Need Study for Electrical Power Plant 2007

040206-EI

FPL

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TABLE OF ABBREVIATIONS

4 x 1	Four-on-one
AFUDC	Allowance for Funds Used During Construction
BACT	Best Available Control Technology
BAFO	Best and Final Offer
Btu	British Thermal Unit
CC	Combined Cycle
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CPVRR	Cumulative Present Value Revenue Requirement
CT	Combustion Turbine
DLN	Dry Low Nitrogen Oxide Combustion Technology
DSM	Demand Side Management
EAF	Equivalent Availability Factor
EFOR	Equivalent Forced Outage Rate
EGEAS	Electric Generation Expansion and System Analysis Model
F.A.C.	Florida Administrative Code
FGT	Florida Gas Transmission
FMPA	Florida Municipal Power Association
FPL	Florida Power & Light Company
FRCC	Florida Reliability Coordinating Council
GDP	Gross Domestic Product

TABLE OF ABBREVIATIONS cont'd

GE	General Electric Corporation
GWh	Gigawatt Hour
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
IRP	Integrated Resource Planning
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LNG	Liquefied Natural Gas
LOLP	Loss-of-Load Probability
LNTP	Limited Notice to Proceed
MGD	Million Gallons per Day
MW	Megawatt
MWh	Megawatt Hour
NEL	Net Energy for Load
NO_x	Nitrogen Oxide
NPGU	Next Planned Generating Unit
OASIS	Open Access Same-Time Information System
O & M	Operation and Maintenance
PC	Pulverized Coal
PEF	Progress Energy Florida, Inc.

TABLE OF ABBREVIATIONS cont'd

PM_{10}	Particulate Matter (larger than 10 microns)
POF	Planned Outage Factor
PPA	Purchase Power Agreement
PPSA	Florida Electrical Power Plant Siting Act
ppmvd	Parts per Million Volume Dry
PV	Progress Ventures, Inc.
RAP	Resource Assessment and Planning
RFP	Request for Proposals
RSM	Sedway Consulting, Inc.'s Response Surface Model
scf/hr	Standard Cubic Feet per Hour
SCA	Site Certification Application
SCR	Selective Catalytic Nitrogen Oxide Reduction
Sedway	Sedway Consulting, Inc., the Independent Evaluator
SJRPP	St. Johns River Power Park
SO_2	Sulfur Dioxide
STG	Steam Turbine Generator
SFWMD	South Florida Water Management District
TIGER	Tie-Line Assistance and Generation Reliability Model
UPS	Unit Power Sales

I. EXECUTIVE SUMMARY

In its 2003 resource planning process, Florida Power & Light Company (FPL) determined it needed to add 1,066 megawatts (MW) of generating capacity in the summer of 2007 to maintain its 20 percent system reserve margin planning criterion. In addition to the need to maintain a 20 percent reserve margin planning criterion, FPL's 2003 planning work identified two other important considerations for evaluating new generation resources for 2007.

One consideration was the growing imbalance between the electric load and generation resources in the southeast area of FPL's service territory. The region is described more particularly in Section V.B., and is referred to throughout this Need Study as "Southeast Florida." The imbalance in Southeast Florida has arisen because FPL has considerably more load in this area than generating resources. This imbalance is forecast to grow because FPL continues to experience significant load growth in this area, yet there are no scheduled generation unit additions in the area or scheduled transmission upgrades that would increase import capability. If not addressed, the size of the imbalance will continue to grow significantly, resulting in increased losses on FPL's system and increased costs to customers due to the need to dispatch less efficient resources within Southeast Florida to maintain system reliability.

Fuel diversity (and by association, fuel cost stability) was the other key consideration identified in the 2003 resource planning process. After many years of stable gas prices that contributed to make gas-fueled generation the technology of choice, gas prices have recently become volatile. As a result, in 2003 FPL initiated the re-evaluation of solid fuel alternatives, including a review of economic and environmental characteristics of these technologies. Most economic analyses suggest that the fuel price differential forecasted between natural gas and solid fossil fuel options might support the higher capital cost of solid fuel facilities. However, there remain significant uncertainties inherent in long-term fuel price forecasts and in the type and cost of emission management systems required for solid fuel options. Therefore, careful consideration of these questions is necessary to assure selection of the most appropriate and economic alternative.

FPL investigated various self-build generating alternatives to meet its 2007 capacity needs. Neither the time for permitting and constructing solid fuel alternatives nor the time necessary for their further evaluation allowed solid fuel alternatives to be considered. In July 2003, FPL concluded that the most cost-effective self-build option available to meet its customers' 2007 capacity needs would be a 1,144 MW natural gas-fired combined cycle (CC) facility known as Turkey Point Unit 5. This option, identified as FPL's next planned generating unit (NPGU), also provided an effective way to address the Southeast Florida load/generation imbalance. This NPGU would require site certification under the Florida Electrical Power Plant Siting Act (PPSA).

In accord with Rule 25-22.082, Florida Administration Code (F.A.C) (the Bid Rule), FPL developed and issued a Request for Proposals (RFP) on August 25, 2003, to solicit proposals for generating capacity to determine whether any combination of viable proposals would be more cost-effective than FPL's NPGU in meeting the resource need of 1,066 MW in the summer of 2007. In its RFP, FPL indicated that proposals would be evaluated against FPL's NPGU. FPL also offered an alternative generating unit (a four combustion turbine (CT) option located at the Turkey Point site) that could be combined with outside proposals.

In developing its RFP, FPL stated both a geographical preference and a fuel diversity preference. The growing Southeast Florida load/generation imbalance and associated need to rely upon transmission import capability increases transmission-related costs to FPL's customers. FPL developed methodologies to quantify the impact of generating resource additions on these increased transmission-related costs. The results of these methodologies demonstrated to FPL that resources located outside of Southeast Florida would tend to have significant cost disadvantages. Primarily because of these known cost attributes, FPL stated a geographic preference in its RFP for alternatives located in Southeast Florida. In addition, to attract existing resources, FPL stated a preference in its RFP for resources that would increase FPL's fuel diversity.

FPL held two workshops and posted answers to questions posed by all interested entities on a dedicated website, or distributed them directly to all participants by e-mail. On October 24, 2003, FPL received five proposals from four different entities.

FPL then conducted the evaluation described in the RFP to compare portfolios to FPL's NPGU to meet the 2007 need. The evaluation consisted of three major steps.

The first step was an initial assessment to determine proposal compliance with minimum requirements. These minimum requirements were designed in large measure to provide meaningful assurance that proposers would perform the obligations undertaken, as well as to protect FPL's customers from the consequences of non-performance. These minimum requirements were specified by FPL in the RFP.

The second step was a full economic evaluation to determine the costs of operating the FPL system with the addition of the various portfolios of proposed generation resources. These costs included all costs involved in the development and operation of the various portfolios as part of the FPL system (e.g., capital costs, fuel, O&M, transmission), as well as costs related to the operational and financial impact on FPL's system created by each of the candidate portfolios. An external consultant conducted an independent evaluation of the generation costs of the proposals.

The third step was a review of non-economic attributes. This review was conducted for FPL's NPGU and the alternative proposal that met the minimum requirements.

Four of the five proposals did not meet the minimum requirements. The proposers who submitted the non-complying proposals were contacted, notified of the non-compliance, and asked to modify their proposals to attain compliance.

In the meantime, and in the interest of a timely analysis, FPL conducted the economic evaluation of all proposals based on the terms received on October 24, 2003. Portfolios were constructed using combinations of the received proposals, or combinations of proposals and FPL's alternative generating unit. The economic evaluation clearly indicated that Turkey Point Unit 5 offered significant savings over all portfolios. The next closest portfolio, in terms of cost, included a combination of FPL's alternative generating unit and a proposal from Progress Ventures, Inc. based on their Desoto peaking facility. This portfolio was more costly than Turkey Point Unit 5 by $266 million cumulative present value revenue requirement CPVRR. The Progress Ventures proposal met all minimum requirements of the RFP.

FPL received notice from non-compliant proposers that they would not, or could not, make their proposals comply. These proposers then were notified that their proposals would not be considered further; however, even had they been compliant, these proposals were not remotely economically competitive with FPL's NPGU.

FPL selected the proposal from Progress Ventures, Inc. to be a finalist and requested Progress Ventures to provide a Best and Final Offer (BAFO). In parallel to this request, the non-economic attributes of the Progress Ventures proposal were reviewed. Both the NPGU and the Progress Venture proposal presented stable, acceptable risk profiles.

The BAFO provided by Progress Ventures slightly increased the cost of Progress Ventures' proposal. In the final analysis, the CPVRR associated with the addition of Turkey Point Unit 5 was more than $271 million less than that of the next closest portfolio (the Progress Ventures' proposal and FPL's 4 CT alternative generating unit). FPL's economic evaluation was confirmed by an independent evaluator who found FPL's Turkey Point Unit 5 to be less expensive by $323 million CPVRR.

The RFP process clearly demonstrated that FPL's Turkey Point Unit 5 is the best, most cost-effective alternative to meet the 2007 capacity need. Turkey Point Unit 5 also will enhance FPL's operating flexibility and reliability margin for Southeast Florida by reducing the growing imbalance between generation and load in this region.

Based on the advantages of Turkey Point Unit 5 demonstrated by its selection as FPL's NPGU and the results of the RFP process, FPL is continuing with the licensing process of Turkey Point Unit 5. This choice is FPL's most cost-effective alternative for maintaining electric system reliability and integrity and providing adequate electricity at a reasonable cost. There is not sufficient additional, cost-effective demand side management (DSM) that is reasonably available to mitigate the need for this unit. The remainder of this Need Study contains more detailed information, analyses and discussion supporting FPL's requested determination of need for Turkey Point Unit 5.

II. INTRODUCTION

A. Purpose and Overview of this Document

This document supports FPL's petition to the Commission to determine the need for Turkey Point Unit 5 electrical power plant. The new unit will be a natural gas-fired CC facility located adjacent to FPL's current Turkey Point complex. Once completed, Turkey Point Unit 5 will have a summer net capacity of approximately 1,144 MW.[1] The net increase in FPL's total generating capacity will be approximately 1,144 MW.

This document contains the information required by Rule 25-22.081, F.A.C. It provides the information that will "allow the Commission to take into account the need for electric system reliability and integrity, the need for adequate reasonable cost electricity, and the need to determine whether the proposed plant is the most cost-effective alternative available...." The following information is provided in subsequent sections:

- a description of the existing FPL system (Section II.B);
- a description of the proposed generating unit (Section III);
- an explanation of FPL's need for the proposed generating unit (Section IV);
- a discussion of factors affecting the selection of the proposed generating unit (Section V);

[1] This is the summer net rating for the unit. The winter net rating is 1,181 MW. For ease of presentation, throughout this Need Study only the summer net rating of the unit is mentioned unless the winter rating is specifically being discussed.

- a discussion of the analyses which determined that the proposed generating unit represents the best alternative to meet FPL's need (Section VI);
- a discussion of non-generating alternatives and an analysis of their potential for mitigating the need for Turkey Point Unit 5 (Section VII); and
- a discussion of the adverse consequences that would result from delay or denial of the completion of Turkey Point Unit 5 (Section VIII).

B. Description of FPL and Its System

FPL is the largest investor-owned electric utility in Florida and is among the largest in the United States. FPL served an average of 4.1 million customer accounts in 35 counties during 2003. FPL's service area contains approximately 27,650 square miles within which the population is approximately 8.1 million. FPL is charged with providing service not only to its existing customers, but also to new customers requesting service. FPL's load forecasts predict substantial continued customer growth within its service territory.

FPL currently serves its customers from a variety of resources including: FPL-owned fossil fuel and nuclear generating units, non-utility-owned generation, DSM, and interchange/purchased power. Each type of resource is discussed in more detail later in this document.

FPL's bulk transmission system is comprised of 1,105 circuit miles of 500 kilovolt (kV) lines[2] and 2,744 circuit miles of 230 kV lines. The underlying transmission network is composed of 1,634 circuit miles of 138 kV lines, 719 circuit miles of 115 kV lines, and 178 circuit miles of 69 kV transmission lines. Integration of the generation, transmission and distribution system is achieved through FPL's 526 substations. FPL is interconnected directly with eight other electric utilities. A list of FPL's major interconnections with other utilities is presented in Appendix A.

1. FPL-Owned Generating Resources

FPL's existing generating resources are located at 14 generating sites distributed geographically throughout its service territory, and they also include partial ownership of one unit located in Georgia and two units located in Jacksonville, Florida. The current generating facilities consist of four nuclear steam units, three coal units, nine CC units, 17 fossil fuel steam units, 52 combustion turbines (CTs), and five diesel units. The location of these generating units, their fuel type(s), and the projected summer capability for 2004 is shown on Figure II.B.1.1. More detailed information regarding FPL's existing generating resources is presented in Appendix B.

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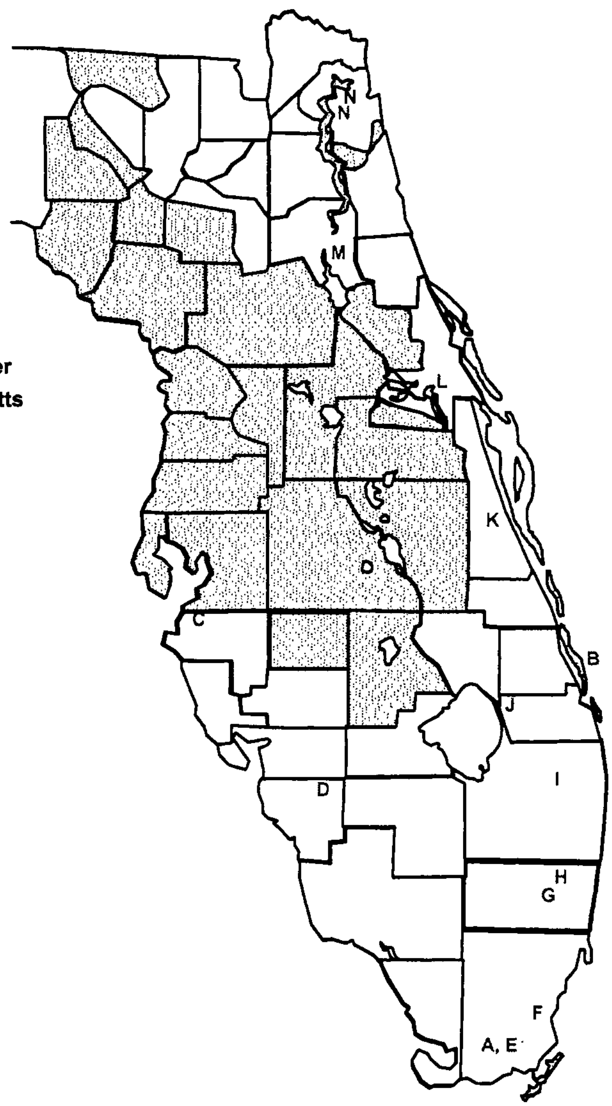
[2] This includes 75 miles of 500 kV lines, comprised of two 37.5 mile lines, between Duval Substation and the Florida-Georgia state line, which are jointly owned with Jacksonville Electric Authority.

Figure II.B.1.1

FPL's Generating Resources
(Projected Summer 2004 Capabilities)



Non-FPL Territory

	Fuel Type	Summer Megawatts
A. Turkey Point	Nuclear	1,386
B. St. Lucie *	Nuclear	1,553
C. Manatee	Oil/ Gas	1,628
D. Ft. Myers	Gas	1,469
E. Turkey Point	Oil/Gas	803
F. Cutler	Gas	206
G. Lauderdale	Oil/Gas	856
H. Port Everglades	Oil/Gas	1,235
I. Riviera	Oil/Gas	566
J. Martin	Gas/Oil	2,604
K. Cape Canaveral	Oil/Gas	806
L. Sanford	Oil/Gas	2,044
M. Putnam	Oil/Gas	498
N. St. Johns River*	Coal	254
Scherer **	Coal	658
Peaking Units	Gas	2,564
FPL GENERATION TOTAL MW		**19,130**

** Represents FPL's ownership share: St. Lucie nuclear: 100 percent unit 1, 85 percent unit 2; St. Johns River: 20 percent of two units.*

*** The Scherer unit is located in Georgia and is not shown on this map.*

2. Purchases from Cogeneration and Small Power Production Facilities

FPL has contracts to purchase firm capacity and energy from seven cogeneration and small power production facilities. A cogeneration facility is one that simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) used for industrial, commercial, or cooling and heating purposes. A small power production facility is one that does not exceed 80 MW of capacity and that uses solar, wind, waste, geothermal, or other renewable resources for at least 50 percent of its energy.[3]

A summary of these firm capacity agreements with cogeneration and small power production facilities is presented in Table II.B.2.1

[3] Certain small power production facilities are exempt from the 80 MW size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990.

Table II.B.2.1

FPL's Firm Capacity and Energy Contracts with Cogeneration and Small Power Production Facilities					
Project	***County***	***Fuel***	***MW Capacity***	***In-Service Date***	***End Date***
Bio-Energy	Broward	Landfill Gas	10.0	05/01/98	01/01/05
Broward South	Broward	Solid Waste	50.6	04/01/91	08/01/09
			1.4	01/01/93	12/31/26
			1.5	01/01/95	12/31/26
			0.6	01/01/97	12/31/26
Broward North	Broward	Solid Waste	45.0	04/01/92	12/31/10
			7.0	01/01/93	12/31/26
			1.5	01/01/95	12/31/26
			2.5	01/01/97	12/31/26
Cedar Bay Generating Co.	Duval	Coal (CFB)	250.0	01/25/94	12/31/24
Indiantown Cogen., LP	Martin	Coal (PC)	330.0	12/22/95	12/01/25
Palm Beach SWA	Palm Beach	Solid Waste	43.5	04/01/92	03/31/10
Florida Crushed Stone	Hernando	Coal (PC)	110.0	04/01/92	10/31/05
			11.0	01/01/94	10/31/05
			12.0	01/01/95	10/31/05
			3.0	02/01/03	10/31/05

3. Demand Side Management

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include both conservation initiatives and load management. FPL's DSM efforts through 2003 have resulted in a cumulative summer peak reduction of approximately 3,270 MW at the generator and an estimated cumulative energy saving of approximately 25,429 Gigawatt Hour (GWh) at the generator. Accounting for reserve margin requirements, FPL's DSM efforts have eliminated the need to construct the equivalent of 10 new 400 MW generating units.

FPL's approved DSM Goals for summer MW reduction are presented in Table II.B.3.1. These DSM Goals are over and above the significant levels of DSM implementation FPL achieved before the year 2000. FPL's current DSM Plan was approved by the Commission in 2000 and was designed to achieve these goals for the 2000–2009 period. FPL's projected need for additional capacity in 2007 includes these DSM levels. There is not sufficient additional, reasonably available, cost-effective DSM available to mitigate FPL's need for Turkey Point Unit 5.

Table II.B.3.1

FPL's Approved DSM Goals
2000 - 2009
Summer MW Reduction

Year	Cumulative Summer MW
2000	122
2001	200
2002	269
2003	339
2004	410
2005	484
2006	554
2007	625
2008	697
2009	765

4. Purchased Power

FPL has a long-term Unit Power Sales (UPS) contract to purchase up to 931 MW of coal-fired generation from Southern Company. FPL also has long-term contracts with JEA for the purchase of 381 MW (summer) and 390 MW (winter) of coal-fired generation from St. John's River Power Park (SJRPP) Units One and Two.[4]

In addition, FPL has a number of short-term, firm capacity purchased power contracts. These firm capacity purchases come from a variety of suppliers, and the capacity supplied will vary from 2004 through 2006. No summer capacity from such purchases will be available in 2007.

FPL incorporated the applicable purchase amounts in the analyses that led to FPL's projection of additional capacity needs in 2007. The annual amounts of these long-term and short-term firm purchases are presented in Table II.B.4.1.

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[4] FPL also has a separate 20 percent ownership interest in these units.

Table II.B.4.1

	FPL's Purchased Power MW							
	UPS		SJRPP		Other Firm Capacity Purchases		Total	
Year	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
2004	931	931	390	381	1,024	1,355	2345	2667
2005	931	931	390	381	1,018	945	2339	2257
2006	931	931	390	381	1,018	945	2339	2257
2007	931	931	390	381	1,018	0	2339	1312
2008	931	931	390	381	0	0	1321	1312
2009	931	931	390	381	0	0	1321	1312
2010	931	931	390	381	0	0	1321	1312
2011	931	931	390	381	0	0	1321	1312
2012	931	931	390	381	0	0	1321	1312
2013	931	931	390	381	0	0	1321	1312

5. Current and Projected Electrical Demand and Sales

In FPL's forecasting work, coincident peak loads both for summer and winter, as well as annual energy amounts, are projected for future years. The peak loads and annual energy amounts are forecasted to increase beyond current levels. FPL also continues to forecast significant customer growth and associated growth in per-customer load and energy usage.

In 2003, FPL experienced a winter coincident total peak load of 20,190 MW and a summer coincident total peak load of 19,668 MW. FPL's 2003 NEL was 108,391 GWh. For 2007, FPL is forecasting winter and summer coincident peak loads of 21,605 MW and 21,851 MW, respectively, before accounting for the impacts of DSM. The projected effects of DSM will result in winter and summer coincident peak loads of 19,882 MW and 20,107 MW, respectively, for 2007.[5] The NEL for 2007 is projected to be 118,430 GWh. FPL's load forecast is in Appendix E.

[5] These projected "firm" peak loads are net of DSM and are the loads upon which FPL bases its capacity need calculations.

III. DESCRIPTION OF THE PROPOSED POWER PLANT

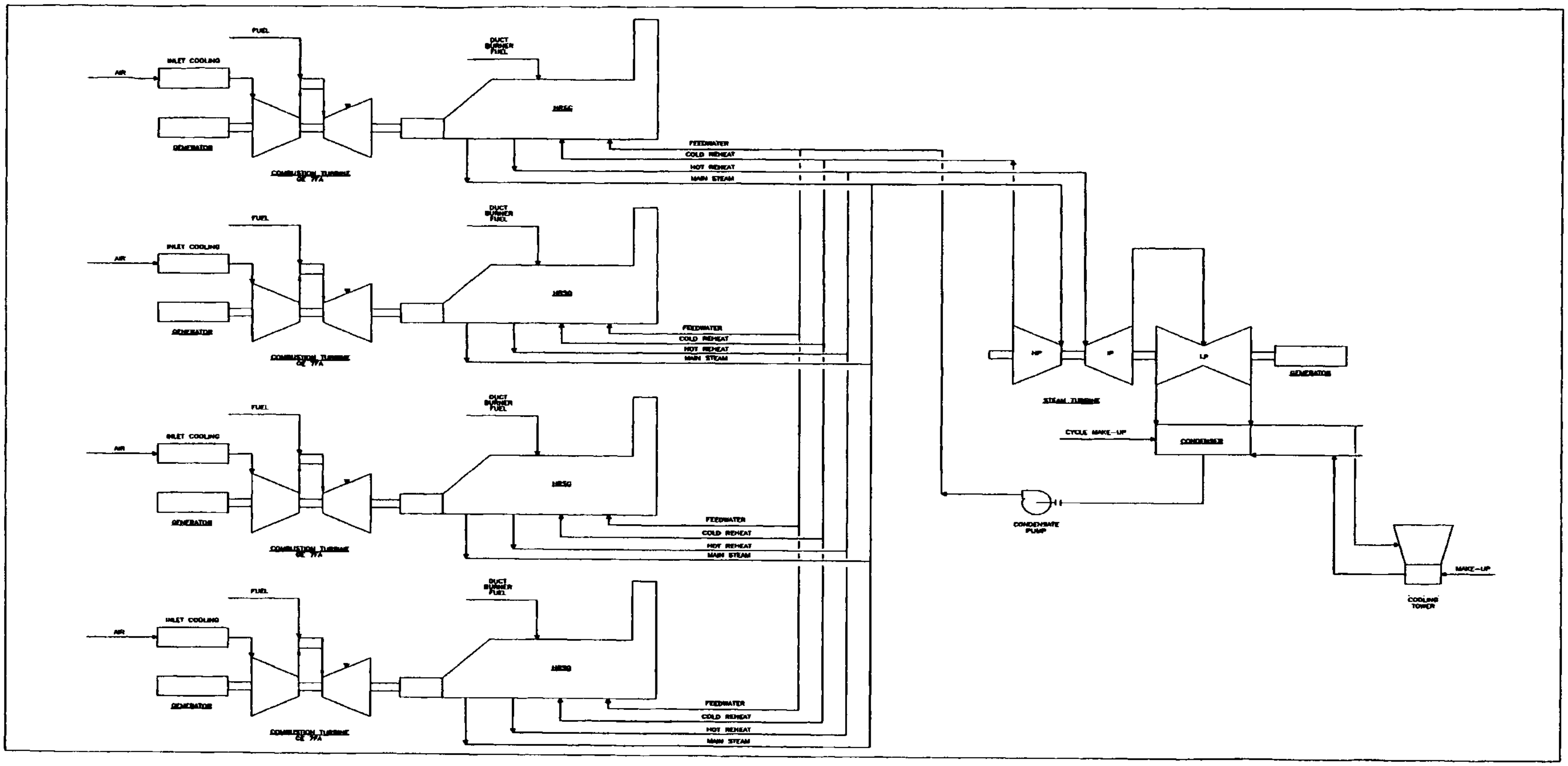
A. Overview

As depicted in Figure III.A.1, and described in Appendix J, Turkey Point Unit 5 is designed to utilize four CTs, four heat recovery steam generators (HRSGs), and one steam turbine generator (STG). The CTs compress outside air into a combustion area where fuel, typically natural gas or light oil, is burned. The hot gases from the burning fuel-air mixture expand to drive a turbine, which directly rotates a generator to produce electricity. The exhaust gas produced by each turbine, with temperatures on the order of 1,100°F, then passes through a HRSG to convert the exhaust gas energy to steam. The cooled exhaust gases exit the stack at approximately 200°F. The steam produced in the HRSGs is collected to drive the common STG. Turkey Point Unit 5 will employ four CT/HRSG trains in combination with one STG, hence the terminology "four-on-one" (4x1) Combined Cycle (CC) plant.

The utilization of waste heat from the CTs in a combined cycle provides an overall plant efficiency that is much better than that of the CTs alone (in simple cycle) or of a conventional boiler steam-electric generating facility. In general, CC plants of this design can be expected to achieve energy conversion rates (heat rates) of less than 7,000 Btu/kWh, which compares favorably to values on the order of 10,000 Btu/kWh for conventional boiler steam-electric generating units, and results in a fuel savings of about 30 percent. FPL anticipates that the new Turkey Point Unit 5 will achieve a highly efficient average base heat rate of 6,835 Btu/kWh (HHV at 75°F).

FIGURE III.A.1

TYPICAL 4x1 CC UNIT PROCESS DIAGRAM



The proposed CC unit will use General Electric (GE) 7-FA series advanced CTs.[6] In simple cycle mode, each of these turbines is peak-rated at 159 MW at summer rating conditions. The 4x1 configuration at Turkey Point is similar to the projects being constructed at the Manatee and Martin sites. Accordingly, the project planning, detailed design, procurement, construction, commissioning, and O & M will involve similar requirements. The resulting engineering and construction savings to FPL customers are reflected in the cost estimate for Turkey Point Unit 5.

Turkey Point Unit 5 will have an approximate summer rating of 1,144 MW, based on ambient conditions of 95°F. The approximate winter rating (at 35°F) is 1,181 MW. Actual summer and winter ratings may vary based upon final design and on the results of performance testing.

Turkey Point Unit 5 will be constructed on a site adjacent to the present Turkey Point units. The existing Turkey Point complex (the Complex) consists of two fossil steam units and two nuclear units. Turkey Point Units 1 and 2 are steam units that burn residual fuel oil and were constructed in the mid-to-late 1960s with commercial in-service dates of April 1967 and April 1968, respectively. Turkey Point Units 3 and 4 are nuclear units and were constructed in the early 1970s with commercial in-service dates of December 1972 and September 1973, respectively. The projected 2004 peak summer capacities of the existing units are as follows:

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[6] The term "advanced CTs" refers to the fact that the GE F series CTs are designed to operate at a higher firing temperature than conventional CTs, which results in higher efficiency.

- Unit 1 – 403 MW
  Steam electric generating unit firing residual oil and natural gas

- Unit 2 – 400 MW
  Steam electric generating unit firing residual oil and natural gas

- Unit 3 – 693 MW
  Nuclear generating unit

- Unit 4 – 693 MW
  Nuclear generating unit

The Complex currently has a total summer net peak generating capability of approximately 2,189 MW. The Complex includes a 5,900-acre cooling canal system that serves Units 1, 2, 3 and 4.

The Complex is located on 11,000 acres in unincorporated Miami-Dade County, approximately 8 miles east of Florida City and 4.5 miles east of the eastern boundary of the city of Homestead. The Complex is also adjacent to the 13,000-acre Everglades Mitigation Bank that is owned and operated by FPL. A map of the Plant site and the surrounding area is shown on Figure III.A.2. The area within the Complex dedicated for the construction of Turkey Point Unit 5 is approximately 90 acres, with temporary and permanent project facilities occupying roughly 73 of those acres. Turkey Point Unit 5 would be located north of Units 1 and 2 within an area currently zoned for power plants. Figure III.A.3 is a drawing or footprint of the proposed Turkey Point Unit 5. The siting of Turkey Point Unit 5 will not have an adverse impact on the existing units at the Complex.

The project will use a number of existing facilities, thus increasing the generating capacity of the Complex without increasing its overall size. The location of the new Unit 5 at the Complex and the selection of the CC technology will maximize the beneficial use of the site while minimizing environmental, land use, and cost impacts typically associated with development of a nominal 1,144 MW power plant.

FIGURE III.A.2
MAP OF TURKEY POINT PLANT SITE AND SURROUNDING AREA

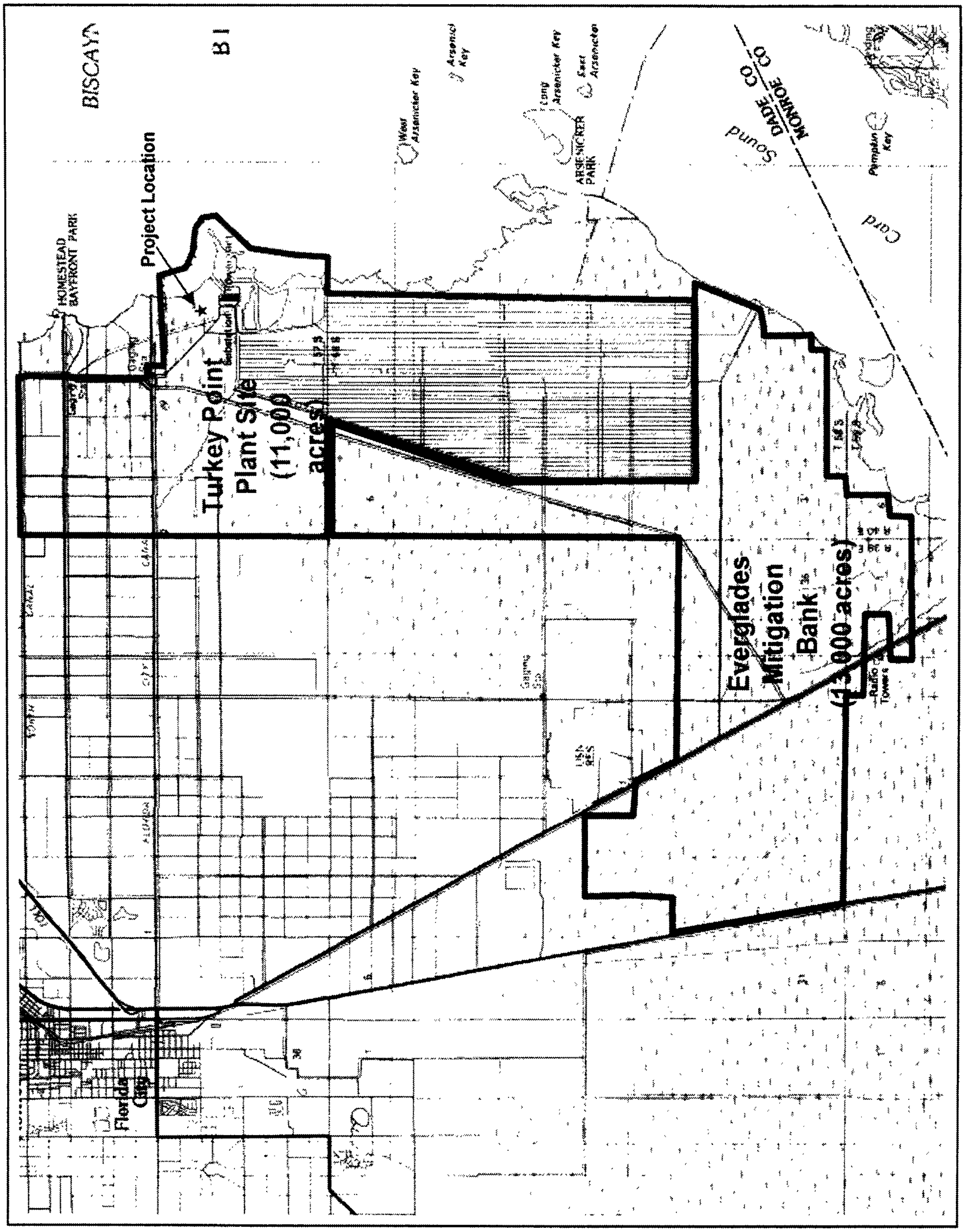
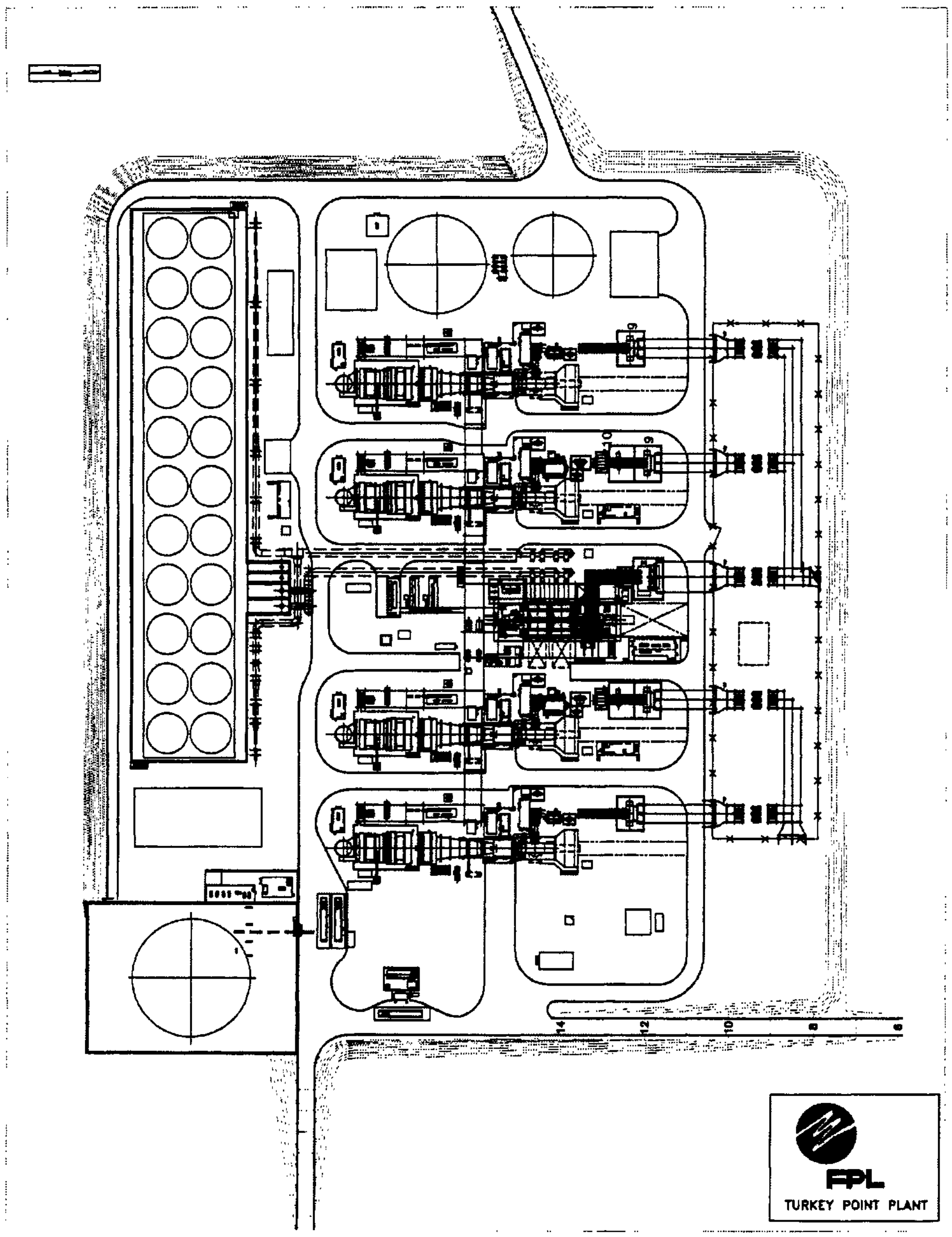


FIGURE III.A.3
FOOTPRINT OR DRAWING OF
PROPOSED TURKEY POINT UNIT 5



B. Turkey Point Unit 5 Design

The Turkey Point Unit 5 4x1 CC unit will consist of four nominal 159-MW GE Frame 7 "F" Class advanced CTs, with dry low nitrogen oxide (NO_x) combustors. Each of the four CTs will exhaust to a HRSG that will convert the waste heat from the CTs to steam. This steam will supply a new STG.

Each CT unit will utilize a type of inlet air evaporative cooling commonly referred to as "fogging." Fogging cools and humidifies the inlet air stream, which allows power to be produced more efficiently and with lower emissions for each MWh generated. For the GE Frame 7FA CT, an 8°F average decrease in temperature typically results in an expected 3.0 percent increase in power and an expected 1.2 percent increase in efficiency (lower heat rate). The inlet foggers would be utilized when the ambient air temperature is greater than 60°F. Based on an average annual temperature of approximately 75°F, the output and heat rate benefits associated with fogging are included in the base heat rate of 6,835 Btu/kWh (100 percent load at 75°F) and the "base operation" summer capacity rating of 984 MW.

Each HRSG will include duct burners. The duct burners allow for direct burn of natural gas and are used during peak demand periods to add an additional 96 MW of summer capacity to the unit at an incremental heat rate of 8,700 Btu/kWh (75°F).

For a peak operating mode, an additional 64 MW of output can be achieved by raising the fuel flow to the CT for "peak firing" and injecting steam into the CT for "power augmentation." Peak firing and power augmentation result in an expected incremental heat rate for this mode of 11,500 Btu/kWh (75°F). However, peak firing and power augmentation will shorten the normal replacement period for some CT components, so it normally will be reserved for peak need periods and will not be routinely dispatched ahead of duct firing. The 984 MW of base operation, 96 MW of duct burner operation, and 64 MW of peak operation sum to a total unit summer capability of 1,144 MW.

The CTs will use natural gas as the primary fuel. The HRSG duct burners will fire natural gas only. Gas will be transported to Turkey Point Unit 5 through an existing Florida Gas Transmission (FGT) owned and operated pipeline. This existing natural gas infrastructure will need to be upgraded to ensure the adequate, reliable delivery of natural gas to the Turkey Point site to meet the requirements of Turkey Point Units 1, 2 and 5. FGT will independently undertake the permitting and construction activities for the necessary upgrades to the existing infrastructure.

Should there be a loss of natural gas to the site, Turkey Point Unit 5 will be designed to use light oil as a backup fuel for an equivalent of up to 500 hours/year per CT at baseload conditions. Light oil will be trucked to the site and stored in a

4 million-gallon tank that will be constructed as a part of the Turkey Point Unit 5 project.

C. Environmental Controls

The use of clean fuels and combustion controls will minimize air emissions from Unit 5 and ensure compliance with applicable emission-limiting standards. Using clean fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter and other fuel-bound contaminants. Combustion controls similarly minimize the formation of NO_x, and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology (DLN) and selective catalytic NO_x reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during CC operation when firing light oil. These design options constitute the Best Available Control Technology (BACT) for air emissions and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of Turkey Point Unit 5 will incorporate features that will make it one of the most efficient and cleanest power plants in the state of Florida.

Primary water uses at Turkey Point Unit 5 will be for condenser cooling, CT inlet foggers, and steam cycle makeup and service water. Water also will be used on a limited basis for NO_x control when firing light oil. Condenser cooling for the steam cycle portion of Unit 5 will be accomplished using a mechanical draft cooling tower with saline make-up water from deep Floridan Aquifer wells. Service and process water for the unit will come from the existing potable water supply servicing the site.

The facility has been designed to minimize direct discharge of process wastewater to offsite surface waters. Non-contact storm water runoff will be collected and routed to a storm water detention pond that has been designed to meet South Florida Water Management District (SFWMD) requirements. All process wastewaters, including process water pre-treatment backwash, plant and equipment drains, and neutralization unit effluent, will be treated as appropriate and recycled to the existing cooling canals.

D. Transmission Interconnection

The project will connect to the existing onsite system substation via generator leads. The existing onsite system substation will be expanded to accommodate the new interconnection to FPL's electric transmission system.

E. Transmission Integration

A study was conducted to determine the impact of integrating Turkey Point Unit 5 into the existing FPL transmission system. Several existing 230 kV transmission line segments in the Turkey Point area in Southeast Florida need to be upgraded to accommodate the proposed plant. The major portion of the upgrades involves the partial rebuild of transmission facilities on the 230 kV path from Turkey Point to the Flagami Substation. On this path, rebuilds are necessary on the Turkey Point to Galloway Tap and the Turkey Point to Killian line segments. Thermal upgrades also are required on the Killian to Miller line segment on the same path. The thermal rating on the 230 kV path from Turkey Point to the Florida City Substation via McGregor also must be upgraded. All of these upgrades will be accomplished within existing transmission rights-of-way, on existing systems, with no environmental impacts. The total transmission interconnection and integration costs are shown in Table III.G.1.

F. Construction Schedule

FPL will begin construction upon receipt of the necessary federal, state, and local approvals, certifications, and permits. The expected construction duration for the Turkey Point Unit 5 project is 24 to 27 months. This is based on FPL's recent experience with CC-based construction activity. To meet the planned in-service date of June 2007, FPL needs to commence construction on or before March 1, 2005. A summary of proposed construction milestone dates is shown on Table III.F.1.

TABLE III.F.1
TURKEY POINT UNIT 5
EXPECTED CONSTRUCTION SCHEDULE

<table>
<tr><th>Milestone</th><th>Begin</th><th>End</th></tr>
<tr><td>Initiate sequence of HRSG orders (LNTP x 4)</td><td>Nov 04</td><td>Dec 04</td></tr>
<tr><td>Initiate sequence of CT orders (LNTP x 4)</td><td>Nov 04</td><td>Dec 04</td></tr>
<tr><td>Issue LNTP for steam turbine</td><td></td><td>Nov 04</td></tr>
<tr><td>Receive approvals necessary to begin construction</td><td></td><td>Feb 05</td></tr>
<tr><td>Site preparation & foundations</td><td>Mar 05</td><td>Jan 06</td></tr>
<tr><td>Balance of Plant</td><td>Aug 05</td><td rowspan="4">Dec 06</td></tr>
<tr><td>Erect HRSGs</td><td>Feb 06</td></tr>
<tr><td>Erect CTs</td><td>Apr 06</td></tr>
<tr><td>Erect steam turbine</td><td>Apr 06</td></tr>
<tr><td>Startup</td><td>Jan 07</td><td>May 07</td></tr>
<tr><td>Commercial operation</td><td></td><td>Jun 07</td></tr>
</table>

G. Estimated Capital Cost

The estimated total installed cost for Turkey Point Unit 5 is $580.3 million (2007 dollars). This cost estimate was used in FPL's economic analysis, and it includes $472.2 million for the power block, $26.4 million for the transmission interconnection and integration costs, $29.9 for gas infrastructure upgrades, and $51.8 million in AFUDC. The components of this total plant cost are shown in Table III.G.1.

TABLE III.G.1

TURKEY POINT UNIT 5
PLANT COST COMPONENTS
(2007 $ MILLION)

Power Block	$472.2
FGT Infrastructure Upgrades	$29.9
Transmission Interconnect & Integration	$26.4
AFUDC	$51.8
Total Plant Cost	$580.3

H. Fact Sheet

The details of the Turkey Point Unit 5 facility are provided in Figure III.H.1.

FIGURE III.H.1
TURKEY POINT UNIT 5
FACT SHEET

Generation Technology - "Four on One" (4x1) Combined Cycle Configuration:

- Four (4) GE 7FA Combustion Turbines w/ Inlet Foggers
- Four (4) Heat Recovery Steam Generators with Duct Burners and Selective Catalytic Reduction System for NO_x Control
- One (1) Single-Reheat Steam Turbine

Expected Plant Peak Capacity:	
Summer (95°F / 50% RH)	1,144 MW
Winter (35°F / 60% RH)	1,181 MW

Projected Unit Performance Data:	
Average Forced Outage Rate (EFOR)	1%
Average Scheduled Maintenance Outages	1 wk/yr (2% POF)
Average Equivalent Availability Factor (EAF)	97%
Base Average Net Operating Heat Rate @ 75°F / 60% RH	6,835 Btu/kWh (HHV)
Annual Fixed O&M – incremental (2007 dollars)	$3.57/kW-yr
Variable O&M – excluding fuel (2007 dollars)	$0.13/MWh

Fuel Type and Base Load Typical Usage @ 75°F:	
Primary Fuel	Natural Gas
Natural Gas Consumption	6,580,000 scf/hr
Backup Fuel	Light Oil
Light Oil Consumption	60,000 gal/hr

Expected Base Load Air Emissions Per Train @ 75°F:	**Natural Gas**	**Light Oil**
NO_x (@ 15% O_2)	2.5 ppmvd	10 ppmvd
CO	9 ppmvd	20 ppmvd
PM_{10}	10.9 lb/hr	17.6 lb/hr
SO_2	9.4 lb/hr	2.8 lb/hr

Water Balance:

- Annual average consumptive use for Turkey Point Unit 5 is approximately 18 MGD.
- Process wastewater recycled to cooling canal.

Linear Facilities:

- One (1) FGT gas lateral currently supplies the Turkey Point site.
- No light oil pipeline – light oil delivered to site by truck

IV. FPL'S NEED FOR THE PROPOSED POWER PLANT

FPL determined in its 2003 integrated resource planning (IRP) work that it would need significant additional resources in 2007 to meet its reserve margin criterion. The reliability assessment (conducted as a part of the IRP) is designed to determine both the magnitude and timing of FPL's resource needs. It is a determination of how much load reduction, new capacity, or a combination of both load reduction and new capacity is needed, and when these resources need to be available to maintain the specified reliability standard. Based on this analysis, FPL determined it would need a minimum of either 1,066 MW of new supply (power plant construction or power purchase) or 888 MW of new DSM to meet its 2007 reserve margin requirement.

A. Reliability Assessment

In the reliability assessment portion of its 2003 IRP analysis, FPL started with updated power plant capability and reliability data, and an updated load forecast. The updated load forecast is presented in Appendix E. In addition, the reliability assessment took into account committed construction capacity additions, firm capacity power purchases and long-term DSM implementation.

1. Near-Term Capacity Additions

FPL included its previously committed construction projects in its 2003 reliability assessment. These projects included the addition of a new 1,100 MW CC unit at FPL's existing Manatee plant site (Manatee Unit 3) plus the conversion of two existing CTs into a 4 CT-based, 1,100 MW CC unit at FPL's existing Martin plant site (Martin Unit 8). The two projects will add approximately 1,890 MW of new generating capacity by mid-2005.

2. Firm Capacity Purchases

FPL took into account all of its short-term and long-term firm capacity purchases from a combination of utility and non-utility generators in its 2003 reliability assessment. These firm capacity purchases are discussed in Section II.B.4 and presented in Table II.B.4.1.

3. Long-Term DSM

Since 1994, FPL's IRP process has used the amount of DSM capacity in FPL's approved DSM Goals as the basis for its analysis. The currently approved DSM Goals for FPL are discussed in Section II.B.3 and presented in Table II.B.3.1. In its 2003 resource planning, FPL used the approved DSM goals through the year 2009 as a key assumption in the analysis. In this way, FPL includes in its reliability analysis the projected incremental impact of all of FPL's DSM programs from 2003-on, plus the cumulative demand reduction capability from its load management programs prior to 2003. The cumulative impact from all of FPL's conservation program efforts before 2003 is captured in the 2003 load forecast discussed in Section V.A.1.

B. FPL's Reliability Criteria

System reliability analyses were based on the dual planning criteria of 1) a minimum summer and winter peak period reserve margin of 20 percent and 2) a maximum of 0.1 days per year Loss-of-Load-Probability (LOLP). The reserve margin criterion of 20 percent applies for reserve margin analyses addressing both summer and winter peak periods beginning in the summer of 2004. The Commission approved this reserve margin criterion in Docket No. 981890-EU. The LOLP criterion of 0.1 days per year is an industry standard that the Commission has accepted in numerous resource planning-related dockets.

Reserve margin analysis is a deterministic approach, while LOLP analysis is a probabilistic approach. The reserve margin analysis is essentially a calculation of excess firm capacity at the time of the summer system peak hour and at the time of the winter system peak hour. This calculation provides a measure of the capability a generating system possesses to meet its native load during peak periods. However, a deterministic approach such as a reserve margin calculation does not take into account probabilistic elements such as the reliability of individual generating units and the total number and sizes of generating units on the system. A deterministic approach also does not fully account for the value of an interconnected system.

Therefore, FPL also utilizes a probabilistic approach, LOLP, to provide additional information on the reliability of its generating system. LOLP is an indicator of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages. LOLP is expressed in units of "number of times per year" that the system demand could not be served and requires a more complicated calculation than does reserve margin analysis. FPL calculates LOLP using the Tie-Line Assistance and Generation Reliability (TIGER) model. A listing and summary of the computer models utilized by FPL in its resource planning work, including the TIGER model, is given in Appendix C.

In a reliability assessment, either the reserve margin criterion or the LOLP criterion will be violated first. This means that, for a given future year, FPL's system will not have a reserve margin high enough to meet its criterion or it will have a projected LOLP value greater than 0.1 days per year. Whichever criterion is violated first is said to "drive" FPL's future resource needs. For the last few years, the summer reserve margin criterion has driven FPL's future needs. This again was the case in FPL's most current reliability assessment performed as part of its 2003 IRP work.

C. FPL's 2003 Reliability Assessment Results

FPL's reliability analyses showed that with no additional resources beyond its existing generating units, existing purchases, and the planned additions mentioned above, FPL would begin to violate its summer reserve margin criterion of 20 percent by the summer of 2007. A minimum of 1,066 MW of additional supply resources would be needed by June 1, 2007 for FPL to continue to meet its summer reserve margin criterion of 20 percent for 2007. This need is demonstrated in Table IV.C.1.

If the 2007 resource need were to be met solely by additional new DSM resources, FPL would need to find an additional 888 MW of cost-effective DSM. Accounting for FPL's 20 percent reserve margin criterion, the 1,066 MW of generating capacity need would become 888 MW of DSM (1,066 MW/1.20 = 888 MW). There is not 888 MW of additional, cost-effective DSM available to meet this need. This will be further discussed in Section VII.C.

Table IV.C.1

Projection of FPL's 2007 Capacity Need
(without Capacity Addition)

Summer

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2007	21,018	2,044	23,062	21,851	1,744	20,107	2,955	14.7%	**1,066**

Winter

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
January of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Winter DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Winter Reserves (MW)	Forecast of Winter Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2007	22,389	2,522	24,911	21,605	1,723	19,882	5,029	25.3%	**(1,053)**

* DSM values shown represent cumulative load management and incremental conservation capability.

D. Consistency with Peninsular Florida Need

FPL's need for an additional 1,066 MW of supply resources (or 888 MW of demand side resources) is consistent with Peninsular Florida's need as identified by the Florida Reliability Coordinating Council (FRCC) in its 2003 reliability work reported in its FRCC 2003 Regional Load & Resource Plan. The FRCC's 2003 reliability work used FPL-specific data contained in FPL's 2003 Ten-Year Site Plan (TYSP) in conjunction with similar information from other Florida electric utilities.

V. FACTORS AFFECTING SELECTION

The origins of the decision to add a new CC unit at the Turkey Point complex are found in FPL's 2003 IRP process. The results of that work, including a review of non-generating alternatives, are described in detail in FPL's 2003 TYSP that is Attachment One to FPL's 2003 RFP (Appendix D of this document). FPL's 2003 IRP process showed that FPL will need 1,066 MW of additional generating capacity, or 888 MW of additional DSM, by 2007 to maintain the 20 percent reserve margin planning criterion.

A. Forecasts and Assumptions

The forecasts of electric load and fuel prices are developed by FPL analysts who aggregate data and employ various analyses to develop the framework of future conditions used in the IRP process.

1. The Load Forecast

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are developed on an annual basis for resource planning work at FPL. These forecasts are a key input to the models used during the IRP process. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

a. Forecast Assumptions

The primary drivers to develop these forecasts are demographic trends, weather, economic conditions, and price of electricity. In addition to these drivers, the resulting forecasts are an integration of economic evaluations, inputs of local economic development boards, weather assessments from the National Oceanographic and Atmospheric Association (NOAA), and inputs from FPL's own customer service planning areas. Population trends by county, characteristics such as housing starts, housing size, and vintage of homes, are assessed in the area of demographics.

Econometric models are developed for each revenue class using the statistical tool called Metrix ND. The methodologies used to develop sales forecasts for each jurisdictional revenue class are outlined below.

b. Forecast Methodology

(i) Sales

(A) **Residential** electric usage per customer is estimated by using a linear multiple regression model that contains the real residential price of electricity, Florida real per capita income, and Cooling and Heating Degree Days as explanatory variables.

(B) **Commercial** sales are forecast using a linear multiple regression model which contains the following explanatory variables: Florida's commercial employment, commercial real price of electricity, Cooling Degree Days and an auto-regressive term.

(C) **Industrial** sales are forecast through a linear multiple regression model using Florida manufacturing employment, industrial real rice of electricity and a dummy variable[7] for economic recessions.

(D) **Resale** (Wholesale) customers are composed of municipalities and/or electric cooperatives. Currently, there are four customers in this class: the Florida Keys Electric Cooperative, City Electric System of the Utility Board of the City of Key West, Florida, Metro-Dade County Solid Waste Management, and the Florida Municipal Power Authority.

Sales forecasts for these and other classes are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, an expansion factor is applied to generate a forecast of annual NEL.

(ii) Net Energy for Load

A separate annual econometric model is also developed to produce a NEL forecast.[8] The key inputs to the model are: the real price of electricity, Heating and Cooling Degree Days, Florida Non-Agricultural Employment and an auto-regressive term. Once the annual NEL forecast is obtained using this methodology, the results are compared for reasonability to the separate NEL forecast generated using the revenue class sales forecasts. The sales by class are then adjusted to match the NEL from the annual econometric NEL model.

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[7] A dummy variable is used to include qualitative factors in a regression.

[8] This calculation is independent from that used to determine NEL by applying an expansion factor to the revenue class sales forecasts.

In addition, a similar monthly model for NEL is developed using Florida's per capita income as the economic variable. The forecasts from the annual and monthly models are combined to develop the 20-year monthly NEL forecast.

(iii) System Peak Forecasts

In recent years, the absolute growth in FPL system load has been associated with a larger customer base, weather conditions, continued economic growth, changing patterns of customer behavior (including an increase in electricity-consuming appliances) and more efficient heating and cooling appliances. The Peak Forecast models were developed to capture these behavioral relationships.

(A) **Summer peak** demand is developed using an econometric regression model developed on a per-customer basis. The key variables included in the summer peak model are total average customers, the real price of electricity, Florida real total personal income, and the maximum peak day temperature.

(B) **Winter peak** demand is forecast using the same methodology and taking into account weather-related variables. The winter peak model is a per customer model that contains the following explanatory variables: the minimum temperature on the peak day, a weather term, which is a ratio of minimum winter day temperature and heating saturation, and Heating Degree Hours for the prior day as well as for the morning of the winter peak day. The model also includes an economic variable: Florida real total personal income.

In addition a dummy variable is used to capture the effects of larger homes, which is multiplied by the minimum temperature.

c. Forecast Results

The historical and projected average annual growth rates in customers, demand and energy are summarized in Table V.A.1.c.1 below.

Table V.A.1.c.1

FPL's 2003 Load Forecast Results

Compound Average Annual Growth

Years	Total Customers	Net Energy For Load	Summer Peak	Winter Peak
1993 - 2003	2.1 percent	3.6 percent	2.6 percent	4.5 percent
2003 - 2013	1.5 percent	2.1 percent	2.3 percent	2.0 percent
2013 - 2023	1.3 percent	1.8 percent	2.1 percent	2.1 percent

The forecasts of peak demands and NEL used in the RFP analyses are presented in Appendix E. Also presented in Appendix E are the output from the models used to develop FPL's peak load forecast and the work papers supporting the peak load forecast used in FPL's reliability assessment.

2. The Fuel Price Forecast

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major factors used in evaluating alternatives for meeting future generating capacity needs. FPL's forecasts are generally consistent with other published contemporary forecasts.

a. Fuel Price Forecast Methodology

FPL's fuel price forecast methodology is consistent for all fuels. It is also consistent with the methodology used by The PIRA Energy Group, Cambridge Energy Research Associates, and many other energy industry consultants. FPL uses the following approach for the development of its long-term fossil fuel price forecast. The major steps in the forecast development process include: (1) the development of a plausible, integrated set of economic, fundamental supply and demand, environmental, and geopolitical assumptions or drivers for the base case; (2) a qualitative and quantitative translation of these assumptions into price forecasts on a constant dollar basis; (3) a comparison to historical values and a current set of published forecasts, on a constant dollar basis, for reasonableness; and (4) a conversion from constant dollar to nominal dollar prices.

FPL develops a forecast that reflects the fuel price trends that are sufficient for use in the resource planning process. The forecast describes market conditions that are considered the most likely to occur. The fuel price forecast is used to develop the various price forecasts for crude oil and mine mouth coal, as these commodities are the determining commodities in current and future energy markets. Forecasts for fuel oils and natural gas then are developed based on expected market price relationships between those fuels and crude oil, as well as the projected supply and demand for each fuel in its respective market. Real price forecasts also are prepared for fuel transportation costs. Delivered real fuel prices are derived by adding the transportation cost component to the price of the commodity. The resulting forecasts are multiplied by Global Insights' forecast of the GDP implicit price deflator to produce nominal delivered fuel price forecasts. These final forecasts for each commodity are reviewed to ensure reasonableness and consistency.

b. Fuel Price Forecast Results

The detailed fuel price forecast for these fuels is presented in Appendix F.

c. Fuel Supply and Availability

(i) Natural gas

Natural gas is the primary fuel for the proposed Turkey Point Unit 5. Natural gas would be supplied through an upgrade of the existing FGT gas infrastructure that is currently used to serve the Turkey Point complex.

Currently, there are significant quantities of proven natural gas reserves in the United States to ensure a continuing long-term supply of natural gas from U.S. production. In addition to the supply of proven reserves, FPL's and energy industry consultants' long-term natural gas supply and demand balances show additional quantities of Canadian imports and LNG imports that will add to sufficiently meet the projected growth in natural gas demand of the United States. According to recent data from the Department of Energy – Energy Information Administration, there is adequate supply and projected natural gas reserves available in the United States to meet the natural gas demand for at least the next 25 years.

(ii) Oil

The proposed Turkey Point Unit 5 also will be capable of burning light oil. Light oil will be used as a backup fuel in the event of a natural gas supply disruption. Light oil would be trucked from local markets to the plant site where it would be stored in a new four million gallon tank. The four million gallons of storage represents approximately three days of light oil burn at base load operation of Turkey Point Unit 5. Sufficient light oil is available to ensure the reliable operation of Turkey Point Unit 5.

3. Financial and Economic Data

The financial and economic assumptions used in the resource planning process, the selection of the NPGU and the analysis of proposals received in response to the RFP are presented in Appendix G.

B. Geographic or Location Preference

The southeast area of FPL's system includes a portion of southern Palm Beach County and Broward and Miami-Dade Counties. Currently, FPL controls approximately 6,459 MW of generation resources in Southeast Florida though ownership or firm contracts. In 2003, FPL experienced a total demand of approximately 11,400 MW in this area. This difference between demand and generation resources located in Southeast Florida is what FPL refers to as the generation / load imbalance in Southeast Florida. This generation / load imbalance causes FPL to rely upon transmission import capability into Southeast Florida. Nominally, FPL has maximum transmission import capability into this region of approximately 7,000 MW (1,000 MW from the west and 6,000 MW from the north).

FPL described its imbalance situation on its Open Access Same-Time Information System (OASIS) website as early as November 2002. The imbalance was again addressed in FPL's 2003 TYSP and in the RFP.

The only aspect of this generation / load imbalance forecasted to change between 2003 and 2007 was the load growth in Southeast Florida. No new generating units were scheduled for addition before 2007, and no new transmission projects that would increase transmission import capability into Southeast Florida were scheduled before 2007. Therefore, the generation / load imbalance in Southeast Florida was forecasted to increase.

This imbalance gives rise to three issues with cost implications. The first is that transmission integration costs will tend to be higher for new generation additions located outside the southeast area. The second issue is that because locating new generation outside the southeast area would increase the amount of power moved over longer distances, transmission losses and the cost of replacing lost capacity and energy would tend to increase. The third issue is that without new, efficient generation located in Southeast Florida, the need to uneconomically dispatch high heat rate gas turbines located in Southeast Florida would tend to occur more frequently because of the load growth in that area, resulting in increased fuel costs.

Given these cost issues, FPL undertook an effort to quantify the economic impact of the location of various resources that could be sited to meet FPL's 2007 resource needs. Ultimately, FPL developed three cost analyses to address the costs associated with the location of various generating alternatives. Estimating transmission integration costs captured the costs of integrating each option into FPL's existing transmission system. FPL had prior experience with such analyses, having used them in its most recent RFP. Estimating the impact of unit additions on transmission system losses was a second means of capturing costs associated with generation location. Quantifying the third cost impact associated with location, the impact of an alternative on FPL's need to dispatch high cost gas turbines in Southeast Florida to maintain area reliability, was the third calculation.

When assessing the costs associated with its self-build options, FPL learned that the difference in costs associated with transmission integration and transmission losses for generation additions located outside Southeast Florida, compared to those for additions within Southeast Florida, could significantly affect the economic analysis. Consequently, in its RFP, FPL clearly stated a Southeast

Florida geographic preference and explained the reason for this preference. Specifically, the preference reflected the likelihood that one or more facilities located in Southeast Florida would prove to be lower cost than a unit outside of the area.

C. Fuel Diversity

In selecting the most cost-effective alternative, FPL considered a desire for greater fuel diversity. Solid fuel and nuclear facilities offer opportunities to capture attributes that could be beneficial to the system by diversifying the generation portfolio fuel mix. The fuel costs associated with these technologies are forecasted to be lower than natural gas and fuel oil into the future, and generally offer less price volatility (more cost stability) than natural gas or liquid fuels. The magnitude of the benefit and the likelihood of obtaining these benefits must be weighed against the significant capital costs and uncertain permitting requirements associated with solid fuel or nuclear facilities. These technologies also have inherently longer development timelines and could not reasonably be developed and constructed in time to satisfy the increased need by the summer of 2007.

FPL will continue to investigate other technologies in the resource planning process with recognition of the lead time necessary to successfully develop and site such alternatives by FPL or others. However, to address fuel diversity in meeting FPL's 2007 need, FPL stated in its RFP a preference for purchases from units that would improve FPL's fuel diversity. This preference was intended to encourage entities with existing units with technologies that contribute to fuel diversity as well as any that might be in an advanced stage of development to respond FPL's RFP.

D. Impact on Capital Structure

The obligations related to new generation resources can significantly impact FPL's capital structure. The selection and approval of generation resources built by FPL requires FPL to finance the development and construction of the facility. For its self-build options, FPL assumes standard financial vehicles, maintaining a 55/45 percent debt and equity ratio. For purchased power proposals, FPL must consider the cost to maintain the same overall capital structure for two reasons. First, it must quantify the cost of a real impact on the Company's capital structure. Second, it must hold neutral in the evaluation the impact on the utility's capital structure of either a self-build or purchased power proposal.

Because a portion of the payment obligation under a purchased power agreement is treated by debt rating agencies as debt equivalent, the selection of purchased power to meet FPL's resource needs will affect FPL's capital structure. The equity adjustment captures the cost to FPL of restoring its capital structure to its target 55 percent equity / 45 percent debt ratio when FPL purchases power and rating agencies impute debt to FPL's capital structure. The cost of this adjustment is a real cost, and must be included to properly capture the actual impact of purchased power on the Company's capital structure. Further, the cost of this adjustment must also be considered in the analysis if a self-build option and purchased power proposal are to be assessed on a comparable, quantitative basis that holds FPL's capital structure neutral. Appendix C of the RFP contains a description of the equity adjustment and the methodology to compute the adjustment, including a contra adjustment reflecting mitigating effects of purchased power relative to its impact on FPL's balance sheet.

E. Customer Protection

The alternatives available to FPL also present financial risks that must be recognized and mitigated through specific actions and requirements. A key financial risk that FPL must address is the credit-worthiness of those who would propose to undertake the construction of a major power plant. In addition, FPL must consider completion and performance security measures to ensure that customers will not be exposed to an unreasonable amount of risk for additional costs in the event of contractual non-performance.

These general concerns have become increasingly important in light of further recent deterioration in the financial condition of many suppliers in the IPP industry. For example, of the 16 proposers who responded to FPL's Supplemental RFP in 2002, nearly all have had their ratings downgraded since May 2002. Specifically, nine now are rated below investment grade, with seven rated at a "B" or lower by S & P, and three are in bankruptcy.

In light of these circumstances, FPL has established certain financial requirements as measures to protect its customers. These measures, such as the minimum financial viability criterion, and adequate security requirements, must be met in order for FPL to consider purchased power options to be reasonably comparable to FPL self-build alternatives in terms of the risks they present to customers.

F. Transmission System Restructuring

FPL endeavors to make generation alternative selections that will offer reliable and cost-effective service to its customers even in the event that governmental actions change the regulatory structure in which FPL must operate. There is significant attention at the state and federal level regarding potential changes to the regulatory framework respecting transmission assets. Generating alternatives selected to meet FPL's customers needs must be capable of delivering resource needs in a number of potential future transmission scenarios. FPL included as a minimum requirement that every proposer agree that, if its proposal were selected to provide capacity and energy under contract, the proposer would obtain and maintain the transmission rights necessary to effectively deliver the output of its generating unit to meet the needs of FPL's customers.

VI. MAJOR AVAILABLE GENERATING ALTERNATIVES EVALUATED

The next step in FPL's 2003 planning work was the evaluation of economic and other key attributes of various self-build generation options available for meeting FPL's forecasted 2007 capacity need. This analysis led to the selection of FPL's NPGU, a unit that would require certification under the PPSA. In accord with the Bid Rule, FPL developed and issued an RFP and conducted an RFP evaluation in which FPL's NPGU was compared to alternative portfolios proposals for meeting its 2007 capacity need to identify the best, most cost-effective alternative available.

A. Self-Build Alternatives Considered

1. General Process

FPL assigns engineers and a project developer to conduct the preparatory analysis necessary to develop and build generation facilities. They work well in advance to identify multiple opportunities. The candidate alternatives then are provided to FPL's Resource Assessment and Planning Department, which conducts an economic analysis and coordinates the overall evaluation necessary to determine the best, most cost-effective self-build generation alternative. This analysis relies upon the skills and experience of environmental specialists, transmission system engineers and fuels specialists in addition to the economic evaluation team. The objective of this process is to develop a recommendation of a resource plan that is both cost-effective and capable of meeting the quality, environmental and reliability standards suitable for inclusion in FPL's system.

FPL's examination of construction options with which it could meet its 2007 need focused on conventional technologies which could be developed, permitted and constructed within four years. These technologies were examined within FPL's IRP process that employs a multi-year, expansion plan analysis to evaluate the economics of competing generating options.

2. Nature of Alternatives Reviewed

FPL periodically examines a variety of generation construction options in the course of determining the most economical self-build options for its system. Several factors influence the decision regarding the different types of alternatives that could reasonably be included in the resource planning process.

FPL changed its planning reserve margin criterion from 15 to 20 percent effective beginning in the summer of 2004. This change has affected both the amount of capacity and timing of when new capacity would be needed. The net effect of this change in the reserve margin criterion has been an increased need of approximately 1,000 MW and an acceleration of that need by more than a year from previous planning processes that utilized a 15 percent reserve margin criterion. Therefore, this reserve margin criterion change has had the effect of reducing the time between FPL's 2003 reliability assessment and FPL's forecasted capacity need.

Solid fuel-based and nuclear power plants require more than six years to permit and construct. In addition, the uncertainties and costs associated with the development and construction of these facilities must be addressed. This process is underway at FPL to address potential needs in future years. In terms of selecting its best self-build potion, these technologies could not address FPL's capacity need for 2007.

Consequently, FPL's 2003 resource planning work focused on CT and CC self-build alternatives to meet its 2007 capacity need. A total of 25 CT and CC options were analyzed to determine FPL's best self-build option for meeting the 2007 need. Among these 25 options were 2x0, 3x0, and 4x0 CT units, and 2x1 and 4x1 CC units at various sites. All of these CT and CC options were based on GE's F-series CT technology.[9]

All of the options analyzed were located at various sites in or near Southeast Florida. FPL believes that siting new generating capacity in Southeast Florida, or if new capacity is located outside of Southeast Florida, enhancing the transmission facilities to allow FPL to importation of additional capacity into

9 FPL briefly considered the Westinghouse G-series CC technology in a 3x1 CC configuration but dismissed it for two main reasons: (1) it showed no cost advantage over the F-series options, and (2) FPL's existing CT/CC fleet is based solely on F-series technology and there are maintenance advantages if FPL operates facilities that have the same CT/CC technology.

Southeast Florida would be needed in 2007 and beyond to address the growing imbalance between load and generation capability in Southeast Florida that was addressed in Section V.B.

3. Evaluation and Selection

The analytic framework for evaluating FPL's self-build options was relatively straightforward. FPL began with a system generation and fuel cost analysis to assess the impact of various options on system revenue requirements over a 25-year horizon. FPL then added the transmission integration costs associated with each option under consideration to those system revenue requirements. An assessment of the costs created by demand and energy losses was added to the total cost of each alternative. The various components of FPL's economic evaluation of self-build options are discussed in the following subsections.

a. Generation and Fuel Cost Analysis. This analysis was performed using the Electric Generating Expansion Analysis System (EGEAS) software to calculate the revenue requirements associated with the FPL system assuming different resource additions. The generation and fuel cost analysis includes capital costs, operation and maintenance (O & M) costs, fuel commodity and transportation, and fuel and transmission interconnection costs, and the variable costs of compliance with current environmental regulations (namely SO_2). FPL captured the impact of self-build alternatives on FPL's capital structure by employing an incremental capital structure of 55 percent equity and 45 percent debt in the EGEAS runs used to develop generation and fuel costs.

b. Transmission-Related Costs. The transmission-related costs were developed for each alternative or combination of alternatives. Load flow analyses for each alternative or combination of alternatives were developed to identify necessary transmission system upgrades and additions. Then cost estimates for these upgrades and additions were computed, and the system revenue requirements associated with making these upgrades and additions were added to the EGEAS cost values.

Capacity and energy losses related to each specific alternative or combination of alternatives also were estimated. In estimating these losses, the transmission integration facilities identified in the transmission integration analysis first were added to the base case load flow so that losses for 2007 could be calculated. The loss calculations for 2007 were assumed applicable for the life of the alternative under consideration.

c. Analysis Results. The analyses of FPL self-build options yielded the following. First, the CC options were clearly more cost-effective for FPL to add compared to the CT options. Second, as mentioned above, the 4x1 CC options were more economical than the 2x1 CCs. This result was consistent with results from resource planning analyses in prior years. Third, when considering only generation-related costs captured in the EGEAS model work, a 4x1 CC sited at FPL's Martin site emerged as the leading candidate. Fourth, after all of the transmission-related costs for integration and losses were added to the generation-related costs, a 4x1 CC unit located at FPL's Turkey Point site emerged as the most economical alternative. Based upon its economic analysis, FPL selected Turkey Point Unit 5 as its NPGU. Turkey Point Unit 5 was FPL's best, most cost-effective self-build option available to meet FPL's 2007 capacity need.

B. Request for Proposal Process

The selection of Turkey Point Unit 5 as the NPGU set in motion the PPSA process. In connection with that process, FPL must obtain a Determination of Need from the Commission. In accord with the Bid Rule, FPL issued its RFP on August 25, 2003 to solicit proposals for generating capacity to meet its resource need of 1,066 MW in the summer of 2007. FPL's 2003 RFP is included as Appendix D to this document.

1. Development and Publication of the RFP

Among the objectives of the RFP was to protect the interests of FPL's customers from a supplier's failure to perform. Another objective was to develop an RFP process that would allow FPL to be responsive to feedback from the various participants and observers. In addition, FPL sought to include in the RFP enhancements to its evaluation methodology based on issues identified in the resource planning process. Some examples of how the RFP's development was influenced by the above-mentioned factors follow.

a. Protection of Customers. FPL developed a number of requirements in its RFP to identify explicitly certain threshold expectations that would need to be satisfied as a pre-condition for FPL to consider an offer from a proposer. Some of these minimum requirements specify criteria that must be met by a proposer or actions and commitments required of the proposer to protect FPL's customers from a supplier's failure to perform. The current financial status of many entities in the independent power industry highlights the need for these requirements. The minimum requirements were set forth in Section III.E of the RFP; the RFP is Appendix D to this Need Study.

b. FPL Responsiveness. FPL drafted its RFP to encourage proposers to present a wide range of resource alternatives (system resources, asset sales, new construction, expansions, etc.). Moreover, FPL considered feedback received from potential proposers and other interested observers.

In accord with the Bid Rule, before issuing its RFP, on August 14, 2003, FPL issued a press release for trade publications and newspapers and published notices in newspapers of general circulation announcing its intent to issue an RFP. FPL's press release and notices also announced pre-issuance and proposal workshop meetings to be held in Miami that interested entities could attend in-person or by telephone. The press release issued by FPL and the notices published by FPL announcing these meetings and FPL's RFP are Appendix H to the Need Study.

Consistent with its press release and published notices, FPL conducted a four-hour pre-issuance meeting in Miami on August 21, 2003. Thirty-two individuals representing 22 organizations participated in the half-day forum in person, or by teleconference. To accommodate points raised at the workshop, FPL agreed to modify the RFP process after this pre-issuance meeting. FPL also agreed to publish the fuel price forecasts to be used in the RFP evaluation to assist proposers in the preparing of their proposals.

When FPL issued its RFP on August 25, 2003, it included a number of provisions that were intended to assist potential proposers in providing proposals that would benefit FPL customers. For example, FPL included a sample contract in its RFP setting forth preferred terms to which potential proposers could state exceptions and propose alternative language. The publication of this information better informed proposers of FPL's preferences and allowed proposers to offer alternatives.

FPL also included an alternative generating unit located in Southeast Florida with which potential proposals could be combined in portfolios. The inclusion of such an alternative generation option was intended to aid proposers by (a) creating an option with which proposals smaller than FPL's entire need could be combined and (b) adding a generating alternative that was located in Southeast Florida, thereby reducing the likely impact of transmission-related costs for portfolios that included proposals located outside Southeast Florida, and the alternative generating unit.

In addition, FPL retained an external evaluator to independently conduct an economic evaluation.

FPL made extensive efforts to be responsive to issues raised in formulating and implementing its RFP, while preserving the requirements FPL felt were necessary to protect customers and properly administer the RFP. FPL established a website on which FPL posted questions and answers regarding the RFP. FPL also held a pre-bid workshop in Miami on September 2, 2003, at which potential proposers could raise questions. Consistent with the Bid Rule, FPL invited not only the Commission Staff, but also the Office of Public Counsel to both the pre and post-issuance workshop.

FPL continued to engage interested participants and observers throughout the process. The result of this flexible and open approach resulted in three Addenda to the RFP that addressed certain points communicated to FPL during the process. These Addenda are more fully discussed in section VI.B.2.

c. Process Enhancements. FPL enhanced portions of its evaluation compared to its 2002 capacity solicitation to capture system costs and benefits presented by different resources. FPL's primary enhancement to its evaluation involved addressing the economic impact on all system costs of integrating individual resources into the transmission system. Specifically, FPL developed and communicated in detail the methodology used to evaluate the costs of transmission capacity and energy losses and increased operational costs in Southeast Florida presented by candidate portfolios. Other enhancements included: 1) a fuel switching credit, added to recognize fuel source economic arbitrage opportunities that could be potentially offered by proposed units; and 2) economic mitigation offered by security amounts provided by proposers.

2. Post–Issuance/Proposal Workshop, Objection Process, and RFP Addenda

As previously noted, after publishing the RFP, FPL hosted a pre-bid RFP workshop in Miami on September 2, 2003 to answer questions from potential participants in an open forum. Twenty-eight individuals representing 21 organizations participated in the workshop in person or by teleconference.

At this workshop potential proposers requested an indexed methodology they could use to price their offerings. In response to this request, FPL developed, published, and filed Addendum One with the Commission on September 4, 2003. All Addenda are included in Appendix D of the Need Study.

In response to other participant requests, FPL issued Addendum Two to the RFP on September 12, 2003, which included fuel price forecasts to be used in the evaluation process. Additionally, FPL used Addendum Two to extend the date for receiving questions on FPL's website and clarified the requirement for providing fuel from two independent sources.

As envisioned by the Bid Rule, participants were provided an opportunity to raise objections regarding whether the RFP complied with the Bid Rule. PACE, an independent power interest group used this opportunity to file objections to FPL's 2003 RFP with the Commission. PACE claimed that the RFP violated the Bid Rule by placing "onerous, unfair and unduly burdensome" requirements on Proposers. PACE raised objections to 14 specific aspects of the RFP document.

On September 9, 2003, FPL filed a detailed response to PACE's objections. In its response, FPL challenged PACE's right to raise objections and rebutted each of PACE's specific objections.

On September 19, 2003, the Commission Staff submitted its Recommendation to the Commission regarding PACE's Objections. In its Recommendation, Staff stated that only nine of the 14 objections filed by PACE were relevant, and it recommended that the Commission conclude that PACE had not demonstrated that the RFP violated the Bid Rule. As part of the Recommendation, Staff stated "FPL has gone beyond the requirements of the rule in order to provide additional information to potential participants to the RFP process." On September 30, 2003, following extensive oral argument regarding PACE's objections to FPL's RFP, the Commission concluded that PACE had not demonstrated that FPL's RFP violated the Bid Rule.

Responding to the discussion that followed the oral arguments, FPL provided revisions to and clarifications of its RFP in the form of Addendum Three, published and filed with the Commission on October 6, 2003. In Addendum Three, FPL changed the RFP to reduce the fee required for submitting variations to a proposal, relaxed the minimum financial requirement, extended the schedule for posting security amounts, allowed greater flexibility in the form of the security, incorporated language from the Bid Rule into the minimum requirement related to regulatory modifications, removed any inference that failure to state exceptions to the draft PPA constituted contractual acceptance of the terms of the draft PPA, and restated the dual-fuel requirement to clarify that the same criteria FPL applies to its own NPGU would apply to all proposals.

Ultimately, FPL received and answered 233 questions from potential proposers. They were either posted on the dedicated website, or distributed directly to all participants by email (see Appendix I).

3. Proposals Received

Four participants provided five proposals in response to FPL's 2003 RFP. This level of response is consistent with the levels of response in the three recent capacity solicitations held by other investor- owned utilities in Florida. The five proposals received by FPL in response to the 2003 RFP are summarized in Table VI.B.3.1. below.

Table VI.B.3.1. Summary of Proposals Received

Proposal	Project	Capacity Term	Technology	Fuel	Company
1	SEP Homestead, Homestead, FL Proposal Five	50 MW, 25 years	Circulating Fluidized Bed, Steam Boiler	Coal / Pet Coke	Summit Energy Partners, LLP.
2	Unnamed St. Lucie Co. Proposal Two	1,220 MW, 15 years	Combined Cycle	Natural Gas	Southern Power Co.
3	Unnamed St. Lucie Co. Proposal One	1,220 MW, 25 years	Combined Cycle	Natural Gas	Southern Power Co.
4	Desoto Energy, Desoto Co. Proposal Four	447 MW, 15 years	Combustion Turbines	Natural Gas	Progress Ventures, Inc.
5	Blue Heron Energy Center, Vero Beach Co Proposal Three	252 MW, 15 years	Combined Cycle	Natural Gas	Calpine Corporation

4. Initial Assessment

As previously discussed, FPL set forth criteria as minimum requirements that had to be met by all proposals. Proposals from Summit Energy Partners, Calpine Corporation, and Southern Company were submitted with specific exceptions to some of these minimum requirements or otherwise were non-compliant. FPL notified these proposers of the nature and extent of the non-compliance and encouraged them to make changes to bring the proposals into compliance. In parallel with this effort, to avoid delays in the evaluation process, FPL initiated its economic evaluation of all proposals. The proposers either were unable or chose not to make the necessary changes to their proposals to bring them into compliance. Table VI.B.4.1 summarizes the areas of non-compliance.

Table VI.B.4.1

Minimum Requirements Not Met

Proposed Project	Unsatisfied Minimum Requirements
SEP Homestead, LLC (Summit Energy Partners)	- Firm Nature of Proposal (100% output) - Financial Viability - Experience of Company - Feasibility of Permit Process*
Blue Heron Energy Center (Calpine Corporation)	- Firm Nature of Proposal (100% output) - Financial Viability - Security Amounts - Dual Fuel Capability*
St. Lucie Co. Project (Southern Power Co.)	- Commercial Operation Date (COD) - Security Amounts - Pricing – Post RTO contingency - Permits – change of law pre-COD - Milestones – Site Certification
St. Lucie Co. Project (Southern Power Co.)	- COD - Security Amounts - Pricing – Post RTO contingency - Permits – change of law pre-COD - Milestones – Site Certification

* Insufficient data submitted to evaluate compliance.

5. Economic Evaluation

FPL conducted an economic evaluation of FPL's NPGU and seven alternative portfolios that met the 2007 need. These seven alternative portfolios were developed by combining RFP proposals or by combining FPL's alternative generating unit (the 4x0 CT, 648 MW alternative) with RFP proposals. The portfolios considered including FPL's NPGU are identified in Table VI.B.5.1 below.

Table VI.B.5.1 Candidate Portfolios

Components of the Candidate Portfolio	Capacity (MW)	Compliant? Y/N
FPL's NPGU (PTF-5)	1,144	Yes
FPL 4CT + Proposal 4	1,095	Yes
FPL 4CT + Proposal 4 + Proposal 1	1,145	No
Proposal 2 (15 yr)	1,220	No
FPL 4CT + Proposal 4 + Proposal 5	1,347	No
Proposal 2 (15 yr) + Proposal 1	1,270	No
Proposal 3 (25 yr) + Proposal 1	1,270	No
Proposal 3 (25 yr)	1,220	No

The economic evaluation quantified three major cost categories: generation-related costs, transmission-related costs, and the impact of each option on FPL's capital structure.

a. Generation-Related Costs. These costs are the CPVRR (over a 25-year term) of generation-related costs for the FPL system including each candidate portfolio. FPL's calculation was performed with the EGEAS model and Sedway Consulting's calculation was performed with its Response Surface Model (RSM). This cost includes all capital costs to develop, construct, commission, and operate the facility for the term of the analysis in the case of a self-build option, and all capacity and energy payments in the case of a PPA. O&M costs as well as fuel commodity, fuel transportation, fuel infrastructure, and transmission interconnection costs are included in the analysis.

The EGEAS model conducts an economic analysis of unit operations recognizing how the unit(s) in the portfolio will be dispatched in the FPL generation system. Therefore, this portion of the analysis reflects system benefits created by how the specific attributes of the portfolio interact with the current FPL generation system. Beyond a plant-level accounting of costs, the EGEAS model allows FPL to capture the economic influence of the portfolio on other current and future FPL resources.

Turkey Point Unit 5 offered the lowest generation-related cost of all alternatives, establishing a \$104 million CPVRR advantage over the next most competitive portfolio. The independent evaluator conducted a parallel system cost analysis using the RSM. That analysis confirmed FPL's results, with the independent evaluator concluding that Turkey Point Unit 5 was the lowest cost option by \$127 million CPVRR. The results of the comparison of the portfolios are shown on Table VI.B.5.a.1.

Table VI.B.5.a.1

Generation-Related Costs Only

Portfolio	MW	CPVRR ($MM)	Difference ($MM)
FPL CC	1,144	62,591	0
FPL 4 CT, Proposal 4	1,095	62,695	104
FPL 4 CT, Proposal 4, Proposal 1	1,145	62,712	121
FPL 4CT, Proposal 5	1,347	62,741	150
Proposal 3, Proposal 1	1,270	62,741	150
Proposal 3	1,220	62,760	169
Proposal 2	1,220	62,763	172
Proposal 2, Proposal 1	1,270	62,788	197

The three closest portfolios in the initial step of the analysis all included the FPL alternative generating unit, the 4x0 CT option, paired with one or more RFP proposals. This demonstrated that FPL's offer to include the alternative generating unit in the analysis worked to the advantage of the proposers. Also, every portfolio consisting solely of RFP proposals (no FPL alternative generating unit) was at least $150 million CPVRR more costly than Turkey Point Unit 5.

b. Transmission-Related Costs. To ensure the evaluation considered the complete system operating cost created by the selection of a particular portfolio, it is necessary to model how that portfolio would be integrated into and operate within FPL's transmission system. There are three aspects to this determination: (1) calculation of system integration costs; (2) calculation of losses; and (3) the calculation of increased Southeast Florida operating costs.

When the portfolios are developed, the portfolio information is provided to transmission engineers who conduct an integration study to determine the capital improvements to the FPL system necessary to integrate the resource(s) in accord with reliability criteria. The costs of these capital improvements comprise the transmission integration cost for the portfolio. Table K-2 in Appendix K lists the estimated direct construction costs of transmission improvements required for each of the eight portfolios.

The transmission engineers also conduct analyses to determine the peak load (MW) and average load (MW) losses associated with the portfolio. The economic evaluation team converted these MW losses into annual energy (MWH) losses. The capacity and energy loss estimates for each portfolio are provided in Appendix L. The physical loss estimates then are converted to monetary costs by the Resource Assessment and Planning Department based on the procedure identified in Appendix E of the RFP. These costs comprise the transmission loss costs for the portfolios. The costs are referenced to the lowest cost portfolio in terms of loss as differential costs and are listed for each portfolio in Appendix M. Finally, an analysis is conducted to determine the cost impact that the portfolios have upon increased operating costs in Southeast Florida based on the procedure identified in Appendix E of the RFP, which is Appendix D to the Need Study. Taken together, these costs are identified as the transmission-related costs for the portfolios and are listed in Appendix M and N for each portfolio.

The results of the transmission analysis increased the separation between Turkey Point Unit 5 and all other portfolios, with Turkey Point Unit 5 now at a $204 million CPVRR advantage over the next most competitive proposal. The recognition of transmission costs also changed the ranking of the various portfolios. The results of this intermediate step are shown in Table VI.B.5.b.1.

Table VI.B.5.b.1
Generation, Fuel and Transmission Costs

Portfolio	MW	CPVRR ($MM)	Difference CPVRR ($MM)
FPL CC	1,144	62,591	0
Proposal 3, Proposal 1	1,270	62,795	204
Proposal 2	1,220	62,827	236
FPL 4 CT, Proposal 4, Proposal 1	1,145	62,831	240
Proposal 3	1,220	62,832	241
Proposal 2, Proposal 1	1,270	62,835	244
FPL 4 CT, Proposal 4	1,095	62,841	250
FPL 4 CT, Proposal 4, Proposal 5	1,347	62,861	270

c. **Impact on Capital Structure.** The goal of this aspect of the analysis was to capture the effect of each portfolio on FPL's capital structure. The impact on FPL's capital structure of FPL's NPGU and FPL's alternative generating unit was addressed by employing an incremental capital structure of 55 percent equity and 45 percent debt in the analysis of these additions. The impact on FPL's capital structure of PPA obligations greater than three years was taken into account through a net equity adjustment applied to the proposals.

The equity adjustment formula was adapted from Standard & Poor's rating methodology. It considers the magnitude and term of the PPA capacity payments, and it employs a 10 percent discount factor and a 30 percent risk factor to calculate an amount of imputed debt. Next, the amount of additional equity necessary to offset the imputed debt and restore a 55 percent equity / 45 percent debt capital structure is calculated. Then the cost of this additional equity is calculated. Additionally, FPL incorporated mitigating factors that contributed to offset the equity adjustment. The combination of the equity adjustment calculation and the mitigating amount is the net equity adjustment for a portfolio. The methodology employed to calculate the net equity adjustment in this RFP was provided in detail in Appendix C to the RFP, which is Appendix D of the Need Study.

The impact on capital structure analysis completed FPL's initial analysis of the competing portfolios and the results are shown in Table VI.B.5.c.1. The primary conclusion to be drawn from this analysis was that Turkey Point Unit 5 was FPL's most cost-effective option by at least $266 million CPVRR. No portfolio containing only RFP proposals was within $300 million CPVRR of Turkey Point Unit 5.

Table VI.B.5.c.1
All Costs, Initial Bids

Portfolio	MW	CPVRR ($MM)	Difference CPVRR ($MM)
FPL CC	1,144	62,591	0
FPL 4 CT, Proposal 4	1,095	62,857	266
FPL 4 CT, Proposal 4, Proposal 1	1,145	62,867	276
FPL 4 CT, Proposal 4, Proposal 5	1,347	62,888	297
Proposal 2	1,220	62,891	300
Proposal 2, Proposal 1	1,270	62,918	327
Proposal 3, Proposal 1	1,270	62,927	336
Proposal 3	1,220	62,945	354

6. Non-Economic Evaluation

There were a number of non-economic attributes associated with each proposal. These attributes taken together presented a risk profile associated with the selection of each proposal. To evaluate these attributes, FPL identified three major areas to be reviewed by subject matter experts. The areas covered environmental, technical/operational and project execution factors.

Based on the non-compliance of some proposals with the minimum requirements, only the portfolio including the Progress Ventures proposal was reviewed for non-economic factors and compared to the NPGU. Appendix B to the RFP provides the detailed assessments of the areas, as summarized below.

a. Environmental Area. This review evaluated the likelihood that each of these portfolios would successfully attain the necessary permits, licenses and regulatory approvals in the time frame needed to meet the needs stated in the RFP. The experience of the proposer was considered along with the technical specifics of the proposal.

b. Technical/Operational Area. This review evaluated the technical and operational merits of the two portfolios. Factors such as the technology employed as well as the design limitations and ratings of the equipment were reviewed. Neither of the alternatives considered caused any concerns in this area because they both use known and accepted technologies and would be operated by experienced companies.

c. Project Execution Area. This review focused on the exceptions taken by Progress Ventures to the RFP terms or the draft PPA (in areas that were not minimum requirements). This allowed FPL to consider the likelihood of reaching a mutually agreeable PPA within the required timeframe should the portfolio containing the Progress Ventures proposal be selected. Progress Ventures took no specific exceptions, so FPL concluded that completion of a contract would not be an obstacle.

d. Overall Assessment. In summary, both the portfolio including the Progress Ventures proposal and FPL's NPGU offered stable, acceptable risk profiles. See Appendix O for the details of these non-economic reviews.

7. Best and Final Offer Selection

The Progress Ventures proposal was the only proposal that met all the minimum requirements of FPL's RFP. After FPL made repeated unsuccessful efforts to convince the noncompliant proposers to bring their proposals into compliance, FPL informed the noncompliant proposers that their proposals would not be considered further because their proposals failed to meet three or more minimum requirements. The Progress Ventures proposal was the only RFP proposal in the second most competitive portfolio identified by the economic evaluation, and it presented an acceptable and stable risk profile. Therefore, FPL informed Progress Ventures that its proposal was being selected as a finalist. FPL requested a BAFO from Progress Ventures.

Progress Ventures submitted its BAFO, and FPL and Sedway Consulting updated their economic evaluations after substituting Progress Ventures' BAFO for Progress Ventures' initial proposal. The impact of the BAFO on the economic analysis was to increase the CPVRR of the portfolio that included Progress Venture's proposal and FPL's alternative generating unit, as well as the other two portfolios containing Progress Ventures' proposal), by $4.8 million. Thus, the total economic benefit of Turkey Point Unit 5 relative to the next lowest cost option available to FPL was increased to $271 million CPVRR.

The results of both FPL's and Sedway Consulting's economic evaluations showed substantial separation in cost between Turkey Point Unit 5 and all alternative portfolios.

Based upon its evaluation, FPL's Resource Assessment and Planning Department recommended to FPL's management that Turkey Point Unit 5 be recognized as the best and most cost-effective alternative available to meet FPL's 2007 need. FPL's management concurred with this recommendation.

VII. NON-GENERATING ALTERNATIVES

A. FPL's Demand Side Management Efforts

FPL has a long history of identifying, developing, and implementing DSM resources to avoid or defer the construction of new power plants. FPL first began offering DSM programs in the late 1970s with its introduction of the Watt-Wise Home Program. An increasing number of additional DSM programs were then offered throughout the 1980s and 1990s. These programs have included both conservation and load management and have addressed the residential, commercial, and industrial markets.

The mix of DSM programs FPL has offered has evolved over time. Indeed, FPL continually looks for new DSM opportunities in its research and development activities. When a new DSM opportunity is projected to be cost-effective, FPL will introduce a new DSM program or incorporate the new DSM opportunity into one or more of its existing DSM programs. In addition, FPL has modified DSM programs over the years whenever possible to maintain the cost-effectiveness of the program and its continued viability. On occasion, FPL also has terminated DSM programs whose viability could not be maintained.

FPL's DSM efforts have made it a recognized leader in DSM in the United States. These efforts have resulted in summer peak demand reduction through 2003 of 3,270 MW at the generator. After accounting both for line losses and reserve margin requirements, this amount of peak reduction that otherwise would have been needed is approximately equivalent to 10 power plants of 400 MW capacity. FPL has achieved this level of demand reduction and avoidance of new generating units without penalizing customers who are non-participants in its DSM programs. This is accomplished by offering only those DSM programs that reduce electric rates for all customers, DSM participants and non-participants alike.

B. FPL's Current DSM Goals

DSM Goals were first set for Florida utilities in 1994 in Order No. PSC-94-1313 FOF. In 1999, new DSM Goals were set for FPL and other Florida utilities in Order No. PSC-99-1942-FOF. In that order, the Commission established for FPL an aggressive goal of achieving 765 MW of incremental summer MW through DSM during the period from 2000 through 2009. This goal reflected what FPL and the Commission believed to be the reasonably achievable, cost-effective levels of incremental DSM on FPL's system. FPL's current DSM Goals were presented in Table II.B.3.1.

FPL's DSM Goals call for FPL to implement 625 incremental MW of summer peak reduction during the 2000 through 2007 time frame. As mentioned in Section III, FPL assumed the successful accomplishment of these DSM Goals in determining its future capacity needs. Without this additional DSM, FPL's future capacity needs would have significantly increased. In fact, FPL's capacity needs would have advanced a year from 2007 to 2006 if the incremental DSM MW called for in the Goals were not implemented. This 2006 capacity need would have been in excess of 700 MW.

FPL forecasts that it will achieve its DSM goals of 625 MW of DSM by 2007 (and, subsequently, the 2009 Goal of 765 MW) through a number of DSM programs. These programs are part of FPL's DSM Plan that was approved by the Commission in Order No. PSC-00-0915-PAA-EG. FPL's current DSM Plan consists of six residential DSM programs, eight commercial/industrial DSM programs, one research program, and four research projects. A brief summary of each of these programs and research projects appears in Appendix P.

C. The Potential for Additional Cost-Effective DSM

FPL is confident there is no additional, cost-effective DSM that could meet FPL's capacity need for 2007. There are several bases for this conclusion.

First, the Commission has previously determined that the reasonably achievable, cost-effective summer MW level of DSM on FPL's system between 2000 and 2007 is 625 MW. Second, FPL has already counted this level of reasonably achievable DSM in its reliability assessment that resulted in the projected need to add 1,066 MW of new supply side resources. Otherwise stated, FPL's analysis had already captured the cost-effective DSM available on FPL's system and determined that FPL still needed additional capacity resources.

Third, if the 2007 resource need were to be met solely by additional new DSM resources, FPL would need to find an additional 888 MW of cost-effective DSM to meet the 2007 resource need. It is unrealistic to conclude that FPL could implement sufficient new DSM programs in the next three years (mid-2004 to mid-2007) to meet this need. The Commission previously determined there was only 765 MW of additional, achievable, cost-effective DSM for the entire ten-year period, 2000-2009. It would be unreasonable to conclude that FPL could achieve an additional 888 MW of cost-effective DSM in the next three years. This is particularly so given that it would take some time to secure Commission approval to proceed with new DSM programs or to modify existing programs. In fact, the time needed to secure this approval would likely reduce the available time to implement additional DSM from 3 years to 2 ½ years. Even if there exists cost-effective DSM not previously found by FPL or the Commission, not enough could be added in the time remaining to meet FPL's 2007 resource needs.

VIII. ADVERSE CONSEQUENCES IF THE PROPOSED CAPACITY ADDITION IS DELAYED OR DENIED

If Turkey Point Unit 5 is not added, there are a number of adverse consequences that FPL's customers will face. If Turkey Point Unit 5 is not added and FPL makes no alternative arrangement to maintain its reliability criterion of a 20 percent reserve margin in 2007, then FPL's customers would be served by a less reliable system than either the Commission or FPL have identified as appropriate. FPL's reserve margin would decrease to less than 15 percent in 2007. If Turkey Point Unit 5 is delayed one year or not built at all, and FPL obtains alternative generation capacity to meet its 20 percent reserve margin, FPL's customers would face increased revenue requirements of at least \$86 million and \$271 million, respectively.[10]

A. Adverse Effects Upon FPL System Reliability

The planned capacity addition, Turkey Point Unit 5, is proposed for commercial service in mid-2007. This addition will add 1,144 MW of capability to FPL's system for the summer of 2007, thus enabling FPL to meet its summer reserve margin criterion of 20 percent.

The addition of Turkey Point Unit 5 by the summer of 2007 enables FPL to maintain its reserve margin planning criterion. However, if the project is delayed

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[10] If Turkey Point Unit 5 is delayed one year, there would also be a higher level of system emissions associated with the Turkey Point Unit 5 energy being generated by other FPL units.

beyond the summer of 2007, FPL would fail to meet its 20 percent reserve margin criterion by a significant margin, and FPL's customers would have a less reliable system to serve them. The amount by which FPL would fail to satisfy its 20 percent reserve margin is shown in Table VIII.A.1.

Table VIII.A.1

Effects of Project Delay or Denial on FPL's 2007 Summer Reserve Margin Without Unit Addition

	Scenario	Projected 2007 Summer Reserve Margin
1)	Turkey Point Unit 5 is in-service by mid – 2007	20.4 percent
2)	Turkey Point Unit 5 is delayed one year	14.7 percent

B. Adverse Impact on Adequate Electricity at Reasonable Cost

Turkey Point Unit 5 will be a highly efficient, reasonable cost unit. If the project is delayed or denied, FPL's customers would forgo the lower costs associated with this generation addition. It would have to be replaced with higher-cost generation resources, either through increased operation of less-efficient existing FPL units, through higher cost power purchases (if enough are available), or through a combination of a higher cost FPL option in conjunction with a higher cost purchase.

If the determination of need requested for Turkey Point Unit 5 is denied, the next most economical option available to meet customer needs, based upon the responses received in response to the RFP, would cost FPL's customers at least $271 million CPVRR more than Turkey Point Unit 5. This cost differential represents the difference between Turkey Point Unit 5 and the next lowest cost portfolio in FPL's economic evaluation. This increased cost to FPL's customers cannot be justified.

If Turkey Point Unit 5 is delayed for one year to 2008, significant additional costs would also be incurred by FPL's customers. These costs would be both generation-related and transmission-related.

In regard to generation-related costs, several factors must be assessed. First, if a one-year delay occurred, FPL assumes that it would attempt to secure a one-year purchase of capacity for its 1,066 MW capacity need. Assuming (perhaps optimistically) that such a large, short-term purchase could be made, FPL estimates that the purchase cost would be at approximately $5/kW-month for a 2007 total of about $64 million (nominal) or approximately $47 million CPVRR. Second, a one-year delay in building Turkey Point Unit 5 would result in increased construction-related costs. It is difficult to determine the impact on construction-related costs because numerous major equipment contracts, materials pricing, and labor market volatility would be involved. So, FPL conservatively assigned zero cost to these known but unquantified changes and merely escalated its existing Turkey Point cost estimate by 1.7 percent, increasing that cost estimate by $10 million. Finally, there are additional expansion plan-related cost impacts that would occur, such as the capital cost savings in 2007 for not building Turkey Point Unit 5 in that year and higher fuel costs in 2007 from not having this fuel-efficient unit in-service during that year. FPL estimates that the net impact of all these generation-related cost impacts is to increase costs by approximately $24 million CPVRR.

In regard to transmission-related cost impacts, there would be both transmission integration costs and a one-year cost of losses that would be incurred in connection with the 2007 purchases. Using the next lowest cost portfolio in the RFP as a basis for these costs, this would add $56 million CPVRR for integration and $6 million CPVRR for losses, for a total of $62 million CPVRR for transmission-related costs.

Consequently, FPL estimates the total costs to FPL's customers of a one-year delay in Turkey Point Unit 5 to be at least $86 million CPVRR. This increased cost to FPL's customers cannot be justified.

IX. CONCLUSION

FPL conducted a resource planning process to identify future capacity needs. FPL identified that 1,066 MW of new capacity was needed by the summer of 2007 to meet its reliability criterion of a 20 percent summer reserve margin. With no new capacity additions, FPL's projected summer reserve margin for 2007 is 14.7 percent.

FPL conducted an evaluation of self-build alternatives to identify the best and most cost-effective alternative to meet the 2007 need. The analysis indicated that a natural gas-fired 4x1 CC facility located in Southeast Florida was the best self-build choice. Because of the nature of the Turkey Point Unit 5 design, FPL would be required to obtain a Determination of Need to support a siting order. In accord with the Bid Rule, FPL issued an RFP and conducted a capacity solicitation process. FPL compared proposals received from participants to the NPGU.

FPL administered the RFP was administered in an open and participatory manner accommodating suggestions from participants at several points. The results of the RFP process clearly demonstrated that FPL's NPGU is the best and most cost-effective alternative to meet the 2007 need by a significant margin. FPL's analysis showed Turkey Point Unit 5 to be the most cost-effective option to meet customers' 2007 needs by $271 million CPVRR. FPL's evaluation and conclusions were confirmed by an independent evaluator, who found the savings to FPL customers to be at least $302 million.

FPL needs Turkey Point Unit 5 to maintain system reliability and integrity in 2007 and beyond. FPL needs Turkey Point Unit 5 to provide adequate electricity at a reasonable cost to its customers. FPL also needs Turkey Point Unit 5 to address the Southeast Florida generation / load imbalance and mitigate associated costs and reliability concerns. Turkey Point Unit 5 is the best, most cost-effective alternative to meet the needs of FPL and its customers in 2007, and there is no additional cost-effective DSM available to mitigate the need of FPL and its customers. The Commission should grant FPL's petition for a determination of need for Turkey Point Unit 5.