BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 07<u>0650</u>-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S
PETITION TO DETERMINE NEED FOR
TURKEY POINT NUCLEAR UNITS 6 AND 7
ELECTRICAL POWER PLANT

NEED STUDY FOR ELECTRICAL POWER

Need Study for Electrical Power

FPL

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ABWR	Advanced Boiling Water Reactor
ACOE	U.S. Army Corps of Engineers
AEC	Atomic Energy Commission
AFUDC	Allowance for Funds Used for Construction
BACT	Best Available Control Technology
BTU	British Thermal Unit
BWR	Boiling Water Reactor
CAAP	Central Appalachian Coal
CC	Combined Cycle
CCC	Carrying Charges of Construction
CFB	Circulating Fluidized Bed
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
COL	Combined Construction and Operating License
COLA	Combined Construction and Operating License Application
CPVRR	Cumulative Present Value of Revenue Requirements
D.C.	District of Columbia
DOE	Department of Energy
DSM	Demand Side Management
EPAct2005	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ESBWR	Economic Simplified Boiling Water Reactor
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
FGT	Florida Gas Transmission
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
GHG	Greenhouse Gas
GPPRP	Green Power Pricing Research Project
GSU	Generator Step Up
GWh	Gigawatt Hour
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Planning
ITAAC	Inspections, Tests, Analysis and Acceptance Criteria
JEA	Jackson Electric Authority
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LNG	Liquefied Natural Gas
LOLP	Loss-of-Load-Probability
MW	Megawatt
MWh	Megawatt Hour
MMBTU	Millions of British Thermal Units

NEL	Net Energy for Load
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corp
NRC	Nuclear Regulatory Commission
NOAA	National Oceanographic and Atmospheric Association
NO_x	Nitrogen Oxide
OPEC	Organization of Petroleum Exporting Countries
PC	Sub-critical Pulverized Coal
PPSA	Florida Electrical Power Plant Siting Act
PSD	Prevention of Significant Deterioration
PV	Photovoltaic
PWR	Pressurized Water Reactor
RFI	Request for Information
RFP	Request for Proposals
SCA	Site Certification Application
SERC	Southeast Electric Reliability Council
SFWMD	South Florida Water Management District
SO_2	Sulfur Dioxide
TIGER	Tie-Line Assistance and Generation Reliability Model
TMI	Three Mile Island
TREC	Tradeable Renewable Energy Credits
TVA	Tennessee Valley Authority
U308	Uranium
U-235	Uranium Atomic Mass of 235
U-238	Uranium Atomic Mass of 238
UF6	Uranium Hexafluoride
UIC	Underground Injection Control
UO_2	Uranium Oxide
U.S.	United States
WCEC	West County Energy Center

I. EXECUTIVE SUMMARY

Florida Power & Light Company (FPL or the Company) is requesting the Commission for approval in its determination of need for the construction of two additional nuclear-fueled generating units at FPL's existing Turkey Point electrical power plant site, together with the associated facilities, including transmission line and substation facilities, needed to integrate, interconnect and transmit energy from the Turkey Point site to FPL's transmission network for delivery to customers. The units and associated facilities are referred to as "Turkey Point 6 & 7" or the "Project".

As one of the most populous states in the nation, Florida continues to be one of the fastest growing. FPL is projecting an annual average increase of approximately 85,000 new customers for the next fourteen years. In addition, with the increase in the number of electricity-consuming devices, even as end-use efficiency has significantly improved, electric usage per FPL customer has increased by approximately 30 % over the past 20 years. Accordingly, FPL must continue to make significant investments in new infrastructure to keep pace with the increasing demand for adequate, reliable power associated with such growth. While FPL continues to advance reduced electricity usage through industry-leading conservation efforts and demand side management (DSM) programs, and actively cultivate the development of additional renewable generating capacity within the state, by themselves these efforts are insufficient to mitigate the need for additional generating capacity. FPL must also at times construct large, baseload capacity additions if the Company is to continue providing electricity to its customers. The proposed Project is intended to help meet FPL's growing need for additional baseload capacity, which is the essential foundation of any utility's supply portfolio, because these plants run year-round to provide the continuous supply of electricity that customers require. The Project also will enhance the reliability of FPL's system by reducing reliance on fossil fuels and diversifying the resource mix.

In its 2007 integrated resource planning (IRP) process, Florida Power & Light Company (FPL) determined that beginning in 2011 and growing through 2020 it needs to add a total of 8,350 MW of firm resources (supply and demand-side) to continue to meet its reserve margin planning criterion approved by the Florida Public Service Commission (Commission), which FPL believes is necessary to meet in order to provide reliable service. This need for additional resources is due in part to the expiration of more than 1,600 MW of power purchases, but is primarily due to the continuing increase in the number of electricity customers in FPL's service territory, which is projected to grow at about 85,000 new customers per year over the next fourteen years. In addition to meeting the growing resource need and maintaining a 20% reserve margin in a cost effective manner, FPL's 2007 IRP process directly addressed two other very important objectives: (1) how best to maintain a balanced fuel mix in FPL's generation portfolio to achieve fuel cost stability and maintain system reliability, and (2) how best to reduce system emissions of Greenhouse Gases (GHG), including carbon dioxide (CO_2).

Maintaining fuel diversity on FPL's system is important for several reasons. Lack of fuel diversity would result in vulnerability to potential supply disruptions in one type of fuel (such as could occur in the event of a major hurricane disrupting the flow of natural gas into Florida or interruption in the pipeline delivery systems), and exposure to price volatility in natural gas.

With the issue of fuel diversity in mind, the Florida Legislature recently enacted the 2006 Florida Energy Act that encouraged fuel diversity by directing the Commission to consider fuel diversity as a key criterion when reviewing Ten-Year Site Plans submitted annually by electric utilities. The 2006 Florida Energy Act further encourages fuel diversity by facilitating the process of developing nuclear generation alternatives, as well as providing for alternative cost-recovery mechanisms for new nuclear power projects. In addition, the Commission has specifically included fuel diversity and reduced dependence on fossil fuels among the goals to be considered in need determination proceedings for new power plants.

FPL will continue to promote DSM measures and renewable resources as potential contributors to satisfying electric demand and improving fuel diversity. However, there will not be sufficient additional cost-effective DSM or renewable resource capacity to meet FPL's resource needs through 2020 even after the addition of Turkey Point 6 & 7. Therefore, FPL must look to new coal and/or nuclear generation to maintain fuel diversity on FPL's system while meeting FPL's customers' needs.

Regarding coal generation, FPL's petition to the Commission for a determination of need to build an advanced technology coal plant in 2013 and 2014 was not granted. Furthermore, because of the need to reduce GHG emissions it is clear that currently available coal-fueled generation technology without carbon sequestration is not an acceptable alternative. Therefore, new nuclear generation must be included in FPL's resource plan and actively pursued in order to maintain system fuel diversity in the future. Because the process required to obtain all necessary permits, design and construct a new nuclear plant unit will take at least eleven years, it is essential that FPL and the

Commission initiate that process now in order to preserve for FPL's customers the option of placing in service two nuclear units in 2018 and 2020, respectively.

Adding new nuclear generating baseload units requires a determination of need by the Commission, as well as a site certification under the Florida Electrical Power Plant Siting Act (PPSA). FPL has elected to place the two new nuclear generating units, Turkey Point 6 & 7, at its existing Turkey Point Plant site in Miami-Dade county.

FPL has conducted comparative economic, fuel diversity, and GHG emission evaluations of three resource plans. The first resource plan includes Turkey Point 6 & 7 in 2018 and 2020, respectively. The first of the two alternate resource plans reflects the addition of gas-fueled combined cycle generation in 2018 and 2020 in place of Turkey Point 6 & 7. The second alternate plan reflects the addition of coal-fueled Integrated Gasification Combined Cycle (IGCC) generation in 2018 and 2020 in place of Turkey Point 6 & 7.

In order to address uncertainty with respect to future costs, the economic analysis initially utilized three fuel cost forecasts and four environmental compliance cost forecasts combined into 9 scenarios of future fuel costs and environmental compliance costs for each of the three resource plans. Then, after considering the different scenarios, FPL removed from further consideration three scenarios comprised of a low natural gas price forecast and medium-to-high compliance costs for CO_2 based on FPL's belief that medium-to-high CO_2 compliance costs will result in upward pressure in natural gas prices. Each of the remaining 9 scenarios was then utilized separately in both the economic and non-economic analyses of the three resource plans.

The results of the economic analyses show that the nuclear breakeven cost ranges are generally higher than FPL's current non-binding capital cost estimate range for new nuclear units; i.e., a range of \$3,108/kW to \$4,540/kW.

In regard to the fuel diversity analysis of these three resource plans, the alternate plan with gas-fueled generation in 2018 and 2020 does not contribute to fuel diversity in FPL's system. Without new nuclear generation additions or IGCC additions, by 2021 75% of FPL's annual energy would be supplied by natural gas with less than 7% being supplied by coal and 16% by nuclear. The plan with Turkey Point 6 & 7 would result in a significantly lower 65% of FPL's annual energy for 2021 being supplied by natural gas and about 27% being supplied by nuclear generation. Therefore, proceeding with developing Turkey Point 6 & 7 is a critical first step in enhancing the balanced, diverse fuel mix in FPL's system.

The addition of new baseload nuclear generation, as a component of FPL's future fuel mix, is even more important given the high likelihood of significant GHG regulation in the near future, including the potential for either federal or state targeted or mandated reductions in GHG emissions being imposed for the relevant planning horizon. The addition of Turkey Point 6 & 7 is a critical component of any plan to reduce system GHG emissions. At present there is no commercially available means of capturing and sequestering CO_2 emissions from an IGCC plant or from a gas-fueled plant in Florida, and the current estimates regarding the cost and adverse effects on plant performance of carbon capture and sequestration make such alternatives much more costly than adding new nuclear generation because generating electricity with nuclear fuel produces no CO_2 emissions.

Based on the results of FPL's evaluations, the addition of Turkey Point 6 & 7 is FPL's best alternative to reliably serve its customer's future demand for electricity, provide adequate electricity at a reasonable cost, contribute to fuel diversity, and reduce GHG emissions.

There is not sufficient additional, cost-effective demand side management (DSM) that is reasonably available or sufficient firm cost-effective renewable resources to mitigate the need for these new nuclear baseload units. For example, FPL already assumes, as part of its resource plan, that from August 2006 through August 2020, FPL will have added sufficient new DSM to offset the need for 2,279 MW of generation capacity. Regarding renewable resources, in April 2007 FPL issued a request for proposals for renewable generation, and by August 15 had received proposals to supply less than 150 MW of new renewable capacity. FPL's resource plan already assumes that all the proposed new renewable resource capacity, as well as all capacity provided under expiring contracts with existing renewable suppliers, will be under contract to FPL by 2012. More importantly, to the extent that additional cost-effective DSM and renewable resources are available in the future, such resources can readily be utilized to provide a share of the between 3,000 MW and 4,000 MW of firm resources that, in addition to the 2,200 MW to 3,040 MW to be provided by Turkey Point 6 & 7, will be needed between 2011 and 2020 to reliably meet FPL customers' demand for electricity.

There are significant areas of uncertainty related to the capital cost, licensing and permitting requirements and schedule of adding new nuclear generation. These areas of uncertainty could affect the viability and cost-competitiveness of new nuclear generation. However, the only way to address these uncertainties is to embark on the process of obtaining the necessary licenses and permits to build Turkey Point 6 & 7. FPL can undertake that effort only after the Commission grants an affirmative determination of need for the addition of these units.

Therefore, FPL seeks from the Commission an affirmative determination of need, consistent with the provisions of Commission Rule 25-6.0423, the Nuclear Power Plant Cost Recovery Rule, for the addition to FPL's generation portfolio of Turkey Point 6 & 7, two nuclear-fueled generating units, each nominally with a net summer capacity rating of up to approximately 1,520 MW, currently projected to be placed in service by June 1, 2018 and June 1, 2020, respectively, including the associated electric transmission facilities described herein and in other documents.

FPL believes that the earliest date that it can place the first new nuclear unit into service is in 2018, and the second unit in 2020, assuming that no unforeseen permitting, construction, or other delays occur. The remainder of this Need Study contains more detailed information, analyses, and discussion supporting FPL's requested determination of need for Turkey Point 6 & 7.

II. INTRODUCTION

A. PURPOSE AND OVERVIEW OF THIS DOCUMENT

This document supports FPL's petition to the Commission to determine the need for the proposed Turkey Point 6 and 7. The new units will be two Advanced Light Water Reactors using nuclear fuel located in Miami-Dade County at FPL's existing Turkey

Point site. Once completed, Turkey Point 6 & 7 will each supply between 1,100 to 1,520 MW, depending on the selected design, for a combined capacity of approximately 2,200 to 3,040 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, fuel diversity and supply reliability, and the need to determine whether the proposed plant is the most cost-effective alternative available." This document also contains information regarding how the proposed new nuclear units would address key planning issues facing the state's electric generation infrastructure today.

1. Fuel Diversity and Energy Independence

The State of Florida continues to enjoy a steadily growing economy and a high quality of life. Supporting and sustaining the economic and social fabric of Florida is a reliable, cost-effective electric generation infrastructure anticipating and meeting the needs of customers. The emergence of climate change as a major driver of developing energy policy in the U.S. and Florida has profoundly affected the view held regarding the viability of different generating alternatives. Proposed changes to economic policies at the state, regional and federal level regarding the cost of carbon are also expected to dramatically change the economic environment in which new generation can be expected to operate.

Florida requires a stable and reliable electric generation infrastructure that will meet the needs of our growing economy in a way that recognizes the need to maintain and enhance the unique environment of Florida. Pursuing new nuclear generation through the use of a time-tested, reliable generating technology near where the energy is consumed is the best choice for FPL and its customers. Developing additional generation at an existing generating site that is emission-free and has a proven track record of safely co-existing with and enhancing a thriving ecosystem is the best choice for Florida. As a result of the proposed project, FPL and Florida would gain increased fuel diversity without incurring additional GHG emissions as well as increased reliability and energy independence for its electric generation infrastructure.

2. FPL's Proposed Approach

Action is required now to create this option for future nuclear generation. Recently passed legislation in Florida has established a careful, methodical approach to new nuclear generation. This legislation and the Commission's Nuclear Cost Recovery Rule recognize the uncertainty in the renewed nuclear deployment process in the U.S. and the need to proceed with full knowledge of that uncertainty. Once a need determination is issued, the process allows FPL to take the initial steps necessary to define fully the costs, schedule, and benefits of the project with the active involvement of the Commission through the annual Nuclear Cost Recovery Rule. Those initial actions include the following key steps:

- Developing and submitting a Combined Construction and Operating License Application (COLA) to the Nuclear Regulatory Commission (NRC);

- Developing and submitting a Site Certification Application (SCA) to the Florida Department of Environmental Protection;
- Supporting the COLA and SCA through the review and determination process;
- Taking steps to secure the commercial operation date as early as possible through procurement of long-lead equipment;
- Developing detailed engineering and construction plans; and,
- Conducting approved site preparation activities.

The steps in the initial permitting and construction process will allow FPL to pursue the option for new nuclear as quickly as is warranted, while keeping the Commission fully informed on the development of the project at all stages. This approach, consistent with the intent of the Legislature, enables FPL to pursue a generation resource that is both proven and environmentally compatible with the vision of a clean Florida.

B. DESCRIPTION OF FPL AND ITS SYSTEM

FPL is the largest investor-owned electric utility in Florida and is among the largest in the U.S. During 2006, FPL served an average of 4.4 million customer accounts in 35 counties. FPL's service area contains approximately 27,650 square miles within which the population is approximately 8.6 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 oil, gas, coal, and nuclear generating units, firm capacity purchases from both utility and non-utility-owned generators, and DSM. Each type of resource is discussed in more detail later in this document.

During 2006, FPL's bulk transmission system consisted of 6,620 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system was achieved through FPL's 542 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 of this Need Study.

1. FPL-Owned Generating Resources

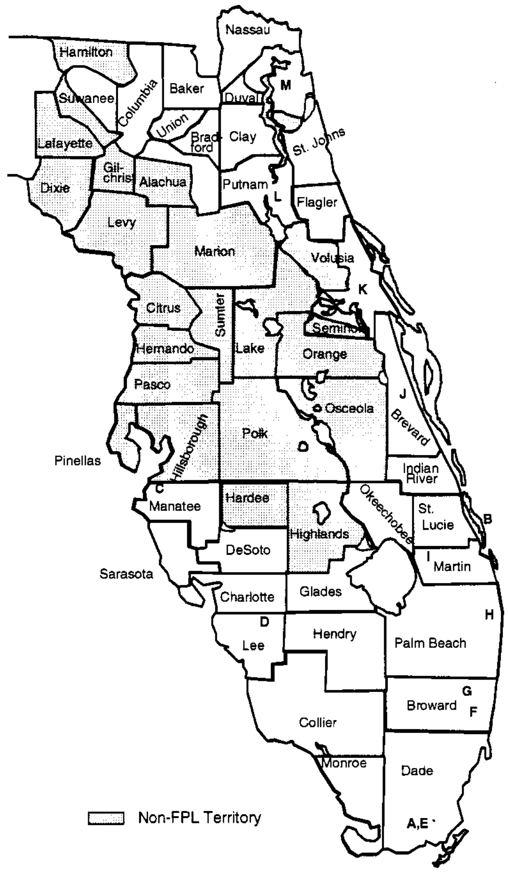
FPL's existing generating resources are located at 14 generating sites distributed geographically throughout its service territory, and also include partial ownership of one unit located in Georgia and two units located in Jacksonville, Florida. As of the Summer of 2007, FPL's generating facilities consist of four nuclear units, three coal units, 12 combined cycle units, 17 fossil fuel steam units, 48 combustion turbines, and 5 diesel units. The location of these generating units, their fuel type and the projected summer capability for 2007 is shown on Figure II.B.1.1. More detailed information regarding FPL's existing generating resources is presented in Appendix B of this Need Study.

FPL has filed separately with the Commission a petition for need determination for capacity uprates at FPL's four existing nuclear units. The proposed capacity uprates will add about 414 MW of capacity to FPL's system in the 2011-2012 time period. In the analyses conducted for this filing, FPL includes the effects of these capacity uprates.

Figure II.B.1 1

FPL Generating Resources by Location for Summer of 2007

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	5	3,328
B	St. Lucie *	2	1,553
C	Manatee	3	2,764
D	Fort Myers	2	1,767
E	Cutler	2	170
F	Lauderdale	2	856
G	Port Everglades	4	1,226
H	Riviera	2	560
I	Martin	5	3,705
J	Cape Canaveral	2	798
K	Sanford	3	2,066
L	Putnam	2	498
M	SJRPP **	2	254
	Scherer ***	1	658
	Gas Turbines	48	1,908
	Internal Combustion Turbines	5	12
	FPL Generation =	90	22,123



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

** SJRPP = St. John's River Power Park

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

2. Firm Capacity Purchases

FPL has contracts to purchase firm capacity and energy from five 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% of its energy.[1]

FPL also has contracts with two utilities, Southern Company (Southern) and Jacksonville Electric Authority (JEA), to purchase 931 MW and 381 MW, respectively. In addition, FPL has a number of short-term firm purchase contracts with other non-utility generators.

For purposes of the analyses conducted for this filing, FPL has included the capacity and energy contributions from six renewable energy purchases not currently under contract for the 2009 – on time period. Three of these assumed purchases are extensions of current purchases from municipal waste-to-energy facilities. The current contracts for these three purchases are scheduled to end in the time period from August 2009 to December 2010. The current total capacity under contract from these three purchases is 143 MW.

In addition, FPL has received three firm capacity proposals in response to its recent Renewable Request for Proposals (RFP). These three proposals, one from a waste-to-energy facility and two from biomass facilities, would provide a total of 144 MW of capacity starting between March 2011 and January 2012 with proposed end dates ranging from 2021 to 2036.

At the time of this filing, FPL is analyzing these three firm capacity proposals received in response to the Renewable RFP. Furthermore, no decision has been made by either FPL

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

or the municipal solid waste-to-energy facilities currently under contract to FPL as to whether new contractual arrangements will occur. Consequently, no decisions have yet been made in regard to any of these six renewable capacity options.

However, for purposes of the analyses conducted for this filing, FPL is assuming that all 287 MW of firm capacity will be in place. The 143 MW from the three municipal renewable waste-to-energy facilities currently under contract is assumed to continue through 2026 when other contracts for smaller capacity amounts from these facilities are scheduled to end. The 144 MW from the three renewable RFP bids are assumed to be in place through their proposed end dates.

A summary of all of FPL's firm capacity purchases, including these 287 MW of assumed new renewable purchases, is presented in Table II.B.2.1. This table presents the dates of the terms of these current contracts and the projected Summer MW purchase amounts through the year 2020.

Table II.B.2. 1

FPL's Firm Capacity Purchases: 2007 – 2020 (Summer MW)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. Broward South	4/1/1991	8/1/2009	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
2. Broward South	1/1/1993	12/31/2026	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
3. Broward South	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
4. Broward South	1/1/1997	12/31/2026	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
5. Broward North	4/1/1992	12/31/2010	45.0	45.0	45.0	45.0	45	45	45	45	45	45	45	45	45	45
6. Broward North	1/1/1993	12/31/2026	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
7. Broward North	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
8.Broward North	1/1/1997	12/31/2026	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
9. Cedar Bay Generating Co.	1/25/1994	12/31/2024	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
10. Indiantown Cogen., LP	12/22/1995	12/1/2025	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
11. Palm Beach SWA	4/1/1992	3/31/2010	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5
12. Florida Crushed Stone	4/1/1992	10/31/2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13. Florida Crushed Stone	1/1/1994	10/31/2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14. Florida Crushed Stone	1/1/1995	10/31/2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		QF Purchases Sub Total:	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. UPS from Southern Co.	7/20/1988	5/31/2010	931	931	931	0	0	0	0	0	0	0	0	0	0	0
2. UPS Replacement	6/1/2010	12/31/2015	0	0	0	930	930	930	930	930	930	0	0	0	0	0
3. SJRPP	4/2/1982	10/31/2015	381	381	381	381	381	381	381	381	381	0	0	0	0	0
		Utility Purchases Sub Total:	**1312**	**1312**	**1312**	**1311**	**1311**	**1311**	**1311**	**1311**	**1311**	**0**	**0**	**0**	**0**	**0**
Total of QF and Utility Purchases =			**2050**	**2050**	**2050**	**2049**	**2049**	**2049**	**2049**	**2049**	**2049**	**738**	**738**	**738**	**738**	**738**

III. Other Purchases:

	Contract Start Date	Contract End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. Oleander/Constellation 1	6/1/2002	5/31/2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2. Progress Energy Ventures/Desoto	6/1/2002	5/31/2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Reliant/Pasco/Shady Hills	2/28/2002	2/28/2007	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Reliant/Indian River	1/1/2006	12/31/2009	354	576	250	0	0	0	0	0	0	0	0	0	0	0
4a. Indian River (Additional)	5/1/2006	12/31/2009	222	0	0	0	0	0	0	0	0	0	0	0	0	0
5. Progress Energy Ventures/Desoto (Put option)	6/1/2005	5/31/2007	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Oleander/Southern Co (Put option)	6/1/2005	5/31/2007	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6a. Oleander (Extension)	6/1/2007	5/31/2012	156	156	156	156	156	0	0	0	0	0	0	0	0	0
7. Williams	3/1/2006	12/31/2009	106	106	106	0	0	0	0	0	0	0	0	0	0	0
8. Progress Energy Ventures	4/1/2006	3/31/2009	105	105	0	0	0	0	0	0	0	0	0	0	0	0
9. Other Renewables							50	144	144	144	144	144	144	144	144	144
		Other Purchases Sub Total	**943**	**943**	**512**	**156**	**206**	**144**	**144**	**144**	**144**	**144**	**144**	**144**	**144**	**144**
Total "Non-QF" Purchase Sub-Total =			**943**	**943**	**512**	**156**	**206**	**144**	**144**	**144**	**144**	**144**	**144**	**144**	**144**	**144**
		Summer Firm Capacity Purchases Total MW:	**2993**	**2993**	**2562**	**2205**	**2255**	**2193**	**2193**	**2193**	**2193**	**882**	**882**	**882**	**882**	**882**

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 year-end 2006 have resulted in a cumulative summer peak reduction of approximately 3,659 MW at the generator and an estimated cumulative energy saving of approximately 38,169 Gigawatt Hour (GWh) at the generator. Accounting for reserve margin requirements, FPL's DSM efforts have eliminated the need to construct the equivalent of more than 11 new 400 MW generating units.

Table II.B.3.1 presents FPL's projected DSM additions from August 2006 through August 2020. This projection includes FPL's approved DSM Goals for Summer MW reduction. These DSM Goals exceed the significant levels of DSM implementation FPL achieved before the year 2005. FPL's current DSM Plan was approved by the Commission in 2004 and was designed to achieve the DSM Goals for the 2005–2014 time periods.

For purposes of the analyses conducted to support this filing, FPL is also projecting a total of 1,899 MW of additional DSM from August 2006 through August 2020, which is presented in Table II.B.3.1.

Table II.B.3.1

Projected Incremental FPL DSM: 2006 – 2020

(Summer MW)

Year	DSM Projected by FPL (Summer MW at Generator) (1)
2006	1,491
2007	1,768
2008	1,908
2009	2,034
2010	2,146
2011	2,264
2012	2,388
2013	2,516
2014	2,651
2015	2,790
2016	2,910
2017	3,030
2018	3,150
2019	3,270
2020	3,390
Incremental DSM MW from 8/2006 through 8/2020 =	1,899

4. Renewable Energy

FPL has been, and continues to be, committed to utilizing renewable energy sources from both a supply side and demand side perspective.

In regard to supply side utilization of renewable energy, FPL has firm capacity contracts with several waste-to-energy facilities as shown in Table II.B.2.1 and has as-available energy contracts with several other facilities that provide energy to FPL on a non-firm basis. FPL is also currently seeking to site a wind energy project in Florida and is supporting Florida Atlantic University's Department of Ocean Engineering in its efforts to evaluate the feasibility of utilizing ocean energy conversion off of Florida's coasts.

On April 23, 2007 FPL issued a RFP for renewable energy-based capacity and energy. Five (5) proposals were received in response to this RFP. Three proposals offered firm capacity, one proposal offered energy only, and the remaining proposal was conceptual in nature. The three firm capacity proposals consist of two biomass and one waste-to-energy proposal. The energy-only proposal was based on ocean current and the conceptual proposal was based on photovoltaic's (PV). The total capacity offered by the three firm capacity proposals is 144 MW. At the time of this filing, FPL is evaluating all five of these proposals.

In regard to utilizing renewable energy for demand side purposes, FPL has offered a variety of DSM programs that have utilized renewable energy and is actively engaged in research projects to identify additional feasible, cost-effective ways in which renewable energy may be used in a DSM offering. A description of FPL's renewable energy DSM activities is presented in Section VIII of this document.

5. Fuel Mix

In 2006, FPL's fuel mix consisted of natural gas (50%), nuclear generation (21%), coal (18%), and fuel oil (9%). If only natural gas-fueled generation were to be added to FPL's system, the contribution of natural gas would increase to approximately 75% by 2021 of total electricity delivered to FPL's customers by 2018, while that of nuclear would decrease to approximately (16%) in 2021 even with the proposed capacity uprates to FPL's four existing nuclear units.

However, if the two new nuclear units are added by 2018 and 2021, the contribution of nuclear would increase to approximately 27% by 2021, while the contribution of natural gas would be approximately 65% by 2021. The addition of these new nuclear units would therefore significantly improve FPL's system fuel diversity.

The primary benefits of greater fuel diversity are improved system reliability and reduced fuel price volatility. An electric system that relies on a single fuel and a single technology to generate all the electricity needed to meet its customers' demand, all else equal, is less reliable than a system that uses a more balanced, fuel-diverse generation portfolio. In addition, greater fuel diversity mitigates the impact of wide or sudden swings in the price of one fuel, a phenomenon that has characterized the natural gas market over the last several years. In section III of this report, the various benefits associated with balancing the fuel mix are addressed in detail.

C. FPL'S PROPOSED APPROACH

1. Choices for Maintaining Fuel Diversity

FPL has previously evaluated four coal-based technologies to determine whether they could reliably contribute to the fuel diversity and capacity needs of FPL's system in the 2012 – 2015 time period. The technologies were: sub-critical pulverized coal (PC), circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), and ultra-supercritical pulverized coal (advanced technology coal). The results of FPL's analyses of these four coal-based technologies established that the advanced technology coal option was the best solid fuel alternative for the 2012 – 2015 time period. However, because a determination of need was not granted for this advanced technology coal option, FPL has continued to consider only the IGCC alternative, along with new nuclear generation, as a potential baseload contributor to fuel diversity for the period beginning in 2018.

2. FPL's Approach: New Nuclear Generation

FPL concluded that new nuclear generation is more cost-effective than IGCC, has reliability that will be as good as, or better than, IGCC, and, unlike IGCC, can be counted on with reasonable certainty to contribute to reducing GHG emissions in the future. Based on these factors, FPL has concluded that the addition of new nuclear generation at its Turkey Point site is the best choice to contribute to fuel diversity and meet FPL's generation capacity need in the 2018 – 2020 time period.

III. FPL'S NEED FOR THE PROPOSED POWER PLANT

FPL determined in its 2006/2007 IRP work that it needs significant additional resources starting in 2012 to meet its reserve margin criterion. The reliability assessment portion of the IRP process 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 added to meet FPL's reliability criteria. Based on this analysis, FPL determined it would need a minimum of either 6,156 MW of new supply (power plant construction or power purchase), or approximately 5,130 MW of new DSM, to meet its 2012-2020 reserve margin requirements. These projections already account for all of the additional 1,899 MW of DSM projected to be added from August 2006 through August 2020, the 414 MW from the proposed capacity uprates of FPL's four existing nuclear units, and the assumed 287 MW of renewable energy purchases discussed previously.

A. Reliability Assessment

In the reliability assessment portion of its 2006/2007 IRP analysis, FPL started with updated power plant capability and reliability data, plus a load forecast prepared after the summer of 2006. This load forecast is presented in Appendix D. In addition, the reliability assessment took into account committed construction capacity additions including the proposed capacity uprates to FPL's existing nuclear units, firm capacity purchases, and DSM.

1. Committed Construction Capacity Additions

FPL included its previously committed generation construction projects in its 2006/2007 reliability assessment. These committed construction projects are the new 1,219 MW CC unit at the West County Energy Center (WCEC) that is scheduled to be placed into service in mid-2009 (WCEC Unit 1), the new 1,219 MW CC unit (WCEC Unit 2) that is scheduled to be placed into service in mid-2010, and the proposed 414 MW from the proposed capacity uprates of FPL's four existing nuclear units.

2. Firm Capacity Purchases

FPL took into account all of its current short-term and long-term firm capacity purchases from a combination of utility and non-utility generators in its 2006/2007 reliability assessment. In addition, 287 MW of renewable energy purchases are also assumed to be added for purposes of this analysis. These firm capacity purchases are discussed in Section II.B.2 and are presented in Table II.B.2.1.

3. Demand Side Management (DSM)

Since 1994, FPL's IRP process has used the amount of DSM capacity in FPL's approved DSM Goals as a basis for the system reliability analysis. The system reliability analysis conducted for this filing assumed continuation of FPL's DSM signups in 2015 through 2020 at current DSM trends. All of this DSM is presented in Table II.B.3.1, which shows the addition of 1,899 MW at the generator of cost-effective DSM during this period. The cumulative impact from all of FPL's conservation program efforts prior to 2006 is captured in the load forecast prepared after the summer of 2006 that is 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 reserve margin of 20%, and (2) a maximum of 0.1 days per year Loss-of-Load-Probability (LOLP). The reserve margin criterion of 20% applies for reserve margin analyses addressing both summer and winter peak hours. The Commission approved this reserve margin criterion in Order No. PSC-99-2507-S-EU.

The LOLP criterion of 0.1 days per year is an electric 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 hours. 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 provided in Appendix C.

In a reliability assessment, either the reserve margin criterion or the LOLP criterion will "drive" the need for additional resources. This means that, for a given future year, FPL's system will not have a reserve margin high enough to meet its 20% criterion or it will have a projected LOLP value greater than 0.1 days per year. Whichever criterion is not met 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 2006/2007 IRP work. The projection of capacity needs summarized above, and discussed in more detail in the next section, is based on summer reserve margin analysis.

C. FPL's 2006/2007 Reliability Assessment Results

FPL's reliability analyses showed that with no additional resources beyond its existing generating units, existing purchases, and the committed construction capacity additions (including the proposed capacity uprates to FPL's four existing nuclear units) mentioned above, FPL would not meet its summer reserve margin criterion of 20% starting in the summer of 2013 and for each summer thereafter. (A relatively small 180 MW capacity need exists in 2012 that results in FPL's projected reserve margin for 2012 being 19.7%. FPL may choose to address this relatively small 2012 need with a short-term purchase(s), enhancements to its existing generating units, and/or additional cost-effective DSM.) Assuming that the small 2012 need is met with a one-year capacity purchase, 6,156 MW of additional supply resources would be needed during the 2012 - 2020 time frame for FPL to continue to meet its summer reserve margin criterion of 20% for those years. This need is demonstrated in Table IV.C.1. This table also shows that meeting the summer capacity needs will also easily meet the much smaller winter need that begins to appear several years after 2012.

If the 2012-2020 resource needs were to be met solely by additional new DSM resources, FPL would need to find an additional 5,130 MW of cost-effective DSM. Accounting for FPL's 20% reserve margin criterion, the 6,156 MW of generating capacity need would become 5,130 MW of DSM (6,156 MW/1.20 = 5,130 MW). There is not 5,130 MW of additional, cost-effective DSM available to meet this need. This will be further discussed in Section VII.D.

Table III.C.1

Projection of FPL's 2007 - 2020 Capacity Needs
(without New Capacity Additions)

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 Reserve Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2007	22,123	2,993	25,116	22,259	1,768	20,491	4,625	22.6%	(527)
2008	22,150	2,993	25,143	22,770	1,908	20,862	4,281	20.5%	(109)
2009	23,370	2,562	25,932	23,435	2,034	21,401	4,531	21.2%	(251)
2010	24,589	2,205	26,794	24,003	2,146	21,857	4,937	22.6%	(566)
2011	24,589	2,255	26,844	24,612	2,264	22,348	4,496	20.1%	(26)
2012	24,899	2,193	27,092	25,115	2,388	22,727	4,365	19.2%	**180**
2013	25,003	2,193	27,196	25,590	2,516	23,074	4,122	17.9%	**493**
2014	25,003	2,193	27,196	26,100	2,651	23,449	3,747	16.0%	**943**
2015	25,003	2,193	27,196	26,772	2,790	23,982	3,214	13.4%	**1,582**
2016	25,003	882	25,885	27,410	2,910	24,500	1,385	5.7%	**3,515**
2017	25,003	882	25,885	28,079	3,030	25,049	836	3.3%	**4,174**
2018	25,003	882	25,885	28,737	3,150	25,587	298	1.2%	**4,819**
2019	25,003	882	25,885	29,391	3,270	26,121	(236)	-0.9%	**5,460**
2020	25,003	882	25,885	30,091	3,390	26,701	(816)	-3.1%	**6,156**

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 Reserve Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2007	22,294	3,862	26,156	22,247	1,555	20,692	5,464	26.4%	(1,326)
2008	23,503	3,026	26,529	22,627	1,649	20,978	5,551	26.5%	(1,355)
2009	23,531	2,700	26,231	23,115	1,750	21,365	4,866	22.8%	(593)
2010	24,866	2,239	27,105	23,587	1,814	21,773	5,332	24.5%	(977)
2011	26,201	2,238	28,439	24,047	1,883	22,164	6,275	28.3%	(1,842)
2012	26,305	2,382	28,687	24,498	1,954	22,544	6,143	27.2%	(1,634)
2013	26,615	2,202	28,817	24,952	2,028	22,924	5,893	25.7%	(1,308)
2014	26,615	2,202	28,817	25,416	2,106	23,310	5,507	23.6%	(845)
2015	26,615	2,202	28,817	26,048	2,188	23,860	4,957	20.8%	(185)
2016	26,615	882	27,497	26,692	2,264	24,428	3,069	12.6%	**1,817**
2017	26,615	882	27,497	27,342	2,334	25,008	2,489	10.0%	**2,513**
2018	26,615	882	27,497	27,994	2,404	25,590	1,907	7.5%	**3,211**
2019	26,615	882	27,497	28,649	2,474	26,175	1,322	5.1%	**3,913**
2020	26,615	882	27,497	29,308	2,544	26,764	733	2.7%	**4,620**

* No new FPL generating unit additions after WCEC 1 in 2009 and WCEC 2 in 2010 are assumed to be added. 287 MW of renewable energy firm capacity purchases starting in the 2009 - 2012 time frame are assumed to be added. 414 MW of the proposed nuclear uprates is assumed. Approximately 104 MW are added in December 2011, 103 MW in May 2012, 103 MW in June 2012, and 104 MW by December 2012.

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

D. Consistency with Peninsular Florida Need

FPL's need for an additional 6,156 MW of supply resources (or 5,130 MW of demand side resources) is generally consistent with the Peninsular Florida need identified by the Florida Reliability Coordinating Council (FRCC) in its 2007 reliability work reported in its FRCC 2007 Regional Load and Resource Plan. The FRCC's 2007 reliability work uses FPL-specific data that was contained in FPL's 2007 Ten-Year Site Plan in conjunction with similar information from other Peninsular Florida electric utilities. FPL's 2007 Ten-Year Site Plan is consistent with the results of the reliability assessment discussed above with three exceptions. One difference between the capacity need projected in this filing and the FPL-specific data included in the Peninsular Florida need forecast is the recent inclusion of 414 MW from the proposed capacity uprates to FPL's four existing nuclear units. A second difference is the assumption of 287 MW of additional renewable energy purchases. The third difference is the assumption of a continuation of DSM signups at current trends for 2015 through 2020. The 2007 Ten-Year Site Plan and the FRCC's reliability work did not address years beyond 2016 due to their ten year focus.

E. System Fuel Diversity

1. Current

In 2006, the last full year for which data was available at the time this document was prepared, FPL's fuel mix consisted of natural gas (50%), nuclear generation (21%), coal (18%), fuel oil (9%), and other sources (about 2%).

2. Future

If only natural gas-fueled generation were to be added to FPL's system in the future, the contribution of natural gas would increase to more than 75% of total electricity delivered to FPL's customers in 2021, while that of coal would decrease to less than 7%, and that of nuclear to about 16%.

With the proposed addition of the two new baseload nuclear units at Turkey Point, the share of electricity produced by natural gas would be approximately 65% in 2021, while that of nuclear generation would be approximately 27%. These fuel mix projections, both with and without the addition of Turkey Point 6 & 7, are presented later in Section VII in Table VII.D.2.1. This table shows that the addition of Turkey Point 6 & 7 is needed to make a significant initial contribution to enhance fuel diversity in FPL's system and reduce FPL's growing dependence on natural gas.

3. Reasons to Balance the Fuel Mix

The primary benefits of fuel diversity are greater system reliability and reduced fuel price volatility. An electric system that relies on a single fuel and a single technology to generate all the electricity needed to meet its customers' demand, all else equal, is less reliable than a system that uses a more balanced, fuel-diverse generation portfolio. In addition, greater fuel diversity mitigates the impact of large and/or sudden swings in the price of one fuel, a phenomenon that has characterized the natural gas market over the last several years.

In regard to improved system reliability, there are at least three ways in which a more fuel diverse system is more reliable than a less fuel diverse system, all other aspects being equal.

a) Fuel Diversity Enhances System Reliability

An electric system that relies exclusively on one fuel is more susceptible to events that cause delays or interruptions in the production of that fuel. For example, in 2005 a significant number of natural gas production facilities in the Gulf of Mexico were shut down as a result of hurricanes. The shutdown of these facilities, which occurred with very little advance warning, significantly reduced the quantities of natural gas available to FPL to meet electricity demand. Had FPL's system relied exclusively on natural gas to produce electricity it would have been difficult, if not impossible, to continue to meet its customers' demand for electricity until some gas production capability was restored. It is unlikely that FPL would have been able to obtain sufficient natural gas from other regions to make up for the reduced gas supply from the Gulf of Mexico, particularly at a time when other natural gas users would also be seeking natural gas supplies to replace what could not be produced in the Gulf of Mexico. However, because FPL's system is fuel-diverse, there was sufficient energy produced by generating units that use other fuels such as nuclear fuel, coal, and oil to enable FPL to offset the reduction in natural gas supply and meet customers' needs. An inventory of these other fuels is maintained on-site at FPL's generation locations to further enhance system reliability.

b) Diversity in Fuel Transportation and Delivery Methods and Routes Also Improves System Reliability.

The ability of a generating system that relies on only one fuel transportation and delivery method and route to serve its customers can be severely impaired by delays or interruptions in the transportation and delivery of that single fuel to the generating plants. Diversity in transportation methods and routes enables a utility to mitigate the effects of such interruptions and delays by fully utilizing other transportation channels that remain unaffected until transportation problems are resolved.

Because different fuels usually originate from different geographical areas and are transported and delivered via different methods and routes, having a fuel diverse generation system helps mitigate the effect of problems related to transportation and delivery as well as production.

c) Diversity, Not Just in Fuel Type, but in Generation Technology, also Improves Reliability

Occasionally, equipment design or manufacturing problems manifest themselves in the form of systematic failure of the same part in a number of generating plants that utilize the same part design, or those plants that use parts produced in the same production batch. Having diversity in generation technology also is important because any generic equipment problem will affect a smaller portion of a utility's generation portfolio, and will make it easier for the utility to mitigate the effect of that problem without adversely affecting service to its customers. Because generating units that use different fuels usually also use different technologies, a fuel diverse system also helps mitigate the effect of equipment problems that affect one specific type of generation technology, such as gas turbines.

4. Alternatives to Balance the Fuel Mix in 2018 and beyond

FPL has previously evaluated four coal-based technologies to determine whether they could reliably contribute to the fuel diversity and capacity needs of FPL's system in the 2012 – 2015 time period to select the best among those technologies that could provide those benefits by 2015. The technologies were: PC, CFB, IGCC, and advanced technology coal. The results of FPL's analyses of these four coal-based technologies clearly established that the advanced technology coal option was the best alternative for the 2012 – 2015 period. However, because a determination of need was not granted for this advanced technology coal option, FPL has continued to consider only the IGCC alternative, along with new nuclear generation, as a potential contributor to fuel diversity for the period beginning in 2018.

5. The Alternative Selected by FPL

FPL concluded that new nuclear generation is more cost-effective than IGCC, has reliability that as good as, or better than, IGCC, and, unlike IGCC, can be relied on to reduce GHG emissions in the future. Based on these factors, FPL has concluded that the addition of new nuclear generation at its Turkey Point site is by far the best choice to contribute to fuel diversity and meet FPL's generation capacity need in the 2018 – 2020 time period.

6. Benefits of the Selected Alternative

All of the benefits described above associated with having fuel diversity in the system are applicable to the addition of Turkey Point 6 & 7. Adding up to 3,040 MW of new baseload nuclear generation to FPL's system will reduce dependence on natural gas and will enable FPL to more effectively offset decreases in natural gas supply because factors that affect gas production will not affect coal production. The nuclear fuel that would be used in Turkey Point 6 & 7 can be produced in the U.S., Canada, Australia and other areas of the world, all different from the area near the Gulf of Mexico where most of FPL's natural gas is produced, and nuclear fuel will be transported via means that are different from the pipelines used to deliver natural gas so any event that affects gas production or transportation would not affect nuclear fuel supply or transportation. The technology to be used in Turkey Point 6 & 7 will be different from that used in most of FPL's gas-fueled units, so technical problems that affect the gas units are less likely to affect Turkey Point 6 & 7.

There are additional benefits in regard to the nuclear refueling process. Nuclear generating facilities typically have sufficient fuel in the core to operate at full power for approximately eighteen months without the need for additional fuel. A natural gas-fueled facility, on the other hand, requires that natural gas be delivered via an interstate pipeline to the generating plant continuously in order to continue to operate. In addition, replacement nuclear fuel is typically delivered to the nuclear plant at least two months prior to the time the fuel is needed to conduct the refueling of each unit. Therefore, Turkey Point 6 & 7 will have, in effect, at least two months of full power "inventory" of fuel at all times. In addition, because the reserves of uranium (U3O8) in the U.S., Canada, Australia, and elsewhere, are so large, fuel supply that meets the specifications required by Turkey Point 6 & 7 from secure sources is assured for the entire operating life of the plant.

7. Hedge Provided by Fuel Diversity

Fuel diversity helps mitigate the effects of price volatility in one or two fuels. For example, if a utility relies solely on natural gas to produce all the electricity needed by its customers, any increase or decrease in the market price of natural gas would translate into a direct and comparable increase or decrease in the cost of electricity. Because natural gas prices are projected to be volatile in the future, the customers would be subject to significant volatility in the future cost of electricity. Recent history has demonstrated how volatile natural gas prices can be. Because the price of nuclear fuel has been and is projected to remain relatively stable, and because changes in nuclear fuel prices are not directly linked to changes in the prices of natural gas and fuel oil, having a fuel diverse portfolio that includes significant contributions from nuclear fuel helps dampen the effect of volatility in natural gas prices. For this reason the addition of Turkey Point 6 & 7 will help dampen the volatility in system fuel costs and make the cost of electricity more stable and predictable.

F. Renewable Energy

According to the U.S. Department of Energy (DOE) data released in July 2007, Florida performs well in producing energy from its renewable resources. Florida ranks second in the nation in renewable energy production when one excludes hydroelectric and geothermal resources that the highest ranking states have, which are not abundant in Florida. FPL has been providing a portion of its customers' energy needs from renewable resources since 1980. Currently, FPL provides more than 300 MW of firm and non-firm capacity and energy from renewable resources yearly. This energy is purchased from owners of waste-to-energy, biomass and landfill gas power plants located in Florida.

During 2003, the FPSC and the FDEP issued "An Assessment of Renewable Electric Generating Technologies for Florida" (the FPSC/FDEP Renewable Assessment). The FPSC/FDEP Renewable Assessment concluded that as of 2003 Florida as a whole had approximately 680 MW of potential renewable capacity, exclusive of waste heat from sulfuric acid manufacturing operations, which the Renewable Assessment estimated as providing an additional 340 MW of potential capacity from renewable resources.

Without understating the importance of renewable energy for Florida, nor FPL's interest in utilizing and promoting the use of such resources, FPL's view is that the FPSC/FDEP Renewable Assessment's conclusions remain correct in terms of the comparatively small potential contribution of renewable energy to overall electricity production in Florida. The resources recognized as reasonably available in the FPSC/FDEP's Renewable Assessment on a commercial basis were modest.

FPL is working to extract as much energy as technically and economically possible from renewable resources and continues to explore the use of emerging technologies. For example, in July 2007, FPL concluded a renewable energy request for proposals (2007

Renewable RFP). The 2007 Renewable RFP sought proposals for new renewable energy with expected in-service dates prior to June 2015. The 2007 Renewable RFP also sought information regarding new renewable firm capacity and/or energy sources with expected in-service dates beyond 2015.

The 2007 Renewable RFP contained no restriction on price and provided maximum flexibility for potential suppliers of renewable energy in order to encourage as much participation as possible. The 2007 Renewable RFP was available to potential bidders in Florida, across the country and beyond for their consideration and response.

As a result of the 2007 Renewable RFP, FPL received proposals from five bidders totaling 144 MW of firm capacity. FPL has incorporated these potential resources into its Integrated Resource Planning (IRP) analyses. In addition, FPL received a proposal for the supply of 100 MW of non-firm capacity and energy from technology under development based on harnessing ocean current energy.

FPL will continue to promote renewable generation in Florida through RFPs and other purchase power agreements, and is exploring direct development of renewable generation projects, including solar and wind. FPL is presently in the process of considering and supporting development of wind, solar and other renewable energy sources in the State of Florida. FPL is committed to developing the maximum cost-effective amount of renewable resources to serve its customers.

FPL has been assessing the commercial wind energy potential of the state of Florida for several years. In this regard, FPL commissioned three wind studies of the state of Florida. These studies are much more detailed than information commonly available through government and general industry sources. The first study addressed the state of Florida as a whole. Two more recent studies focused on the Southwest and Northeast Florida geographical regions. The studies all had similar overall findings:

- Florida's wind resource is minimally adequate to produce some power along portions of its coast;
- The wind resources decline significantly inland; and
- Florida's wind resource is seasonal, and is more productive during winter (October through March).

From these studies, and FPL's other work assessing possible wind energy development in Florida, FPL concludes that (i) the wind energy that may be subject to development is on or near Florida's beaches (including possible offshore wind); and (ii) while wind power might offset some winter energy use, it is not meaningfully available during FPL's Summer load peak and, therefore, cannot contribute to meeting FPL's reserve margin on a reliable basis.

Since 2004, FPL has attempted to site a wind project along Florida's coast, utilizing several potential locations, but has not yet obtained site approval for a project. Concerns raised with respect to the possible siting of the project have included potential radio signal interference, avian concerns, aircraft flight paths, land availability, and other local land use matters. In June 2007, FPL announced the St. Lucie Wind Project, a 3 to 4.5 MW project, which FPL hopes to site near its St. Lucie nuclear generating plant. FPL is pursuing the necessary permits and performing due diligence required for this project. In addition, FPL will be pursuing additional wind opportunities that would add to its renewable portfolio, which FPL will build, own and operate to provide renewable energy for customers. In contrast with a baseload generating resource, wind energy provides intermittent electric energy and is not a dependable source of electrical capacity, meaning that wind generation cannot be counted on to provide electricity upon demand when customers require it.

FPL is also supporting deployment of solar energy technologies. FPL has a solar PV project at its Martin plant site that was first energized in the 1990s. Under FPL's Sunshine Energy Program, a 250 kW PV array is being built in Sarasota, Florida that is expected to be in commercial operation around the end of 2007. Additionally, FPL recently announced a major solar energy initiative in Florida, which is expected to result in installation of up to 300 MW of solar capacity at a cost of up to an estimated $900 million. This is expected to begin with installation of about 10 MW of capacity at an existing FPL generating site. While this major new initiative is subject to regulatory, land use and other approvals as well as business due diligence, FPL is optimistic about the potential of using a new solar generating technology to provide service to customers in Florida.

FPL is commissioning a study to better evaluate the potential solar resource in FPL's service territory. Development of utility scale solar projects in Florida requires extensive land resources, estimated to be in the range of 10 acres/MW. Distributed installations of rooftop solar PV generation is feasible but due to low capacity factor, high cost and intermittent availability is not a substitute for high capacity factor, high reliability baseload generation. Because solar power is an intermittent resource with a low capacity factor, many more MW of solar would need to be installed to equate with the energy production of reliable baseload electric generating resources.

FPL is assisting Florida universities and others with the investigation of possible electric generation using ocean currents. Florida is one of the few places in the world that has a major ocean current located near electric load centers. FPL is actively involved with Florida Atlantic University's Florida Center of Excellence in Ocean Energy Technology in developing this non-emitting renewable technology. FPL is hopeful that it may be commercially deployed to serve its customers first in experimental and ultimately in commercial amounts in the future.

In summary, FPL believes there is a role for renewable energy in FPL's resource plan. However, that role is limited in several respects. First, as projected in the FPSC/FDEP Renewable Assessment, Florida as a whole was projected to have approximately 680 MW of potential renewable capacity (exclusive of waste heat from sulfuric acid manufacturing operations). FPL serves approximately one half of the electricity customers in the state. Therefore, assuming that one half of this renewable potential was available as firm capacity to serve FPL's customers would result in 340 MW of renewable firm capacity. A 340 MW firm capacity amount equates to less than 6% of the 6,156 MW of firm capacity need projected for FPL by 2020 as presented in Table III.C.1.

Consequently, renewable resources cannot be expected to fully meet FPL's capacity needs by 2020.

Second, as discussed above, a significant amount of the renewable potential – particularly solar and wind resources – is intermittent in nature. Resources with intermittent availability cannot be reliably counted on to meet FPL's firm capacity needs during peak load hours. Therefore, an amount less than 340 MW – and perhaps significantly less than 340 MW – will actually be available to help meet FPL's firm capacity needs. Third, many renewable energy options are relatively expensive to construct or install on a dollars per installed kilowatt basis. This fact, when combined with their lower capacity factors, can result in the cost of energy on a dollars per megawatt-hour basis produced by renewable energy options being quite expensive.

For these reasons renewable energy cannot be reasonably be expected to avoid the Turkey Point 6 & 7 units. These new nuclear units can be expected to provide firm capacity reliably, to operate at very high capacity factors, and, as will be discussed later in this document, are currently projected to be economically competitive with other commercially available baseload generating technologies.

IV. NEW NUCLEAR GENERATING UNITS

A. Resumption of Nuclear Deployment in the U.S.

Nuclear power generation is an important and reliable contributor to the national energy mix, providing approximately 19.4% of the electricity in the U.S. from 104 licensed reactor facilities. This significant contribution stands in contrast to the fact that no new reactor plants have been ordered in the U.S. since the Three Mile Island (TMI) accident in 1979. The resulting hiatus in new nuclear plant design and construction was the result of the confluence of many technical, economic, and regulatory issues. Internationally, nuclear generation technology continued to grow, mature and safely serve many customers using the designs that were developed in the U.S. The following provides a brief review of how the nuclear generation industry has learned from the U.S. experience, continued to mature in the U.S. and internationally, and is now poised to resume deployment with full knowledge of the lessons learned from its own history.

1. Early Days

The commercial nuclear power generation industry began in the 1960s following the success of first generation small scale plants operated at Shippingport, Pennsylvania and Dresden, Illinois. The second generation of plants that followed was based on similar designs, but as the relatively new technology evolved during the decade, so did the designs applied to each subsequent project. Additionally, the Atomic Energy Commission (AEC) (then the agency charged with oversight of all nuclear reactors in the U.S.) was continually modifying and adapting its regulatory requirements to reflect new information regarding siting and design safety analysis. The non-standardization of design and evolving regulatory requirements began to create delays and cost overruns in the large number of projects that were under construction in the late 1960s and early

1970s. In 1974, the AEC was dissolved and replaced by the Nuclear Regulatory Commission (NRC).

As the seventies continued, reactor construction projects continued to face the problems created by non-standardization of design. Costs grew and delays were frequent. In efforts to maintain the project economics, designs were often modified during construction to incorporate increased capacity or higher efficiency components. This exacerbated the standardization issue. Probabilistic Risk Analysis, now the standard for predicting the likelihood of a severe nuclear accident, was just developing and being applied – an effort led by the NRC. This resulted in further delays.

2. Turning Point

This early period of U.S. nuclear generation history ended with the loss of coolant accident at TMI. The accident, in which no lives were lost and relatively little radiation was released offsite, triggered a Presidential Commission review (the Kemeny Commission) that called for sweeping changes in the operation and regulation of nuclear reactors. The Kemeny Commission's recommendations shaped the U.S. nuclear industry's focus on safety, training, emergency preparedness, and technical assessment for which it is known and internationally respected today.

At the time of TMI, there were over one hundred nuclear units in some form of planning or construction. Fifty of those units were completed over the next decade. Revisions to designs and construction practices required by regulation or spurred by an effort to increase the economics of the facilities continued the trend of non-standardization in these plants.

The strong commitment of the nuclear power industry to operational safety, along with the increased focus on risk assessment, have been the foundation for the successful track record of the industry in the past two decades. The industry safety record is strong, and nuclear power today is one of the most dependable forms of energy generation (the capacity factor for all U.S. nuclear plants was 90.1% for 2006). Economically, the investment continues to pay off for the customers served by nuclear power, providing low cost, stably priced energy with no GHG emissions. Increasing the capacity of existing reactor units continues to be one of the best choices for new capacity. Since 1977, the NRC has approved up to 4,900 MW of capacity uprates at existing facilities.

3. Lessons Learned

The lessons of the absence of standardization and regulatory stability that resulted in delays and cost overruns in the second generation of nuclear units were taken seriously as the NRC and the industry began to contemplate how new nuclear licensing and construction could be made feasible in the U.S.

A key feature of the renewed deployment of nuclear generation in the U.S. is the focus and unanimous support from potential owners, designers, and regulators for design standardization. Such standardization not only reduces the cost of units using the same design, it streamlines the regulatory reviews and allows for significant operational synergies in the future. This approach has been demonstrated as a highly successful model in France, where designs are held standard for multiple units before changes are allowed for the next fleet of units to be built.

Until 1992, the federal licensing process was a two-step process wherein a prospective owner would apply for and receives a construction license that would authorize the construction of a plant. Once built, the owner would apply for an operating permit. This two step process proved unwieldy and prone to delays. The potential of not being able to operate a facility following the investment in construction deterred potential investment. The NRC began to review and design a streamlined process to provide the regulatory framework that would allow new nuclear generation to move forward in the U.S.

B. Modifications to the Regulatory Processes

Regulatory processes at the federal and state level have been modified to accommodate the concerns of the past and address the issues that would, otherwise, present insurmountable barriers to the development of new nuclear generation in the U.S. These modifications, along with the specific supporting legislation passed in 2005 and 2006, enhance the licensing process for new nuclear generation.

1. NRC's Combined Construction and Licensing Process

The two-step nuclear licensing process, under which the second generation of nuclear units was licensed, had two distinct license review periods separated by the construction period. The initial Construction Permit application process required approximately four years from planning to receipt of license, following NRC review and legal proceedings. The construction period for post-TMI units averaged approximately eight years. Then the owner applied for an Operating License at the NRC. This process essentially re-opened issues deliberated during the Construction Permit hearing.

The Combined Construction and Operating License (COL) process developed by the NRC in the past several years has reorganized the review process to require the careful review of all issues in a single process that occurs prior to the commencement of construction. This allows for all issues to be thoroughly heard prior to the commencement of nuclear system construction. Importantly, the new process also requires that a defined set of Inspections, Tests, Analysis and Acceptance Criteria (ITAAC) be developed and agreed upon prior to construction. In this way, the documentation of these important quality measures are developed and reviewed through the construction phase. When construction is complete, the ITAAC are presented and reviewed to ensure the facility was constructed and tested according to plan. At this stage, the owner is granted permission to load the facility with fuel and begin operations.

Standardization of design remains a critical facet to the successful deployment of new nuclear generation and success in the revised NRC review process. The first COL application for each design will be deemed the reference design. All subsequent COL applications using that design will be based on the reference design, with the exception of site-specific issues (geology, seismology, cooling water source, etc.). This common basis will allow a significant streamlining of the NRC review process and subsequent inspections and operating procedures. Industry participants are uniformly supportive of this standardized approach, and FPL intends to leverage the approach to reduce risk and manage costs for our customers.

2. Federal Legislation Signals Support

Federal legislation enacted in 2005 signaled a validation of nuclear energy's renewed importance as a national resource and the increasing public acceptance of new nuclear generation as a credible emission-free alternative that should be pursued. The Energy Policy Act of 2005 (EPAct 2005) recognized the need to assist potential nuclear plant owners by providing incentives and tools to help manage the risks of undertaking nuclear development activities. Among other initiatives, EPAct 2005 provided three proposed programs designed to benefit up to six first wave new nuclear plants developed in the U.S. that meet specific development and construction milestones: a form of "risk insurance" designed to cover costs incurred by an owner as a result of delays created in the commercial operation of a new nuclear plant by the NRC failure to act in a timely manner; a Loan Guarantee program intended to reduce the lending costs associated with a new nuclear project; and production tax credits that would come into effect when operational. These programs are promising, but limited in their ability to materially offset deployment risks. Given the number of announced projects that would be competing for the benefits, and the uncertain value that would be obtained by any given project, FPL chose not to begin expenditures towards the preparation of a Construction and Operating License Application (COLA) in order to meet the first milestone, filing of a COLA prior to the end of 2008.

The EPAct 2005 legislation is an important signal to FPL and other utilities that there is support for new nuclear generation. The EPAct 2005 and state level initiatives have advanced the development of new nuclear generation in Florida.

3. Florida Demonstrates Clear Intention to Support New Nuclear Generation

The Florida Energy Act of 2006 provided significant legislative direction to enact rules that allow Florida utilities to actively consider and pursue new nuclear generation. Recognizing the uncertain and developing status of new nuclear development, the Florida Legislature directed the Commission to take concrete steps to modify the rules associated with Power Plant Need Determinations to allow for the initial investigative steps for new nuclear generation to be initiated without the same level of certainty that is required when a utility proposes to build most fossil-fueled facilities. Additionally, the Florida Energy Act of 2006 created a mechanism by which the Commission could oversee the progress and expenditures of the project on an annual basis and utilities can file for interim cost recovery of prudently incurred costs, a feature that lowers the overall costs customers will pay. This legislation was implemented in early 2007 with the adoption of the Commission's Nuclear Cost Recovery Rule, clearing the way for FPL to present this request for Determination of Need.

C. Considerations Related to Nuclear Technology

1. Protecting Public Safety

Safety of the public is a top priority at FPL. Nuclear operations, both for FPL and for FPL Energy-operated facilities in other states, are rigorously managed to maintain public safety. In addition, FPL's emergency preparedness programs work in close coordination with local authorities to ensure response systems are ready and personnel are trained to manage a range of potential events.

Turkey Point 3 and 4 sustained no significant damage during the Category 5 Hurricane Andrew in 1992. New designs will be even more fortified than the second generation facilities and are more robust in the face of severe weather than conventional fossil-fueled plants.

Location of new nuclear generation units at Turkey Point utilizes an existing nuclear facility with a strong established network of local public safety officials ready to support emergency preparedness plans. The significant buffer region around the existing site maintains an appropriate perimeter, while preserving the land as a valuable habitat for a range of wildlife native to the area.

2. Ensuring Plant Security

FPL's security program is designed to be able to respond to a wide range of potential threats, including terrorist attacks. The "defense-in-depth" strategy is built on layers of protection including heavily fortified buildings, expertly trained and screened personnel, and extensive physical security measures. FPL's security team works closely with local, state, and federal agencies to continually assess threats and ensure the security program adapts to and anticipates potential threats.

Siting a new nuclear plant at Turkey Point leverages the experience of on-site and local authorities in addressing the specific concerns surrounding security of nuclear installations. The new facility would be secured by an independent security force that would complement and reinforce the existing security force at Turkey Point 3 and 4.

3. Provisions for Safe Spent Fuel Storage

Nuclear reactors are designed with safe storage facilities that can hold a significant quantity of fuel after it has been used in the electric generation process. These facilities are adjacent to the reactor and allow the fuel to cool underwater after use in the reactor. As these storage facilities begin to reach capacity in plants across the U.S., the nuclear industry has designed safe and secure methods for storing and controlling the used fuel assemblies. While the U.S. Department of Energy continues to develop a long-term national repository, many plants have begun to use a licensed and approved process called dry storage.

Dry storage allows the stabilized used fuel assemblies to be placed into cylindrical shielded casks and stored on site in protected areas. This process has been in use for over 20 years. Dry cask storage will be pursued at FPL's existing nuclear facilities, and is a safe and reliable option for disposition of used fuel from new nuclear generation until a long term national repository can be developed and made operational.

4. Decommissioning Costs

Operation of nuclear units is conducted with a full commitment to the complete lifecycle of costs associated with facility, including the eventual decommissioning of the facility when its operating life has been completed. Operating plants are required to periodically project the cost to decommission the facility and ensure that appropriate funds will be available to pay the costs of decommissioning.

The estimates being used for fixed operations and maintenance costs for the Turkey Point 6 & 7 project are based on costs in FPL/FPLE's current fleet, and include decommissioning costs.

D. Cost Control and Stepwise Decision Making

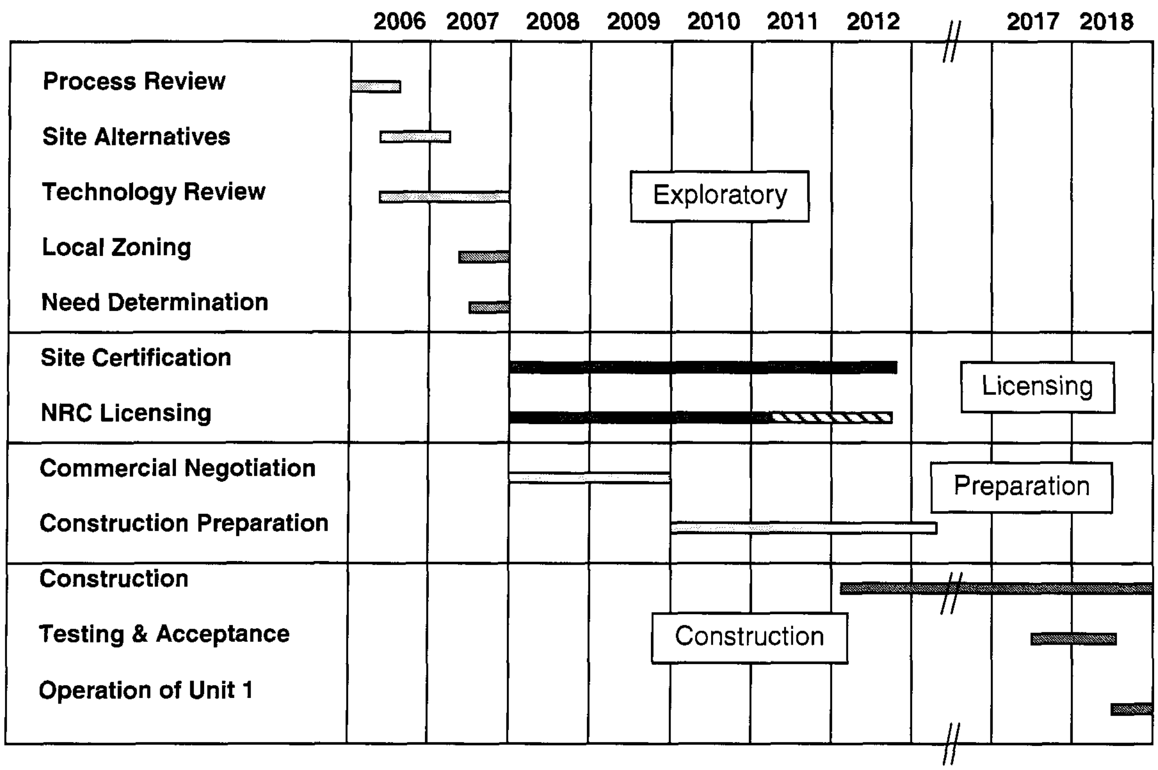
The revisions to the Need Determination Rule and the development of the Nuclear Cost Recovery Rule explicitly acknowledge the unique nature of new nuclear generation with regard to cost certainty and the need to initiate early steps in the process to create the option for new nuclear generation at the earliest possible date. Specifically, the Nuclear Cost Recovery Rule recognizes a non-binding cost estimate as the appropriate level of information to be provided at the early stages of the long and complex nuclear deployment process. Under the Nuclear Cost Recovery process, the expenditures for the project are periodically reviewed and an annual decision is made to continue the project based on the best current information.

FPL believes the framework established by the revised Need Determination Rule and the newly developed Nuclear Cost Recovery Rule will provide the joint assurance and cost control necessary to deploy new nuclear in Florida.

1. Near-Term in Sharper Focus

The deployment process for new nuclear involves four phases; the exploratory phase followed by Licensing, Preparation and Construction phases. These phases are characterized in Figure IV.D.1.

Figure IV.D.1 Phases of New Nuclear Project Deployment



The early steps of the Exploratory and Licensing phases are well understood. These steps allow FPL to project the expected cost to develop a COL Application to file with the NRC and a Site Certification Application to be filed with the Florida Department of Environmental Protection with a higher level of certainty than costs later on in the deployment process. COL applications are being completed now in a number of southeastern U.S. states. Additionally, FPL has current experience with the information necessary to satisfy the filing requirements of the state Site Certification process. The development of these applications will begin following an affirmative Need determination and will be completed and filed in 2009. The available background information and FPL's experience provide a firm basis from which to estimate costs for the development of the applications for Turkey Point 6 & 7 within this relatively short time frame.

2. Follow-up Steps Less Certain

Following application submission, several steps in the process are initiated that do not have the same level of precedent as the application development. The most notable step involves supporting and defending the applications through the review process. Other critical steps preceding construction include site preparation and long lead procurement.

The first COL applications will be submitted late in 2007 and will not complete the review process for several years. The pace and cost of that review process, including the cost of defending the applications in judicial or quasi-judicial proceedings, will be demonstrated over the next several years for the first wave of applications. FPL will be in the second wave of applications and may or may not benefit from this position. The uncertainty, however, adds to the complexity of estimating costs at this juncture.

The Preparatory phase steps are unrelated to the licensing phase, but are critical items that must be accomplished in advance of the Construction phase. Postponing these steps will postpone the commercial operation. Investing in these steps in advance of receiving the license are prudent enabling decisions that FPL will recommend as circumstances warrant.

For example, manufacturing space for ultra-heavy forgings is a critical path item that must be secured to enable the earliest practical deployment schedule. FPL recommends that procuring an option for the necessary manufacturing space to support this schedule should be a priority activity following a Need determination. In the event the Turkey Point 6 & 7 project is not pursued, the option may have a market value for other users that can be recovered.

Additionally, in order to maintain the earliest practical deployment schedule, expenditures will be recommended as warranted to begin the detailed engineering design and site preparation activities. The costs of these steps will be able to be determined with certainty as they are recommended, allowing the Commission to fully understand the justification and reasonableness of the proposed expenditure.

V. FACTORS AFFECTING SELECTION

A. FORECASTS AND ASSUMPTIONS

The forecasts of electric load and fuel prices are developed by FPL analysts who aggregate data and perform various analyses to develop these forecasts that are used in FPL's IRP process.

1. The Electrical 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 the 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, plus 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, income, Cooling and Heating Degree Days as explanatory variables, and dummy variables for hurricanes and historical periods.

(B) Commercial sales are forecast using a linear multiple regression model which contains the following explanatory variables: Gross Domestic Product, commercial real price of electricity, Cooling Degree Days, and dummy variables for hurricanes and historical periods.

(C) Industrial sales are forecast through a linear multiple regression model using Gross Domestic Product, Cooling Degree Days, and several dummy variables for outliers, hurricanes, and months.

(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; the 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 monthly model econometric model is also developed to produce a NEL forecast.[2] The key inputs to the model are: the real price of electricity, Heating and Cooling Degree Days, and Real Florida Personal Income. Once the 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 revenue class sales forecasts are then adjusted to match the NEL from the monthly econometric NEL model.

(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.

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[2] This calculation is independent from that used to determine NEL. It is developed by applying an expansion factor to the revenue class sales forecasts described above.

(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 Personal Income, average temperature on peak day, and a heat buildup factor consisting of the sum of the Cooling Degree hours during the peak day and three prior days.

(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 square of the minimum temperature on the peak day and Heating Degree hours from the prior day until 9:00 a.m. of the peak day. The model also includes an economic variable: Florida Real Personal Income.

c) Load Forecast Results

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

Table V.A.1.c.1
FPL's 2006 Load Forecast Results
Compound Average Annual Growth

Years	Total Customers	Net Energy For Load	Summer Peak	Winter Peak
1997-2006	2.2%	3.1%	3.1%	2.0%
2007-2016	1.8%	3.1%	2.3%	2.0%
2017-2040	1.1%	2.2%	2.1%	2.1%

The actual forecasts of peak demands and NEL used in the IRP analyses are presented in Appendix D. These forecasts address the 2006 through 2040 time period. For purposes of the analyses, FPL assumed that the load was constant from 2041 through 2060.

2. The Fuel Price Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers 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

Future fuel oil and natural gas prices, and to a much lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of fuel oil, natural gas, coal, and petroleum coke. These drivers include: (1) current and projected worldwide demand for crude oil and petroleum products; (2) current and projected worldwide refinery capacity/production; (3) expected worldwide economic growth, in particular in China and the other Pacific Rim countries; (4) Organization of Petroleum Exporting Countries (OPEC) production and the availability of spare OPEC production capacity and the assumed growth in spare OPEC production capacity; (5) non-OPEC production and expected growth in non-OPEC production; (6) the geopolitics of the Middle East, West Africa, the former Soviet Union, Venezuela, etc.; (7) the impact upon worldwide energy consumption of various factors including worldwide environmental legislation; (8) current and projected North American natural gas demand; (9) current and projected U. S., Canadian, and Mexican natural gas production; (10) the worldwide supply and demand of Liquefied Natural Gas (LNG); and (11) the growth in solid fuel generation on a U.S. and worldwide basis.

The volatility of natural gas and fuel oil prices, as compared with solid fuel and nuclear fuel prices, clearly underscored the need to develop a set of plausible fuel oil, natural gas and solid fuel price scenarios that bound the reasonable set of long-term price outcomes for economic evaluation purposes. In this light, FPL developed Low, Medium, and High Gas Cost forecasts for oil, natural gas, and solid fuel which were used in the analyses of the three resource plans.

FPL's Medium Gas Cost forecast methodology is consistent for fuel oil and natural gas. For fuel oil and natural gas commodity prices, FPL's Medium Gas Cost forecast applies the following methodology: (1) for 2007 through 2009, the methodology used the July

31, 2007 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil and Henry Hub natural gas commodity prices; (2) for the next two years (2010 and 2011), FPL used a 50/50 blend of the July 31, 2007 forward curve and annual projections from the PIRA Energy Group; (3) for the 2012 through 2020 period, FPL used the annual projections from the PIRA Energy Group; and (4) for the period beyond 2020, FPL used the rate of real (constant dollar) price changes from the Energy Information Administration (EIA). All constant dollar changes were then converted to nominal dollars using a 2.5% annual escalation rate. In addition to the development of commodity prices, price forecasts also were prepared for fuel oil and natural gas transportation costs. The addition of commodity and transportation projections resulted in delivered price forecasts.

FPL has used a consistent approach in developing the Medium Gas Cost forecast methodology for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach: (1) the price forecasts for Central Appalachian coal, South American coal, and petroleum coke were provided by JD Energy; (2) the marine transportation rates from the loading port for coal and petroleum coke to an import terminal were also provided by JD Energy; (3) the terminal throughput fee was based on a range of offers from comparable facilities throughout the Southeast U.S.; and (4) the rail transportation rates from Central Appalachia and from the import terminal facility were based on the proposed rail transportation rates as of the second quarter of 2007. In order to achieve the maximum fuel supply diversity and delivery flexibility for FPL's customers, FPL assumed that the delivered price of solid fuel for IGCC units in FPL's

Plan without Nuclear -- IGCC would be a mix of 25% Central Appalachian coal, 25% South American coal, and 50% petroleum coke.

These delivered price forecasts for fuel oil, natural gas and solid fuel were used in the economic evaluation of Turkey Point 6 & 7 and the alternative expansion plans.

The development of FPL's Low and High Gas Cost forecasts for fuel oil, natural gas, coal, and petroleum coke prices was based upon the historical relationship of the high and low prices realized by FPL's customers for each fuel between January 2000 and April 2007, to the average fuel prices in that same time frame. For example, the January 2000 through April 2007 average natural gas price delivered to FPL's system was \$6.65/MMBtu. The high price of the range was \$9.09/MMBtu or 137% of the average and the low price of the range was \$4.57/MMBtu or 69% of the average. These factors were multiplied by the monthly Medium Gas Cost forecast to determine the Low and High price for each commodity for the duration of the forecast period. This same process was applied to fuel oil, coal and petroleum coke consistently. FPL developed these forecasts to account for the uncertainty that exists within each commodity as well as across commodities. These forecasts align with FPL's actual price variability realized during the January 2000 to April 2007 period, thus ensuring that the analyses of the three Resource Plans will reflect a range of reasonable forecast outcomes.

FPL's long-term oil, natural gas and solid fuel price forecasts are reasonable and appropriate for the economic evaluation of Turkey Point 6 & 7 and the alternative plans.

FPL's fuel price forecasts identify a reasonable set of forecast outcomes based on an actual historical range of prices realized by FPL's customers during the January 2000 through April 2007 period, a period of time that experienced high variability among commodity prices, high price volatility on a domestic and worldwide basis, and periods of both low and high price differentials between commodities.

b.) Nuclear Fuel Price Forecast Methodologies

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. Therefore, there are four separate markets evaluated to develop nuclear fuel price projections.

During the first step, uranium is mined from the ground using techniques such as open pit, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U3O8 (sometimes referred to as yellowcake). Uranium is produced in many countries such as Canada, Australia, Kazakhstan and the U.S.

During the second step, the U3O8 is chemically converted into UF6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

The third step is called enrichment. Natural uranium contains 0.711 % of uranium at an atomic mass of 235 (U-235) and 99.289 % of uranium at an atomic mass of 238 (U-238). Similar to current reactors, the next generation of nuclear power reactors will use uranium with a higher percentage of U-235 atoms, up to five percent (5%). Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711 % to a level specified when designing the reactor core (typically in a range from approximately 3% to as high as 5%). The output of this enrichment process is enriched uranium in the form of UF_6.

During the last step, fuel fabrication, the enriched UF_6 is changed to a UO_2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

In developing prices for each step of the fuel fabrication process, different forecasts are reviewed to help establish a range of prices to reflect various scenarios of future supply and demand scenarios. A later section of this report will address availability of supply which formed the bases for the range of prices, used in this study.

A reference, nuclear fuel cost forecast was utilized in the analyses of the three resource plans. This forecast is provided in Appendix E. The calculations for the fuel cost forecasts were developed in a manner consistent with the method currently used for FPL's Fuel Clause filings, including the assumption of a fuel lease. Because current nuclear fuel price forecasts did not extend to 2060, FPL extended the forecasts by escalating them at 2.5% per annum.

c) Fuel Supply, Availability, and Delivery

(i) Natural gas

It was assumed that, for all gas-fired CC units contained in the three resource plans used in the analyses, natural gas was the primary fuel source and light oil was the backup fuel. (Please refer to section VI.C for details regarding these three resource plans.)

Natural gas is currently delivered into Florida from the U.S. Gulf Coast on-shore and off-shore regions via the Florida Gas Transmission (FGT) and Gulfstream Natural Gas System (Gulfstream) pipelines and from the regasification of imported LNG at the Elba Island, Georgia terminal via the Cypress pipeline. On May 1, 2007, Phase I of the Cypress pipeline was placed into service and began providing an incremental 220,000 MMBTU per day of natural gas into Florida. Phase I of the Cypress pipeline operates near or at capacity today, and future Phase II and Phase III expansions should be available by 2008 and 2010. While the FGT and Gulfstream infrastructure has provided a high level of reliability over the years, the demands on both pipelines have continued to grow. FGT is currently fully subscribed and by mid-2009 Gulfstream will be fully subscribed. Even with the planned Phase II and Phase III expansions of the Cypress pipeline, the addition of incremental natural gas-fired generation will likely require an expansion of one or both of the FGT and Gulfstream pipelines.

The need to consider alternatives to promote the diversity of supply is also critical to maintaining system reliability. Alternatives could include the addition of a new interstate pipeline, additional underground natural gas storage and the development of alternate supply sources, including access to new producing regions as well as the addition of LNG supply. Deepwater LNG receiving ports have been proposed on both the east and west coast of Florida and both projects are currently in the Maritime Administration (MARAD) approval process. In addition to providing incremental transportation capacity, these projects will also provide natural gas supply diversity from offshore and onshore locations in the Gulf of Mexico region.

(ii) Oil

The three resource plans assumed that all combined cycle additions will be capable of burning light oil as a backup fuel in the event of a natural gas supply disruption. Light oil would be trucked from local markets to the plant sites where it would be stored.

(iii) Coal (Domestic and International)

The fuel supply plan for the IGCC units included in one of the three resource plans analyzed for this filing assumes that low-sulfur bituminous coal from domestic and international sources will supply 50% of the fuel mix. These coal sources are expected to be the least-cost on a delivered basis because of the proximity of these coals to Florida, resulting in lower transportation costs. The principal domestic coal source is the Central Appalachia coal supply region in East Kentucky, Virginia, Tennessee, and Southern West Virginia. This is the largest coal-producing region in the East, with 2005 production exceeding 230 million tons. A diverse group of producing companies report 38 years of coal reserves at current production rates. Demand for this coal is expected to decline, as utilities in the Midwest switch to local high sulfur coals, which will extend the supply availability of low sulfur coal for plants in Florida and the Southeast. Central Appalachia coal would be delivered by two railroads that serve the coal fields, the CSX railroad and the Norfolk Southern railroad.

International coal supplies would be delivered by ocean vessel to a port facility in the Southeastern U.S. The coal would be loaded into railcars at the terminal for final delivery to the plant. The most likely sources of imported coal will be from Colombia and/or Venezuela which have large and growing coal supplies. These are the most likely sources because their proximity to Florida minimizes the cost of ocean freight. Coal from a number of other countries would also be potential sources of supply including Russia, South Africa, Indonesia, and Australia.

(iv) Petroleum Coke

Petroleum coke is expected to be a low-cost source of fuel which will supply 50% of the solid fuel mix for the IGCC units included in one of the three resource plans analyzed for this filing. This fuel is a by-product of the refining of crude oil. The largest worldwide source of petroleum coke supply is from oil refineries located on the Gulf Coast (Texas, Louisiana, and Mississippi) and in the Caribbean. With increasing demand for transportation fuels, petroleum coke production is expected to continue to grow, as refineries add coking capacity to upgrade heavy oil into light products. Petroleum coke would be delivered by vessel to a port in the Southeastern U.S. and loaded into railcars at the terminal for final delivery to the IGCC plants.

(v) Solid Fuel Receiving Terminal

FPL's solid fuel price forecasts have assumed access to a solid fuel receiving terminal with direct access to rail. The terminal Throughput Fee that was included in the delivered cost of solid fuel to the IGCC units in all three fuel cost forecasts assumed that the terminal could receive large vessels and maintain adequate throughput capacity to handle 100% of the proposed fuel requirements for the IGCC units. In addition, the site would be able to store up to 30 days supply of coal and petroleum coke in order to allow for uninterrupted service to be provided at the terminal for loading of unit trains.

(vi) Fuel Reliability via On-site Storage

Although a significant amount of on-site fuel supply is inherent in the design of, and included in the cost estimates for, the IGCC and Turkey Point 6 & 7 units (60 days of supply for the IGCC and up to 18 months for Turkey Point 6 & 7), the on-site fuel supply for the CC units is for three to four days of backup fuel oil supply. Therefore, the Turkey Point 6 & 7 units offer a very substantial advantage over CC units in terms of fuel supply reliability. This advantage is difficult to quantify, however, because the amount of unburned fuel remaining in a nuclear generating unit declines steadily over the course of an operating cycle and hence there is no fixed, consistent level of nuclear fuel "reserve" on-site from which to calculate the cost of equivalent fuel supply at a CC unit. In any event, FPL's analyses show that the Plan with Nuclear appears to be at least as economic as the Plan without Nuclear – CC even without including a quantified benefit for the inherent on-site fuel supply at a nuclear unit.

The IGCC units would be able to store up to 60 days of solid fuel at the plant site and the capital cost, operation and maintenance expenses, and working capital were assumed in the economic evaluation of the IGCC units. In comparison, a natural gas-fired combined cycle plant is assumed to not have access to on-site natural gas storage, mainly due to the lack of economically viable sites for natural gas storage in Florida.

viii. Uranium

Uranium supply, Availability, and Current Delivery

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert firms. Though there is a current shortage of uranium, which has pushed the current spot market price up, these higher market prices have motivated additional production expected to come on line over the next few years, which should bring uranium prices back to a level consistent with market fundamentals. The higher demand scenario is due to a more optimistic projection of construction of new nuclear units. As firm orders for new units are placed, uranium suppliers will commit to support the higher demand. Because the lead times to bring on line new nuclear units and new mining production are similar, it is expected that the higher demand will be met with higher uranium production in the future.

Other Steps of the Fuel Fabrication

The other steps of the fuel fabrication have and will continue to behave consistent with the market fundamentals. The reference costs scenario used in this study uses the most likely price scenarios which FPL developed by reviewing a number of consultant reports.

Conversion Services Supply, Availability, and Delivery

Similar to the market for raw uranium, an increase in demand for conversion services would result from the need to supply new nuclear units. As with additional raw uranium production, supply will expand beyond current level once more firm commitments are made to building new nuclear units. Capacity expansion of conversion services can be handled within the lead time for constructing a new nuclear unit, leading to sufficient supply with long term prices following cost fundamentals.

Enrichment Services Supply, Availability and Delivery

With no new production capacity, and if the current restrictions on imports of enrichment services from Russia and France were to continue, the current tight market supply for economically produced enrichment services would continue. Fortunately, there are a number of new facilities coming on line in that time frame and FPL expects that the current restrictions will be lifted, at least partially if not totally. In addition, as with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible and anticipated within the lead time for constructing new nuclear units.

Fabrication Services Supply, Availability, and Delivery

The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

(i) Nuclear Fuel Reliability

The practice in the industry continues to be the scheduling of deliveries of fuel assemblies no later than 2 months prior to a refueling outage. In addition to allowing plant personnel proper time to stage the fuel to be reloaded ahead of the outage, this time also allows sufficient contingency in case of supply disruption during the fabrication process.

In addition, nuclear units have the capability to continue power production beyond the end of fuel life. This is done by slightly reducing core temperature at first, and reducing power level over time. Although power production is reduced during that period, the rate of power reduction is between 0.3% to 1.2% on the average per day, depending on the specific nuclear unit, or whether the unit is a boiling water reactor or a pressurized water reactor. In case of supply disruption, either in the nuclear fuel or other fuels supply chain, a nuclear unit can provide power for an extended time, beyond its initially scheduled outage.

3. Environmental Regulations

Turkey Point 6 & 7 will be required to obtain federal, state and regional environmental approvals and permits. The principal state environmental approval is the Site Certification under Florida's PPSA. Site Certification is a comprehensive review of environmental and land use aspects of Turkey Point 6 & 7 coordinated through the Florida Department of Environmental Protection (FDEP) and involving state and regional agencies with environmental and land use responsibility and those agencies potentially affected by the project. This includes, but is not limited to, the FDEP, Florida Department of Community Affairs, Florida Department of Transportation, Florida Fish and Wildlife Conservation Commission, South Florida Water Management District (SFWMD), and Miami-Dade County. This comprehensive environmental review evaluates the environmental controls for Turkey Point 6 & 7 and determines compliance with applicable state, regional, and local environmental standards. PPSA process ultimately leads to a comprehensive analysis and report by agencies that include Conditions of Certification that set forth environmental requirements. The PPSA also provides opportunity for public comment and public hearings regarding the land use and environmental aspects of Turkey Point 6 & 7. Decisions on the environmental aspects of Turkey Point 6 & 7 are made by the Secretary of FDEP or by the Governor and Cabinet acting as the Siting Board.

Turkey Point 6 & 7 will also require federal approval and federally delegated permits. Under the requirements of the Nuclear Regulatory Commission (NRC) an environmental review is conducted by the NRC staff in accordance with the National Environmental

Policy Act (NEPA). The review is conducted pursuant to 10 CFR Part 51, Environmental Protection Regulations for Domestic Licensing and Related Regulatory Matters, Subpart A, National Environmental Policy Act, Regulations Implementing Section 102(2). These regulations specify the procedures and requirements for the NRC staff environmental review. After completing the initial review, the NRC issues a Draft Environmental Impact Statement for comment by the appropriate Federal, State, and local agencies as well as by the public. Afterwards, the agency issues a Final Environmental Impact Statement that addresses all comments received.

Other possible federal approvals include an approval by the U.S. Army Corp of Engineers (ACOE) for impacts to wetlands, a Prevention of Significant Deterioration (PSD)/Air Construction Permit by the FDEP for support facilities, and an Underground Injection Control (UIC) Permit from the FDEP.

The ACOE permit is required under Section 404 of the Clean Water Act and includes a demonstration that impacts to wetlands have been minimized and providing compensatory wetland mitigation. Turkey Point 6 & 7 will be designed to minimize impacts to wetlands and higher quality wetlands in the Everglades Mitigation Bank and other areas of the Turkey Point site are available for mitigation.

Under the federally authorized FDEP PSD program, support equipment for Turkey Point 6 & 7 such as emergency generators and cooling towers may be required to install Best Available Control Technology (BACT) and demonstrate that the project will comply with all air quality standards including those applicable to the PSD Class I Areas, which includes the Everglades National Park. FDEP PSD rules are codified in Rule 62-212 Florida Administrative Code (F.A.C.). The support equipment for Turkey Point 6 & 7 will be designed to meet these requirements.

Turkey Point 6 & 7 may be required to obtain approval under FDEP's federally delegated UIC Program codified in Rule 62-528 F.A.C. in the event wastewater disposal is required. This process may consist of obtaining approval to perform an exploratory UIC well at the Turkey Point site and converting this to a test injection well after site-specific information is developed.

In the future, Turkey Point 6 & 7 will have economic advantages relative to fossil-fuel fired electrical generation alternatives regarding the potential regulation of CO_2. Although there are no current laws regulating emissions of CO_2, the future regulation of CO_2 is likely. Over the last several years, including this year, there have been federal legislative initiatives that have proposed different forms of CO_2 regulation. These initiatives have included both multi-sector and electric sector regulation with variable reductions of CO_2 emissions and cap-and-trade systems. Since electrical generation from nuclear technology does not emit CO_2 from operations, nuclear technology may be given preferential economic consideration over fossil-fuel fired generation. For example, the CO_2 emissions from a natural gas fired combined cycle plant are about 750 pounds per megawatt-hour (lb/MWh). For a 1,000 MW combined cycle plant, about 3 million tons per year of CO_2 will be emitted assuming a 90% capacity factor. In contrast, nuclear power generation has no associated CO_2 emissions, which could result in even lower relative operational costs than natural gas combined cycle if CO_2 emissions are regulated for this type of fossil fuel plant.

While it is uncertain what type of legislation will ultimately be adopted, at the very least there would be no direct economic impact on nuclear technology compared to other generation options. However, costs for fossil fuel generation options, especially operational costs, will increase. Nuclear generation technology would not only have economic benefits if potential future CO_2 regulation were enacted but would have the significant environmental advantage of providing electric generation with no CO_2 emissions. For example, if a $10 per ton of CO_2 cost were placed on fossil fuel-fired generation, a 1,000 MW natural gas-fired combined cycle plant would have an additional operational cost of about $30,000,000 per year, assuming that the plant was not granted offsetting CO_2 allowances. The same amount of generation from nuclear units would not incur any cost from CO_2 emissions. In addition, since natural gas has the lowest amount of CO_2 emissions of all fossil fuel-fired generation, the regulation of CO_2 emissions would increase the pressure on the supply and cost of natural gas. While the extent of CO_2 costs and the influence on natural gas price is unknown, it is certain the costs associated with any regulation of CO_2 emissions and the resulting increase in natural gas costs would improve the relative economics of Turkey Point 6 & 7.

4. Transmission Facilities

a. Overview

The transmission facilities required to interconnect and integrate Turkey Point 6 & 7 were determined for the range of unit sizes; 1,100 and 1,520 MW, being considered for these units. This section discusses the transmission facilities associated with the two nuclear units.

With respect to the Turkey Point site, substantial new transmission facilities will be required in order to reliably interconnect and integrate the amounts of additional generation being projected at this site. The requirement to add major transmission facilities is the result of the need to deliver from 2,200 MW (from two 1,100 MW units) to 3,040 MW (from two 1,520 MW units) of new generation northward from the existing Turkey Point site in the southern most part of Miami-Dade County in order to serve FPL's load. This results in significant transmission facilities being required in the area from Turkey Point to central Miami-Dade County.

An additional factor that may affect the interconnection of Turkey Point 6 & 7 is the size of the generator selected. Turley Point 6 & 7 are each individually expected to be the single largest generating unit in Peninsular Florida. The size of the single largest generator in peninsular Florida is a significant factor because the transmission system must be capable of sustaining the loss of that generator without violating any North American Electric Reliability Corporation (NERC) or Florida Reliability Coordinating Council (FRCC) Reliability Standards. This requirement may have a direct impact on the import capability from the Southeast Electric Reliability Council (SERC). The import capability into peninsular Florida from SERC is in large part determined based on the contingency of the instantaneous loss of the largest single generating unit in the FRCC, and the attendant sudden in-rush of power from the eastern U.S. interconnection reacting to replace such lost power source until more generation is dispatched in the FRCC region (within thirty minutes). Currently, based upon preliminary assessments by FPL, the sudden outage of a unit size of approximately 1,200 MW gross output or less should not adversely impact the FRCC's import capability from SERC in this time frame. If the unit size increases, more detailed studies will be needed to determine the specific impacts and mitigation alternatives.

b. Transmission Interconnection and Integration Assumptions

Turkey Point 6 & 7 will be connected to a new 500 kilovolt (kV) switchyard at the Turkey Point site because the existing Turkey Point 230 kV switchyard that serves the Turkey Point fossil units 1, 2, and 5 and nuclear units 3 and 4 is utilized at near full capacity. This new 500 kV switchyard will be connected to the FPL transmission system by two 500 kV transmission lines to the 500 kV section of the existing Levee substation in central Miami-Dade County which is located approximately 42 miles north of the Turkey Point site.

A new 230 kV line, approximately 13 miles long, also will be required from the Levee substation to the Gratigny substation located northeast of the Levee substation in central Miami-Dade County. The new switchyard at Turkey Point also will have a 230 kV section. The new 500 and 230 kV sections will be connected via a 500/230 kV auto-transformer. The new 230 kV section will be connected to the Davis substation in southern Miami-Dade County utilizing an approximately 18 mile line which will be rerouted from the existing Turkey Point plant switchyard and rebuilt to larger capacity. Additionally, the 230 kV line rerouted from the existing Turkey Point plant switchyard will be replaced with a new 230 kV circuit from the switchyard to the Levee 230 kV substation. The aforementioned facilities are required for either the 1,100 MW units or the 1,520 MW units.

Finally, depending upon the amount of generation output of Turkey Point 6 & 7, certain other 230 and 138 kV upgrades to existing facilities are also required. A summary of the base and additional facilities is set forth below:

Base Facilities Required for Two 1,100 MW Net Units:

- The connection of Turkey Point 6 Generator Step-Up (GSU) transformer to the new Turkey Point switchyard, and attendant bus equipment
- The connection of Turkey Point 7 GSU transformer to the new Turkey Point switchyard, and attendant bus equipment
- The new Turkey Point 500/230 kV switchyard
- The two 500 kV transmission lines from the new Turkey Point switchyard to Levee Substation (Approximately 42 miles each)
- The 230 kV transmission line from the Levee Substation to the Gratigny Substation (Approximately 13 miles)

- Rebuild and rerouting of the existing Turkey Point-Davis #1 230 kV line to the new Turkey Point 230 kV switchyard
- Replace the line removed from the existing Turkey Point switchyard with a new line from the existing Turkey Point switchyard to Levee 230 kV (Approximately 42 miles)
- Upgrade Killian-Turkey Point 230 kV line
- Upgrade Turkey Point-Galloway Tap 230 kV line
- Upgrade Davis-Montgomery 138 kV line
- Upgrade Dadeland Tap-Snapper Creek 138 kV line
- Two 5-Ohm Reactors installed on the 230 kV side of the autotransformers at Levee (one per autotransformer)
- Two 5-Ohm Reactors installed on the 230 kV side of the autotransformers at Andytown (one per autotransformer)
- Two 5-Ohm Reactors installed on the 230 kV buses at the existing Turkey Point 230 kV switchyard.

Additional Facilities Required for Two 1,520 MW Net Units[3]

- Upgrade Killian-Miller 230 kV line
- Upgrade Mitchell-Court 138 kV line
- Upgrade Kendall-Suniland 138 kV line
- Upgrade Marion-Village Green 138 kV line
- Upgrade Marion-Montgomery 138 kV line

[3] These facilities do not include other potential facilities that may be required to mitigate the effect of the largest unit in the FRCC being larger than 1,200 MW gross output.

5. Nuclear Project Cost Estimate Range

In August of 2005, a joint study was published by the Tennessee Valley Authority (TVA) that provided a detailed assessment of new generation nuclear construction cost in the U.S.[4]. The study included contributions from key industry participants such as General Electric, Toshiba Corporation, Bechtel Corporation and Global Nuclear Fuels – America. The study provides the most comprehensive cost and schedule evaluation conducted in recent years, providing significant guidance into all facets of developing a cost and schedule estimate for a third generation nuclear project. While the study focused on proposed GE ABWR technology units to be built at TVA's Bellefonte Site, the information is representative of all third generation technologies because it is based on the construction methods and approaches that will be applied in new nuclear construction in the next decade. As such, the unit cost information (or the dollar-per-kilowatt value) provides a good indicator of unit costs of construction for other third generation designs.

FPL analyzed the TVA Study to obtain an understanding of the costs and schedules associated with the construction of a third generation nuclear unit, and adapted that information to reflect the issues and features of FPL's proposed project. By reviewing the study and making appropriate modifications, FPL was able to form the basis of a cost estimate range for new nuclear at FPL's Turkey Point Site. The cost estimate range created through this approach benefits from an industry effort to ensure all costs were captured and characterized.

[4] ABWR Cost/Schedule/COL Project at TVA's Bellefonte Site, DE-AI07-04ID14620, Tennessee Valley Authority, August 2005.

The following provides the cost estimate range for the Turkey Point 6 & 7 project in three stages. First, an overnight cost estimate range is developed using the TVA Study for comparison to the Economically Feasible capital cost range developed by the system cost based analysis. Next, a project schedule and associated expenditure plan is developed. Finally the Economically Feasible range is paired with the project schedule and expenditure plan to illustrate the annual expenditures and time related costs of the total project cost estimate range.

a) Development of the Overnight Cost Estimate Range

The overnight cost is an approximation of the expenditures necessary to build a specific project if all costs could be paid at one point in time. The overnight cost is a common way of comparing projects and leveraging cost information from other projects for application to a specific project. The TVA Study presents the overnight cost (in 2004$) for the construction of the power island, but does not address the site specific additional costs or time-related costs (such as escalation or interest) that are required to develop a complete cost perspective. FPL began with this information as our starting point in developing the cost estimate range.

Modifications were made to the base construction cost information provided in the TVA Study to adapt the information to an FPL specific cost estimate range. First, cost information was reviewed in line-item detail to ensure a complete scope of supply was included. This involved adding to the cost estimate to reflect site specific issues, such as site preparation costs. Second, FPL developed estimates for certain Owner Cost areas (staffing, fuel, licensing, etc.) that were not addressed in the TVA Study. Then the basic assumptions developed in the TVA Study were reviewed. Once the scope was determined to be complete and the basic assumptions had been reviewed, the study costs were escalated to current year dollars (2007$) using appropriate construction cost indices to reflect the recent escalation seen on equipment, materials and labor related to power plant construction. Finally, several key areas were evaluated to determine their effect on the range of the estimate.

The areas that most influenced the cost estimate range are; 1) the recent and dramatic escalation of material, equipment and labor indices, 2) the items included in Owner's scope which can vary between designs, 3) the accuracy of the Owner' scope estimate and 4) the cost estimate range of the transmission integration proposed for the Turkey Point 6 & 7 project. Table V.A.5.1 provides a summary of the three cases developed for the overnight construction cost estimate range. A more detailed breakdown of costs is provided as an Exhibit to FPL Witness Scroggs' testimony.

Table V.A.5.1 - Overnight Construction Cost Estimate Range

Cost Category	Case A. TVA Study Modified for FPL Scope (2007$, $/kW)	Case B. Reduced Escalation, Owner's scope and Owner's costs (2007$, $/kW)	Case C. Increased Escalation and Owner's costs (2007$, $/kW)
Power Island Costs	$2,802	$2,444	$3,582
Owner's Costs	$579	$466	$717
Transmission Costs	$215	$198	$242
Total Overnight Costs (2007$, $/kW)	**$3,596**	**$3,108**	**$4,540**

Cost Escalation - Between 2004 and 2007, the two key materials escalators increased by 54% and 63%, respectively. Application of these escalators to the 2005 costs would represent the cost of material and equipment if procured at today's indexed costs. However, the procurement of these items will occur over the span of the construction. Application of the 2007 index may turn out to be a fair representation of the final cost, or it may over- or under-estimate the index at the time of procurement. Therefore, a reduced escalation is shown (representative of 27% and 32% for materials) in Case B as well as an increased escalation (representative of 81% and 95% for materials) and increased labor costs in Case C.

Owner's Scope – Various additional scope areas, such as cooling towers and auxiliary boilers, were identified. Discussions with various technology vendors have indicated that they are included in some vendor scope and excluded in others. These scope items were removed for Case B, and included in Cases A and C.

Owner's Cost Estimate – The Owner's cost could also vary based on the technology selected, as well as the conditions placed on the project through the final approvals phase by the Construction and Operating License or Site Certification process. A base cost estimate was developed for Case A, with a 10% reduction applied in Case B and a 10% premium applied in Case C to non-labor items, with a 30% premium applied to labor items.

Transmission Integration – The costs to integrate the selected technology will be the result of a series of transmission studies that are just now beginning. A cost estimate range has been developed, however, based on preliminary information covering the range of the technologies under consideration. The average of the cost estimate range is used in Case A, while the low end of the range is applied in Case B and the high end of the range in Case C.

b) Construction Schedule and Expenditure Plan

In order to estimate the time related costs of construction, a construction schedule and corresponding expenditure plan was developed. FPL consulted with each technology vendor to obtain input into the key milestones in the construction schedule and how expenditures in the various categories were expected to be incurred. The resulting construction schedule and expenditure curves are representative and achievable with any of the technologies under consideration. Table V.A.5.2 presents the project milestones and the percentage of the overall project expenditure estimated for each year of the project. Optional activities are identified and included that allow completion of Unit 1 by 2018 and Unit 2 by 2020.

Table V.A.5.2 - Project Construction Schedule and Expenditure Plan

Project Year	Milestones	Annual Expenditure (%)	Cumulative Expenditure (%)
2008	Site Selection complete, COLA Preparation begins, Detailed Engineering begins Optional: Long Lead Procurement (Ultra-Heavy Forgings: Pressure Vessels, Steam Generator Vessels)	0.9%	0.9%
2009	COLA filed at NRC, SCA filed at FDEP, Application Review begins, Detailed Engineering Optional: Long Lead Procurement (Forgings, Training Simulator)	0.7%	1.6%
2010	Detailed Engineering and COLA review continues, SCA Hearing, Optional: Site clearing and Long Lead Procurement (Forgings, Training Simulator, Major Equipment)	1.1%	2.7%
2011	COLA review complete, Detailed Engineering continues Optional: Site Preparation and Long Lead Procurement (Forgings, Training Simulator, Major Equipment)	1.1%	3.7%
2012	ASLB convenes license hearing, Detailed Engineering continues, Non-nuclear Construction commences Optional: Site Preparation completes	5.5%	9.2%
2013	Safety Related (NRC jurisdictional) Construction commences, foundation for Unit 1 constructed	8.5%	17.7%
2014	Reactor Pressure Vessel and major components for Unit 1 delivered and set	11.0%	28.7%
2015	Unit 1 system construction, foundation for Unit 2 constructed	14.7%	43.4%
2016	Reactor Pressure Vessel and major components for Unit 2 delivered and set	17.3%	60.8%
2017	Unit 1 Substantial Completion and ITAAC Hearing	14.9%	75.7%
2018	Unit 1 Fuel Load, Testing and commercial operation.	14.9%	90.6%
2019	Unit 2 Substantial Completion and ITAAC Hearing	5.2%	95.8%
2020	Unit 2 Fuel Load, Testing and commercial operation.	4.2%	100.0%

* Optional activities needed to maintain earliest practical deployment schedule.

Based on the TVA Study, costs were grouped into four major cost categories. These categories are materials (11%), vendor equipment (46%), miscellaneous (11%) and labor/services (32%). This allows the overnight cost to be allocated among the four categories and each category escalated as appropriate over time.

c) Total Project Cost Estimate Range

The deployment schedule associated with a new nuclear project includes a licensing phase of up to 5 years, as well as a construction phase of 5 years. Therefore, the impacts of time through cost escalation and the accumulation of interest during construction is more significant on the final project costs than the impact would be to the shorter timeline for conventional fossil fuel deployment.

The rate at which the components of the project escalate over time is difficult to predict and is a source of uncertainty in the cost estimate. This is particularly challenging in the case of new nuclear, where the beginning of construction is over four years into the future. Couple this challenge with the fact that recent activity in the industrial sector has created significant near term increases to the cost of raw materials, fabrication and labor required to construct power plants. As with all market driven commodities the long term price trajectory may continue to rise, may moderate or could potentially decline. The impact of escalation on the project is further complicated by the fact that materials and equipment are procured in advance of when they are required in the construction period. FPL assumed that the escalation of materials, equipment and labor matched the pace of inflation in the long term in its construction cost estimate range development.

Interest charges that accumulate during construction also have an influence on overall project cost. The implementation of the Nuclear Cost Recovery Clause will reduce the impact of these interest charges. Table V.A.5.3 and Table V.A.5.4 provide summaries of the time related costs and the corresponding project cost estimate range.

Table V.A.5.3 - Project Construction Cost Estimate Range for 2,200 MW Project [1]

Cost Category	A. TVA Study Modified for FPL Scope ($/kW)	B. Reduced Escalation, Owner's scope and Owner's costs ($/kW)	C. Increased Escalation and Owner's costs ($/kW)
Total Overnight Costs (2007$, $/kW)	$3,596	$3,108	$4,540
Escalation @ 2.5%	$892	$764	$1,139
CCC [2] @ 11.04%	$1,837	$1,573	$2,345
Preconstruction Cost adjustment [3]	$47	$47	$47
Project Unit Cost (Year Spent $, $/kW)	**$6,700**	**$5,780**	**$8,071**
Total Cost for 2,200 MW Project (Year Spent $, $B)	**$14.0**	**$12.1**	**$17.8**

1) 2,200 MW is representative of a project deploying 2 Westinghouse AP 1000 units.
2) Carrying Charges of Construction (CCC)
3) Preconstruction Cost Adjustment separates costs included in the preconstruction phase totaling $191 $/kW in the TVA Study, and scales them for the 2,200 MW project. Adjustment = $191 * (1,371/1,100 - 1).

Table V.A.5.4 - Project Construction Cost Estimate Range for 3,040 MW Project [1]

Cost Category	A. TVA Study Modified for FPL Scope ($/kW)	B. Reduced Escalation, Owner's scope and Owner's costs ($/kW)	C. Increased Escalation and Owner's costs ($/kW)
Total Overnight Costs (2007$, $/kW)	$3,596	$3,108	$4,540
Escalation @ 2.5%	$892	$764	$1,139
CCC @ 11.04%	$1,837	$1,573	$2,345
Preconstruction Cost adjustment [3]	($19)	($19)	($19)
Project Unit Cost (Year Spent $, $/kW)	$6,306	$5,426	$8,005
Total Cost for 3,040 MW Project (Year Spent $, $B)	**$19.2**	**$16.5**	**$24.3**

1) 3,040 MW is representative of a project deploying 2 General Electric ESBWR units.
2) Carrying Charges of Construction (CCC)
3) Preconstruction Cost Adjustment separates costs included in the preconstruction phase totaling $191 $/kW in the TVA Study, and scales them for the 3,040 MW project. Adjustment = $191 * (1,371/1,520-1).

d) Cost Escalation Sensitivity

As previously discussed, the uncertainty of the final cost of material, equipment and labor has a significant impact on the cost estimate range. The initial cases addressed the gross impact of cost escalation as it relates to the overnight cost estimate. The time related contribution of escalation to uncertainty can be estimated by a simple sensitivity.

An increase of 1% (from 2.5% to 3.5%) to all escalators would increase the contribution of escalation to total project costs from $892 MM to $1,307 MM, an increase of $415 MM for Case A of the Cost Estimate Range for a 2,200 MW project. A decrease of 1%

to all escalators would reduce the contribution of escalation from $892 MM to $512 MM, a decrease of $380 MM for Case A, 2,200 MW project.

6. Financial and Economic Data

The financial and economic assumptions used in FPL's IRP process and in all analyses conducted that led to the selection of Turkey Point 6 & 7 are presented in Appendix G.

VI. GEOGRAPHIC OR LOCATIONAL PREFERENCE

The siting of nuclear generation requires a comprehensive and thorough assessment of a wide range of criteria. FPL's process was guided by the Electric Power Research Institute (EPRI) Siting Guide, NRC site suitability requirements, and the need to comply with National Environmental Policy Act (NEPA) requirements to consider alternative sites.

Twenty three candidate sites were identified and evaluated. Criteria such as water supply, regional population, transmission access, and ecology/environmental factors were developed and given weighting factors by a panel of experts. Through a series of screening steps, the list of candidate sites was narrowed, increasing the level of detail at each screening step. In the final analysis, the Turkey Point site rated highest among the candidate sites. Turkey Point scored high in many areas because of the supporting infrastructure that exists at or near the site. This is consistent with NRC findings recognizing that incremental generation at existing sites has specific attributes that generally recommend these projects above projects on previously undeveloped sites.

From a system perspective, the high rating of Turkey Point as a site for incremental nuclear generation makes sense. The site has 11,000 acres that would allow development of additional generation with limited impact on surrounding areas. Transmission infrastructure to deliver the new capacity to the grid is available with modest improvements, particularly in comparison to undeveloped sites. Additionally, location of the generation near the load center reduces the amount of transmission loss and increases the overall system efficiency. Location of new generation that is not dependent on contemporaneous fuel delivery for the production of electricity at the southern end of the FPL system provides significant system reliability advantages in the event of fuel supply disruptions.

The unique combination of these beneficial characteristics, make the Turkey Point site the most favorable location for the addition of the new nuclear generating units in the FPL system.

VII. MAJOR AVAILABLE GENERATING ALTERNATIVES EVALUATED

A. NUCLEAR DESIGN CHOICES

1. Design Choices Background and Evaluation

The nuclear power industry commonly recognizes several generations of reactors: the first generation of prototype reactors developed in the 1950s and 1960s; the second generation of reactors typified by the current U.S. fleet and most of the nuclear power plants in operation today; and the third generation, which are the advanced reactors recognized as the latest technology for commercial power plants in the industry. The third generation consists of improved light-water reactors offering enhanced safety and economy, and is the focus of FPL's review process.

FPL conducted an engineering evaluation of current design options available for new nuclear generation in mid-2006. This survey canvassed thirteen known designs, screening the list of candidates to five principal designs that were considered in detail. The initial screening selection was made based on the current commercial offerings and licensing activities at the NRC. These five principal designs are summarized in Table VII.A.1.

Table VII.A.1 Nuclear Designs Evaluated

Supplier	Reactor Model	MWe (Type) *	NRC Status
Areva	US EPR	1573 (PWR)	Application late 2007
Mitsubishi NES	APWR	1560 (PWR)	Application late 2007
General Electric	ABWR	1350 (BWR)	Certified Design
General Electric	ESBWR †	1520 (BWR)	Application in Review
Westinghouse	AP1000 †	1100 (PWR)	Certified Design

*) PWR = Pressurized Water Reactor; BWR = Boiling Water Reactor.[5]
†) Technologies designated as reference designs in the NuStart Consortium COLA projects

[5] Pressurized Water Reactors (PWRs) have three distinct, separate loops of water. In the primary system, the uranium fuel heats water through a fission process. This hot water is circulated through thousands of tubes in a steam generator. Here, a separate supply of water flows over the hot tubes containing the water that has been heated by the reactor. This secondary water turns into steam, which turns the fan-like blades of a turbine. As the generator turbine spins, it produces electricity. The non-radioactive steam flows through tubes of cooling water in a condenser and is turned back into water by a third system that circulates cooling water around the tubes.

In a Boiling Water Reactor (BWR), heat from nuclear fission boils water in the upper portion of the reactor vessel to form steam, eliminating the need for steam generators. From there, the steam flows to the turbine and turns it to make electricity. The spent steam is condensed back into water for recirculation to the reactor vessel and the process is repeated.

A Request for Information (RFI) was sent to the four companies to provide documentation on all five designs. The review is summarized in Appendix J of the Need Study Document. Based on the review of the information, FPL concluded that all five designs were technically acceptable. However, there are significant differences in the status of the deployment of these new technologies in the U.S.

2. Technology Summary

Third generation nuclear technologies can be broadly categorized by how the designs were developed and the type of safety strategy they employ to protect the plant in the event of a design basis accident. "Evolutionary" designs, such as the EPR, APWR, and ABWR, are designs that have evolved from similar generation two designs. They employ an "active" safety strategy wherein action is required by operators and associated systems to protect the plant. Alternatively, "non-evolutionary" reactors with inherent safety features contain design elements that are new. These technologies, ESBWR and AP 1000, employ a "passive" safety strategy wherein the design does not require operator action to protect the plant. The following is a summary of the designs considered and the deployment status of these designs. The capacity (MW) values listed for each design are all net MW.

Areva EPR – 1,573 megawatts

Areva's model is an evolutionary pressurized water reactor with active safety features. The design is based on an original Westinghouse PWR design. Design features include four 100-percent capacity trains, or sub-systems, each of them capable of performing the entire safety function on its own; a double-walled containment; and a "core catcher" for containment and cooling of core materials in case of reactor vessel failure. In the event of a power blackout, diesel generators, housed in two separate buildings, supply electricity to the safety functions.

Areva is developing the Design Certification Application for filing with the NRC in early 2008, with a targeted completion by mid-2011. No models are operating, but a similar design is under construction in Finland with plans for others in France. Four industry groups are preparing COLA applications that will reference the EPR design.

Mitsubishi APWR (Japan) – 1,560 megawatts

Mitsubishi's model is an evolutionary pressurized water reactor with active safety features. The design is based on an original Westinghouse PWR design. The design includes high-performance steam generators, a neutron reflector around the core to increase fuel economy, redundant core cooling systems, refueling water storage inside the containment building, and fully digital instrumentation and control systems.

Mitsubishi is developing the Design Certification Application for filing with the NRC in early 2008, with a targeted completion by mid-2011. No models are operating, but a unit of similar design is under construction in Japan. One company (Texas Utilities) is preparing COLA applications that will reference the APWR design.

General Electric ABWR - 1,350 megawatts

General Electric's model is an evolutionary boiling water reactor with active safety features. The design incorporates features of BWR designs in Europe, Japan, and the U.S. using improved electronics, computer, turbine, and fuel technology. The design is expected to increase plant availability, operating capacity, safety, and reliability. The design also includes safety enhancements such as protection against over-pressurizing containment, passive core debris flooding capability, an independent water makeup system, three emergency diesels, and a combustion turbine as an alternate power source.

The original GE-ABWR design was certified by the NRC and built only in Asia. Upgrades and modifications under consideration for the U.S. market will require an amendment to the original design certification. One U.S. company, NRG Energy, is preparing a COLA for this model. The ABWR, while certified with operating reactors in place, is not expected to be as cost-effective as GE's larger ESBWR due to economies of scale.

General Electric ESBWR - 1,520 megawatts

The ESBWR design is a non-evolutionary boiling water reactor with passive safety features. The design uses features of the certified advanced boiling water reactor. A passive safety system is a key feature of this design. Natural circulation replaces recirculation pumps. The plant's simplified design means that operating and maintenance staff requirements are reduced; and low-level waste generation is reduced. Fewer active components (active safety systems) reduce the maintenance and online surveillance requirements. According to General Electric, reductions in building volumes and required manufactured components shorten the length of time needed for ESBWR construction, resulting in improved cost-effectiveness.

General Electric filed the Design Certification Application with the NRC in 2005 and is currently responding to requests for additional information to support the NRC review with a targeted completion by mid-2010. No models of this design are operating. Two utilities will submit three COLAs referencing this design in early 2008.

The ESBWR is one of two designs that are to be designated as Reference COLAs. The Reference COLAs have been developed and supported by the NuStart Consortium and will serve as a base document which can be replicated by other NuStart members. As a member of NuStart, FPL would be able to leverage the work accomplished by the earlier filings, and address issues identified in these reviews.

Westinghouse AP1000 – 1,100 megawatts

The AP 1000 is a non-evolutionary pressurized water reactor with passive safety features. It is design-certified, but no models are operating or under construction. Five U.S. utilities are preparing combined operating license applications for this model. The AP1000 is a larger version of the previously approved AP600 design, using a longer reactor vessel to accommodate longer fuel, and includes larger steam generators and a larger pressurizer. Compared to today's plants, the AP 1000 will need 50% less building volume, 50% fewer valves, 80% fewer pipes, 35% fewer large pumps, and 70% less control cable. Therefore, the actions required by the plant operator are reduced. Westinghouse affirms that modular construction will reduce construction time to 36 months and lead to savings in plant costs.

The design received initial Certification in 2006. A Design Certification Amendment is currently being developed that will modify specific aspects of the design in response to NRC requests for additional information with a targeted completion by 2009. No models of this design are operating; however, this design is the most referenced in current COLA activity. Six utilities will submit COLAs referencing this design by 2009.

The AP 1000 is the second design that will be designated as a Reference COLA. As a member of NuStart, FPL would also be able to benefit from the work accomplished by the earlier filings.

3. Technological Improvement in the Future

Existing technologies, such as natural gas CC or wind power, often demonstrate improvements in efficiency, capital cost, or both. The rate at which these technologies improve is generally related to the rate at which they become adopted into the mainstream of power generation applications. The efficiency improvements and cost reductions seen in gas turbine- and wind turbine-based generation over the last thirty years has been dramatic, but is now stabilizing as these technologies mature.

Emerging technologies are those technologies which do not currently provide a significant portion of electrical generation, but hold some potential for doing so in the future. Technologies such as IGCC or ocean current generation qualify as emerging generation technologies.

FPL continues to track the technological development of existing and emerging generation technologies, developing a view of what is currently achievable and what may be achievable in the future. Many of these technologies have potential, but are in early stages of development where the true long term cost and reliability has yet to be proven. FPL does not anticipate that the improvements to existing or emerging technologies will be sufficient in the next ten to twenty years to cast doubt on the pursuit of new nuclear technology today. Moreover, FPL evaluates third generation nuclear as having the best potential for improvement among existing technologies and therefore offers the largest potential for benefiting FPL's customers.

B. NON-NUCLEAR TECHNOLOGIES

1. General Process

The previous section discussed information considered as part of FPL's decision to further evaluate the addition of new nuclear generating units that could be brought in-service starting in 2018. However, in order to fully evaluate the decision to add new nuclear generating units to FPL's system, it was necessary to also analyze non-nuclear choices that FPL would likely choose to build if the new Turkey Point 6 & 7 nuclear units were not built.

The process FPL used to perform this analysis involved the selection of gas-fired and coal-fired units that are representative of what FPL might build if Turkey Point 6 & 7 were not built, and then combining these units into generic, representative alternate resource plans that could be compared to a resource plan featuring Turkey Point 6 & 7. The resource plan that included Turkey Point 6 & 7 was designated as the Plan with Nuclear. The two alternate resource plans were designated as the Plan without Nuclear – CC and the Plan without Nuclear - IGCC.

2. Gas-Fired Technologies Selected

In the process of selecting gas-fired CC units for this analysis, FPL decided that the most representative type of CC unit for the near-term would be a unit similar to those recently approved for construction at the West County Energy Center (WCEC) site. These CC units are 3x1 G Technology (G) machines with a summer net capacity rating of 1,219 MW. These 3x1 G machines were used as the basis for the near-term CC capacity options that were used in all three resource plans for the years 2012 through 2016 and in place of the Turkey Point 6 & 7 units in the Plan without Nuclear - CC. In all three plans a 2x1 Class G CC unit was assumed to be added in 2017. For the 2021 – on time period, smaller 2x1 F Technology (F) CC machines with a summer capacity rating of 553 MW were used as filler units in all three resource plans. All of the three resource plans also included the proposed 414 MW capacity uprates to FPL's four existing nuclear units, the 1,899 MW of assumed DSM additions from August 2006 through August 2020, and the assumed 287 MW of renewable energy purchases. All of these resource additions have been previously discussed.

In the Plan without Nuclear – CC, one 1,219 MW CC is assumed to be added in 2018 and another 1,219 MW CC is assumed to be added in 2020.

3. Coal-Fired Technologies Selected

For purposes of the analyses conducted in support of this filing, FPL assumed that IGCC units would be used as the coal-based technology that would be included in the coal-based alternate resource plan.

In the Plan without Nuclear – IGCC, it is assumed that one pair of 600 MW IGCC units would be added in 2018 and a second pair of these units is added in 2020.

C. Analysis Approach

1. Economic Analysis

a) Development of Resource Plans to be Analyzed

FPL selected new nuclear units at FPL's existing Turkey Point site as potentially the best economic choice to meet future capacity needs, to promote fuel diversity, and to lower CO_2 emissions on FPL's system starting in 2018. For analysis purposes, specific in-service dates are required and FPL's analyses assume that the two nuclear units will come in-service in June 2018 and June 2020, respectively. These dates represent the earliest practical deployment schedule for new nuclear units to be added to FPL's system. However, in order to fully evaluate that selection, FPL needed to develop a long-term resource plan that could be used to analyze the long-term system impacts of the addition of the new nuclear units. This resource plan is referred to in this filing as the Plan with

Nuclear. In addition, FPL needed to develop alternate resource plans that did not include new nuclear unit additions that could be used in comparative analyses with the nuclear-based resource plan. These are referred to in this filing, respectively, as the Plan without Nuclear – CC in which comparably sized CC capacity is added in 2018 and 2020, and the Plan without Nuclear – IGCC in which comparably sized IGCC capacity is added in 2018 and 2020.

In developing these resource plans, FPL had several criteria. First, each resource plan chosen must meet FPL's system reliability criteria for all years, especially the reliability criterion that currently drives FPL's resource needs, the 20% Summer reserve margin criterion that FPL currently believes is necessary to provide reliable service. This ensures that the resource plans will be both meaningful and comparable in regard to system reliability. Second, the cost and performance assumptions (heat rate, availability, etc.) for the generating units that are included in each resource plan should be current assumptions of comparable confidence levels to the extent possible. Third, the resource plans should focus as much as possible on the assumed in-service or decision years in question, 2018 - 2020, and should seek to minimize as much as possible influencing the cost and other system impact differences between resource plans that could be caused by the addition of units in other years.

Therefore, the three resource plans are identical through 2017 and all of the plans meet all of the criteria discussed above. These three resource plans are presented in Table VII.C.1.a.1.

Table VII.C.1.a.1

The Three Resource Plans Utilized in the Analyses

Plan with Nuclear	2011	2012	2013	2014	2015	2016	2017	2018
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	Turkey Point 6
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,100
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	5,983
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	22.9%

Plan without Nuclear - CC	2011	2012	2013	2014	2015	2016	2017	2018
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	3x1 CC
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,219
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	6,102
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	23.4%

Plan without Nuclear - IGCC	2011	2012	2013	2014	2015	2016	2017	2018
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	2 - IGCC
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,200
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	6,083
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	23.3%

Notes:
- assumes extension of DSM implementation through 2020 at currently planned implementation rates for 2012 - 2014 time frame
- assumes extension of three expiring waste-to-energy purchases and addition of three renewable energy capacity purchases totaling 287 MW
- assumes no peak load or annual energy growth after 2040

* One of the four nuclear uprates is scheduled to occur in Dec 2011, one in May 2012, one in June 2012, and one in Dec 2012. Because the 2011 uprate will occur after the Summer calculation purposes the first three uprates are accounted for starting with the 2012 Summer reserve margin calculation. The fourth uprate is accounted for starting with the 2013 S

The assumption of gas-fired combined cycle units for all three plans in the 2011 – 2017 time period does not represent definitive resource decisions for FPL for those years. Resource plans are dynamic and decisions for those years have not yet been made. As those decisions are eventually made, a variety of resource options will be evaluated including additional DSM, renewable energy, power purchases, and gas-fired and coal-fired generating units.

For purposes of analysis, FPL had to make certain assumptions regarding the three multi-year resource plans and how future capacity needs prior to the 2018 – 2020 time period would be met. For these analyses, an identical assumption of combined cycle units for each of the three resource plans was selected. It is important to note that whichever resource options are eventually selected for 2011 – 2017, these decisions would have been made for any of the three resource plans analyzed for this filing.

b) Development of Fuel Cost and Environmental Compliance Cost Forecasts to be Used in the Analyses

When comparing generating technologies that burn different fuels, i.e., nuclear units, natural gas units, and coal units, it is appropriate that different fuel cost forecasts be utilized in order to determine the relative economics between the technologies. In this way the analyses can address the uncertainty that exists regarding future fuel costs, particularly in regard to the future cost differential between natural gas, coal, and nuclear fuel.

Although there are virtually an inexhaustible number of possible future fuel cost outcomes, a small number of forecasts that effectively reflect a reasonable range of future fuel costs are sufficient to conduct a meaningful economic analysis. Consequently, three different fossil fuel cost forecasts that reflect a reasonable range of future fossil fuel costs were developed and used in these analyses. These three fossil fuel cost forecasts are referred to as the High Gas Cost forecast, the Medium Gas Cost forecast, and the Low Gas Cost forecast. In addition, forecasted nuclear fuel costs were also developed and used in the analyses. All of these fuel cost forecasts are provided in Appendix E of this document.

Just as there is uncertainty in regard to the future cost of fuels, there is uncertainty in regard to the future environmental regulations and the costs of complying with those regulations. When comparing generating technologies that burn different fuels and have different emission profiles, such as is the case with nuclear, natural gas, and coal units, the future environmental regulations will determine how the differences in the emission profiles of the generating technologies will affect the relative cost of the technologies. Therefore, FPL found it appropriate to conduct its analyses using different environmental compliance cost forecasts to address the uncertainty that exists regarding future environmental regulations and the costs of complying with those regulations. These environmental compliance cost forecasts addressed four emissions: sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury (Hg), and CO_2.

As is the case with future fuel costs, there are also a large number of future environmental cost outcomes. However, a small number of forecasts that effectively reflect a reasonable range of future environmental compliance costs are sufficient to conduct a meaningful economic analysis. Therefore, four different environmental compliance cost forecasts that reflect a reasonable range of future environmental compliance costs were developed and used in these analyses. These four environmental compliance cost forecasts, referred to as Env I through Env IV, are provided in Appendix F of this document.

FPL initially combined the three fuel cost forecasts with the four environmental compliance cost forecasts to develop a total of 12 initial scenarios of forecasted fuel costs and environmental compliance costs. Then, after examining the different scenarios, FPL removed from further consideration three scenarios comprised of a low natural gas price forecast and medium-to-high compliance costs for CO_2 based on FPL's belief that medium-to-high compliance costs for CO_2 will result in upward pressure on natural gas prices. In other words, an assumption of medium-to-high environmental compliance costs for CO_2 is incompatible with an assumption of low natural gas prices. Each of the remaining 9 scenarios was then utilized separately in both the economic and non-economic analyses of the three resource plans.

Because the fuel cost forecasts are designated as High Gas Cost, Medium Gas Cost, and Low Gas Cost, and the environmental compliance cost forecasts are designated as Env I through Env IV, the 9 scenarios of fuel costs and environmental compliance costs are designated as High Gas Cost Env I through High Gas Cost Env IV, Medium Gas Cost Env I through Medium Gas Cost Env IV, and Low Gas Cost Env I. (The three eliminated scenarios are Low Gas Cost Env II, Low Gas Cost Env III, and Low Gas Cost Env IV.)

c) Two Steps in the Economic Analyses

The economic analysis approach utilized for analyzing the addition of two new nuclear units to FPL's system consisted of two steps. In the first step, the cumulative present value of revenue requirements (CPVRR) in 2007$ for the Plan with Nuclear, the Plan without Nuclear – CC, and the Plan without Nuclear – IGCC were developed and compared. The analysis approach used in this step was virtually identical to the approach used in FPL's most recent Need filings. However, there are two differences in this analysis approach step as applied for Turkey Point 6 & 7 when compared to this approach as utilized in the most recent Need filings.

The first difference is that the cost of transmission losses for the resource plans is not included because there are no known sites for the CC and IGCC units selected to compete with the new nuclear units in 2018 and 2020. Consequently, it is not possible to calculate losses for the two alternate Plans without Nuclear.

The second difference in the economic analysis approach step that developed CPVRR costs for the resource plans is that no generation or transmission capital costs associated with Turkey Point 6 & 7 were included in the analysis. The reason for this is that FPL does not believe it is currently possible to develop a precise projection of the capital costs associated with new nuclear units with in-service dates of 2018 – on.

Consequently, FPL's economic analysis approach normally used to evaluate generation options has been modified to include a second economic analysis step.

The second step in the economic analysis consists of taking the CPVRR cost differential between the Plan with Nuclear and one of the Plans without Nuclear for a given scenario of fuel costs and environmental compliance costs, then using this differential to determine the capital cost (generation and transmission) of the two nuclear units that could be spent so that the CPVRR costs for the two plans would be identical. In other words, a "breakeven" capital cost for the nuclear units is determined for each of the 9 scenarios versus both CC and IGCC capacity that might otherwise be added. These breakeven costs are presented in terms of $/kW in 2007$.

In summary, the objective of this two-step economic analysis is to allow FPL to determine a breakeven capital cost range of potential generation and transmission capital costs for Turkey Point 6 & 7 in which these new nuclear units are projected to be equal to the cost of alternative, non-nuclear generating technologies. This cost-effective range of potential generation and transmission capital costs were then compared to FPL's current capital cost estimate for Turkey Point 6 & 7 in terms of $/kW in 2007$.

2. Non-Economic Analysis

In addition to economic analyses of the two resource plans, non-economic analyses were also performed. These analyses focused on two different perspectives of the FPL system: projections of FPL's annual system fuel mix and projections of FPL's annual system CO_2 emissions. In regard to FPL's annual system fuel mix, projections of the percentages of total annual energy output that is provided by coal/petroleum coke, natural gas, oil, nuclear, and "other" (i.e., primarily purchases from waste-to-energy facilities) for each of the three resource plans for the 2018 – 2021 time period were developed. The years 2018 – 2021 were chosen to address the range of years from the year when the first new nuclear unit is projected to go in-service (2018) through the first year in which both new nuclear units are in-service for a full year (2021).

In regard to FPL's annual system CO_2 emissions, projections of system CO_2 emissions for each of the three resource plans for the 2007 – 2021 time period were developed.

D. Results of the Analysis

1. Economic Analysis Results

Table VII.D.1.1 presents the economic evaluation results for the three resource plans for one fuel cost and environmental compliance cost scenario, the High Gas Cost Env I scenario, using the same presentation format that FPL used in its most recent Need filings. The values presented are cumulative present value of revenue requirements (CPVRR) for the time period 2007 through 2060 in 2007$.

In this table, the costs for the Generation System are broken out into two categories; Fixed Costs and Variable Costs, and a list of what costs are included in these two categories is shown.

Table VII.D.1.1

Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario:
(millions, CPVRR, 2007$, 2007 - 2060)

Fuel Cost Forecast = High Gas Cost

Environmental Compliance Cost Forecast = Env I

	(1)	(2)	(3) = (1) + (2)	(4)
	System Costs			Difference from Lowest Cost Plan
Resource Plan	Fixed Costs *	Variable Costs **	Total Costs	
Plan with Nuclear	22,676	198,228	220,904	0
Plan without Nuclear - CC	23,684	209,368	233,052	12,148
Plan without Nuclear - IGCC	30,171	204,002	234,173	13,269

* Generation system fixed costs include: capital, capacity payments, fixed O&M, capital replacement, and firm gas transportation. (Note that nuclear generation and transmission capital costs are assumed to be zero in this analysis.)

** Generation system variable costs include: variable O&M, plant fuel, FPL system fuel, and environmental compliance costs.

Although these results are valid for only one of the 9 fuel cost and environmental compliance cost scenarios, these values do indicate two cost results that will hold true for all of the analyses involving the remaining 8 scenarios.

The first such result is that the Plan with Nuclear has lower fixed costs, lower variable costs, and lower total costs than does either of the two alternate plans without Nuclear. This is expected because, as previously discussed, the Plan with Nuclear contains no capital costs for the two new nuclear units. Therefore, the Plan with Nuclear is expected to have lower fixed costs. Nuclear units also have lower energy costs than either CC or IGCC units so a resource plan containing new nuclear units is expected to have lower variable costs than a comparable plan without nuclear units. The second such result is that the System Fixed Costs for a specific plan are established solely by the generation capacity additions in that resource plan and will not change as fuel costs and/or environmental compliance costs change. Therefore, the System Fixed Costs shown in this document for the three resource plans will remain unchanged for all 9 fuel cost and environmental compliance cost scenarios while the System Variable Costs will change from one scenario to another.

Table VII.D.1.2 presents the total costs for the three resource plans for all 9 of these scenarios. In addition, the total cost differences between the three plans are also shown. The total cost results shown on this document for the High Gas Cost Env I scenario for the three resource plans are the same as the total cost results presented for the resource plans in Table VII.D.1.1.

Table VII.D.1.2

Economic Analysis Results: Total Costs and Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

(millions, CPVRR, 2007$, 2007 - 2060)

(1)	(2)	(3)	(4)	(5)	(6) = (3) - (4)	(7) = (3) - (5)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans			Total Cost Difference Plan with Nuclear - Plan without Nuclear - CC	Total Cost Difference Plan with Nuclear - Plan without Nuclear - IGCC
		Plan with Nuclear	Plan without Nuclear - CC	Plan without Nuclear - IGCC		
High Gas Cost	Env I	220,904	233,052	234,173	(12,148)	(13,269)
High Gas Cost	Env II	233,322	246,544	249,099	(13,222)	(15,777)
High Gas Cost	Env III	242,937	256,648	259,966	(13,711)	(17,029)
High Gas Cost	Env IV	252,296	266,663	270,943	(14,367)	(18,647)
Medium Gas Cost	Env I	170,391	179,356	182,648	(8,965)	(12,257)
Medium Gas Cost	Env II	182,700	192,694	197,474	(9,994)	(14,774)
Medium Gas Cost	Env III	192,190	202,702	208,218	(10,512)	(16,028)
Medium Gas Cost	Env IV	201,428	212,635	219,099	(11,207)	(17,671)
Low Gas Cost	Env I	129,850	136,175	141,533	(6,325)	(11,683)

Note: A negative value in Columns (6) and/or (7) indicates that the Plan with Nuclear is less expensive than the comparative Plan without Nuclear (CC or IGCC). Conversely, a positive value in Columns (6) and/or (7) indicates that the Plan with Nuclear is more expensive than the comparative Plan without Nuclear (CC or IGCC).

The results from Table VII.D.1.2 show that, as expected for the first step of the economic analysis, the Plan with Nuclear has a lower CPVRR cost under all scenarios of fuel cost forecasts and environmental compliance cost forecasts for the reasons discussed above.

Table VII.D.1.2 provides a significant amount of cost and cost differential data for the three resource plans. In order to simplify this comparison of costs for the plans, the cost differentials for the plans that are shown in Table VII.D.1.2 are reorganized and presented again in matrix format in Table VII.D.1.3.

Table VII.D.1.3

Economic Analysis Results: Matrix of Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

Plan with Nuclear - Plan without Nuclear-CC

Total Cost Differentials
(millions, CPVRR, 2007$, 2007 - 2060)

Fuel Cost Forecasts

Environmental Compliance Cost Forecasts		High Gas Cost	Medium Gas Cost	Low Gas Cost
Environmental	Env I	(12,148)	(8,965)	(6,325)
Compliance	Env II	(13,222)	(9,994)	
Cost	Env III	(13,711)	(10,512)	
Forecasts	Env IV	(14,367)	(11,207)	

Plan with Nuclear - Plan without Nuclear-IGCC

Total Cost Differentials
(millions, CPVRR, 2007$, 2007 - 2060)

Fuel Cost Forecasts

Environmental Compliance Cost Forecasts		High Gas Cost	Medium Gas Cost	Low Gas Cost
Environmental	Env I	(13,269)	(12,257)	(11,683)
Compliance	Env II	(15,777)	(14,774)	
Cost	Env III	(17,029)	(16,028)	
Forecasts	Env IV	(18,647)	(17,671)	

Note: A negative value indicates that the Plan with Nuclear is less expensive than the comparative Plan without Nuclear (CC or IGCC). Conversely, a positive value indicates that the Plan with Nuclear is more expensive than the comparative Plan without Nuclear (CC or IGCC).

The results of the first step in the economic analysis presented above show the expected result: that the Plan with Nuclear (that assumes no capital costs for the new nuclear units) has a lower CPVRR cost for all scenarios than do either of the Plans without Nuclear. Second, the CPVRR cost advantage of the Plan with Nuclear versus the Plan without Nuclear – CC is greater on the left side of the matrix presented due to the higher gas cost forecasts on the left hand side. Also, the CPVRR cost advantage of the Plan with Nuclear versus either of the Plans without Nuclear is greater in the bottom rows of the matrix due to the higher environmental compliance costs in those rows and the fact that operation of the new nuclear units will result in essentially no SO_2, NO_x, Hg, or CO_2 emissions.

These results are then used to determine the breakeven capital costs of the new nuclear units in the second step of the economic analysis.

Having determined the CPVRR cost differentials between the three plans for all 9 scenarios in the first step of the economic analysis, FPL then developed an estimated projection of the recovery schedule of nuclear capital costs prior to the in-service dates of Turkey Point 6 & 7. This information, when combined with the traditional recovery of annual revenue requirements after the in-service dates for the two nuclear units, allows the calculation of how a $1/kW capital cost in 2007$ translates into a CPVRR capital cost. Appendix H presents this projection and CPVRR calculation. This calculation shows that a new nuclear unit cost of $1/kW in 2007$ equates to $1.973 million CPVRR in 2007$.

Using the CPVRR cost differentials for each scenario presented in Table VII.D.1.3, and the above-mentioned $1.973 million CPVRR capital cost calculated in Appendix H, a nuclear capital breakeven cost was calculated for each of the 9 scenarios versus the alternate Plans without Nuclear. The nuclear breakeven capital costs are presented in Table VII.D.1.4.

Table VII.D.1.4

Economic Analysis Results: Breakeven Cost for Nuclear Capital Costs for All Fuel and Environmental Compliance Cost Scenarios

Plan with Nuclear vs. Plan without Nuclear-CC

Breakeven Nuclear Capital Costs ($/kw in 2007$)

Fuel Cost Forecasts

Environmental Compliance Cost Forecasts		High Gas Cost	Medium Gas Cost	Low Gas Cost
	Env I	6,157	4,543	3,206
	Env II	6,701	5,065	
	Env III	6,949	5,327	
	Env IV	7,281	5,680	

Plan with Nuclear vs. Plan without Nuclear-IGCC

Breakeven Nuclear Capital Costs ($/kw in 2007$)

Fuel Cost Forecasts

Environmental Compliance Cost Forecasts		High Gas Cost	Medium Gas Cost	Low Gas Cost
	Env I	6,725	6,212	5,921
	Env II	7,996	7,487	
	Env III	8,630	8,123	
	Env IV	9,450	8,956	

These breakeven capital costs range from $3,206/kW in 2007$ to $7,281/kW in 2007$ versus the Plan without Nuclear – CC, and ranged from $5,921/kW in 2007$ to $9,450/kW in 2007$ versus the Plan without Nuclear - IGCC. As expected from the CPVRR cost differences presented in Table VII.D.1.3, the higher breakeven costs were calculated for the scenarios on the left hand side versus the Plan without Nuclear – CC due to higher gas costs and in the bottom rows of the matrix versus both Plans without Nuclear due to higher environmental compliance costs.

The breakeven nuclear capital cost ranges show the current projection for the range of nuclear capital costs that would allow the addition of two new nuclear units, one in 2018 and one in 2020, to yield identical CPVRR system costs over a 40-year period compared to an equivalent amount of gas-fired or coal-fired capacity added in the same years.

These two breakeven nuclear capital cost ranges are generally higher than FPL's current non-binding cost estimate range for new nuclear units i.e., the non-binding cost estimate of $3,108/kW to $4,540/kW in 2007$ presented in section V.A.5. Consequently, FPL believes it is reasonable to begin making these expenditures in order to continue to obtain refined cost and performance projections for new nuclear units; i.e., to retain the options of adding new nuclear generating capacity, Turkey Point 6 & 7, by the 2018-2020 time period.

2. Non-Economic Analysis Results

The first non-economic analysis focused on the projected annual system fuel mixes for the three resource plans for the 2018 – 2021 time period in order to determine the impact of the two new nuclear units on FPL system fuel diversity. Table VII.D.2.1 provides the results of these analyses for two scenarios, High Gas Cost Env III and Low Gas Cost Env I, selected to represent a range of fuel cost forecasts and environmental compliance cost forecast scenarios.

Table VII.D.2.1

Non-Economic Analysis Results: FPL System Fuel Mix Projections by Plan

Scenario: High Gas Cost Env III

	Plan with Nuclear					Plan without Nuclear - CC					Plan without Nuclear - IGCC				
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
2018	7.3%	69.6%	2.0%	20.8%	0.3%	7.3%	73.3%	1.8%	17.3%	0.3%	10.6%	69.7%	2.2%	17.3%	0.2%
2019	7.1%	67.6%	2.6%	22.3%	0.4%	7.1%	73.4%	2.4%	16.9%	0.2%	12.7%	67.4%	2.8%	16.9%	0.2%
2020	7.0%	65.2%	1.9%	25.7%	0.2%	7.0%	74.5%	1.5%	16.7%	0.3%	15.4%	65.4%	2.2%	16.7%	0.3%
2021	6.6%	64.7%	1.9%	26.5%	0.3%	6.6%	74.9%	2.1%	16.1%	0.3%	17.2%	63.6%	2.9%	16.1%	0.2%

Scenario: Low Gas Cost Env I

	Plan with Nuclear					Plan without Nuclear - CC					Plan without Nuclear - IGCC				
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
2018	6.6%	70.4%	1.9%	20.8%	0.3%	6.6%	74.1%	1.7%	17.3%	0.3%	9.9%	70.8%	1.8%	17.3%	0.2%
2019	6.5%	68.4%	2.5%	22.3%	0.3%	6.6%	74.1%	2.2%	16.9%	0.2%	12.0%	68.5%	2.3%	16.9%	0.3%
2020	6.4%	65.9%	1.7%	25.7%	0.3%	6.5%	75.2%	1.3%	16.7%	0.3%	14.9%	66.4%	1.7%	16.7%	0.3%
2021	6.2%	65.3%	1.7%	26.5%	0.3%	6.2%	75.5%	1.9%	16.1%	0.3%	16.7%	64.6%	2.4%	16.1%	0.2%

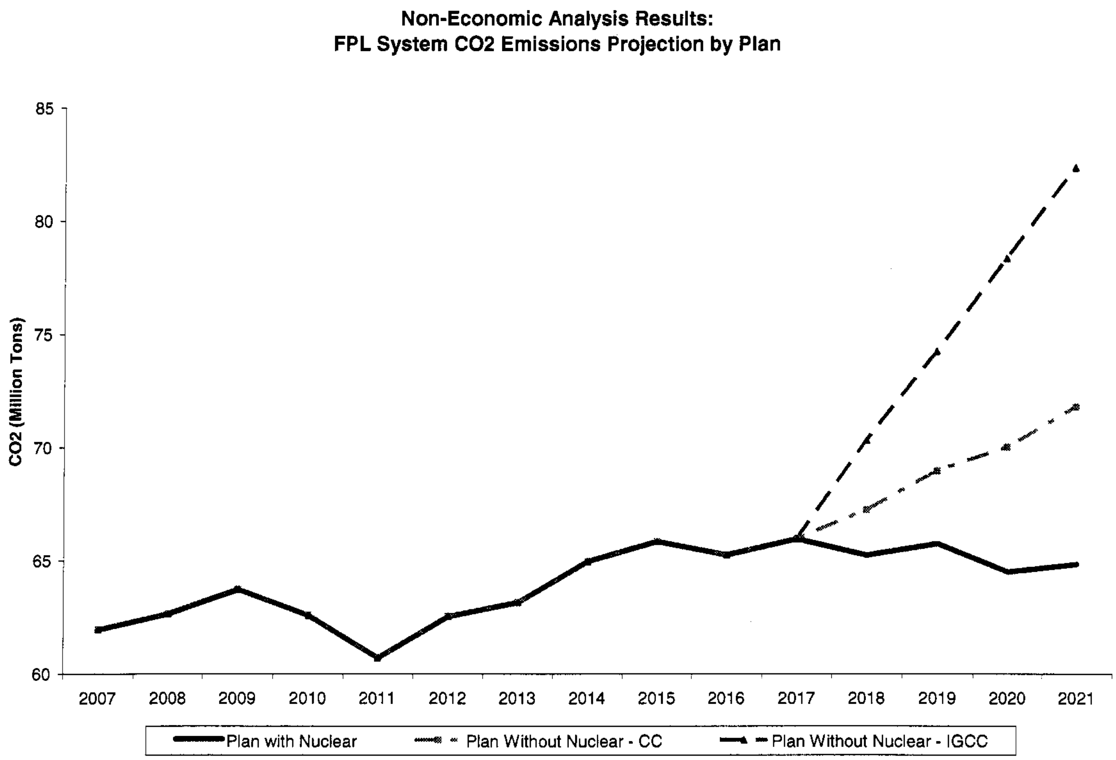
As shown in the above table, the Plan with Nuclear holds a significant advantage in regard to fuel diversity compared to the Plan without Nuclear – CC, and has a similar fuel diversity impact to the Plan without Nuclear - IGCC. When looking at the results for the High Gas Cost Env III scenario for the year 2021, it is projected that the Plan with Nuclear will result in FPL's system supplying approximately 27% of its energy with nuclear, 65% with natural gas, and 7% with coal/petroleum coke. By comparison, it is projected that the Plan without Nuclear - CC will result in FPL's system supplying only 16 % of its energy with nuclear, 75% with natural gas, and 7% with coal/petroleum coke and the Plan without Nuclear – IGCC will result in FPL's system supplying only 16% with nuclear, 64% with natural gas, and 17% with coal.

For the Low Gas Cost Env I scenario, the relative fuel mix percentages for the various fuels are relatively unchanged for the three resource plans.

Therefore, the Plan with Nuclear is projected to have a significant fuel diversity advantage, as indicated by its approximately 10% higher reliance on nuclear energy and 10% lower dependence upon natural gas, over the Plan without Nuclear – CC and has a similar fuel diversity advantage as the Plan without Nuclear - IGCC.

The second non-economic analysis focused on the projected annual CO_2 system emissions for the three resource plans for the 2007 – 2021 time period. Figure VII.D.2.2 provides the results of these analyses.

Figure VII.D.2.2



As expected there are no differences between the three plans for the years 2007 through 2017 because the plans are identical. However, starting in 2018, there are significant differences in CO_2 emissions between the plans. The Plan with Nuclear shows dramatically lower CO_2 emissions in the 2018 – 2021 time period due to the fact that nuclear power plant operations result in essentially zero CO_2 emissions.

For 2021, the first year for which the 2018 and 2020 unit additions are operating for a full year, the projected FPL system CO_2 emissions for the three plans are as follows:

- Plan with Nuclear = 64.9 million tons
- Plan without Nuclear – CC = 71.8 million tons
- Plan without Nuclear – IGCC = 82.4 million tons

Comparing these values shows that the CO_2 emission projection for 2021 for the Plan without Nuclear – CC is 6.9 million tons per year higher than for the Plan with Nuclear, and the Plan without Nuclear – IGCC is 17.5 million tons per year higher than for the Plan with Nuclear.

From a percentage perspective, the Plan with Nuclear would result in approximately a 10% reduction from the Plan without Nuclear – CC and approximately a 21% reduction from the Plan without Nuclear – IGCC.

3. Summary of Analysis Results

The economic analyses resulted in a wide range of breakeven capital costs for new nuclear units. This wide range of \$3,206/kW to \$7,281/kW in 2007\$ versus the Plan without Nuclear – CC, and \$5,921/kW to \$9,450/kW in 2007\$ versus the Plan without Nuclear – IGCC, compares favorably to the current non-binding estimate range of \$3,108/kW to \$4,540/kW in 2007\$ for new nuclear units. Therefore, it appears there is a very good possibility that new nuclear units at Turkey Point can be constructed at a cost that would, at worst, break even with the total system cost of non-nuclear units that might otherwise be constructed, and that there is a very good chance that the new nuclear units would result in lower total system costs

The non-economic analyses showed that the Plan with Nuclear has a significant advantage in regard to system fuel diversity compared to the Plan without Nuclear –CC, and similar fuel diversity impacts compared to the Plan without Nuclear - IGCC. The non-economic analyses also showed that the Plan with Nuclear will result in reducing FPL system CO_2 emissions by approximately 10% compared to the Plan without Nuclear – CC and by 21% compared to the Plan without Nuclear – IGCC.

In summary, the results of the analyses show that new nuclear units are likely to be the economic choice compared to either CC or IGCC units starting in 2018 over a variety of fuel cost and environmental compliance cost forecasts. In addition, new nuclear units offer significant system fuel diversity and CO_2 emission reduction advantages over either of these non-nuclear alternatives.

VIII. NON-GENERATING ALTERNATIVES

A. FPL's Demand Side Management Efforts

FPL has a long history of identifying, developing, and implementing DSM resources to cost-effectively avoid or defer the construction of new power plants. FPL first began offering DSM programs in the late 1970s with the introduction of its Watt-Wise Home Program. FPL has continued to develop and offer additional DSM programs to its customers. These programs have included both conservation and load management programs, targeting the residential and business markets.

FPL's portfolio of DSM programs has evolved over time. FPL continually looks for new DSM opportunities as part of its research and development activities. When a new DSM opportunity is identified and projected to be cost-effective, FPL attempts to either implement a new DSM program or incorporate this DSM opportunity into one or more of its existing DSM programs. In addition, FPL has modified DSM programs over time in order to maintain the cost-effectiveness of the programs. This allows FPL to continue to offer the most cost-effective programs available. On occasion, FPL has also terminated DSM programs that were no longer cost-effective and could not be modified to become cost-effective.

Since the inception of FPL's DSM programs through the end of 2006, the last full year for which data was available at the time this document was prepared, FPL has achieved 3,659 MW (at the generator) of Summer peak demand reduction, 2,816 MW (at the generator) of Winter peak demand reduction, 38,169 GWh (at the generator) of energy savings, and has completed over 2,360,000 energy audits of its customers' homes and facilities. This amount of peak demand reduction has eliminated the need for the equivalent of 11 power plants of 400 MW Summer capacity each (after accounting for the impact of reserve margin requirements).

Most importantly, FPL has achieved this level of demand reduction without penalizing customers who are non-participants in its DSM programs. FPL has been able to avoid penalizing non-participating customers by offering only DSM programs that reduce electric rates for all customers, DSM participants and non-participants alike.

DOE reports on the effectiveness of utility DSM efforts through its Energy Information Administration. Based on the most current data available, which is for the year 2005, FPL is ranked number one nationally for cumulative conservation achievement and number four in load management. To put this further in perspective, FPL serves about 3% of the total U.S. consumers but has achieved 13% of the total US conservation and 6% of the total load management. Therefore, FPL's success is not attributed just to its size relative to other utilities, but to its commitment to achieving the maximum amount of cost-effective DSM.

B. FPL's Current DSM Goals, Plan, and Projection

DSM Goals were first set for Florida utilities in 1994 in Order No. PSC-94-1313 FOF. In 2004, new DSM Goals were set for FPL and other Florida utilities in Order No. PSC-04-0763-PPA-EG. In that order, the Commission established for FPL goals of achieving 883 MW of incremental Summer MW at the generator through DSM during the period from 2005 through 2014. 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 continually investigates additional cost-effective DSM opportunities and requests Commission approval of revisions to its DSM plan as appropriate. In 2005, FPL's peak load forecast increased significantly. There were also modifications to minimum equipment efficiency standards and other changing market conditions. As a result of these changes, FPL performed a comprehensive review of all its DSM programs as well as other potential measures. This resulted in FPL revising 8 of its existing DSM programs. These modifications included changing the minimum qualifying Seasonal

Energy Efficiency Ratio for air conditioners to reflect minimum mandated levels by the DOE, modifying incentive levels for numerous program measures, enhancing program operating parameters, and adding new measures to existing DSM programs. In addition, FPL requested Commission approval of two new DSM programs -- Business Water Heating and Business Refrigeration. After review and consideration, the Commission issued Order No. PSC-06-0535-PAA-EG in Docket No. 060286-EG (Consummating Order No. PSC-06-0624-CO-EG issued July 20, 2006), approving changes to FPL's residential and business HVAC programs. On September 1, 2006, the Commission issued Order No. PSC-06-0740-TRF-EI in Docket No. 060408-EI (Consummating Order No. PSC-06-0801-CO-EI, issued September 26, 2006) approving the remaining modifications to FPL's DSM Plan for achieving these DSM reductions.

The next Commission-sponsored DSM goals-setting docket, which will include the time period 2015-2019, is expected to occur in 2009. While FPL does not have approved DSM goals past 2014, for purposes of the analyses conducted for this filing, FPL assumed a continuation of DSM signups at currently projected trends.

The net result is that FPL projects the addition of 1,899 MW of cost-effective DSM from August 2006 through August 2020. As mentioned in Section III, FPL assumed the successful accomplishment of this amount of DSM in determining its future capacity needs.

FPL forecasts that it will achieve its DSM Plan through a number of Commission-approved DSM programs. FPL's current DSM Plan includes seven residential DSM programs and ten business DSM programs. A brief summary of each of these programs appears in Appendix K.

C. FPL's Demand Side Management Renewable Efforts

FPL has a long history of programs and research and development addressing the needs of its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was no longer cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program. FPL's Passive Home Program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to the revisions of the Florida Model Energy Building Code. The revision was brought about in part by FPL's Passive Home Program.

In early 1991, FPL received approval from the Commission to conduct a research project to evaluate the feasibility of using PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. However, the high cost of PV, the significant percentage of sites with unacceptable shading and various customer satisfaction issues remain as barriers to wide acceptance and use of this particular solar application.

FPL has analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach did not require all of its customers to bear PV's high cost, but allowed customers who were interested in facilitating the use of renewable energy the means to do so. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund that FPL used to make PV purchases in bulk quantities. FPL began the effort in 1998 and received approximately $89,000 in contributions (that significantly exceeded the goal of $70,000). FPL purchased PV modules and installed them at FPL's Martin Plant site.

In 2000, FPL launched the Photovoltaic Research, Development and Education Project. This demonstration project's objectives were to: increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks (as well as the total annual energy capabilities of roof tile PV systems) and assess the homeowner's financial benefits and costs of PV roof tile systems. This project, which was completed in 2003, provided valuable data to assess the cost-effectiveness of this technology for FPL and its customers.

In November of 2004, FPL launched its Green Power Pricing Research Project (GPPRP) that was marketed as the Sunshine Energy® program. The objective of the project was to allow residential customers to sign up voluntarily and pay for energy produced by renewable resources, thus fostering the development of supplies of renewable energy that would not otherwise be developed. GPPRP participants paid a monthly premium of $9.75 per month for a 1,000 kWh block of renewable energy attributes. To supply the renewable energy for the GPPRP, FPL entered into a contract with a supplier for the purchase of tradable renewable energy credits (TRECs). In addition, for every 10,000 participants, FPL agreed to have built 150 kW of photovoltaic capacity in Florida. In its short history, the GPPRP became one of the top programs in the country with 28,742 customers enrolled by the end of 2006. The GPPRP purchased 1,894 GWhs of TRECs as of year end 2006 making it the third largest renewable energy program in the country. It also received the 2005 Green Power Leadership Award from the U.S. Department of Environmental Protection and the Department of Energy. The program has continued to grow, with 34,000 participants as of June, 2007.

On September 17, 2006, FPL filed a petition with the Commission to convert the GPPRP to a permanent program and to extend the program to business customers. On December 1, 2006, the Commission issued Order No. PSC-06-0924-TRF-EI in Docket No. 060577-EI approving this request.

D. The Potential for Additional Cost-Effective DSM

FPL is confident there is not sufficient additional, cost-effective DSM that could eliminate or significantly mitigate FPL's total capacity needs through 2020. There are several bases for this conclusion.

First, in 2006 FPL completed a comprehensive review of all demand side management opportunities. This analysis identified all the cost-effective DSM potential for this time frame. In addition, while FPL does not have Commission approved DSM goals for 2015 through 2019, it is projecting to implement 1,899 MW of cost-effective DSM from August 2006 through August 2020. In addition, while there has been a small increase in the penetration of demand side renewable energy options over the last several years, the economics of the various technologies has not yet reached the level to make any significant impact on FPL's summer peak.

Second, FPL has already counted this level of reasonably achievable DSM in its reliability assessment, which resulted in the projected need for new capacity resources in the 2018 – 2020 time period. 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 resource needs for just 2018 through 2020 were to be met solely by additional new DSM resources, FPL would need to identify and implement an additional 538 MW at the generator of cost-effective DSM to meet the 2018 resource needs and another 1,114 MW at the generator to meet the 2019 and 2020 resource needs, for a total of 1,652 MW at the generator just to meet that 3-year resource requirement. FPL's DSM commitment already take into account both maintaining FPL's large existing DSM resources and substantially increasing DSM through implementation of all of the additional cost-effective DSM that FPL has identified. Accordingly, there is no reasonable basis for concluding that FPL could implement sufficient new cost-effective DSM programs – over and above those already being performed and planned to be implemented - to meet these needs. While FPL hopes to identify and implement additional sources of cost-effective DSM in future years, FPL has no basis for believing that 1,652 MW at the generator of additional cost-effective DSM resources could be identified and implemented prior to 2020, especially when considering that 1,899 MW of DSM represents all of the currently known cost-effective DSM from August 2006 through August 2020, including a continuation of cost-effective DSM from 2015 through 2020, and that this amount of DSM is already incorporated into FPL's resource planning.

IX. ADVERSE CONSEQUENCES IF THE PROPOSED CAPACITY ADDITIONS ARE DENIED

As the Commission is well aware, FPL's recent plan to add new baseload coal generation was not approved. Significant uncertainty exists as to whether any other projects that use coal as a fuel, even with IGCC technology, will be approved for the foreseeable future. In any event, the likelihood that significant reductions in GHG emissions will be required in the future raises questions regarding the practical feasibility of coal-fueled additions in Florida until carbon capture and sequestration becomes readily applicable in Florida. Although FPL will actively continue to pursue cost-effective DSM increases and additional generation from renewable resources, currently available information indicates that that these alternatives will make only a modest contribution compared to the projected need for new resources to meet growth in electricity demand based largely on population growth and to replace expiring power purchases from coal generation. Without nuclear generation, the only alternative that can be counted on to provide sufficient new generation capacity to ensure reliable electric service through 2020 is additional natural gas generation.

With further reliance on natural gas generation, FPL's customers would face significant adverse consequences related primarily to the reduced system reliability due to significantly lower fuel diversity for the foreseeable future. As evidenced by the fuel diversity results presented in Table VI.D.2.1 and discussed above, with the addition of Turkey Point 6 & 7, nuclear generation would be used to produce approximately 27% of the electricity delivered to FPL's customers in 2021. Conversely, without new nuclear generation, by 2021 nuclear fuel would contribute only 16% while natural gas would contribute 75%, if combined cycle units are added instead..

In this situation, a gas supply interruption would severely affect electric service reliability throughout Florida. Fuel diversity contributes to greater system reliability because it helps offset reduced availability of one fuel, be it due to supply constraints or transportation interruptions, and helps mitigate the effect of equipment problems that affect one type of generation technology.

From an economic perspective, greater reliance on natural gas is expected to result in higher electricity costs and greater volatility in the cost of electricity. FPL believes that the effort to avoid GHG emissions will result in greater utilization of natural gas throughout the U.S. and that this general increase in gas utilization will contribute to higher natural gas prices. Without additional nuclear generation, because a greater portion of electricity would be generated using natural gas, the price of electricity would be more directly affected by the rising price of natural gas. Similarly, any volatility in natural gas prices will translate very directly in volatility in the price of electricity.

Moreover, FPL's analyses show that the addition of Turkey Point 6 & 7 can provide to FPL's customers all these benefits at a cost that is projected to be lower than that of adding additional gas-fueled generation under almost all conditions, and lower than adding IGCC, and that its reliability would be as good as that of combined cycle generation and far better than that of IGCC.

The failure to approve Turkey Point 6 & 7 would be a missed opportunity to significantly lower FPL's system CO2 emissions. As shown in Table VII.D.2.2 the FPL system is projected to have CO2 emissions 10% higher if CC capacity were to be installed in 2018 and 2020 instead of Turkey Point 6 & 7, or 21% higher if IGCC capacity were to be installed instead in 2018 and 2020. A denial of FPL's petition would eliminate the best, most cost-effective means of reducing GHG emissions in the future, while continuing to meet the future electricity needs of FPL's customers. Denial of FPL's petition would not be in FPL's customers' best interests.

It is important to note that an affirmative determination of need for Turkey Point 6 & 7 is a first step, not an irreversible decision, because FPL and the Commission will periodically review the Project's benefits on behalf of FPL's customers in light of new information that may be developed over time. However, granting this petition enables FPL to move forward and maintain the ability to bring the benefits of new nuclear generation to its customers in the 2018-2020 time frame – an extremely valuable option given the analysis results obtained for a wide range of future fuel and environmental scenarios – through a commitment of a comparatively modest level of resources. In contrast, denial of FPL's petition will preclude that option.

X. CONCLUSIONS

FPL, through its 2007 integrated resource planning (IRP) process, determined that 8,350 MW of new resources (demand side and generation capacity) would be needed between 2011 and 2020, including about 1,600 MW to replace expiring power purchase agreements, to continue to meet the reliability criterion of 20% summer reserve margin approved by the Commission and considered necessary by FPL to provide reliable service. Of this resource need, FPL projects that 1,490 MW can be avoided through increased DSM, about 290 MW could be provided by renewable resource purchases, 414 MW will be provided by capacity uprates at FPL's existing nuclear units, and between 2,200 MW and 3,040 MW will be provided by the proposed Turkey Point 6 & 7 addition in 2018 and 2020. The remaining resource need (between 3,120 MW and 3,960 MW) will be provided between 2011 and 2017 by a combination of resources that could include additional DSM and additional generation capacity (self-build or purchased) from renewable resources, new gas-fueled generation and coal-fueled generation.

Assuming that sufficient resources have been added between 2011 and 2017 to maintain a 20% reserve margin through 2017, without the proposed addition of Turkey Point 6 & 7, FPL's summer reserve margin would drop to 17.5% in 2018, 15.1% in 2019, and 12.6% in 2020, far less than the reserve margin requirement that FPL and the Commission have agreed is necessary to ensure system reliability. In addition, without these capacity additions in 2018 and 2020, by 2021 FPL's need would exceed 2,700 MW, and the need would continue to grow thereafter.

FPL has also determined that if all new generation capacity added to FPL's system through 2020 were to be natural gas-fired generation, fuel diversity in FPL's system would be significantly reduced. Specifically, by 2021 natural gas would provide more than 75% of all electricity delivered by FPL to its customers.

FPL conducted an evaluation of various generation alternatives to identify the best plan to address key objectives of its resource planning process, including meeting projected capacity needs in the future in a cost-effective manner, maintaining system fuel diversity and reducing GHG emissions. FPL's analysis indicated that adding the proposed Turkey Point Nuclear Units 6 and 7 in 2018 and 2020, respectively, would be the best plan to meet these objectives. Because of the nature of these proposed additions, FPL would be required to obtain a Determination of Need to support a site certification for each of these units. In this proceeding, FPL seeks a Need Determination for Turkey Point 6 & 7 and associated transmission facilities.

In order to determine how adding nuclear generation to FPL's portfolio compared to continuing to add natural gas-fired generation, or adding new coal-fueled IGCC generation, FPL conducted economic, fuel diversity and GHG emission evaluations to compare a resource plan that includes the addition of Turkey Point 6 & 7 in 2018 and 2020, respectively, to an alternate plan that includes the addition of gas-fueled generation instead of nuclear generation in those years, and to another alternate resource plan that includes the addition of IGCC generation instead of nuclear generation. FPL utilized 9 of forecasted fuel costs and environmental compliance costs in these analyses in order to reflect the range of uncertainty regarding future fuel costs and environmental requirements. The results of those analyses showed that the resource plan with Turkey Point 6 & 7 is more cost effective than the alternate plans that do not include new baseload nuclear generation.

The resource plan with Turkey Point 6 & 7 provides the only effective means of maintaining fuel diversity in FPL's system in 2018 and 2020, which is essential in maintaining system reliability and mitigating the effect of volatility in the price of natural gas. Furthermore, the addition of Turkey Point 6 & 7 is a necessary part of any strategy to reduce GHG emissions in the future, even while demand for electricity continues to increase.

In short, FPL needs Turkey Point 6 & 7 to maintain system reliability, to maintain system fuel diversity, to provide adequate electricity at a reasonable cost to its customers and to reduce GHG emissions. There is not sufficient additional cost-effective DSM or other renewable resources available to mitigate the need for these new nuclear baseload units.

FPL is also requesting that any need order reflect strong support for the Project, affirming the importance of taking steps now to preserve nuclear as a resource option to meet needs as early as 2018, acknowledging the risks and costs associated with a project of such magnitude, and clearly indicating the importance of, and Commission's intent to provide, continued regulatory support throughout the process.

Therefore, the Commission should grant FPL's petition for a determination of need for Turkey Point 6 and 7 in 2018 and 2020, respectively.