, 215 South Monroe Street, Suite 600-A, Tallahassee, Florida 32301, appearing on behalf of the Florida Reliability Coordinating Council, Inc.

JON C. MOYLE, JR. Moyle, Flanigan, Katz, Kolins, Raymond & Sheehan, 210 South Monroe Street, Tallahassee, Florida 32301, appearing on behalf of PG&E Generating Company.

ROBERT SCHEFFEL WRIGHT, Landers & Parsons, 310 West College Avenue, Tallahassee, Florida 32302, appearing on behalf of Duke Energy New Smyrna Beach Power Company, Ltd., L.L.P.

FREDERICK M. BRYANT, General Counsel, Florida Municipal Power Agency, 2010 Delta Boulevard, Tallahassee, Florida 32315, appearing on behalf of Florida Municipal Power Agency.

THOMAS J. MAIDA, III, Foley & Lardner, Post Office Box 508, Tallahassee, Florida 32302, appearing on behalf of Seminole Electric Cooperative.

KENNETH A. HOFFMAN, Rutledge, Ecenia, Underwood, Purnell and Hoffman, P. O. Box 511, 215 South Monroe Street, Suite 420, Tallahassee, Florida 32302-0551, appearing on behalf of the City of Tallahassee.

MICHAEL B. WEDNER, Office of General Counsel, 117 West Duval Street, Suite 480, Jacksonville, Florida 32202, appearing on behalf of Jacksonville Electric Authority.

ROBERT V. ELIAS, GRACE JAYE and COCHRAN KEATING, FPSC Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

ORDER APPROVING STIPULATION

BY THE COMMISSION:

During our reviews of the Ten Year Site Plans filed in 1997 and 1998, we expressed concerns about the adequacy of the reserve margins planned for Peninsular Florida. At the December 15, 1998, Internal Affairs meeting, we directed staff to open this docket to consider the reserve margins planned for Peninsular Florida electric utilities.

By Order No. PSC-99-1274-PCO-EI, nineteen issues were identified for consideration in this proceeding. The investor-owned utilities, the cooperative utilities, several municipal utilities, the various intervenors, and Commission staff filed testimony concerning these issues. The hearing was scheduled for November 2nd and 3rd, 1999.

At the outset of the hearing, Florida Power & Light Company (FPL), Florida Power Corporation (FPC), and Tampa Electric Company (TECO), presented a proposal designed to settle the case; addressing what they believe are the Commission's major concerns. By the proposal, these three utilities stipulated to voluntarily adopting a twenty percent reserve margin planning criterion. Each of these three utilities would achieve the twenty percent level by the summer of 2004. Further, pursuant to the proposal, no decisions would be made concerning the specifically enumerated issues, and the docket would be closed. FPL, FPC, and TECO would be the only utilities adopting the twenty percent criteria.

Other parties argued in support of and against the proposal. The Florida Industrial Power Users Group (FIPUG) requested additional time to present a counter-proposal. The hearing was continued until November 30, 1999, and the parties were directed to attempt to reach a negotiated settlement. FIPUG offered a counter-proposal on November 17, 1999. No settlement was reached.

At the continued hearing, we considered both proposals. After discussion, FPL, FPC, and TECO agreed to further modifications to their proposal. A document incorporating these agreed-upon changes was filed on December 15, 1999. A copy of this document (hereinafter the "Stipulation") is included in this Order as Attachment A and is incorporated herein by reference. FPL, FPC, and TECO have each agreed to achieve a planned twenty percent reserve margin by the summer of 2004. In response to concerns expressed by some of the other parties, each utility has agreed to make a good faith effort to notify the Commission if it opts to modify the twenty percent criterion. The three utilities signing the Stipulation further acknowledge in paragraph 9 at page 4 that

> the Commission shall retain the ability and discretion to consider all facts and circumstances applicable to a given utility and/or peninsular Florida. Further, with respect to the evaluation of the adequacy of reserves in peninsular Florida, the Commission may employ any methodology and consider any facts and circumstances it deems appropriate, subject to applicable legal requirements.

We approve the Stipulation agreed to by Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company. It addresses the basic concern about the adequacy of planned reserve margins for Peninsular Florida. Collectively, these three utilities plan for approximately 80 percent of the Peninsular Florida load. Thus, a twenty percent planning criterion adopted by these three utilities is a significant increase over the fifteen percent criterion currently employed.

Further, we will convene a workshop to receive and consider information regarding how distributed resources, both demand and supply-side, may be used to meet Florida's energy service reliability needs. In addition, we will convene a workshop for the consideration of the appropriate relationship between the non-firm load of an individual utility and the total reserves required to maintain the utility's appropriate reserve margin.

Based on the foregoing, it is therefore

ORDERED by the Florida Public Service Commission that the Stipulation agreed to by Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company, which is included in this Order as Attachment A and is incorporated by reference herein, is approved. It is further

ORDERED that this docket shall be closed.

By ORDER of the Florida Public Service Commission this 22nd day of December, 1999.

Blanca S. Bayó

BLANCA S. BAYÓ, Director
Division of Records and Reporting

(S E A L)

RVE

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of Records and reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida
/

Docket No. 981890-EU

STIPULATION

WHEREAS, the Florida Public Service Commission initiated this proceeding regarding reserve margins of Peninsular Florida utilities in December 1998; and

WHEREAS, subsequent to that date Staff and parties identified certain issues to be addressed and procedures to be followed; and

WHEREAS, Florida Power & Light Company (FPL), Florida Power Corporation (FPC), and Tampa Electric Company (TECO) (collectively, the IOUs) have asserted, and continue to assert, that the scope of the proceeding has been expanded beyond the intent of the Commission, and that the procedural posture of this proceeding is such that the Commission cannot lawfully take formal action that would affect their substantial interests at this time; and

WHEREAS, in Orders No. PSC-99-1274-PCO-EU and No. PSC-99-1716-PCO-EU the Commission overruled the IOUs' procedural objections, clarified the scope of the docket, identified specific issues to be addressed, and confirmed its intent to conduct a formal evidentiary proceeding in this docket and take the actions it deems appropriate; and

WHEREAS, Reliant Energy Power Generation, Inc (Reliant Energy), Florida Industrial Power Users Group (FIPUG), PG&E Generating Company (PG&E), the Legal Environmental Assistance Foundation, Inc. (LEAF), and Duke Energy North America, LLC, and Duke Energy New Smyrna Beach Power Company, Ltd., LLP (Duke Energy), (hereinafter referred to as Intervenors), filed Petitions to Intervene in which they alleged the actions contemplated by the Commission in this docket would affect their substantial interests; and

WHEREAS, the Commission granted Intervenors' petitions to intervene, and Intervenors have participated as full parties to the proceeding; and

WHEREAS, on October 29, 1999, FPC, acting on behalf of the IOUs, submitted to the Commission Staff a proposal for the resolution of the issues in this proceeding; and

WHEREAS, upon receipt of the proposal the Commission continued the hearing scheduled for November 2, 1999 and convened on that date a conference of all parties for the purpose of discussing the proposal of the IOUs; and

WHEREAS, upon consideration of the IOUs' proposal, without waiving their respective litigation positions and for the purposes of compromise and settlement, the undersigned, representing all of the parties to this proceeding that have been identified by the Commission or allowed by Commission to intervene, have decided to prepare this Stipulation, and present it to the Commission for the purpose of concluding this docket.

NOW, THEREFORE, the parties stipulate and agree as follows:

1. The IOUs will each voluntarily adopt a minimum reserve margin planning criterion of twenty percent (20%).

2. The twenty percent (20%) reserve margin planning criterion will be a minimum; no maximum or cap will be represented or implied by this criterion.

3. No utility other than the three IOUs identified hereinabove is agreeing to adopt a twenty percent (20%) reserve margin planning criterion by virtue of this Stipulation.

4. The IOUs will calculate the minimum twenty percent (20%) reserve margin by employing their current methodology; i.e., Reserve Margin (%) = [(Total Firm Capacity - Peak Firm Demand)/Peak Firm Demand] x 100, where Total Firm Capacity will be based on generating capacity owned by the IOUs or capacity for which there is a firm commitment to these IOUs and

where Peak Firm Demand means total demand reduced by demand side resources.

5. The IOUs will undertake to implement the twenty percent reserve margin criterion over a transition period of four years, meaning that they will plan to achieve a twenty percent (20%) reserve margin by the Summer of 2004.

6. The IOUs agree to adopt the twenty percent (20%) reserve margin planning criterion with the good faith intention of maintaining that planning criterion for the indefinite future, but each IOU must reserve the prerogative individually to modify its planning criteria to adapt to relevant circumstances. By the same token, it is understood that the Commission remains free to initiate an investigation or to take other appropriate action to review and to respond to any changes that the IOUs may make in the future regarding their planning criteria.

7. Should any IOU exercise its prerogative to change its twenty percent (20%) minimum reserve margin planning criterion discussed herein, such IOU will make a good faith effort to provide notice of the change to the Commission.

8. Neither the adoption by the IOUs of the minimum twenty percent (20%) planning criterion nor the approval of this Stipulation by the Commission shall be deemed to create any presumption that capacity additions must be through any particular mix of generation and/or demand-side resources. Nor shall said adoption or approval be deemed to create any presumption with respect to any proposals for adding generating capacity or create a presumption that a generating capacity addition proposed by any entity is not needed. All current and future proceedings under the Electrical Power Plant Siting Act, including those for the consideration of merchant plants, and all statutes, rules, regulations, and policies bearing on the Commission's determination of need for new generation (including the need determination criteria in § 403.519, Florida Statutes); the IOUs' obligation to solicit proposals for generating capacity; and the

obligations of the IOUs to otherwise prudently avail themselves of reasonably available conservation alternatives and cost-effective resource options; and the obligations of the IOUs to best serve their retail customers through their respective resource planning processes, are unaffected by this Stipulation and the approval thereof.

9. The parties acknowledge that for all regulatory purposes, the Commission shall retain the ability and discretion to consider all facts and circumstances applicable to a given utility and/or peninsular Florida. Further, with respect to the evaluation of the adequacy of reserves in peninsular Florida, the Commission may employ any methodology and may consider any facts and circumstances it deems appropriate, subject to applicable legal requirements.

10. The Commission is encouraged to take the following actions in conjunction with the approval of this Stipulation:

A. Convene a workshop, with the participation and the assistance of the Regulatory Assistance Project, to receive and consider information regarding how distributed resources, both demand and supply-side, may be used to meet Florida's energy service reliability needs, to be followed by any additional proceedings and/or actions relative to this matter that the Commission deems appropriate.

B. Convene a workshop for the consideration of the appropriate relationship between the non-firm load of an individual utility and the total reserves required to maintain the utility's appropriate minimum reserve margin, to be followed by any additional proceedings and/or actions relative to this matter that the Commission deems appropriate.

11. The parties enter into this Stipulation for the purpose of effecting a compromise and of achieving closure of this docket. By its participation in this Stipulation, no party expresses its endorsement of any individual provision included by any other party.

12. By entering this Stipulation, no party waives any position it has taken with respect to any aspect of this proceeding or any of the issues identified in this proceeding or any other proceeding. Further, no party waives the right and opportunity to petition the Commission to institute any action designed to provide any relief deemed appropriate or desirable by that party at any time.

13. The parties to this Stipulation agree that, by approving this Stipulation, the Commission does not waive its right and ability, pursuant to governing law, to initiate any proceeding or take any action for which it has requisite jurisdiction and authority.

14. In the event the Commission declines to approve this Stipulation in its entirety, it shall become null and void.

AGREED this 14th day of December 1999.

Matthew M. Childs
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Steel Hector
215 South Monroe Street, Ste. 601
Tallahassee, FL 32301-1804
Attorneys for Florida Power & Light Company

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EXHIBIT NO. 78

DOCKET NO: 150196-EI

WITNESS: JOHN WILSON

PARTY: SACE

DESCRIPTION: SACE / WILSON BLOG

DOCUMENTS:

PROFFERED BY: FPL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 78
PARTY: FPL
DESCRIPTION:SACE/Wilson Blog

CleanEnergy Footprints

- home
- contributors
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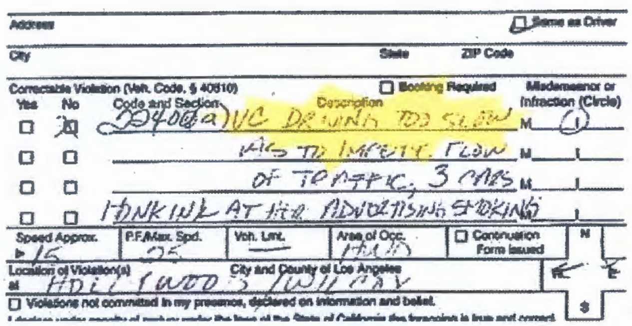
- get widget
- photos

Driving energy efficiency too slow

October 22nd, 2011 › Energy Efficiency, Utilities › John D. Wilson ›


Address ☐ Same as Driver
City State ZIP Code
Correctable Violation (Veh. Code, § 40610) ☐ Booking Required Misdemeanor or Infraction (Circle)
Yes No Code and Section Description
22400(a) VC DRIVING TOO SLOW M (I)
AS TO IMPEDE FLOW M I
OF TRAFFIC, 3 CARS M I
HONKING AT HER ADVERTISING SMOKING I
Speed Approx. 15 P.F./Max. Spd. 25 Veh. Lmt. Area of Occ. ☐ Continuation Form Issued
Location of Violation(s) at City and County of Los Angeles
☐ Violations not committed in my presence, declared on information and belief.

Florida energy regulators have been in the slow lane, dragging out the implementation of a 2009 law mandating stronger energy efficiency programs.

Just a brief update for those who are interested in why Florida is moving so slowly on energy efficiency. As recently noted by the American Council for an Energy Efficient Economy, "regulators in Florida … took actions to render their energy savings target ineffective." Similarly in response, the Southern Alliance for Clean Energy is protesting the regulatory decision to effectively eviscerate the energy efficiency goals set by the Florida Public Service Commission for Florida Power and Light and Progress Energy Florida.

Yesterday, we filed our brief protesting the rollback decision. Essentially, we are asking the Commission to reconsider its decision under a corrected interpretation of Florida law. Here's the crux of our legal argument:

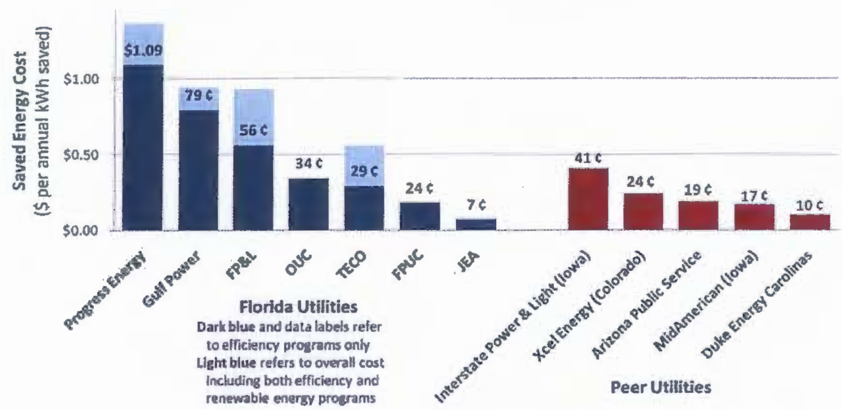
> The Commission violated Fla. Stat. §366.82(7) … by relying on this statutory provision as authority to effectuate a change in FPL's and PEF's applicable conservation goals. This is a clear procedural violation as §366.82(7) only allows the Commission to, following the adoption of goals pursuant to the goal setting provisions of the statute, approve, modify, or deny DSM plans submitted by utilities to ensure the plans meet applicable goals. The Commission simply cannot adopt or change goals pursuant to §366.82(7); rather, the statute is clear and unambiguous in that goals can only be adopted or changed pursuant to §§366.82(2), (3) and (6), Fla. Stat.
>
> … the legislative history of the 2008 amendments to the statute is clear that the Legislature intended for more robust conservation goals to be set, and that the

Commission must find ways to meet the goals in the most efficient and cost-effective manner. Thus, the Commission's orders are in direct contravention to legislative intent.

The brief asks the Commission to either approve the plans submitted earlier this year by the utilities (which the utilities believe will achieve the goals), or to approve the parts of the plans that the Commission believes are reasonable. If the commission only approves part of the plans, it should direct the utilities to file improved plans.

The process for reviewing these plans has now stretched to over a year and a half. During that time, SACE has continuously argued that Florida's utilities have proposed energy efficiency plans with bloated costs. (See our comments filed here, here, here, here, and hear. Hear! Hear!) Then, Florida utilities have argued that those bloated costs are the reason that the programs should be rolled back. The Florida Public Service Commission's responsibility is to direct the utilities to develop cost-effective plans that reflect industry best practices, as Susan Glickman recently reminded us.

In their Original Plan Filings, Some Florida Utilities Proposed Energy Efficiency Programs with Bloated Costs



Notes: "Saved Energy Cost" is calculated as the total cost to the utility (program costs plus incentives) per total annual energy savings attributed to those programs, irrespective of measure life. A program with a saved energy cost of 40 ¢ per kWh with an expected measure life of ten years would cost about 4 ¢ per kilowatt hour per year. See tables 2 and 3 of our findings for the data illustrated above.

Ironically, on the same day that the Florida Public Service Commission argued that helping customer save energy was too expensive, it also approved a program that will require existing customers to subsidize the energy bills of new businesses, but the Commission did not examine the costs and rate impacts of *that* program. Deeply hypocritical and misguided, as energy efficiency promotes job growth and helps existing businesses manage their bottom line.

Like 0 G+1

Tags: ACEEE, electric rates, Energy Efficiency, Florida, florida power and light, FPL, public service commission

3 Comments

Comments RSS

Very nice post. I just stumbled upon your blog and wished to say that I've really enjoyed surfing around your blog posts.

EXHIBIT NO. 79

DOCKET NO: 150196-EI

WITNESS: **SIM**

PARTY: **FPL**

DESCRIPTION: **Rebuttal Testimony& Exhibits of Roberto R. Denis (September 27, 1999) Docket No. 981890-EU**

DOCUMENTS: **Rebuttal Testimony & Exhibits of Roberto R. Denis (September 27, 1999) Docket No. 981890-EU**

PROFFERED BY: **SACE**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150196-EI EXHIBIT: 79
PARTY: SACE
DESCRIPTION: Sim/Rebuttal testimony and Exhibits of Roberto Denis September 27, 1999

39

STEEL HECTOR & DAVIS

REGISTERED LIMITED LIABILITY PARTNERSHIP

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215 South Monroe, Suite 601
Tallahassee, Florida 32301-1804
850.222.2300
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Matthew M. Childs, P.A.

ORIGINAL

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RECORDS AND REPORTING

September 27, 1999

Ms. Blanca S. Bayó, Director
Division of Records and Reporting
Florida Public Service Commission
4075 Esplanade Way, Room 110
Tallahassee, FL 32399

RE: DOCKET NO. 981890-EU

Dear Ms. Bayó:

Enclosed for filing please find an original and fifteen(15) copies of Florida Power & Light Company's Rebuttal Testimony of Roberto R. Denis in the above referenced docket.

Very truly yours,

Matthew M. Childs, P.A.

MMC:ml
Enclosure
cc: All Parties of Record

EAG
AFA-2
PAI-2
Legal-1
WAS-5+org
Sec-1

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DOCUMENT NUMBER-DATE
11657 SEP 27 99
FPSC-RECORDS/REPORTING

CERTIFICATE OF SERVICE
DOCKET NO. 981890-EU

I HEREBY CERTIFY that a true and correct copy of Florida Power & Light Company's Rebuttal Testimony of Roberto R. Denis has been furnished by Hand Delivery*, U.S. Mail this 27th day of September, 1999 to the following:

Robert V. Elias, Esq.*
Leslie J. Paugh, Esq.
Division of Legal Services
FPSC
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By: ____________________
Matthew M. Childs, P.A.

ORIGINAL

BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

DOCKET NO. 981890-EU
FLORIDA POWER & LIGHT COMPANY

GENERIC INVESTIGATION INTO
THE AGGREGATE UTILITY RESERVE MARGINS
PLANNED FOR PENINSULAR FLORIDA

REBUTTAL TESTIMONY & EXHIBITS OF:

ROBERTO R. DENIS

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SECOND REBUTTAL TESTIMONY OF ROBERTO R. DENIS

DOCKET NO. 981890-EU

SEPTEMBER 27, 1999

Q. Please state your name and business address.

A. My name is Roberto Denis and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I have previously filed testimony in rebuttal of Mr. Slater, the witness for the Duke entities, in accordance with the pre-hearing order in this docket. This rebuttal testimony responds to the testimony of the Staff witnesses, Mr. Ballinger and Mr. Trapp. While I address a number of specific observations of their testimony, my rebuttal testimony has six major points.

First, Staff's exercise of looking at historic projections of reserve margins over time rather than looking at reliability criteria used for planning is misleading. It ignores the historic reasons that past projections of reserve margins have been above reserve margin criteria, and it fails to recognize years of Commission practice that have approved reliability criteria that are consistent with the 15% minimum reserve margin criterion that the Florida Reliability Coordinating Council (FRCC) has employed for the last two years.

Second, Staff's analysis and conclusions regarding the FRCC's 15% reserve margin are flawed. The analysis fails to demonstrate either that the 15% minimum reserve margin proposed for Peninsular Florida by the FRCC is inappropriate or why a 20% reserve margin criterion proposed by Staff is appropriate.

Third, Staff's testimony and focus on reserve margin fails to acknowledge the reliability of Peninsular Florida system as measured by Loss-of-Load Probability (LOLP). Staff's dismissal of LOLP appears to be based solely on disagreement with the outcome of recent LOLP analyses performed for Peninsular Florida. While Staff questions projected unit availability rates, the rates used are consistent with recent experience. Staff's rejection of the LOLP studies is therefore arbitrary and unreasonable. The Commission has long recognized use of LOLP to measure supply adequacy for Peninsular Florida, and Staff's suggestion that the Commission adopt a reserve margin criterion without consideration of LOLP fails to recognize the reliability of the Peninsular Florida system.

Fourth, Staff's suggestion that reliance upon non-committed capacity to achieve reserve margin criteria is a departure from years of Commission practice that would damage rather than enhance reliability. The Commission has never required utilities to replace firm resources with non-firm resources, though the state has had these resources available for many years.

Fifth, Staff's suggestion that a one-size-fits-all reliability standard should be adopted for Peninsular Florida and individual utilities fails to recognize the varying degrees of reliability among the numerous systems that comprise Peninsular Florida and advances a concept of central planning that the Commission should reject. If there are reliability problems within the State of Florida, they are first and foremost individual utility problems that must be addressed at an individual utility level. For much the same reason a single standard should not be applied in judging individual utilities' Ten-Year Site Plans.

Sixth, it is inappropriate for the Commission to adopt in this proceeding a policy, creation of a 20% reserve margin criterion, and apply it retroactively to assess the suitability of Ten-Year Site Plans filed when there was no such policy in place and when prior Commission practice was consistent with the use of planning criteria utilized by individual utilities. The unfairness of Staff's recommendation should be readily apparent to the Commission.

Q. Are you sponsoring any exhibits?

A. Yes. My exhibit consists of the following document:

Document No. RRD-2: Commission Approved Reliability Criteria

Q. Before continuing, do you have any general concerns with this proceeding?

A. Yes. The testimony presented by Staff's witnesses reinforces FPL's concerns about the type of proceeding we are involved in and whether or not the results will have any binding impact on FPL and its customers. FPL has stated its concerns on several occasions about these issues. What began as a generic investigation into reserve margin methodology has become a proceeding to determine and enforce a new reserve margin standard.

Let me be clear in stating FPL's position one more time. FPL does not question the Commission's authority to investigate these issues, nor do we seek to limit or impede the Staff's ability to carry out any directive from the Commission.

However, a generic investigation, such as this docket, is not intended in my opinion, to determine guilt or innocence, but rather to educate the Commission on issues the Commission has identified to be of interest. What concerns us here is process, not authority. If the Commission wishes, after considering all of the information presented, to initiate a rulemaking to establish a reserve margin standard, that is certainly within the Commission's discretion.

Aside from the general process concerns, I am also disturbed by the introduction of issues which are only peripherally related to reserve margin methodology, and the participation in this proceeding by entities which are not regulated utilities who will be required to comply with the outcome, nor will be substantially affected in any way. The issues related to merchant plants, which were supposed to be the subject of a separate investigation as I understand it, have not only been reintroduced in this proceeding, but seem to be influencing some of the recommendations. This generic investigation has expanded in scope well beyond what is necessary to fill the Commission's needs for information.

In summary, I believe this investigation is inappropriately directed at enforcing a yet-to-be identified standard, overly broad in its scope, and I would go so far to say that what we have here is a solution in search of a problem. Nevertheless, I will address the specific factual allegations raised in Staff's testimony.

I. Staff's Misleading Failure to Distinguish Historic Projections of Reserve Margin Levels from Reserve Margin Criteria, Their Failure to Acknowledge Improved System Reliability and the Reliability Standards That Have Withstood the Test of Time.

Q. On pages 4 and 5 of his direct testimony, Mr. Ballinger reports a decline in utility "planned reserve margins for Peninsular Florida", discusses his perception of the driving forces behind the trend, and then concludes with the observation that "caution should be taken before adopting any reliability standard that has not withstood the rigors of time testing." What is your response?

A. I have two points I would like to make. First, Mr. Ballinger fails to explore the reasons underlying the apparent "decline" in planned reserve margins. Had he done so, he would have discovered that historic projections of reserve margins did not result solely from reliability standards used in resource planning. Other considerations, well known to the Commission, influenced projected reserves. Second, when one considers the Commission's decisions over the period 1984 through 1999, particularly the 1989 through 1999 period Mr. Ballinger addresses in his testimony, it is clear that a 15% reserve margin criterion and a LOLP criterion of 0.1 day/year have not only withstood the rigors of time testing, but also have been repeatedly approved by the Commission as reasonable planning criteria.

Q. Please explain your observation that Mr. Ballinger fails to explore the reasons underlying the apparent "decline" in planned reserve margins.

A. On page 4 of his testimony, Mr. Ballinger reports what he calls "planned reserve margins" for Peninsular Florida. He goes on to recount his opinion as to why the "planned" reserve margins have declined and then concludes that "caution should be taken before adopting any reliability standard that has not withstood the rigors of time testing". He is confusing reserve margins projections resulting from a reliability planning process with historic projections of reserve margins which may have resulted from other considerations in addition to reliability planning.

The "planned reserve margins" of approximately 50% he reports were not reserve margins that were the product of reliability standards. At no time during the period 1984 through present has any Peninsular Florida utility or the FRCC or its predecessor had a 50% or even a 40% reserve margin criterion. The historically high reserve margins in the mid-to-late 1980s reported by Mr. Ballinger were due to other well documented factors that Mr. Ballinger has ignored or overlooked. A comparison of "planned reserve margins" with current reserve margin planning standards or criteria is, at best, misleading when the "planned reserve margins" resulted from considerations other than reliability. It makes it appear that there has been a dramatic decline in the reserve margin planning standard, and that is not the case.

Q. You stated that there were well documented factors that explain the historically high reserve margins in the mid-to-late 1980s, other than the factors cited by Mr. Ballinger. Please explain?

A Mr. Ballinger overlooks the fact that the high reserve margin levels of the mid-to-late 1980s and early 1990s are readily attributable to two Commission actions associated with the implementation of the Florida Energy Efficiency and Conservation Act (FEECA): i) adoption of very aggressive, mandatory conservation goals, and ii) the approval of oil backout projects. I will address each, in turn.

In its implementation of FEECA in 1981, the Commission approved mandatory conservation goals that required utilities to reduce demand and energy by certain Commission prescribed percentages. When these Commission-approved goals were factored into utilities' load forecasts, there was an immediate increase in the resulting reserve margins, simply due to lowered projections of firm load.

The introduction of these conservation goals resulted in some initial reluctance to cancel or defer new generating units that were already planned but not yet under construction. In some cases, these units remained in individual electric utility plans (and were subsequently built) for reasons other than reliability, with the utility's resulting reserve margin increasing.

The impact of the Commission's conservation goals on reserve margins is perhaps most easily seen in two determination of need cases decided by the Commission in 1981. Prior to the Commission's adoption of conservation goals, both Tampa Electric Company (TECO) and Orlando Utilities Commission (OUC) had been planning major coal unit additions for the mid-1980s. After the Commission adopted its mandatory conservation goals, the need for these plants could no longer be based on a reliability standard alone. The Commission noted in TECO's Big Bend 4 decision, "achievement of the conservation goals would obviate Peninsular system's need for Big Bend 4 from an adequacy viewpoint." In the OUC Stanton Unit 1 case the Commission noted that with the recently approved FEECA goals the unit was not needed to meet a Peninsular Florida reserve margin criteria until 1992, six years after its scheduled in-service date. Ultimately, the Commission justified the need for these units on an immediate oil backout and fuel savings rationale as well as longer term reliability needs (needs in the early 1990s). That leads me to the other factor that explains the high reserve margin levels of the mid-to-late 1980s.

This other factor was based on another aspect of FEECA. It concerned an intent to reduce reliance on foreign oil - oil backout. As a result, the Commission made a concerted effort to reduce the reliance of Florida utilities on foreign oil by promulgating an oil backout rule, approving a major oil backout project, and approving power plant construction that was based upon economic savings associated with displacing oil-generated power. This policy, which promoted power plant additions not based on meeting reliability criteria, also contributed to Peninsular Florida reserve margins increasing dramatically to the levels reported in Mr. Ballinger's testimony.

In 1982, for example, the Commission approved the St. John's River Power Park Units 1 and 2 based on oil backout. In addition, in 1982 the Commission approved the construction of two 500 kV transmission lines and associated coal-by-wire purchases as an oil backout project under the Commission's recently adopted oil backout rule. The Commission acknowledged that the projects would increase reliability but stated that their primary purpose was oil backout.

When the combined capacity of these four coal units, 2,200 MW and the coal-by-wire purchases of approximately 2,600 MW, were reflected in Peninsular Florida's reserve margins (reserve margins that were already inflated by Commission mandated conservation goals) in the mid-to-late 1980s, the resulting reserve margins were quite large. However, it would be misleading to suggest that these resulting reserve margins were the product of reserve margin or planning standards which were then in place.

For FPL, planning criteria have not declined in the 1989-to-present period Mr. Ballinger discusses. In fact, FPL bolstered its planning criteria in 1997 when it began using a 15% Winter reserve margin in addition to its 15% Summer reserve margin criterion and its 0.1 day/year LOLP criterion.

Q. On Page 4 of his testimony, Mr. Ballinger suggests that reevaluated maintenance procedures have led to the emergence of unprecedented generating unit availabilities. He then suggests that such improved availabilities have not stood the test of time and should be discounted for their effect resulting in lower planned reserve margins. What is your response?

A. I can only speak for FPL, but improved generating performance has been a management objective, a conscious effort by FPL. Of course, that is also exactly what the Commission intended when it proposed for investor-owned utilities a Generating Performance Incentive Factor (GPIF) almost twenty years ago. It was adopted to provide utilities an incentive to improve their generating performance, including their unit availabilities. Not surprisingly, that is exactly what has happened and continues to happen. The factor is designed to provide a reward for improved unit performance and to penalize unit performance that does not exceed prior performance.

Because FPL has higher unit availability in 1999 than in 1989, FPL's system and Peninsular Florida's systems are more reliable. Fewer outages of shorter duration mean that units are available more of the time to meet system requirements. The impact of improved unit availability is directly captured in FPL's other reliability methodology: LOLP. Its impact on the LOLP factor has been dramatic, driving the value well below the standard of 0.1 days/year. Ignoring the favorable impact of improved unit availabilities on system reliability, as Mr. Ballinger and Mr. Trapp suggest in promoting a higher reserve margin standard, in effect denies FPL's customers the savings that result from that improvement.

Q. Mr. Ballinger cautions about adopting a reliability standard that has not withstood the rigors of time testing. What reliability criteria have withstood the rigors of time testing since 1989?

A. Looking to Commission orders where the Commission has had occasion to review and approve reliability criteria since 1989, I conclude that there are two reliability criteria that have withstood the rigors of time testing and Commission review: a minimum reserve margin of 15% and a Loss of Load Probability of 0.1 days/year.

In the last decade the Commission, in a variety of cases, has reviewed and based some aspect of its decision on reliability criteria on at least twenty-two occasions. Attached to my testimony is Document No. RRD-2, which summarizes those decisions. As you can see, in nineteen of the twenty-two decisions the Commission approved or relied upon a reserve margin criterion. In fifteen of those nineteen decisions the Commission approved a reserve margin criterion of 15% (and in one case the Commission approved a reserve margin criterion as low as 10%). Indeed, in 1996 the Commission even adopted a rule that embraces a 15% reserve margin criterion. <u>The Commission's most recent approval of a 15% reserve margin criterion was in May of this year</u>.

In addition to addressing reserve margin, in eleven of those decisions, the Commission also approved a LOLP of 0.1 day/year as an appropriate reliability criterion. Not once in the last ten years has the Commission approved a LOLP standard of other than 0.1 day/year.

Adopting a reserve margin standard of 20% would deviate significantly from prior Commission practice in the majority of cases decided in the last ten years. A 20% standard has been approved only four times in the last decade, and in each instance it was for a relatively small utility compared to the size of Peninsular Florida. In fact, on at least one occasion the Commission observed that its approval of the 20% reserve margin was related to the size of the utility. In TECO's 1992 IGCC need case the Commission noted that its 20% "winter reserve margin is a reasonable one for a utility of Tampa Electric's size."

II. Staff's Analysis of the FRCC's Reserve Margin Assessment Is Flawed.

Q. What conclusions did Staff's draw from their analysis of the FRCC's assessment of its 15% reserve margin last year?

A. In response to the 1998 FRCC's Assessment of the 15% reserve margin, the Staff performed an analysis to assess the adequacy of the FRCC 15% reliability standard.

Staff arrived at the following conclusions from its analysis:

The FRCC Load and Resource Plan summer reserves were found to be adequate for the entire 10-year horizon.

Generating capacity may be inadequate during the 1999/2000 and 2000/2001 Winter seasons.

In fact, Staff suggested there was only a 6% probability that Peninsular Florida could be short by 955 MW for the Winter of 1999/2000. For the Winter of 2000/2001 there was an 8.3% probability the Peninsular Florida could be short as much as 1041 MW.

Q. What conclusions do you draw from your review of the Staff's critique of the FRCC's assessment of its 15% reserve margin criterion in 1998?

A. First, Staff's conclusions last year bear remembering. The only problem that Staff identified was a near-term Winter-only problem in two specific years. No problem was identified with Summer reserve margins. There was no long-term reliability problem, and there was no proposed 20% reserve margin standard.

Second, even the above-mentioned conclusion of only a two-year Winter potential problem is overstated, since Staff's analysis of the FRCC's assessment of its 15% reserve margin standard was flawed in a manner that made its results too pessimistic. (Mr. Villar's rebuttal testimony addresses the studies performed by FRCC in an attempt to correct the flaws in Staff's analysis.)

As flawed as it was, Staff's analysis still shows that there is a greater than 90% probability that no problem will occur even in those two Winters. When Staff's analysis is corrected to account for its flaws, there was not even a short term reliability problem based upon the 1998 Ten-Year Site Plans.

Third, Staff did not recommend a new reliability standard as a result of its analysis last year. Even though it had concerns about the Ten-Year Site Plans submitted as well as the FRCC's 15% reserve margin criterion, the concerns were not serious enough to warrant the adoption of a new and different reliability standard.

Q. In his testimony Mr. Ballinger has offered an entirely new critique of the FRCC's assessment of its 15% reserve margin criterion. Please explain why you think his critique is flawed?

A. Mr. Ballinger begins his critique (starting on page 6 of his testimony) with three "shortcomings" about the FRCC's assessment: load diversity, off-peak periods, and load forecast error rates. I will address each in turn.

Mr. Ballinger takes the position that instead of using coincident load data to measure reserve margin the FRCC should use non-coincident load data is unsound.

Peninsular Florida is comprised of numerous utilities which have different customer mixes and are geographically spread over 400 miles. These individual systems do not experience their peak demand at the same time. It would be illogical to expect that weather patterns, a large driver of peak load, would drive utility loads over such a large area to simultaneous peaks. The FRCC's refinement in 1999 of applying a diversity factor in its testing of the suitability of its 15% reserve margin standard is appropriate. It reflects reality and proper planning.

Q. Mr. Ballinger also takes issue with the FRCC using peak periods to measure reserve margins and advocates, on page 7 of his testimony, that the FRCC should also measure reserve margins in off-peak periods. Please respond.

A. In Florida, the Winter peak typically occurs in December or January. Summer peaks generally occur in the June through September period. The remaining six months, generally considered to be "shoulder" or off-peak months, are typically when utilities plan outages of their units for maintenance. Since maintenance scheduling is a manageable activity with a short-term (less than 1 year) horizon, it is a short-term or operational concern not a long-term planning concern. It would make no sense to project or consider reserve margins for off-peak months beyond one year in the future, and even for the near-term, utilities can manage the reserve margins at any point in time by managing maintenance schedules. When the FRCC analyzed the reasonableness of 15% reserve margin criterion, it appropriately ignored system peaks occurring in off-peak months when a number of units were on maintenance, because these "peaks" resulted from mild weather. If a problem occurs in an off-peak month, it is more appropriately addressed by short-term planning, e.g. managing planned outages, not as part of a long-term planning process intended to identify the need for new capacity.

Q. Mr. Ballinger's third observation regarding the FRCC's reserve margin assessment is found on page 8 of his testimony and states that the FRCC used a simple average of load forecast error rates and that allowing over-and under-forecast rates to net out each other understates the load forecast error. Please respond.

A. Mr. Ballinger's observation was based on only a selected portion of the FRCC's work. In both its 1998 and 1999 analyses of the suitability of its 15% reserve margin standard, the FRCC used both a simple averaging approach recognized by Mr. Ballinger and a "worst case" approach which Mr. Ballinger did not recognize. The simple averaging approach to load forecast errors did allow over- and under- forecasts to net out against each other. This was not done to understate the load forecast error, but rather to give a true picture of what actual loads, on average, were being experienced. This approach properly balances system reliability vs. cost by recognizing that over forecasting can lead to overbuilding, and thus higher costs, as surely as under forecasting can have an effect on ratepayers.

The FRCC's use of the worst case load forecast was designed to give the FRCC a projection of "needed" reserves if the worst accuracy levels of recent load forecasts were to recur. Use of the worst case forecast resulted in a finding that, even in the very unlikely case in which the recent historical worst forecast accuracy levels occur every year for the next 10 years, no action by Peninsular Florida utilities is now necessary.

Q. Mr. Trapp states that his 20% reserve margin criterion is based upon the analyses performed by Mr. Ballinger. What is your response?

A. Mr. Trapp's 20% reserve margin recommendation and Mr. Ballinger's supporting analyses are flawed. Mr. Villar is addressing the flaws with Mr. Ballinger's Exhibit ____(TEB-3), so I will focus on Mr. Ballinger's Exhibit____(TEB-2).

First, it should be noted that not even Mr. Ballinger suggests that his analysis supports on (TEB-2) a 20% reserve margin standard as proposed by Mr. Trapp. Second, the analysis confuses operating reserves with reserve margins. Third, the simple response is that if utilities had reserve margins as low as 15%, they would plan their maintenance differently to be able to meet their operating reserve margin requirement. I do not believe this analysis shows the Commission that more than a 15% reserve margin standard is reasonable or necessary.

Consider Mr. Ballinger's starting point – he examines capacity advisories issued during 1998 and 1999. Under the extreme weather plan implemented pursuant to the Commission's extreme weather rule, capacity advisories are the first of three reactions available to Peninsula Florida utilities to meet extreme weather conditions. The other two more elevated status situations are alerts and emergencies. In 1998 Mr. Ballinger shows 12 capacity advisories. In 1999 year to date Mr. Ballinger shows 9 capacity advisories. Now, consider that the triggers for advisories are either <u>forecasted</u> extreme temperatures or any individual utility making a public appeal for its customers to conserve. This is the lowest level of notice in the current emergency plan, and it does not equate to a capacity shortfall in Peninsular Florida. Dealing with advisories merely means an efficient management of available resources when extreme weather threatens.

What Mr. Ballinger's exhibit shows is that Peninsula Florida, despite a very hot 1998 and an unprecedented natural gas pipeline interruption, has experienced the mildest status of notice only 21 days during the course of the roughly 630 days during the period examined. That is a low incidence of advisories.

Only once does Mr. Ballinger show that the operating reserve margin was not met. Once again, that is an extremely low level of incidence during the period examined. Even in that one instance, that does not mean there was a service interruption. That means the operating reserve was slightly below the prescribed level. That does not even mean that there would have been service interruptions if the largest unit on the system had tripped. There were other resources available that could have been implemented before a service interruption occurred.

Mr. Ballinger then lowers actual operating reserves by the difference between the planned reserve margin and either a 15% or 16% reserve margin to determine how often the operating reserve margin would have been violated. I have several observations. First, even then there would have been a low incidence of the operating reserve margin having been violated – 2 to 5 times in 630 days. Second, nothing can be concluded from the exhibit, because it is unreasonable to assume that utilities would plan their maintenance the same way they did with a 15 or 16% reserve margin as they did with a 17-19% reserve margin. Third, it fails to show the operational measures available to avoid service interruptions if the largest unit tripped off-line. Fourth, it fails to address the probability of the largest unit tripping off-line coincident with the other extremes Mr. Ballinger posits. Finally, it shows that the extreme weather operational plan developed at the instruction of the Commission to address extreme weather circumstances is working as intended. There is not now, as there was not when the Commission decided to require a plan, a need to build new capacity to address weather extremes.

III. Staff Fails to Acknowledge the Reliability of the Peninsular Florida System as Measured by Loss Of Load Probability.

Q. Please explain your earlier observation that Staff's testimony fails to acknowledge the reliability of Peninsular Florida as measured by Loss of Load Probability?

A. I am quite concerned that Staff's testimony and recommendations fail to meaningfully discuss reliability as measured by Loss of Load Probability. Mr. Ballinger makes a few passing references to LOLP, but quickly moves beyond it after mentioning the impact of generating unit availability on LOLP, leaving the erroneous impression that LOLP is no longer a valid measure of reliability. Mr. Trapp, in making a recommendation of a 20% reserve margin criterion, appears to ignore LOLP and the reliability of the Peninsular Florida system as measured by LOLP.

In 1997, and again in 1998, the FRCC performed LOLP reliability assessments for Peninsular Florida. The LOLP analyses show that Peninsular Florida is a most reliable system and that it would continue to be reliable with the resource plan developed while utilizing the 15% reserve margin standard adopted by the FRCC.

Q. Please explain the LOLP approach and how it is used to measure reliability?

A. LOLP analyses are probabilistic analyses performed on computer models that measure the probability that load will exceed available generation on an electric system. The analyses are far more refined than reserve margin analyses. LOLP analyses take into account a number of factors that reserve margin calculations cannot reflect, such as: scheduled and forced outages, assistance from interconnected utilities, hourly peak demands, seasonal capabilities of generating units, and seasonal capabilities of DSM.

The end product of a LOLP assessment is an expected value of the number of times that load will exceed available generation in a given system over a time horizon. The generally accepted standard of LOLP reliability within the industry is 0.1 days/year. LOLP values lower than this suggest that a system is reliable, and values above this level suggest that a closer look needs to be taken at reliability.

Q. Do you believe the Commission should continue to recognize LOLP as one measure of system reliability?

A. Yes. LOLP is still a valid method of measuring system reliability. That is why FPL continues to use dual reliability criteria of 15% Summer and Winter minimum reserve margins and an LOLP of 0.1 day/year. Moreover, what the Commission said in 1981 about the value of analyzing Peninsular Florida reliability through LOLP remains true today:

> In addition to capacity sufficient to meet system peak demand, an electric utility must maintain reserve capacity sufficient to cover scheduled and forced outages. The amount of reserve capacity required by an electric utility is a function of many factors, including but not limited to system generation mix, unit forced outage rates, unit sizes, maintenance cycles, peak and off peak demands, and transmission tie dependency. On a complex system such as Peninsular Florida, which has over two hundred generating units ranging from 0.1 megawatts to over 800 megawatts, generation adequacy must be evaluated by probabilistic loss of load probability (LOLP techniques which take into account numerous factors. An LOLP index of 0.1 days per year for firm load has generally been accepted by the electric utility industry as the goal of generation expansion planning. (Order No. 9749).

Staff's failure to acknowledge either the continuing value of LOLP analysis or the reliability of Peninsular Florida as measured by LOLP makes Mr. Trapp's recommendation of a 20% reserve margin criterion inappropriate, as Florida's electric system is highly reliable at a 15% reserve margin.

IV. Mr. Trapp's Recommendation that Non-Committed Capacity be Recognized in the Computation of Reserve Margins is Inconsistent with Prior Commission Practice and Would Damage Rather than Enhance Reliability.

Q. What do you understand Mr. Trapp's position to be regarding whether non-committed capacity should be recognized in the calculation of reserve margins?

A. On page 19 of his testimony, Mr. Trapp suggests that the potential contribution of non-committed capacity should be considered in the calculation of individual utility reserve margins if the FRCC and individual utilities credibly quantify the availability of merchant plant capacity being developed in Florida.

He also states that he is not troubled by recognizing merchant capacity that is "planned and certified." However, he then has a discussion of 2500 MW of merchant capacity that is scheduled to be placed in-service and is not subject to a determination of need. Since there is no listing of the projects comprising Mr. Trapp's 2500 MW and Mr. Trapp has testified the projects require no determination of need, it is difficult to discern whether these projects fit his criteria of "planned and certified."

Q. Why do you believe that Mr. Trapp's observations regarding the recognition of non-committed capacity in reserve margin are inconsistent with prior Commission practice?

A. For years the Commission has dealt with the issue of utility reliance upon non-committed capacity and related issues. The Commission has consistently determined that non-committed capacity should not be treated as firm capacity, declining to recognize non-committed capacity in the computation of reserve margins and declining to require utilities to make capacity payments to Qualifying Facilities (QFs) for as-available energy.

Three prior Commission decisions evidence the Commission's prior practice of not recognizing non-committed capacity in reserve margin calculations. Those three cases are the Dade County Resource Facility expansion determination of need, the Commission's reserve margin rulemaking, and the recent Duke New Smyrna determination of need proceeding.

Q. What did the Commission have to say about the contribution of non-firm generating resources to system reliability and the proper calculation of reserve margins in the Dade County case?

A. In the Dade County Resource Recovery Facility's determination of need, the facility did not have a firm contract to sell its output, making it an uncommitted capacity resource; the Commission had this to say about its potential contribution to reliability:

We find that Dade County's expanded solid waste facility will not contribute to the reliability and integrity of the state's electric system. Dade County has not committed to sell firm capacity pursuant to a Commission-approved contract. Dade County has only stated that it might sell as-available energy from its expanded facility. Because there are no plans to sell firm capacity, there is no way to analyze any effect on the state's reliability and integrity due to Dade County's energy sales. (Order No. PSC-93-1715-FOF-EQ).

The Commission went on to state the following about the proper calculation of reserve margins:

Because there is no firm capacity commitment, the only consequence to FPL is that its customers will not receive any as-available energy from Dade County if the facility expansion is not complete. A utility's reserve margin is calculated using only firm capacity sources. (Order No. PSC-93-1715-FOF-EQ).

Q. What did the Commission say about the recognition of uncommitted capacity resources in reserve margin calculations in the reserve margin rulemaking docket?

A. In the Commission's reserve margin rulemaking proceeding, the Commission adopted a reserve margin standard of 15% ("to achieve an equitable sharing of energy reserves, Peninsular Florida utilities shall be required to maintain, at a minimum, a 15% planned reserve margin") and adopted a rule provision that only firm power purchases were to be recognized in calculating reserve margins absent a waiver. (Order No. PSC-96-1076-FOF-EU). That rule provision provides:

> (2) Treatment of Purchased Power. Only firm purchase power agreements may be included as a resource for purposes of calculating a planned or operating reserve. A utility may petition for a waiver of this requirement based on a very high availability of specific non-firm purchases. Rule 25-6.035(2).

Q. What did the Commission have to say about the recognition of uncommitted generating resources in long-term reserve margin calculations in the recent Duke New Smyrna need case?

A. In the recent Duke New Smyrna need determination case, the Commission found that absent a contract for its output the unit could not be counted for long-term reserve margins: "The capacity should be considered for hourly and short term operating reserves, but not for long term planning reserve margins, unless contracted for." (Order No. PSC-99-0535-FOF-EM).

Q. Are there other Commission decisions in which the Commission has indicated that non-committed generating resources should not be treated as firm capacity?

A. Yes. Beginning with its cogeneration rules, and continuing well into the implementation of those rules, the Commission had to address the issue of whether as-available energy provided by QFs should be treated as a capacity resource by purchasing utilities or just as energy. The Commission consistently chose to price as-available energy without recognizing any capacity contribution to the purchasing utility.

For instance, in 1983 when adopting cogeneration rules the Commission had this to say about the uncommitted resource of as-available energy: "[b]ecause as-available energy carries with it no enforceable assurances as to quantity, time or reliability of delivery, the rule provides that no capacity payments shall be made to a QF for the delivery of as-available energy." (Order No. 12634). In response to a proposal that as-available energy be given capacity payments, the Commission stated, "there was no showing that what, in essence, is an interruptible source of supply, not controlled by the utility, would be able to permit a prudent utility to defer any capacity related costs." (Order 12634).

Similarly, the Commission promulgated rules for identifying avoided units for pricing cogeneration, and those rules required utilities not to include non-contracted-for QF capacity when determining the avoided unit. The

Commission noted that this decision not to recognize non-committed capacity in generation expansion plans was intentional. (Order No. 13247).

Looking back at Commission practice over time, Mr. Trapp's suggestion that non-committed capacity and as-available energy should be recognized in the calculation of reserve margins if its impact can be credibly quantified is surprising. His suggestion is inconsistent with prior Commission practice and a Commission rule. Indeed, the Commission has stated that the impact on reliability of an uncommitted resource cannot be analyzed absent a firm contract.

Q. How could reliance on uncommitted capacity damage reliability?

A. If utilities begin to count upon resources that are uncommitted instead of their own plants upon which they have first claim or instead of entering into firm contracts for capacity, then utilities would be counting upon non-firm capacity to meet firm load. This results in a less reliable system than a system that relies solely upon firm capacity resources.

V. Staff's Uniform Approach to Measuring Reliability for Peninsular Florida and Individual Utilities Ignores System Differences and May Mask Underlying Reliability Problems.

Q. Does a single reliability criterion of a reserve margin of 20% make good planning sense for both Peninsular Florida and Individual Utilities?

A. No. As I pointed out in my direct testimony, there are fundamental differences among the various utility systems that comprise Peninsular Florida. I will not repeat those distinctions, but they do affect the reliability of systems differently. FPL has found that measuring reliability on its large system is best done through dual reliability criteria. Criteria applicable to a large system such as FPL's or Peninsular Florida's are not necessarily equally applicable to smaller utilities. It is not uncommon for smaller utilities to have reserve margin criteria which are larger than those of large utilities, and that practice simply recognizes one of the many differences among systems.

Staff has abandoned LOLP without any explanation or justification, and is encouraging the Commission to adopt a single reserve margin standard for every utility in the state, without regard for size or any other distinguishing characteristics. Staff suggests no other standard for judging Ten-Year Site Plan suitability other than the very simple approach of whether in every year every plan shows a reserve margin of 20%. If it is 20% or above, it is suitable. If it is below 20% for any given year out of a ten year horizon, then the plan is to be judged unsuitable.

The problem with the criterion is that it does not really address whether Ten-Year Site Plans are suitable or serve as a general measure of whether electric systems are reliable. That judgement has to be made after extensive reviews of the various elements comprising and underlying each plan. That judgement is not made by the simplistic assessment of whether in every year for a ten-year horizon the reserve margin meets arbitrary standard.

VI. Mr. Trapp's Recommendation that a New 20% Reserve Margin Criterion be Applied Retroactively to Judge the Suitability of Ten-Year Site Plans Is Unreasonable and Unfair.

Q. Starting on page 3 of his testimony Mr. Trapp urges the Commission to adopt a 20% reserve margin criterion and to use the criterion to judge the suitability of Ten-Year Site Plans. What is your response?

A. I have two responses. First, I am surprised by the recommendation. I did not know that the suitability of Ten-Year Site Plans was contested in this case. If I had, I would have submitted FPL's Ten-Year Site Plan in my direct testimony as an exhibit and discussed why it should be found suitable.

Second, the site plans pending before the Commission were submitted in April of this year, five months before Mr. Trapp made his recommendation, and the underlying planning work was conducted almost a year ago. I think it is most unreasonable for the Commission to apply any standard it may adopt in this case retroactively to judge the suitability of any Ten-Year Site Plans. The plans should be judged on their individual merit, not on an arbitrary standard suggested five months after they were filed. While I could elaborate upon the basic unfairness of Mr. Trapp's recommendation that his more demanding standard be applied retroactively to judge plans developed well before a hint of a new standard was issued, I trust the Commission to see the readily apparent unfairness of Mr. Trapp's recommendation.

V. Other General Observations

Q. What other observations do you have regarding the Staff's testimony?

A. I have a number of other concerns regarding Mr. Trapp's testimony. First, I agree with his conclusion on page 11 of his testimony that there should not be a limit on the ratio of non-firm load to MW reserves, but his suggestion that more study is needed is surprising and troubling. Mr. Trapp suggests, but does not document, that there is a problem requiring further study.

Second, Mr. Trapp makes an observation on page 12 of his testimony that it is not clear whether lost revenues associated with avoided off-system sales that would have been made in the absence of the DSM program have been considered in the program cost-effectiveness, and suggests that perhaps the Commission may want to revisit this in conservation program approval dockets or ECCR. To my knowledge no attempt has been made by the Commission in any proceeding using avoided cost to measure cost-effectiveness, whether conservation dockets or cogeneration pricing dockets, to quantify the avoided off-system sales that would have been made by the avoided unit. As a practical matter, the analysis that he suggests should be done, cannot reasonably be performed. This refinement of conservation cost-effectiveness is not warranted, not practical nor possible, and the Commission should not address this issue in any docket.

Third, on page 13 of Mr. Trapp's testimony there is another suggestion that should be critically reviewed. He would recognize the non-committed capacity, in the Southern Company and in other regions, that is consistently available in Florida. Of course, he does not explain how such a probabilistic analysis would be performed or considered in the non-probabilistic reserve margin analysis. He just makes the observation without explanation or justification. I find this unsupported suggestion troubling. There is no basis for the Commission to judge its validity.

Q. Does this complete your rebuttal testimony?

A. Yes.