BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070650 -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

DIRECT TESTIMONY & EXHIBITS OF:

STEVEN R. SIM

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEVEN R. SIM

DOCKET NO. 07_____ - EI

OCTOBER 16, 2007

Q. Please state your name and business address.

A. My name is Steven R. Sim, and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what position do you hold?

A. I am employed by Florida Power & Light Company (FPL) as a Supervisor in the Resource Assessment & Planning Business Unit.

Q. Please describe your duties and responsibilities in that position.

A. I supervise a group that is responsible for determining the magnitude and timing of FPL's resource needs and then developing the integrated resource plan with which FPL will meet those needs.

Q. Please describe your education and professional experience.

A. I graduated from the University of Miami (Florida) with a Bachelor's degree in Mathematics in 1973. I subsequently earned a Master's degree in Mathematics from the University of Miami (Florida) in 1975 and a Doctorate in Environmental Science and Engineering from the University of California at Los Angeles (UCLA) in 1979.

While completing my degree program at UCLA, I was also employed full-time as a Research Associate at the Florida Solar Energy Center during 1977 - 1979. My responsibilities at the Florida Solar Energy Center included an evaluation of Florida consumers' experiences with solar water heaters and an analysis of potential renewable resources including photovoltaics, biomass, and wind power applicable in the Southeastern United States.

In 1979 I joined FPL. From 1979 until 1991, I worked in various departments including Marketing, Energy Management Research, and Load Management, where my responsibilities concerned the development, monitoring, and cost-effectiveness of demand side management (DSM) programs. In 1991, I joined my current department, then named the System Planning Department, as a Supervisor whose responsibilities included the cost-effectiveness analyses of a variety of individual supply and DSM options. In 1993, I assumed my present position.

Q. Are you sponsoring any exhibits in this case?

Yes. I am sponsoring the following Exhibits SRS-1 through SRS-11, which are attached to my direct testimony:

Exhibit SRS-1	Projection of FPL's 2007 - 2020 Capacity Needs
Exhibit SRS-2	Projected Incremental FPL DSM: 2006 – 2020
Exhibit SRS-3	Projection of FPL's 2007 – 2020 Capacity Needs: with Turkey Point 6 & 7
Exhibit SRS-4	The Three Resource Plans Utilized in the Analyses

Exhibit SRS-5 Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario

Exhibit SRS-6 Economic Analysis Results: Total Costs and Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

Exhibit SRS-7 Economic Analysis Results: Matrix of Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

Exhibit SRS-8 Economic Analysis Results: Breakeven Cost for Nuclear Capital Costs for All Fuel and Environmental Compliance Cost Scenarios

Exhibit SRS-9 Economic Analysis Results: Projection of Approximate Bill Impacts with Turkey Point 6 & 7: 2009 - 2021

Exhibit SRS-10 Non-Economic Analysis Results: FPL System Fuel Mix Projections by Plan

Exhibit SRS-11 Non-Economic Analysis Results: FPL System CO_2 Emission Projections by Plan.

Q. Are you sponsoring any sections in the Need Study document?

A. Yes. I am co-sponsoring Sections II, III, V, VII, and IX of the Need Study document. I also sponsor Appendices B and G, and co-sponsor Appendices C and H.

Q. What is the scope of your testimony?

A. My testimony addresses ten main points:

(1) I briefly discuss FPL's integrated resource planning (IRP) process and note that the application of the IRP process in 2006/2007 focused in large part on promoting fuel diversity in FPL's system.

(2) I identify FPL's additional resource needs for 2007 - 2020, with particular emphasis on the 2018 through 2020 time period, and explain how these needs were determined.

(3) I discuss why demand side management (DSM) cannot reasonably be expected to eliminate these resource needs.

(4) I present an overview of the analysis approach used to evaluate the addition of the two new nuclear units, Turkey Point 6 & 7, to FPL's system versus the most likely non-nuclear competing technologies, natural gas-fired combined cycle (CC) units or coal-fired integrated gasification combined cycle (IGCC) units, from both an economic and non-economic perspective. The economic analysis was designed to identify the breakeven capital costs for these new nuclear units versus the competing technologies. The non-economic analysis provides projections of FPL's system fuel mix and system carbon dioxide (CO_2) emissions.

(5) I discuss three resource plans: one plan assuming nuclear units are added in 2018 and 2020, a second plan assuming CC units are added in 2018 and 2020, and a third plan assuming IGCC units are added in 2018 and 2020.

(6) I discuss FPL's use of various fuel cost forecasts and environmental compliance cost forecasts that were combined into 9 fuel cost and environmental compliance cost scenarios that were used in the analyses of the three resource plans.

(7) I present the results of FPL's economic analyses of the three resource plans that identify what the breakeven nuclear capital costs are projected to be for each of these scenarios. A projection of approximate customer bill impacts from the addition of the two new nuclear units is also provided.

(8) I present the results of the non-economic analysis of the three resource plans that includes projections of system fuel mix by fuel type and system CO_2 emissions.

(9) I discuss the adverse consequences in regard to economics, system fuel diversity, and CO_2 emission impacts that would occur if a Need Determination for the two new Turkey Point nuclear units is not approved.

(10) I present the conclusions I draw from the above referenced analyses.

Q. What is your primary conclusion?

A. Based on the analyses that have been performed, the two new Turkey Point nuclear units in 2018 and 2020 are currently projected to be the economically competitive choice for addressing FPL's future capacity needs in the 2018 through 2020 time period. In addition, these two new nuclear units are also projected to be the best choices for both promoting fuel diversity and lowering FPL's CO_2 system emissions beginning in 2018. The increase in the annual amount of nuclear energy produced from Turkey Point 6 & 7 is equivalent in 2021 to the annual total electrical usage of approximately 1,075,000 residential customers. For these reasons, it makes sense to continue to pursue the option of additional capacity and energy from new nuclear generating units at Turkey Point in 2018 and 2020.

Q. Please summarize your testimony.

A. FPL's 2006/2007 resource planning work determined that FPL has future resource needs starting in 2012 and growing through 2020 to a total of 6,156 MW of incremental capacity (power plant construction and/or new purchases) or 5,130 MW at the generator of additional cost-effective DSM. All DSM that is known to be cost-effective through 2014, plus an assumption that currently projected annual implementation levels of cost-effective DSM will be continued for 2015-2020, have already been reflected in FPL's 2006/2007 resource planning work. This amount of known and projected cost-effective DSM through 2020 is 1,899 MW. In order to fully meet FPL's resource needs of 5,130 MW through 2020 with DSM, one would have to assume the availability of approximately three times this amount of 1,899 MW of cost-effective DSM that FPL already projects in its resource planning projections.

Consequently, FPL cannot meet its resource needs through 2020 solely with DSM. Therefore, in order to meet FPL's summer reserve margin criterion of 20% through 2020, FPL needs new capacity (power plant construction and/or purchase). This large capacity need provides significant opportunities for a wide variety of options – renewable energy options, new fossil units, additional DSM and other energy efficiency options (such as building standards and appliance standards), plus new nuclear generating capacity – to play a role in FPL's resource plans.

FPL also determined that a key objective during this resource planning cycle was to select capacity options that would promote FPL's system fuel diversity. FPL projects that the earliest practical deployment schedule for new nuclear units would bring these units in-service no earlier than 2018 and 2020 if it acts now. Therefore, FPL is seeking an affirmative determination of need that will enable it to pursue the option of two nuclear units at its existing Turkey Point site, one in 2018 and one in 2020.

FPL developed three resource plans for analyzing these nuclear unit additions. These three resource plans include: a Plan with Nuclear that included the two new nuclear units described above, an alternate Plan without Nuclear – CC that added CC units in 2018 and 2020, and another alternate Plan without Nuclear – IGCC that added IGCC units in 2018 and 2020. The use of these resource plans allows the evaluation of the economic and non-economic impacts of adding the new nuclear units. FPL's analyses compared the Plan with Nuclear to these two alternate Plans without Nuclear under 9 scenarios of forecasted fuel costs and environmental compliance costs.

Because of the uncertainty in capital costs for new nuclear units, the economic analysis consisted of two steps. In the first step the cumulative present value of revenue requirements (CPVRR) for the three resource plans was calculated for each of the 9 scenarios. The Plan with Nuclear that included Turkey Point 6 & 7 assumed zero capital costs for the two new nuclear units. In the second step, the CPVRR cost differential between the resource plans for each scenario was divided by the CPVRR cost equivalent of $1/kW of new nuclear capital cost. The resulting value is a "breakeven" cost in terms of $/kW of nuclear capital cost for a given scenario; i.e., what the capital cost for the two new nuclear units can be and have identical total CPVRR costs for the resource plans.

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, are generally higher than FPL's current cost estimate range for new nuclear units of $3,108/kW to $4,540/kW in 2007$. Therefore, it is reasonable to expect 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. Customer bill impacts from the addition of Turkey Point 6 & 7 will depend upon a number of factors including, but not limited to, the capital cost of the new nuclear units, fuel costs, and environmental costs. Using a capital cost assumption for the new nuclear units of $3,800/kW in 2007$, approximately the mid-point of FPL's projected capital cost range, a customer bill impact for one of the 9 scenarios ranging from approximately $0.43 to $5.80 per 1,000 kWh is projected for the 2009 – 2020 time period. The projected bill impact is -$0.36 per 1,000 kWh, a reduction, for 2021, the first year in which both of the new nuclear units are in-service for a full year.

The non-economic analysis 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 increased nuclear energy generation from Turkey Point 6 & 7 would serve the total electricity needs of about 1,075,000 residential customers in 2021. The Plan with Nuclear also has a significant advantage in regard to FPL system CO_2 emissions compared to both of the two alternate plans.

I. FPL'S INTEGRATED RESOURCE PLANNING PROCESS

Q. What are the objectives of FPL's integrated resource planning process?

A. The fundamental approach used in FPL's IRP process was developed in the early 1990s and has been used and refined since that time to accomplish three primary objectives: 1) determine the timing of when new resources are needed to maintain the reliability of the FPL system; 2) determine the magnitude (MW) of the needed resources; and 3) determine the type of resources that should be added. The analysis required to accomplish the first two objectives – determining the timing and magnitude of needed resources – is often referred to as the reliability assessment portion of FPL's IRP process and these analyses are relatively straightforward.

The analyses required to accomplish the third objective – determining the type of resources that should be added – is more complex and involves the consideration of both economic and what I'll refer to as non-economic perspectives. From an economic perspective, the type of resources that should be added is primarily based on a determination of the resources that result in the lowest system average electric rates for FPL's customers. It should be noted that when only power plants or power purchases are the resources in question, the determination can be made on the basis of lowest total costs (cumulative present value of revenue requirements, CPVRR). The lowest total cost perspective (CPVRR) in these cases is the same as the lowest average electric rate perspective, because the number of kilowatt-hours over which the costs are distributed does not change, as would be the case when DSM resources are being examined.

However, the decision of what type of resources to add is also influenced by considerations such as whether a resource can be brought into service on FPL's system in time to meet a projected capacity need and whether a given resource or resource plan is best suited to address system concerns that may have been identified in the resource planning process. While these system concerns usually have an economic component or impact, they are often discussed in quantitative, but non-economic terms, such as percentages, etc. rather than in terms of dollars.

Q. What are these system concerns and how are they addressed in FPL's IRP process?

A. One of the system concerns is that of promoting (i.e., maintaining and/or enhancing) system fuel diversity. FPL's IRP work in 2006/2007 has directly addressed this concern. Accordingly, in addition to this proposal for the addition of two new nuclear units to address FPL's capacity needs in 2018 and 2020, FPL has separately proposed capacity uprates to its four existing nuclear units. Promoting system fuel diversity will continue to be an issue that FPL's resource planning work addresses in coming years. The issue of fuel diversity is further discussed in FPL witnesses Yupp's and Silva's testimonies.

Another system concern is maintaining a regional balance between load and generating capacity, particularly in Southeastern Florida. This concern has been satisfactorily addressed for the near-term with the addition of Turkey

Point 5, West County Energy Center (WCEC) 1, and WCEC 2 generating units, all in Southeastern Florida.

A third system concern, that of moving in the direction of lowering utility system CO_2 emissions over the long-term, has been prompted by growing interest in reducing greenhouse gas emissions.

System concerns such as these are generally addressed in the IRP process in regard to meeting the third objective described above - determining the type of resources that should be added. The selection of resource options and resource plans for analyses is done with these system concerns in mind. Then, in conducting the analyses needed to determine which resource options and resource plans are best for FPL's system, both the economic and non-economic analyses are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan.

Q. Did FPL utilize its IRP process in the analyses that led to FPL seeking approval of a determination of need for two new nuclear units in 2018 and 2020?

A. Yes. However, the process was modified for this analysis as will be discussed shortly. FPL utilized its IRP process to first determine the timing and magnitude of resource needs over a multi-year period. It was determined that FPL's first resource need was in 2012 and that this resource need increased every year thereafter, including the 2018 through 2020 time period for which it is possible to address capacity needs with new nuclear units, and in all years after 2020. Second, FPL identified resource options and resource plans that could meet these 2018 and 2020 capacity needs. FPL then determined through economic analyses what the CPVRR costs were in 2007$ for these competing resource plans.

However, because it is not possible to accurately determine the capital costs of new nuclear units at this time, FPL's IRP process was modified to enable FPL to address this fact. The CPVRR total cost differences between the resource plans were used to determine what the capital costs for new nuclear units in 2018 and 2020 could be and have the CPVRR costs for the resource plans be equal. FPL refers to this as a "breakeven" capital cost analysis.

In addition, the impacts on FPL's system in regard to promoting system fuel diversity and of lowering system CO_2 emissions were determined for each of these resource plans.

Q. At the same time FPL has filed for approval of a Determination of Need for Turkey Point 6 & 7 in this docket, FPL has also recently filed for approval of a Determination of Need for capacity uprates for its four existing nuclear units. Do these two filings share common elements?

A. Yes. These two filings contain a number of common elements. The major common elements include: load forecast, fuel cost forecasts, environmental compliance cost forecasts, purchase power projections, and DSM projections. In addition, the two filings have common financial and economic assumptions including escalation rates, cost of capital, allowance for funds used during construction (AFUDC) rates, etc.

The analyses that support both filings compare alternate resource plans. One resource plan is common to both filings although it is described by different names in the two filings. It is described as the Plan with Nuclear in this filing and is described as the Plan with Nuclear Uprates in the other filing. In both filings this resource plan contains the nuclear capacity uprates, the new Turkey Point 6 & 7 nuclear units, and the same non-nuclear unit additions.

Q. In its analyses, what in-service dates were assumed for the Turkey Point 6 & 7 units?

A. For purposes of its analyses, FPL assumed that the in-service dates for the two new nuclear units are June 2018 for Turkey Point 6 and June 2020 for Turkey Point 7, the earliest practical deployment schedule for the new nuclear units. However, given the long lead times inherent in these assumed dates, these dates could change.

II. FPL'S FUTURE RESOURCE NEEDS

Q. How did FPL decide it needed additional resources and what was the magnitude of the needed resources?

A. FPL uses two analytical approaches in its reliability assessment to determine the timing and magnitude of its future resource needs in order to continue to provide reliable electric service to its customers. The first approach is to make projections of reserve margins both for Summer and Winter peak hours for future years. A minimum reserve margin criterion of 20% is used to judge the projected reserve margins. The 20% reserve margin criterion is based on the reliability planning standard FPL currently believes is necessary to ensure reliable service, and which FPL committed to maintain and the Commission approved in Order No. PSC-99-2507-S-EU.

The second approach is a Loss-of-Load-Probability (LOLP) evaluation. Simply stated, LOLP is an index 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 the reserve margin approach, the LOLP approach looks at the daily peak demands for each year, while taking into consideration the probability of individual generators being out of service due to scheduled maintenance or forced outages. LOLP is typically expressed in units of "numbers of times per year" that the system demand could not be served. FPL's LOLP criterion is a maximum of 0.1 days per year. This LOLP criterion is generally accepted throughout the electric utility industry.

For a number of years, FPL's projected need for additional resources has been driven by the summer reserve margin criterion. This again was the case in

FPL's 2006/2007 reliability assessment work that was the basis for FPL's projected resource needs. Assuming that the proposed nuclear uprates are in-service in the targeted in-service years of 2011 and 2012, significant additional resources (MW) are needed for each year beginning in 2013 to meet the summer reserve margin criterion of 20%. (A relatively small 180 MW need also exists in 2012.)

The additional incremental MW needed by the Summer of 2013 is projected to be 493 MW if the resource is to be provided by a supply side option (i.e., power plant construction or purchase) or, due to the 20% reserve margin criterion, (493 MW/1.20 =) 411 MW if provided by a DSM-based reduction to the forecasted peak load. The similar incremental need values for the Summers of 2014 - 2020, respectively, are an additional 450 MW (supply) or 375 MW (DSM) for 2014, an additional 640 MW (supply) or 533 MW (DSM) for 2015, an additional 1,933 MW (supply) or 1,611 MW (DSM) for 2016, an additional 659 MW (supply) or 549 MW (DSM) for 2017, an additional 645 MW (supply) or 538 MW (DSM) for 2018, an additional 641 MW (supply) or 534 MW (DSM) for 2019, and an additional 696 MW (supply) or 580 MW (DSM) for 2020. Furthermore, the trend of annual increased resource needs of at least 600 MW (supply) or 500 MW (DSM) continues after 2020.

These incremental annual resource need values add to a cumulative need value for 2012 - 2020 of approximately 6,156 MW if the resource need is to be met by supply options. The corresponding cumulative resource need for this period is approximately 5,130 MW if the resource need is to be met by DSM. The projections of resource needs to meet the Summer reserve margin criterion for 2012 - 2020 if the resource needs are to be met by supply options are shown in Exhibit SRS-1. This document also shows that, if these levels of supply additions are added to meet the summer needs, these additions will also easily satisfy the smaller resource needs to meet the winter reserve margin criterion. This projection of capacity needs was used in the development of the three resource plans analyzed for this filing.

These projections rely upon FPL's IRP 2006 load forecast that was developed in September 2006 and used in both FPL's recent Need filing for advanced technology coal units and the current Need filing for the proposed capacity uprates at FPL's existing four nuclear units. This same load forecast was used in the economic and non-economic analyses discussed in the remainder of my testimony. This load forecast is discussed by FPL witness Green in his testimony.

Q. Do these resource need projections take into account the proposed capacity uprates to FPL's existing four nuclear units?

A. Yes. As previously mentioned, these projections include the proposed 414 MW of capacity uprates to FPL's four existing nuclear units in 2011 and 2012. Without the inclusion of these uprates, FPL's projected resource needs through 2020 discussed above would have been 414 MW higher.

This projection of future capacity need does not take into account the impact of any other additional generating capacity from existing FPL generating units or any new FPL generating units after the WCEC 1 and 2 units added in 2009 and 2010, respectively.

Q. Do these resource need projections take into account any projections of purchased power beyond what is currently under contract?

A. Yes. 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. However, new contractual arrangements have not yet been developed.

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.

Although no contracts have been developed in regard to any of these six renewable capacity options, for purposes of the analyses conducted for this filing, FPL is assuming that all 287 MW of firm capacity will be in place to serve FPL's customers. The 143 MW from the three municipal waste-to-energy facilities currently under contract is assumed to continue from the above-mentioned contract expiration dates through 2026 when other contracts for smaller capacity amounts from these same facilities are scheduled to end. The 144 MW from the three renewable RFP proposals are assumed to be in place through their proposed end dates.

Arguably, assuming that every MW from these renewable options will be available and realized for the benefit of FPL's customers, might be considered overly, if not unduly, optimistic. At the very least, it serves to provide a conservative projection of FPL's future resource needs by lowering FPL's projected resource needs by 287 MW.

Q. **Why is the 1,933 MW incremental capacity need for 2016 so much larger than for the other years in the 2012 – 2020 time period?**

A. In addition to the forecasted peak load growth in 2016, two significant power purchases are projected to no longer be providing capacity and energy to FPL starting in 2016. One of these is a 931 MW power purchase agreement with the Southern Company that expires at the end of 2015. The other is a 381 MW power purchase from the St. Johns River Power Park (SJRPP). Due to Internal Revenue Service regulations, FPL will no longer be able to receive capacity and energy from the SJRPP agreement once a certain amount of energy has been received. FPL currently estimates that this point will be reached at the end of 2015. After accounting for the loss of these two capacity resources, the remaining capacity need attributed solely to FPL system growth is 621 MW (= 1,933 – 931 – 381). This 621 MW capacity amount attributable solely to projected load growth is similar to the annual capacity need amounts described earlier for other years.

III. DEMAND SIDE MANAGEMENT

Q. Do these projections of FPL's resource needs include all of the cost-effective DSM currently known to FPL?

A. Yes. These projections already incorporate all of the cost-effective DSM currently known to FPL through the year 2014 plus a projection of continued DSM implementation for 2015 – 2020 at currently planned annual implementation rates. This amount of DSM includes not only FPL's current DSM Goals, but also a significant amount of additional DSM through 2014 that FPL has identified as cost-effective, and which the Florida Public Service Commission has approved, since the current DSM Goals were established. In addition, these projections include an assumption that FPL will continue to implement additional, cost-effective DSM for each of the remaining years 2015 through 2020 at the same implementation rates that are projected for the years immediately preceding 2015. FPL witness Brandt's testimony provides additional information regarding the DSM Goals and additional DSM amounts.

In summary, FPL now projects implementing 1,899 MW at the generator of additional Summer DSM demand reduction capability from August 2006 through August 2020 as presented in Exhibit SRS-2. This amount of additional DSM is incorporated into the projection of FPL's resource needs presented in Exhibit SRS-1 and discussed above.

Q. Could FPL meet its 2012 through 2020 resource needs with DSM?

A. No. As discussed above, FPL's resource needs presented in Exhibit SRS-1 already account for all of the reasonably achievable, cost-effective levels of DSM for FPL through 2014, plus the assumption that this trend of implementing additional cost-effective DSM would be continued through 2020, as is presented in Exhibit SRS-2. As shown in this document, FPL's DSM activities will result in 1,899 MW at the generator of incremental DSM from August 2006 through August of 2020. In other words, FPL's reliability assessment has already captured the cost-effective DSM known to be available on FPL's system, plus a projection that this DSM trend will continue, resulting in almost 1,900 MW of incremental cost-effective DSM. Even after accounting for the very large amount of incremental DSM, FPL still needs a significant amount of additional capacity (6,156 MW) to meet its resource needs.

As previously discussed, if the resource needs for the years 2012 through 2020 were to be met solely by additional new DSM resources, one would have to assume the availability of an additional 5,130 MW (= 6,156 MW / 1.20) of cost-effective DSM to meet these resource needs. It is unrealistic for one to assume the existence of another 5,130 MW of cost-effective, incremental DSM to meet these needs. This is especially so considering that this amount of DSM is approaching three times the maximum amount (1,899 MW) of cost-effective DSM known to FPL, plus projections, for the August 2006 through August 2020 time period, and that is already included in the projection of capacity needs. Consequently, cost-effective DSM could not meet FPL's incremental resource needs for this time period. These resource needs must be met by capacity (construction and/or purchase) additions; i.e., the system resource needs presented in this testimony are actually capacity needs and will be referred to as such in the remainder of my testimony.

Q. What would FPL's projected resource need be without the contribution of the nuclear uprates capacity, the renewable energy purchase capacity, and FPL's DSM?

A. The 6,156 MW of capacity need that is shown in Exhibit SRS-1 would increase to a capacity need of 8,350 MW if one were to ignore the projected contributions of 414 MW from the nuclear uprates, the 287 MW from the renewable energy purchases, and 1,493 MW of DSM capacity equivalence. The DSM capacity equivalence number is derived from Exhibit SRS-2 by first calculating 1,244 MW of incremental DSM from 2010 to 2020 (3,390 MW for

2020 minus 2,146 MW for 2010 = 1,244 MW incremental), and then multiplying that value by 1.20 to account for FPL's 20% reserve margin criterion. The resulting projection of FPL's capacity need if these contributions were ignored would be 6,156 MW + 414 MW + 287 MW + 1,493 MW = 8,350 MW of need.

IV. OVERVIEW OF THE APPROACH USED TO ANALYZE THE NEW NUCLEAR GENERATING UNITS VERSUS NON-NUCLEAR GENERATING UNITS

Q. Please provide an overview of the analysis approach FPL utilized to evaluate the impacts of adding two new nuclear units to FPL's system versus the most likely non-nuclear options, CC and IGCC units.

A. The analytical approach FPL utilized can be summarized as follows. First, FPL developed one resource plan that includes the two new nuclear units. This resource plan is referred to in this filing as the Plan with Nuclear. In this resource plan, FPL assumed that the proposed two new nuclear units, Turkey Point 6 & 7, would be added, Turkey Point 6 by June 2018 and Turkey Point 7 by June 2020. FPL next developed a second resource plan that does not include any new nuclear unit additions, but assumes that CC units are added in 2018 and 2020. This plan is referred to in this filing as the Plan without Nuclear - CC. Finally, a third resource plan was developed that does not include any new nuclear unit additions, but assumes that IGCC units are added in 2018 and 2020. This plan is referred to in this filing as the Plan without Nuclear – IGCC. A comparable amount of capacity is added in 2018 and 2020 in all three resource plans.

These resource plans assumed specific, representative generating units for the 2011 – 2017 time period and utilized generic "filler" units for the 2021 – on time period. These resource plans are discussed in more detail later in my testimony. Second, economic and non-economic analyses were then carried out to compare the three resource plans.

The economic analyses were carried out in two steps. In the first step, the CPVRR amounts in 2007$ for the three resource plans were determined. In this first step, the assumption was made that the new nuclear units would have no capital costs for either generation or transmission facilities for reasons that will be discussed later in my testimony. In the second step, the differences in the CPVRR results for each of the resource plans were calculated and utilized to determine the amount of CPVRR capital costs for the new nuclear units that would make the total CPVRR costs equal for each resource plan. These capital costs, expressed in terms of 2007 dollars per kilowatt ($/kW), represent the "breakeven" capital costs for the new nuclear units. In addition, a projection of approximate customer bill impacts from the addition of Turkey Point 6 & 7 was also made.

The non-economic analysis compared FPL's system projections of fuel mix by fuel type and CO_2 emissions for the three resource plans. This analysis allows the fuel diversity and CO_2 emission impacts of the addition of two new nuclear units to be determined.

Q. You mentioned above that "resource plans" were used in the analyses. Why is it appropriate to perform the economic and non-economic analyses based on multi-year resource plans?

A. It is not only appropriate to do this, but also necessary if one is to fully capture and fairly compare all of the economic and non-economic impacts of different capacity options that could be added to a utility system.

For example, assume we are comparing Option A and Option B. Option A offers 500 MW of capacity and has a heat rate of 7,000 Btu/kWh while Option B has a 9,000 Btu/kWh heat rate, but offers 600 MW of capacity. Evaluating these options from a resource plan perspective allows one to capture the economic impacts of both the heat rate and capacity differences. The lower heat rate of Option A will allow it to be dispatched more than Option B, thus reducing the run time of FPL's existing units more than Option B will. This results in greater production cost savings for Option A. However, Option B's greater capacity means that it is better able to defer the need for future capacity additions. Therefore, Option B will get greater capacity avoidance benefits.

Only by taking a multi-year resource plan approach to the analysis can factors such as these be captured and effectively compared. In the economic analysis, the resource plans created addressed impacts to the FPL system through the year 2060 to address the projected 40-year life of new nuclear units that would be added in 2018 and 2020.

Q. Why are "filler" units needed in a resource plan analysis?

A. The three resource plans that FPL developed for use in the analyses each contained various unit additions to address FPL's capacity needs for the 2011 - 2017 time period as will be discussed later in my testimony. The generic "filler" units are also needed in a multi-year resource plan analysis as a proxy resource added to meet FPL's capacity needs in later years. In these analyses, filler units were used for 2021 – on (i.e., after the 2018 and 2020 options have been added in each resource plan). In this way the three resource plans being compared both meet FPL's reliability criteria for each year in the analysis period, ensuring both that the resource plans are comparable in regard to meeting the 20% reserve margin criterion and that the results of the evaluation of those plans are meaningful.

Q. How were the economic analyses performed?

A. The economic analyses were carried out using Resource Assessment & Planning's "integrated model." This model primarily consists of a Fixed Cost Spreadsheet and the P-MArea production costing model from P-Plus. The Fixed Cost Spreadsheet model captures all of the fixed costs (capital, fixed O&M, capital replacement, capacity payments for purchases, firm gas transportation, etc.) associated with the three resource plans. The P-MArea model captures variable costs (such as fuel, variable O&M, and environmental compliance costs) in its production costing calculations, projects the annual emission levels associated with the resource plans, and incorporates the effects of system transmission transfer limits on the dispatch of generating units. This integrated model approach was used in FPL's recent advanced technology coal unit filing and in FPL's current filing for capacity uprates for its four existing nuclear units.

Two additional spreadsheets are also used in analyzing the resource plans. One spreadsheet was used to download the annual emission levels projected in P-MArea and then to calculate the annual net costs for those emissions after allowances, if applicable, are accounted for. The other spreadsheet projected the annual amounts of nuclear capital costs that would be incurred both prior to, and after, the in-service dates of the nuclear units. This projection was then used to develop a CPVRR cost value for a $1/kW in 2007$ capital cost for a new nuclear unit. This CPVRR value was then used in determining the breakeven capital costs for the nuclear units.

Q. **What were the bases of comparison for the economic and non-economic analyses of the three resource plans?**

A. In regard to the economic analyses, the basis of comparison was the calculated breakeven capital cost of the nuclear units that was compared to the non-binding capital cost estimates for the new nuclear units. The breakeven capital cost includes both the generation and transmission capital cost of the units and is presented in terms of $/kW in 2007$. A range of breakeven capital costs was developed using a number of combinations (or scenarios) of fuel cost forecasts and environmental compliance cost forecasts.

In regard to the non-economic analyses, there are two bases of comparison. The first basis of comparison is a projection of annual system energy by fuel type, or system fuel mix, for the three resource plans using the same fuel cost and environmental compliance cost scenarios for the 2018 – 2021 time period. This four-year time frame was chosen because it addresses the time period starting when the first nuclear unit is assumed to come in-service (2018) through the first year that both nuclear units are in-service for a full year (2021).

The second basis of comparison is a projection of cumulative CO_2 emissions for the FPL system under each of the three resource plans for the 2007 – 2021 time period.

Q. Why did FPL utilize more than one fuel cost forecast and more than one environmental compliance cost forecast in its analyses?

A. In order to address the potential impacts of uncertainty in both future fuel costs and environmental compliance costs on generating unit options – nuclear, CC, and IGCC units - that use different types of fuel, namely uranium, natural gas, and coal and which have different emission profiles, three different fuel cost forecasts and four different environmental compliance cost forecasts were used in the analyses. These three fuel cost forecasts and four environmental compliance cost forecasts could be combined into 12 potential scenarios of forecasted fuel costs and environmental compliance costs. After considering these 12 possible scenarios, it was determined that three of the scenarios, those with a combination of a low gas cost forecast and a medium-to-high CO_2 environmental compliance cost forecast, were very unlikely to occur. Consequently, these three scenarios were dropped from further consideration and FPL utilized the 9 remaining scenarios of fuel cost forecasts and environmental compliance cost forecasts in its analyses.

The specific fuel cost forecasts are discussed in detail in FPL witnesses Yupp's and Villard's testimonies and the specific environmental compliance cost forecasts are discussed in detail in FPL witness Kosky's testimony.

V. THE THREE RESOURCE PLANS UTILIZED IN THE ANALYSES

Q. Please discuss the development of the three resource plans used in the analyses.

A. As FPL began its analyses, it considered 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. However, in order to fully evaluate this possibility, 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 and Plan without Nuclear - IGCC.

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.

In regard to meeting the first criterion listed above, the 20% reserve margin criterion, Exhibit SRS-3 was developed to present a revised projection of FPL's capacity needs assuming that Turkey Point 6 & 7 are added in 2018 and 2020, respectively. Each unit is assumed to provide 1,100 MW of capacity. By comparing this document with Exhibit SRS-1, it is clear that the capacity needs are lower by 1,100 MW in 2018 and 2019, and by 2,200 in 2020.

Exhibits SRS-1 and SRS- 3 were then utilized to develop the three resource plans. These three plans are presented in Exhibit SRS-4. The three resource plans are identical through 2017 and all of the plans meet all of the criteria discussed above.

Q. Does the use of an assumed capacity of 1,100 MW each for the two new nuclear units discussed above mean that FPL has decided upon a size for these new nuclear units?

A. No. As discussed in several places in FPL's filing documents, FPL is currently examining different new nuclear unit technologies that would result in capacities for the new nuclear units ranging from approximately 1,100 MW to 1,520 MW per unit. For analysis purposes it is necessary to select a capacity rating for these units and a unit capacity of 1,100 MW was selected for these analyses.

Q. Is the Plan with Nuclear a dynamic long-term resource plan?

A. Yes. By definition, any long-term resource plan, such as the three resource plans utilized in these analyses, is a dynamic plan that is subject to change as conditions change.

As demonstrated through this filing, FPL believes that the nuclear units included in the Plan with Nuclear are currently projected to be the best choice for meeting FPL's capacity needs from an economic perspective, for promoting fuel diversity in FPL's system, and for lowering FPL system CO_2 emissions starting in 2018.

The other capacity additions shown in the Plan with Nuclear (and in the Plan without Nuclear – CC and Plan without Nuclear - IGCC) in the 2011 – 2017 time period are reasonable assumptions for meeting system capacity need requirements at the time of this filing. All new generating unit additions in the three resource plans for the 2011 – 2017 time period are assumed to be new CC unit additions.

To date, none of the new advanced technology coal generating units for which recent approval has been sought in Florida has received both Need and permitting approval. Therefore, it appears possible that any new generating unit additions in the relative near-term will be gas-fired. Consequently, the new generating units included, for analysis purposes, in these resource plans in the 2011 – 2017 time period are CC units similar to the 3x1 G technology (G) CC units being built at FPL's WCEC site or 2x1 G CC units. However, because FPL is not at this time making definitive selections for 2011 - 2017, these CC additions would be re-evaluated in the future using updated information when it is necessary to make those resource decisions. FPL will evaluate a variety of resource options including additional DSM, renewable energy options, gas-fired and coal-fired generating units, and power purchases prior to making its eventual decision on how best to meet its resource needs for the 2011 – 2017 time period and for the 2021 – on time period.

In addition, as previously discussed, for purposes of these analyses FPL has included 6 renewable energy purchases totaling 287 MW. At the time of this filing no contracts regarding any of these 6 capacity options have been entered into.

Therefore, although a number of the capacity additions assumed for the three resource plans may ultimately change in the future due to re-evaluation and/or evolving factors, these capacity additions are reasonable and representative additions for all years for analysis purposes. Regardless of whether these other capacity additions may change, FPL believes such changes would be applicable to all three resource plans so that the centerpiece of the Plan with Nuclear, the two new nuclear units themselves, will remain as potentially the best option to add. The new nuclear units will provide capacity to meet FPL's future resource needs, plus promote fuel diversity and lower system CO_2 emissions.

Q. In developing the resource plans, what assumptions were made in regard to the near-term, 2011 - 2017, unit additions?

A. Other than the previously mentioned 287 MW of additional renewable energy purchases and 414 MW of capacity uprates at FPL's four existing nuclear units, all capacity additions in all three resource plans were assumed to be new generating units. In developing the resource plans presented in Exhibit SRS-4, several assumptions were made regarding these new unit additions for 2011 - 2017 time period.

First, it was assumed for analysis purposes that all new unit additions in the resource plans would have a June 1 in-service date for the respective year in which the capacity addition is needed to meet the reserve margin requirement. Second, sites for the assumed CC units in the 2011 – 2017 time period are not known (in large part because no decision to build these new CC units has been made as discussed above). However, in order to develop costing for these assumed CC units, costs and performance characteristics for a greenfield CC of similar design and capacity as the two 3x1 G CC units being constructed at FPL's WCEC site were used.

Third, in regard to the size of the CC units included in the three resource plans in the 2011 – 2016 time period, the same size (1,219 Summer MW representing a 3x1 G CC unit) as the WCEC units was assumed. For 2017, a 2x1 G CC unit with a capacity of 812 MW was assumed. Finally, all three resource plans are identical in terms of their capacity additions for the 2011 – 2017 time period.

Q. Is the fact that all three resource plans have the same type of capacity additions in the 2011 - 2017 time period important in regard to the analyses that were conducted?

A. Yes. As previously discussed, FPL does not yet know what type of capacity additions will eventually be made in the 2011 – 2017 time period. These selections will be made at later dates. In regard to the analyses presented in this filing, the system impact of adding two new nuclear units in 2018 and 2020, respectively, will largely (if not totally) be unaffected by the type of capacity added in 2011 – 2017. Therefore, the type of capacity options selected for inclusion in the analyses in 2011 - 2017 should not be viewed as critical factors in the analyses. The fact that the three resource plans are identical in the 2011 – 2017 time period ensures this is the case for analysis purposes.

Q. Please discuss the 3x1 G CC unit in 2011 assumed for each of the resource plans.

A. Because FPL is constructing 3x1 G CC units with in-service dates of 2009 and 2010 at its WCEC site, it is anticipated that significant construction cost savings are possible if a third unit of identical design could be built for 2011 at a location near the WCEC site because key personnel in regard to the engineering and construction of the units could move from the WCEC 1 & 2 work directly to the construction of the 2011 unit. Second, FPL's preliminary analyses show that system fuel savings from an earlier (2011 instead of 2012) 3x1 G CC unit would be beneficial to FPL's customers even without these potential construction cost savings if an earlier unit could be built.

Although FPL has made no firm decisions at the time of this filing to proceed with a 2011 CC, for analysis purposes in this filing it was decided to assume that such a unit would be included in both resource plans.

Q. How does the assumption of a 2011 CC unit impact the economic and non-economic analyses of the three resource plans?

A. Because the 2011 CC unit is assumed to be in each of three resource plans, it has no impact on the relative differences between the three resource plans in regard to the economic and non-economic analyses.

Q. In developing the resource plans, what assumptions were made in regard to additions for the period 2021 - on?

A. The remainder of FPL's capacity needs for 2021-on are assumed to be met by the requisite number of unsited 2x1 F technology (F) CC filler units to meet FPL's system reserve margin requirements. The timing and number of these filler units varies slightly between the three resource plans due to the difference in the capacity of the nuclear units (1,100 MW), the 3x1 G CC units (1,219 MW), and the IGCC units (600 MW) added in 2018 and 2020. The decision to utilize 2x1 F CC units as the filler units for the 2021-on time period was made to minimize the potential impact that differences in unit types for filler units between the resource plans in these latter years might have on the analysis results. And, as previously discussed for the capacity options included in the resource plans for the 2011 – 2017 time period, these 2x1 F CC filler units do not represent FPL's definitive resource plan for the 2021 – on time period. They are utilized for analysis purposes solely to better focus the analysis on the resource decision years of 2018 – 2020.

Q. How would the Plan with Nuclear change if the size of the new nuclear units were to change from 1,100 MW to approximately 1,520 MW?

A. As previously mentioned, FPL has steadily growing cumulative resource needs each year after 2012 so such an increase in the capacity of the new nuclear units could definitely be utilized. An increase of approximately 420 MW (= 1,520 MW – 1,100 MW) of capacity for each of the nuclear units would introduce a change to the previously described Plan with Nuclear assuming that no other change to the plan occurred prior to 2018.

This change to the Plan with Nuclear is that the additional 840 MW (= 420 MW per unit x 2 units) of capacity from the two new nuclear units would reduce the number of 2x1 filler units for the 2021 – 2040 time period from 38 to 37 and would also alter the timing of these filler unit additions. In addition, it is possible that changes to other factors (such as the project schedules or the load forecast) could result in a later in-service date for the second of two larger nuclear units.

In summary, a change in the size of the nuclear units from 1,100 MW to approximately 1,520 MW would have only a slight impact to the Plan with Nuclear after 2020; primarily reducing the number of, and changing the timing of, subsequent filler unit additions. The additional 840 MW would definitely be usable on FPL's system to meet future capacity needs. In addition, a greater amount of nuclear capacity would also be useful from both a fuel diversity perspective and a CO_2 emission reduction perspective.

VI. FUEL COST AND ENVIRONMENTAL COMPLIANCE COST FORECASTS AND SCENARIOS USED IN THE ANALYSES

Q. Please discuss the use of different fuel cost forecasts in the analyses.

A. 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. As indicated by this naming convention, the High Gas Cost forecast projects high natural gas costs, the Medium Gas Cost forecast projects medium natural gas costs, and the Low Gas Cost forecast projects low natural gas costs. In addition, forecasted nuclear fuel costs were also developed and used in the analyses.

These forecasts are provided in Appendix E of the Need Study Document. FPL witness Yupp's testimony addresses the fossil fuel forecasts and FPL witness Villard's testimony discusses the forecasted nuclear fuel costs.

Q. Please discuss the use of different environmental compliance cost forecasts in the analyses.

A. 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 (NOx), 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 are referred to as Env I through Env IV. These forecasts are provided in Appendix F of the Need Study Document. FPL witness Kosky addresses the environmental compliance cost forecasts in his testimony.

Q. How did FPL make use of the three fuel cost forecasts and four environmental compliance cost forecasts in its analyses?

A. As previously discussed, 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 cost forecast and medium-to-high environmental compliance cost forecasts for CO_2 based on

FPL's belief that medium-to-high environmental 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.)

VII. RESULTS OF THE ECONOMIC ANALYSES

Q. You previously indicated that FPL's IRP process was used in these analyses. How does the economic analysis used to compare these three resource plans compare to the economic analyses used in previous FPL determination of need filings?

A. The economic analysis approach utilized for analyzing the addition of two new nuclear units to FPL's system consisted of two steps. The first step is to develop and then compare the CPVRR costs for the Plan with Nuclear, the Plan without Nuclear – CC, and the Plan without Nuclear - IGCC. The analysis approach used in this step was virtually identical to the approach used in FPL's most recent Need filings (i.e., the filings for the Turkey Point 5, the WCEC 1 and 2, and the advanced technology coal generating units) and that is being used in FPL's current Need filing for capacity uprates at FPL's four existing nuclear generating units. 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. FPL witness Scroggs' testimony addresses the subject of FPL's current projection of capital costs for new nuclear units in more detail. Consequently, FPL's economic analysis approach normally used to evaluate generation options has been modified to include a second step in the economic analysis.

The second step in the economic analysis used to compare the Plan with Nuclear with the alternate Plans without Nuclear 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 versus both CC and IGCC 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. Later in my testimony I will discuss how this breakeven capital cost range of potential generation and transmission capital costs compares to FPL's current non-binding capital cost estimate range for Turkey Point 6 & 7. FPL witness Scroggs' testimony addresses this non-binding cost estimate range based upon currently available information. FPL's capital cost estimate range will become more refined as the project continues to develop, especially as contracts are negotiated. Both the breakeven capital cost range and FPL's capital cost estimate range for the new units will continue to be updated as capital costs, fuel costs, environmental compliance costs, etc. evolve. This will provide ongoing points of comparison for FPL and the Commission as the project continues to develop.

Q. What costs are included in the first step of the economic analysis?

A. The first step of the economic analysis addresses total system costs for the FPL system including all fixed and variable costs, upstream gas costs, and cost of capital impacts for the two Plans without Nuclear. All of these costs, except for capital costs for the new nuclear units in the Plan with Nuclear as discussed above, were addressed in the analyses for all three resource plans.

However, for the three resource plans in this analysis, there were no upstream gas costs and cost of capital impacts (i.e., net equity adjustment) were not included. The upstream gas cost adder is essentially used to account for any additional gas transportation infrastructure cost resulting from the combined effect of one or more gas-fired option that is offered to FPL from an outside party for use in a resource plan (such as when bids are received by FPL in response to a Request for Proposals). Because FPL was assumed to supply all of the gas-fired units in each resource plan and the amount of gas needed by, and the timing of, those units were known in advance when creating the resource plans, all gas-related costs were accounted for in the unit and fuel cost information and no upstream cost adders were needed.

Likewise, all cost of capital impacts were already accounted for by assuming an incremental 55.8% equity / 44.2% debt investment for the new units assumed in each resource plan.

In order to show that the cost categories that were addressed in these economic analyses are similar to those addressed in FPL's recent Need filings (with the exception of capital costs for the new nuclear units), Exhibit SRS-5 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. As discussed above, because the costs for Upstream Gas Pipeline and Net Equity Adjustment are zero for each of the three resource plans, these cost categories are not shown.

Q. **How were the environmental compliance costs captured in the economic analyses?**

A. The environmental compliance costs were captured in the economic analyses through four steps. First, for each fuel cost and environmental compliance cost forecast scenario, the production costing analyses carried out with the P-

MArea model include a projection of the cost of allowances for each applicable emission category. Using the emission rates for each generation unit in FPL's system, P-MArea incorporates the allowance costs for each emission into the dispatch cost for each generating unit and dispatches the generating units on an economic basis to minimize system production costs.

Second, once the production cost projection was completed, the costs of the allowances included in the production costs were subtracted from the production cost projection. Third, the projected annual system emission levels were extracted from the P-MArea results and compared to a projection of the allowance levels for each emission that are assumed to be granted to FPL. (For purposes of these analyses, FPL assumed that no CO_2 allowances would be granted.) The annual differences between emissions and allowances for each emission type are then calculated.

Finally, for each year in which FPL's allowances are less than the projected amount of emissions for each emission type, the net deficit amount of allowances needed to cover emissions is multiplied by that year's projected allowance cost to derive a compliance cost for that year. Conversely, for each year in which FPL's allowances exceed the projected amount of emissions, the net excess amount of allowances is multiplied by that year's projected allowance cost to derive the value of the excess allowances that could be sold. This value is entered as a negative compliance cost for that year. If the amount of allowances exactly equals the projected emissions for a given year, there is no net deficit or excess allowances for the year and, therefore, a zero compliance cost is entered for that year. The compliance costs – positive, negative, or zero – for each year are then summed over the analysis period and the present value of that sum is calculated. This present value amount is then added to P-MArea's fuel and variable O&M costs to derive the System Variable Costs for that scenario.

Q. What conclusions can be drawn from these results shown in Exhibit SRS-5?

A. It is important to remember that the results shown in Exhibit SRS-5 provide a comparison of the costs for the three resource plans under only one of the 9 fuel cost and environmental compliance cost scenarios, the High Gas Cost Env I scenario.

Exhibit SRS-5 shows that the Plan with Nuclear is approximately $12.1 billion CPVRR in 2007$ less expensive than the Plan without Nuclear – CC, and approximately $13.3 billion CPVRR in 2007$ less expensive than the Plan without Nuclear – IGCC for this scenario.

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 to follow 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 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 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 Exhibit SRS-5 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.

Q. Please explain the nature of the Transmission System costs that are included in the analyses of the resource plans.

A. In practice, transmission capital expenditures are required when new power plants are built due to the need for new transmission facilities required to connect the new power plant additions to the transmission grid and to allow the transmittal of the new plant's output throughout the transmission system. These costs are referred to, respectively, as transmission interconnection and integration costs. In the economic analyses that FPL has performed, certain representative transmission interconnection capital costs are assumed, but no transmission integration capital costs were assumed for the 2011 – 2017 power plant additions that are identical in each of the three resource plans because no sites are known for the power plant additions assumed for analysis purposes. A designation of sites would be necessary in order to determine transmission integration costs. Similarly, for the filler units that appear in each of the plans for the 2021 – on time period, no transmission integration capital costs are assumed for the same reason.

In the Plan without Nuclear – CC and the Plan without Nuclear – IGCC, a total transmission capital cost addressing both transmission interconnection and integration of $500 million is assumed for the 2018 and 2020 capacity additions. This approach was taken because FPL's non-binding cost estimate range for Turkey Point 6 & 7 does include a similar total transmission capital cost estimate. Therefore, the inclusion of transmission capital costs for the 2018 and 2020 CC and IGCC capacity additions allows the calculation of breakeven capital costs for Turkey Point 6 & 7, and the subsequent comparison to the non-binding estimates, to be more meaningful. Given that these generating additions are of similar capacity in the same years, it is reasonable to assign a similar magnitude of cost for transmission capital costs.

In discussing the transmission facilities that are initially projected for Turkey Point 6 & 7, FPL witness Sanchez's testimony generally addresses how transmission analyses are carried out and what requirements are examined in these analyses.

Finally, as previously discussed, the cost of losses for the three resource plans are not included because sites for these assumed future generating unit additions are not known.

Q. What were the results of the first step of the economic analyses in which all 9 of the fuel cost and environmental compliance cost scenarios were included?

A. Exhibit SRS-6 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 High Gas Cost Env I scenario for the resource plans are the same as the total cost results presented for the resource plans in Exhibit SRS-5.

The total cost results shown on Exhibit SRS-6 for the remaining 8 scenarios have not been previously presented. However, by examining Exhibits SRS-5 and SRS-6 and considering that the System Fixed Costs shown on Exhibit SRS-5 do not change as the scenarios change, it is clear that all of the cost differences shown on Exhibit SRS-6 are due to the System Variable Cost category on Exhibit SRS-5. In other words, all of the differences are from changes in the fuel costs and/or environmental compliance costs.

In regard to the columns titled Total Cost Difference in Exhibit SRS-6, a negative value indicates that the costs for the Plan with Nuclear are lower than those of the alternate Plan without Nuclear to which the Plan with Nuclear is being compared (while a positive value would indicate that the costs for the Plan with Nuclear are higher than those of the comparable Plan without Nuclear).

Exhibit SRS-6 shows 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. This is because the capital cost of the new nuclear units is assumed to be zero for this first analysis step and the Plan with Nuclear will have lower variable costs.

Exhibit SRS-6 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 Exhibit SRS-6 are reorganized and presented again in matrix format in Exhibit SRS-7. The intent is to provide a somewhat more easily understood summary of the Total Cost Difference column results in Exhibit SRS-6, particularly as the results relate to the different fuel cost and environmental compliance cost forecasts.

Q. How would you summarize the information for each resource plan that is presented in Exhibit SRS-7?

A. First, as previously mentioned, these results of the first step in the economic analysis 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 in Exhibit SRS-7 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 are greater nearer the bottom of the matrix due to the higher environmental compliance costs nearer the bottom of the matrix and the fact that operation of the new nuclear units will result in essentially no SO_2, NOx, Hg, or CO_2 emissions.

Exhibit SRS-7 summarizes the results at the conclusion of the first step of the economic analysis. These results are then used to determine the breakeven capital costs of the new nuclear units.

Q. How did the second step of the economic analysis convert the results presented in Exhibit SRS-7 into breakeven nuclear capital costs?

A. 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 of the Need Study Document 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 Exhibit SRS-7, 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 calculation consists of dividing the CPVRR differences in Exhibit SRS-7 (the differences are presented in terms of millions of dollars) by 1.973 (also in terms of millions of dollars) to obtain the breakeven capital cost in $/kW in 2007$.

Q. What were the results of this second step of the nuclear capital cost breakeven analysis?

A. The nuclear breakeven capital costs are presented in Exhibit SRS-8. These breakeven capital costs range from $3,206/kW to $7,281/kW in 2007$ versus the Plan without Nuclear – CC, and ranged from $5,921/kW to $9,450/kW in 2007$ versus the Plan without Nuclear - IGCC. As expected from the CPVRR cost differences presented in Exhibit SRS-7, the higher breakeven costs were calculated for the scenarios on the left hand side of the matrices due to higher gas costs and nearer the bottom of the matrices due to higher environmental compliance cost forecasts.

Q. What conclusions did FPL draw from these economic analysis results?

A. 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 versus a comparable amount of CC or IGCC capacity added in the same years.

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

Q. Are there comparative aspects between the three resource plans that FPL has not quantified in these economic analyses results that would further favor the addition of Turkey Point 6 & 7?

A. Yes. There are four comparative aspects of the resource plans that have not been quantified in the economic analyses presented in these exhibits. All four of these comparative aspects would be expected to further favor the addition of Turkey Point 6 & 7. FPL has quantified one of these four comparative aspects. The remaining three comparative aspects have not been quantified for reasons that will be discussed shortly.

Q. Please discuss the one comparative aspect that FPL has quantified.

A. This comparative aspect involves the difference in CO_2 emissions between the nuclear, CC, and IGCC options. The economic analysis results presented in Exhibits SRS-5 through SRS-8 take this difference in CO_2 emissions into account by utilizing the CO_2 compliance costs from the different environmental compliance cost forecasts. The annual costs of CO_2 compliance for the CC unit, and even more so for the higher CO_2-emitting IGCC unit, are increased by the inclusion of these CO_2 compliance costs.

However, it is expected that another way to address CO_2 emissions will ultimately become an option: carbon capture and sequestration (CCS) which would result in physically preventing, at least to a significant degree, CO_2 emissions during power plant operation. Although this approach will result in lower CO_2 emissions, it will also result in higher capital and operating costs for the generating unit which utilizes CCS. In order to project what the overall cost impact of CCS might be on the breakeven capital cost estimates for Turkey Point 6 & 7 presented in Exhibit SRS-8, FPL reevaluated the Plan without Nuclear – IGCC after assuming that the 2018 and 2020 IGCC units would have CCS capability.

The capital and operating cost impacts of CCS are not currently known with any significant level of precision, so the actual values by which the breakeven costs are projected to change with the inclusion of CCS should be taken with reservations. It is for this reason that FPL has not presented the economic analysis results with CCS in the same format as Exhibits SRS-5 through SRS-8. However, the direction and approximate magnitude of these changes in the breakeven costs for Turkey Point 6 & 7 are meaningful.

When the Plan without Nuclear – IGCC was reevaluated with CCS costs, the breakeven previously presented in Exhibit SRS-8 increased significantly in each of the 9 scenarios. The range of increase in the breakeven costs ranged from a low of approximately $374/kW for the Medium Gas Cost Env IV scenario which features high CO_2 compliance costs to $2,836/kW for the Low Gas Cost Env I scenario which features low CO_2 compliance costs. In the Low Gas Cost Env I scenario, the higher capital and operating costs associated with CCS are not offset to any significant degree with reduced CO_2 compliance costs. In the Medium Gas Cost Env IV scenario, the high CO_2 compliance costs avoided by the CCS equipment at least partially offsets the higher CCS costs.

Exhibit SRS-8 already shows that, for all 9 scenarios, the breakeven costs for Turkey Point 6 & 7 versus IGCC capacity are already higher than the non-binding cost estimate range for new nuclear units. The inclusion of CCS costs would significantly increase these breakeven costs. Consequently, Turkey Point 6 & 7 are projected to be even more cost-effective versus IGCC capacity with CCS than versus IGCC capacity without CCS.

Q. What are the three remaining comparative aspects between the resource plans that FPL has not quantified?

A. These three comparative aspects include: (1) the differential in costs to maintain an on-site operating fuel supply between the nuclear, CC, and IGCC technologies; (2) the cost of losses; and (3) a periodic system concern in FPL's resource planning, a recurring imbalance between generation and demand in the Southeastern Florida region.

The first of these comparative aspects, on-site fuel supply, highlights the fact that 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 second comparative aspect that was not quantified is the cost of losses. As previously discussed, the cost of losses was not included in the economic analyses due to lack of knowledge regarding where new CC or IGCC units might be built in 2018 and 2020. However, if the costs of losses were to be calculated, the Turkey Point site for the new nuclear units would likely result in a significant advantage for the new nuclear units due to the proximity of the Turkey Point site to FPL's load center.

In addition, the fact that the Turkey Point site is located in the Southeastern Florida region means that Turkey Point 6 & 7 would likely also have an advantage in regard to the third comparative aspect that has not been quantified: the recurring regional imbalance between generation and load in the Southeastern Florida region. As mentioned earlier in my testimony, concern regarding this imbalance has been addressed for a number of years in the immediate future with the addition of the Turkey Point Unit 5 (added in 2007) and the addition of WCEC Units 1 and 2 (to be added in 2009 and 2010, respectively). However, as the electrical load continues to grow, additional generation will subsequently need to be built in Southeastern Florida or additional transmission facilities that increase the ability to import power into the region will have to be built. The addition of two large units, such as Turkey Point 6 & 7, in Southeastern Florida would certainly be helpful in addressing this imbalance.

Therefore, while neither the inherent on-site fuel supply benefits of Turkey Point 6 & 7, nor the benefits in regard to losses and regional imbalance associated with siting new nuclear units at Turkey Point, have been quantified in the economic analyses, these advantages are real. If a quantification of these advantages of Turkey Point 6 & 7 had been made, the projected nuclear breakeven capital costs for Turkey Point 6 & 7 would be increased beyond what is presented in Exhibits SRS-5 through SRS-8.

Q. **What is the approximate magnitude of the impacts to FPL's customers' bills that can be expected from Turkey Point 6 & 7?**

A. At this time it is not possible to precisely project bill impacts due to uncertainty in a number of key factors including, but not limited to, the capital costs for Turkey Point 6 & 7, the fuel costs, and the environmental compliance costs as has been previously discussed. However, monthly bills for FPL's customers can be expected to increase in years preceding the in-service dates of Turkey Point 6 & 7 as capital costs are recovered with no system fuel or environmental compliance cost savings yet occurring. Once the new nuclear units begin to come in-service and provide system fuel and environmental compliance cost savings, these savings begin to offset the capital and fixed operating costs. Over time, as the annual capital cost recovery amounts decline due to depreciation and the annual fuel and environmental compliance cost savings are expected to increase as these costs rise, the projected increased bill amounts will steadily decrease and then turn into bill savings.

In order to present a representative bill impact projection, FPL has assumed a capital cost of $3,800/kW in 2007$ for both Turkey Point 6 & 7. This assumed capital cost value falls in the middle of FPL's projected range of non-binding cost estimates for these new units. Then, an approximate customer bill impact has been calculated for the years 2009 – 2021 for one of the fuel cost and environmental compliance cost forecast scenarios, Medium Gas Cost Env II, and is presented in Exhibit SRS-9. The range of years 2009 – 2021 begin with the first year in which recovery of capital costs for the new nuclear units is projected through 2021 that is the first full year in which the two new nuclear units are projected to be in operation.

The calculation is based on a system average rate differential for each year between the Plan with Nuclear and one of the alternate Plans without Nuclear, the Plan without Nuclear - CC. The difference in the annual revenue requirements between the Plan with Nuclear and the Plan without Nuclear – CC is calculated first. Then this annual revenue requirement differential is divided by the projected annual sales amount to develop a system average rate differential for each year. Finally, this system average rate differential is multiplied by 1,000 kWh to develop an approximate customer bill impact between the two plans.

As shown in Exhibit SRS-9 the results of that calculation for a 1,000 kWh bill range from $0.43 to $5.80 for 2009 through 2020. For 2021, the first year in which both new nuclear units are in-service for a full year, the projected 1,000 kWh bill impact is -$0.36, a reduction.

Q. Has FPL projected the annualized base revenue requirements for the first 12 months of operation of Turkey Point 6 & 7?

A. Yes. However, it is not possible at this time to precisely project the annualized base revenue requirements, also referred to as non-fuel costs, because the capital costs for Turkey Point 6 & 7 are not yet known. As indicated throughout FPL's filing, FPL's current non-binding capital cost estimate for the new nuclear units ranges from $3,108/kw in 2007$ to $4,540/kw in 2007$. For purposes of providing a projection of the non-fuel costs for the first 12 months of operation of Turkey Point 6 & 7, FPL assumed the same capital cost value of $3,800/kW in 2007$ for both Turkey Point 6 & 7 that was used in the customer bill impact projection. This assumed capital cost value falls in the middle of FPL's projected range of non-binding cost estimates for these new units. Using this capital cost assumption and the assumption that both units will go in-service on June 1 of their respective in-service years, the approximate non-fuel costs for the first 12 months of operation are $1,242 million for Turkey Point 6 and $761 million for Turkey

Point 7. Both of these values include the non-fuel costs for the 7 months of operation in the in-service year (2018 for Turkey Point 6 and 2020 for Turkey Point 7) and for 5 months of the following year.

These cost projections are based on the in-service dates, the mid-range single point capital cost estimate, the projected fixed O&M and capital replacement costs, and the financial/economic assumptions used in the economic analyses. If the actual values are different for one or more of these assumptions, then these projected cost values may also change.

Q. You mentioned earlier that FPL's analyses assumed a 55.8% equity / 44.2% debt capital structure. What is the basis for this assumption?

A. This capital structure represents FPL's projection of its capital structure over the long-term. This projection also uses the 11.75% return on equity value reflected in FPL's last base rate settlement agreement.

Q. Is it possible that additional risk may be attributed to the construction and permitting of new nuclear generating units, thus affecting FPL's present long-term capital structure and return on equity assumptions?

A. Yes, it is possible. However, it is not possible at this time to accurately gauge the level of additional risk that will be attributed to the construction of new nuclear units in Florida compared to other forms of generation to which nuclear might be compared and what the economic impact of that risk would be. FPL's filing is basically intended to provide a first cut at how the cost of new nuclear units would compare to other generating units that might be built.

FPL believes its analytical approach of looking at a broad range of breakeven costs for new nuclear units provides a reasonable comparison of the capital costs of new nuclear units to those of non-nuclear generation options.

VIII. RESULTS OF THE SYSTEM NON-ECONOMIC ANALYSES

Q. How were the effects of the three plans on FPL's system fuel diversity evaluated?

A. The effects of the three resource plans on FPL's system fuel diversity were evaluated by projecting the annual percentage of system energy that is supplied by each fuel type - coal/petroleum coke, natural gas, oil, nuclear, and other (primarily purchases such as from waste-to-energy facilities) - for the resource plans for the 2018 - 2021 time period; i.e., a system fuel mix projection. This four-year time frame was chosen because it addresses the time period starting when the first nuclear unit is assumed to come in-service (2018) through the first year that both nuclear units are in-service for a full year (2021).

Generation unit dispatch is affected by the types of generating units available, the fuels they use, and the relative fuel costs and/or environmental compliance costs. Because unit dispatch determines the relative amount of energy that is supplied by each unit, and consequently by each fuel type, the system fuel mix is also affected by the types of generating units available, the fuels they use, and the relative fuel costs and/or environmental compliance costs. Consequently, the fuel diversity results will be presented for each resource plan 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.

Q. What were the differences in the FPL system fuel mix between the three resource plans?

A. Exhibit SRS-10 presents the annual projection for 2018 - 2021 of the percentage of energy produced by coal/petroleum coke (coal), natural gas, oil, nuclear, and other for the resource plans for the two scenarios mentioned above.

As shown in Exhibit SRS-10, 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 for nuclear, natural gas, and coal/petroleum coke, 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 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. The contributions of oil and other fuel remain essentially unchanged at 2% and less than 1%, respectively, for all three plans.

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 measured 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.

An increase of 10% in nuclear's contribution to the system annual fuel mix on a utility system the size of FPL's system is definitely meaningful. This is more readily apparent when the difference is translated into terms of increased MWh supplied by the new nuclear units, and the equivalent number of residential customers whose total annual energy usage could be supplied by the additional energy output from these units.

For 2021, the first full year in which both new nuclear units are in-service, the Plan with Nuclear will provide an increase of approximately 17.64 million MWh from nuclear compared to the two alternate Plans without Nuclear.

Taking into account that FPL's average residential customer is projected to use approximately 16,400 kWh in 2021, the increased nuclear energy generation from Turkey Point 6 & 7 would serve the total electricity needs of about 1,075,000 residential customers in 2013.

Q. Another perspective would be to examine how much fossil fuel would be consumed if the annual output of the new nuclear units were to be provided by conventional fossil fuel generating units. If FPL were to generate the Turkey Point 6 & 7 projected annual energy output with such units, how much oil, coal, or natural gas would be needed?

A. If this same amount of annual energy were to be produced by existing units in 2021, the projected amount of oil consumed would be approximately 27.6 million barrels of oil if the energy were solely produced with oil units, 7.1 million tons of coal if the energy were solely produced with coal, and 123.5 billion cubic feet (BCF) of natural gas if the energy were solely produced with natural gas. Taking into account the projected 40 year life of the Turkey Point 6 & 7 units, these annual amounts would increase to the following approximate amounts over this 40 year period: 1.1 billion barrels of oil, 284 million tons of coal, and 4,900 BCF of natural gas.

Q. How were the effects of the three plans on FPL system emissions of CO_2 evaluated?

A. The effects of the three resource plans on FPL's projected CO_2 emission levels were evaluated by projecting the annual CO_2 emission levels for the resource plans for the 2007 - 2021 time period.

Q. What were the results of the CO_2 emission analysis?

A. The results of this analysis are presented in Exhibit SRS-11. 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 operation results in essentially zero CO_2 emissions as further discussed in the testimony of FPL witness Kosky.

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 with Nuclear is 6.9 million tons per year lower than for the Plan without Nuclear – CC. Also for 2021, the Plan with Nuclear is 17.5 million tons per year lower than for the Plan without Nuclear - IGCC.

From a percentage perspective for 2021, the Plan with Nuclear would result in approximately a 10% reduction in annual CO_2 emissions compared to the Plan without Nuclear – CC and approximately a 21% reduction in annual CO_2 emissions compared to the Plan without Nuclear – IGCC.

Q. **Would these CO_2 emission reductions for the Plan with Nuclear be sustained for years after 2021?**

A. Yes. Assuming that the post-2021 capacity additions for each of the three plans would be identical, the projected CO_2 emission differentials between the three plans would be maintained for the life of Turkey Point 6 & 7.

Q. **Please summarize the results of the non-economic analyses of the three plans.**

A. In regard to system fuel diversity, the Plan with Nuclear is projected to have a significant advantage over the Plan without Nuclear – CC and a comparable result to the Plan without Nuclear – IGCC. The increased nuclear energy generation from Turkey Point 6 & 7 would serve the total electricity needs of about 1,075,000 residential customers in 2021. In regard to system CO_2 emissions, the Plan with Nuclear has significant advantage over both alternate plans. By 2021 the Plan with Nuclear has an advantage of 6.9 million tons per year (or a 10% reduction) compared to the Plan without Nuclear – CC and an even larger advantage, 17.5 million tons per year (or a 21% reduction), compared to the Plan without Nuclear – IGCC.

IX. ADVERSE CONSEQUENCES OF NOT APPROVING TURKEY POINT 6 & 7

Q. Would there be adverse consequences if a Need Determination for Turkey Point 6 & 7 is not approved?

A. Yes. If FPL's request for a Need Determination for Turkey Point 6 & 7 is not approved, FPL's ability to pursue the option of capacity additions from new nuclear units would be seriously hampered. As discussed in the previous section, this would likely lead to adverse consequences in regard to economics. This is evidenced by the favorable projections of breakeven capital costs for new nuclear units compared to FPL's non-binding cost estimates for such units.

In addition, a decision not to approve the Need petition for Turkey Point 6 & 7 would definitely lead to adverse consequences in regard to promoting fuel diversity and lowering CO_2 emissions in the long-term for FPL's system. This is evidenced by the projections of significant gains in system fuel diversity and reduced system CO_2 emissions from Turkey Point 6 & 7.

Q. How would FPL's ability to pursue the option of capacity additions from new nuclear units be affected if a Need Determination for Turkey Point 6 & 7 were not approved?

A. If a Need Determination for Turkey Point 6 & 7 is not approved, FPL would not be able to obtain needed information regarding the costs and performance for new nuclear units and to proceed with the necessary licensing steps for approval of new nuclear units. Delay in pursuing the option of new nuclear generating units would be inevitable. This would greatly restrict FPL's options in regard to reliably and economically meeting future capacity needs with generating options that could also significantly increase system fuel diversity and lower system CO_2 emissions.

X. CONCLUSIONS

Q. Would you please explain the conclusions you draw from the analyses previously discussed?

A. Yes. I draw the following four conclusions from the results of these analyses:

1) The range of breakeven capital costs for new nuclear units at Turkey Point is a broad one that encompasses FPL's current range of non-binding cost estimates for new nuclear units. Therefore, it appears there is a strong likelihood that new nuclear units at Turkey Point can be constructed at a cost that would allow the units to be economic compared to CC and/or IGCC units that might otherwise be constructed.

2) The Plan with Nuclear has a significant advantage in regard to system fuel diversity compared to the Plan without Nuclear – CC and has similar fuel diversity advantages to the Plan without Nuclear - IGCC. The increased nuclear energy generation from Turkey Point 6 & 7

would serve the total electricity needs of about 1,075,000 residential customers in 2021.

3) The Plan with Nuclear has a significant advantage in regard to system CO_2 emissions compared to the Plan without Nuclear – CC and an even larger advantage compared to the Plan without Nuclear – IGCC.

4) Failure to obtain Need approval for Turkey Point 6 & 7 will, at the very least, significantly delay FPL from pursuing the option of obtaining capacity addition from new nuclear units. This would greatly restrict FPL's options in regard to reliably and economically meeting future capacity needs with generating options that could also significantly increase system fuel diversity and lower system CO_2 emissions.

Based on these four results from the analyses, my overall conclusion is that FPL's Need Determination petition should be approved so that FPL can pursue the option of capacity and energy from new nuclear units at the Turkey Point site for the benefit of its customers.

Q. Would your conclusion be the same if the in-service dates of Turkey Point 6 & 7 were different from those used in the analyses?

A. Yes. The projected economic and non-economic advantages of the new nuclear units as analyzed are significant and their addition should benefit FPL's customers regardless of the in-service date.

Q. Does this conclude your testimony?

A. Yes.

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.

Projected Incremental FPL DSM: 2006 - 2020

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 2006 through 2020 =	1,899

Notes: (1) The DSM Summer MW shown are from column (5) in Exhibit SRS -1 and reflect projected DSM signups from 8/2006 through 8/2020. These values reflect FPL's DSM Goals through 2014 plus additional DSM through 2014 identified as cost-effective after the DSM Goals were established and for which Commission approval has been obtained. These values also include a projected continuation of DSM signups for 2015 - 2020.

Projection of FPL's 2007 - 2020 Capacity Needs: With Turkey Point 6 and 7

Summer

August of the Year	(1) Projections of FPL Unit Capability (MW)	(2) Projections of Firm Purchases (MW)	(3) = (1)+(2) Projection of Total Capacity (MW)	(4) Peak Load Forecast (MW)	(5) Summer DSM Forecast ** (MW)	(6)=(4)-(5) Forecast of Firm Peak (MW)	(7)=(3)-(6) Forecast of Summer Reserves (MW)	(8)=(7)/(6) Forecast of Summer Reserve Margins w/o Additions (%)	(9)=((6)*1.20)-(3) 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)
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2017	25,003	882	25,885	28,079	3,030	25,049	836	3.3%	**4,174**
2018	26,103	882	26,985	28,737	3,150	25,587	1,398	5.5%	**3,719**
2019	26,103	882	26,985	29,391	3,270	26,121	864	3.3%	**4,360**
2020	27,203	882	28,085	30,091	3,390	26,701	1,384	5.2%	**3,956**

Winter

January of the Year	(1) Projections of FPL Unit Capability (MW)	(2) Projections of Firm Purchases (MW)	(3) = (1)+(2) Projection of Total Capacity (MW)	(4) Peak Load Forecast (MW)	(5) Winter DSM Forecast ** (MW)	(6)=(4)-(5) Forecast of Firm Peak (MW)	(7)=(3)-(6) Forecast of Winter Reserves (MW)	(8)=(7)/(6) Forecast of Winter Reserve Margins w/o Additions (%)	(9)=((6)*1.20)-(3) 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	26,304	2,382	28,686	24,498	1,954	22,544	6,142	27.2%	(1,633)
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	27,715	882	28,597	28,649	2,474	26,175	2,422	9.3%	**2,813**
2020	27,715	882	28,597	29,308	2,544	26,764	1,833	6.8%	**3,520**

* This exhibit is identical to Exhibit SRS-1 except that 1,100 MW from Turkey Point 6 are assumed to be added in June 2018 and 1,100 MW from Turkey Point 7 are assumed to be added in June 2020.

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

The Three Resource Plans Utilized in the Analyses

Plan with Nuclear	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021 - 2040**
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	Turkey Point 6	(none)	Turkey Point 7	38 - 2x1 CC
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,100	0	1,100	21,014
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	5,983	5,983	7,083	28,097
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	22.9%	20.4%	21.9%	(all meet criteria)

Plan without Nuclear - CC	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021 - 2040**
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	3x1 CC	(none)	3x1 CC	38 - 2x1 CC
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,219	0	1,219	21,014
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	6,102	6,102	7,321	28,335
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	23.4%	20.9%	22.8%	(all meet criteria)

Plan without Nuclear - IGCC	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021 - 2040**
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	2 - IGCC	(none)	2 - IGCC	38 - 2x1 CC
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,200	0	1,200	21,014
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	6,083	6,083	7,283	28,297
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	23.3%	20.8%	22.7%	(all meet criteria)

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 of 2011, for reserve margin 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 Summer reserve margin calculati

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.

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).

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

		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

		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).

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	

Economic Analysis Results: Projection of Approximate Bill Impacts with Turkey Point 6 & 7: 2009 - 2021

Scenario: Medium Gas Cost Env II

	(1)	(2)	(3) = (1)-(2)	(4)	(5) = ((3)x1,000,000x100) / ((4)x1,000,000)	(6) = ((5)x1,000) / 100
Year	Plan with Nuclear Annual Total Revenue Requirements ($millions, Nominal $)	Plan without Nuclear - CC Annual Total Revenue Requirements ($millions, Nominal $)	Differential in Annual Total Revenue Requirements ($millions, Nominal $)	Projected Total Sales After DSM (GWh at the meter)	Differential in System Average Electric Rates (cents/kwh)	Differential in Customer Bill of 1,000 kwh ($)
-------	-------	-------	-------	-------	-------	-------
2009	6,278	6,160	118	116,870	$0.10	$1.01
2010	6,289	6,184	105	120,715	$0.09	$0.87
2011	6,364	6,253	111	124,562	$0.09	$0.89
2012	6,433	6,378	56	128,243	$0.04	$0.43
2013	6,922	6,763	159	131,170	$0.12	$1.21
2014	7,646	7,352	294	134,617	$0.22	$2.18
2015	8,733	8,270	463	138,217	$0.33	$3.35
2016	9,944	9,281	663	142,209	$0.47	$4.66
2017	10,768	9,924	843	145,542	$0.58	$5.80
2018	11,611	10,870	742	149,218	$0.50	$4.97
2019	12,489	11,898	591	152,896	$0.39	$3.86
2020	13,077	12,907	170	157,170	$0.11	$1.08
2021	13,872	13,931	-59	161,572	-$0.04	-$0.36

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.
(3) For purposes of this analysis, a capital cost of $3800/kW (2007$) is assumed for both nuclear units.

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Non-Economic Analysis Results
System Fuel Mix Projections by Plan
Exhibit SRS-10, Page 1 of 1

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

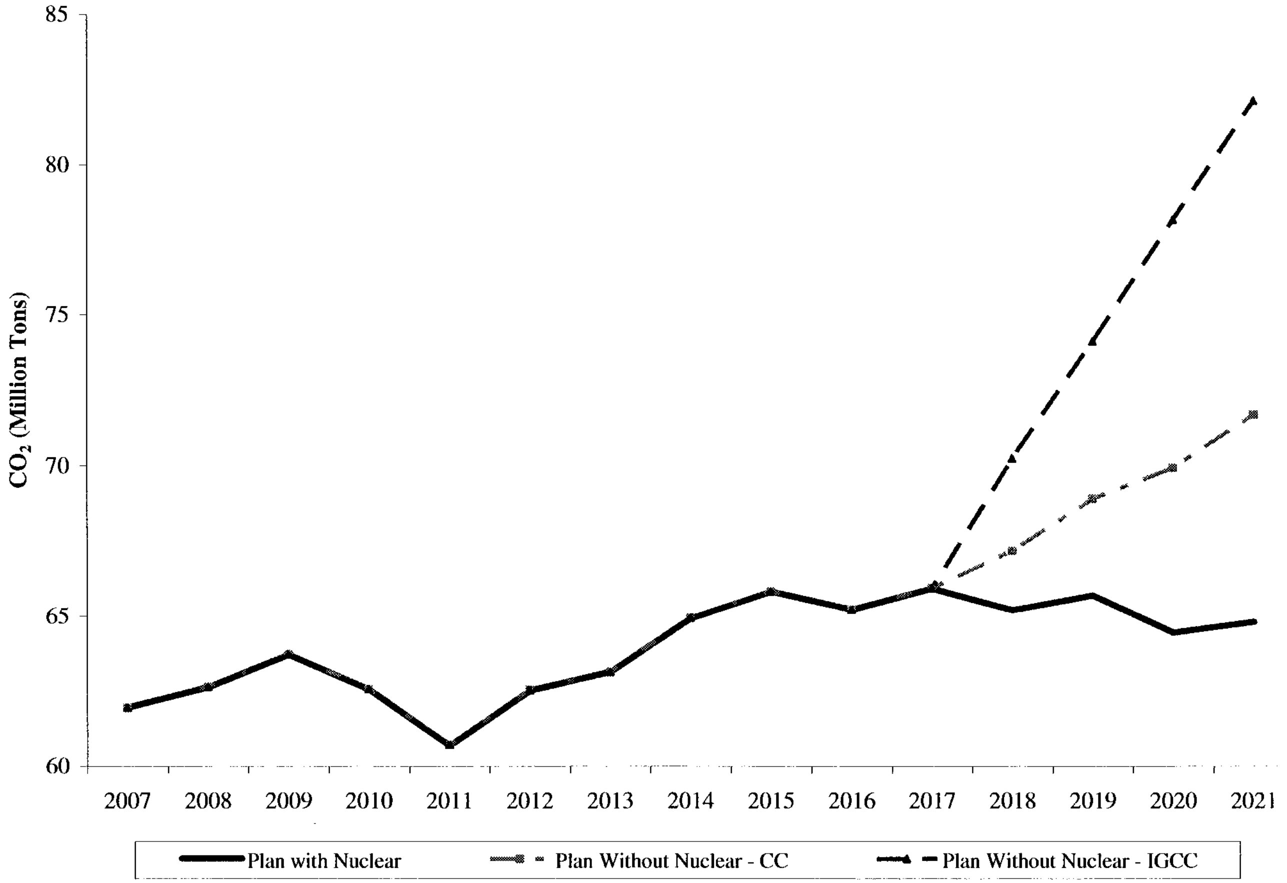
Scenario: High Gas Cost Env III

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Plan with Nuclear					Plan without Nuclear - CC					Plan without Nuclear - IGCC				
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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Plan with Nuclear					Plan without Nuclear - CC					Plan without Nuclear - IGCC				
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%

Non-Economic Analysis Results:
FPL System CO_2 Emissions Projection by Plan



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Non-Economic Analysis results: FPL
FPL System CO2 Emissions
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