BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 040206-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR TURKEY POINT UNIT 5 ELECTRICAL POWER PLANT

DIRECT TESTIMONY & EXHIBIT OF:

N. DAG REPPEN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF N. DAG REPPEN

DOCKET NO. 04 _____-EI

March 8, 2004

Q. Please state your name and business address.

A. My name is N. Dag Reppen, and my address is 19 Crimson Oak Ct., Niskayuna, NY 12309.

Q. By whom are you employed and what is your position?

A. I am the manager and sole member of the consulting firm Niskayuna Power Consultants, LLC organized in the State of New York. I am an independent consultant on matters relating to transmission systems.

Q. For what purposes have you been engaged by Florida Power & Light Company ("FPL")?

A. I have been engaged to work for FPL on transmission impact issues, including the supervision and oversight of FPL's analysis and development of transmission integration requirements, transmission losses and estimates of increased operating costs in Southeast Florida, as they relate to FPL's Request for Proposals for a resource need for 2007 ("RFP").

Q. Please state your educational background, business and professional association experiences.

A. I hold a Power Engineering Degree from the Technical University of Norway. I am a licensed professional engineer in the State of New York. I am a fellow of the Institute of Electrical and Electronics Engineers ("IEEE") with a citation reflecting work in power system reliability and security assessment. I have been chairman of the power system reliability subcommittee of IEEE and have written numerous publications in the area of power system reliability applied to operation and planning.

I began my career in the electric power industry by conducting statistical transmission line design studies for General Electric Co. In 1969, I co-founded Power Technologies, Inc. ("PTI"), a consulting company providing leading edge power system analysis to electric utilities, power system equipment manufacturers and utility organizations.

During my time at PTI, I served as a senior consultant on grid issues, manager of PTI's Power System Reliability unit, and as a senior consultant in PTI's Competitive Power Market Solutions Group. I also managed a power system study group in Brazil from 1973-1974 and was the coordinator of a power system reliability research portfolio in Norway in 1982-1983. In November 1999, I formed Niskayuna Power Consultants, LLC.

In my more than 35 years as a consultant in the power system industry, I have developed a number of areas of expertise including:

i. Power system reliability and security assessment;

ii. Development of methods and software for power system planning and operation, and,

iii. Transmission planning studies.

I have over 30 years of experience in various facets of transmission planning with emphasis on reliability issues and reliability/economic analyses. I have conducted numerous transmission planning projects for many different utilities that have varied from specific facility reinforcements to long-term strategic transmission expansion plans. I have developed leading edge study methodologies for transmission planning and coordinated the development of PTI software programs supporting these methodologies. One of these programs, TPLAN, is applied by FPL and other United States and foreign utilities for transmission planning and probabilistic and deterministic reliability assessment. During the 1980s, I coordinated the development of many of the methods and algorithms presently used in the Electric Power Research Institute's transmission reliability assessment software package.

I have reviewed and designed transmission planning and operating criteria for several utility organizations and developed methodologies for reliability assessment and economic ranking of projects accounting for impacts arising from transmission losses and out-of-merit dispatch caused by congestion. I have also been the project manager for numerous power system planning studies and created methodologies for developing transmission expansion plans that are robust with respect to uncertainties in load forecasts, possible future interconnections with neighboring utilities, and location of future generating resources.

I have recently performed congestion analysis for the New England Independent System Operator and others, including evaluation of congested transmission paths, calculation of locational marginal prices, and assessment of the severity of transmission constraints. I also participated in rulemaking procedures for interconnection impact studies and interconnection cost allocation in New York.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the overall evaluation process and the results of transmission system related cost studies for the various portfolios of capacity options as defined by the FPL Resource Assessment and Planning ("RAP") department. I will additionally review the results of the integration studies as they pertain specifically to FPL's proposed 1,144 MW combined cycle plant at Turkey Point.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring Composite Exhibit ____, which consists of the following documents:

Document NDR-1, Summary of Requirements and Cost for Upgrades or New Construction

Document NDR-2, Transmission Loss Estimates

Document NDR-3, Increased Operating Cost Estimates in Southeast Florida

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

A. Yes, I sponsor the portions of Section III addressing transmission integration and co-sponsor portions of Section VI.B.5 addressing the economic evaluation of the various portfolios. In addition, I sponsor Appendices K, L and N of the Need Study document.

Evaluation Process for Determining FPL Transmission System Related Costs

Q. Please describe FPL's process for determining the transmission system related costs for the various portfolios and your participation in that process.

A. In its evaluation of capacity proposals, FPL considered four categories of costs that arise from the proposed delivery of additional power over FPL's transmission system. Each of these categories of costs was evaluated for 8 portfolios of capacity options defined by the FPL RAP department. I worked with and supervised FPL's transmission planning engineers in the evaluation of three of these four categories of costs. These four categories of costs can be summarized as follows:

First, we analyzed transmission integration costs that capture the cost of upgrades of existing transmission facilities and the cost of new facilities required for reliable operation of the generation capacity additions included in each portfolio as an FPL Network Resource.

Second, we analyzed and calculated the incremental costs associated with changes in FPL transmission losses resulting from the generation capacity additions comprising each portfolio. This cost aspect has two components: the new generation capacity required to compensate for the additional losses during peak load conditions and the cost of energy losses throughout the year.

Third, we calculated the incremental operating costs resulting from increases in the hours more expensive peaking plants may be required to be uneconomically dispatched in Southeast Florida in order to maintain reliable operation. In this context, Southeast Florida is generally defined as the portion of the eastern FPL system located south and east of and including FPL's Corbett Substation. During high load conditions or during planned or forced outages of generation in Southeast Florida, the transmission system may limit the amount of power that can be imported into Southeast Florida. This may necessitate the operation of more expensive gas turbines at Fort Lauderdale and Port Everglades plants at times when less expensive generation is available outside of Southeast Florida. Such occurrences result in increased operating cost.

The fourth component concerns the cost of interconnecting proposed new generation to the FPL transmission system. Interconnection costs were reviewed for reasonableness by FPL engineers and all were found to be acceptable as provided by the bidders. FPL's substation and transmission engineers prepared interconnection cost estimates for the capacity additions proposed by FPL.

Prior to the issuance of the RFP, I worked with FPL's transmission planning engineers to define the study methodologies and procedures to be used in estimating the transmission related costs. After the capacity proposals had been received by FPL, FPL's RAP department defined the set of portfolios for which transmission related costs were to be evaluated. I received these portfolio definitions from RAP, worked with FPL's transmission planning engineers to evaluate the transmission related costs, and transmitted the results of the analysis to RAP. For each portfolio, these results included transmission integration costs, transmission loss components to be used by RAP to estimate the cost of additional capacity required to compensate for losses as well as the cost of energy losses, and estimates of increased costs associated with uneconomic dispatch of gas turbines in Southeast Florida.

I. Transmission Integration Costs

Q. Please describe FPL's transmission integration evaluation process.

A. The evaluation process consisted of three steps.

The first step was to perform load flow screening studies to identify new facilities and facility upgrades that would be needed to integrate the capacity resources in each portfolio into the transmission system as a network resource for FPL while meeting reliability criteria. I worked with FPL transmission planning engineers to develop the methodology that was used to perform these load flow screening studies and participated in the identification of possible cost-effective transmission reinforcements. I was in constant communication with the FPL transmission planning engineers who performed the load flow screening studies. In parallel with the system studies performed by FPL, I personally performed load flow screening studies to better understand system requirements and independently propose alternative possible transmission upgrades and new facility additions. Finally, I reviewed and approved the results of the load flow screening studies and prepared a list of new facilities and facility upgrades required to integrate the capacity resources in each portfolio into the transmission system as a network resource for FPL.

Once a list of new facilities and facility upgrades required to integrate the portfolio was identified, I directed the second step of the evaluation process, which consisted of developing cost estimates for the new and upgraded transmission facilities. FPL substation and transmission engineers prepared the cost estimates based on portfolio-specific lists of upgrades and new facilities that I forwarded to them. Before the cost evaluation, I reviewed the procedures and assumptions to be applied in the cost evaluation process and developed the work sheets to be used in documenting the basis for the cost estimates. During this step I worked with the substation and transmission engineers to ascertain to my satisfaction that the assumptions and cost estimates were reasonable and that assumptions were applied consistently to all portfolios.

The final step in the process involved compiling (i) a total transmission integration cost for each portfolio and (ii) an estimated monthly cash flow of the costs for the transmission projects. The cash flow projections were also performed by FPL substation and transmission engineers. After I reviewed the transmission integration cost information and cash flow projections and satisfied myself that the results were reasonable and that the cost assumptions were consistently applied across all portfolios, I prepared summary sheets of the transmission integration costs for the eight portfolios and transmitted the information to the FPL RAP department. Document NDR-1 contains a list of the 8 portfolios and their associated transmission integration costs.

Q. Please describe the load flow analyses performed.

A. Of the 8 portfolios defined, only 6 were distinctly different from the standpoint of transmission integration requirements in the year 2007. For each of these 6 portfolios, load flow studies were performed to assess necessary transmission system upgrades. All studies were performed using the latest available Florida Reliability Coordinating Council 2007 load flow case representing 2007 summer peak load conditions. The case was updated to include the most up-to-date information on the FPL system. These studies were considered screening type studies but are adequate to identify the facilities that may become overloaded because of the integration of the capacity options in each portfolio as well as the incremental transmission facilities required to mitigate such overload(s). Voltage problems violating reliability criteria were also considered, leading to the addition of shunt capacitor banks for some of the portfolios.

For each portfolio, the 2007 load flow case was subjected to a contingency screening of all transmission elements in accordance with reliability criteria. In this process, hundreds of load flow calculations are performed, each with one transmission element or generator out of service. Any violation of reliability criteria detected on any of FPL's transmission elements for one or more of these single contingency load flow solutions indicates the need for transmission reinforcements unless the overload problems can be safely handled by an obvious switching action immediately after the contingency has occurred. When transmission reinforcement is needed, the most cost-effective alternative available, whether by facility upgrades or by new facilities that could be integrated into a feasible and practical system reinforcement process, is selected. All proposed transmission reinforcements were represented in the load flow case and tested with another full contingency screen in order to verify that the set of remedies proposed were sufficient to satisfy reliability criteria.

Q. Do you have a general observation regarding the results of the analysis?

A. Yes. Generally, the results of the load flow analysis indicated that a limited amount of capability exists to transfer power from the west coast to the east coast load centers of FPL. Therefore, if a substantial amount of additional capacity resources is located in the west coast of Florida, upgrades of the west to east interconnections may be required. Also, to meet reliability criteria, the import capabilities into Southeast Florida will need to be increased by 2007 in order to support portfolios where most of the new capacity is located to the north or to the west of Southeast Florida. In addition, local transmission reinforcements of the 138 kV or 230 kV systems may be required in all regions in the proximity of substantial capacity additions.

Q. Once the need for incremental transmission facilities was determined for each portfolio, how were the costs of such incremental transmission facilities estimated?

A. Based on the need for incremental transmission facilities identified in each portfolio, a cost estimate for the facilities necessary for integration was developed in a consistent manner for each portfolio. These were budget grade estimates based on sound engineering judgment, readily available data and existing estimates, and records of facility limitations and equipment ratings. The estimates did not involve any field inspections, or the type of detailed analysis that would be performed in response to a specific request for interconnection or transmission service, but they are adequate for their intended purpose. That is, they provide all the necessary information to make effective comparisons of the relative transmission integration costs associated with the portfolios. The estimated costs of the facilities for each portfolio were summed, and the total estimated portfolio integration costs determined. Exhibit NDR-1 summarizes the estimated costs of individual transmission facilities and total integration cost for each portfolio. The costs are "overnight construction costs" in 2007 dollars.

Q. Please summarize the cost estimates associated with integration for the 8 capacity portfolios.

A. Of the 8 portfolios defined, only 6 were distinctly different from the standpoint of transmission integration requirements in the year 2007. These 6 portfolios can be further divided into three groups as follows:

Portfolio 1 has a single 1,144 MW combined cycle plant at Turkey Point. This plan requires the upgrades of several 230 kV lines out of Turkey Point. The total upgrade cost for this portfolio was estimated as $4.5 million.

Portfolios 2, 6, and 10 all include 4 CTs totaling 648 MW at Turkey Point and 4 CTs totaling 447 MW on the west coast of Florida. All three portfolios require a new 230 kV line in the west and an upgrade of one of the existing 230 kV connections between the west and east coasts. The transmission integration costs for each of these portfolios were estimated at approximately $23 million for the new 230 kV circuit and about $22 million for the upgraded 230 kV west to east connection, yielding a total estimated cost of approximately $45 million.

This leaves Portfolios 3, 4, 7, and 8. For the year 2007, portfolios 3 and 4 are identical from the standpoint of transmission integration costs. They consist of a single 1,220 MW combined cycle plant located on the 500 kV system between Martin and Midway. Portfolios 7 and 8 are similar to Portfolios 3 and

4, but each has a 50 MW capacity resource in Southeast Florida in addition to the 1,220 MW plant included in Portfolios 3 and 4. These portfolios all require upgrades of 138 kV lines immediately south of the Riviera Substation. In addition, a substantial amount of shunt capacitors are needed in Southeast Florida in order to accommodate the higher import into this area without violating voltage and voltage collapse criteria. The transmission integration cost for each of these portfolios was estimated at approximately $5 million.

II. Costs Associated with Transmission Losses

Q. Please describe how transmission loss effects were included in the economic comparison of portfolios and how the loss calculations were performed.

A. Each of the portfolios assessed results in a transmission loss impact when incorporated into the existing FPL generation portfolio and integrated into the FPL transmission system. A calculation procedure was developed to capture the difference in the cost impact of transmission losses between the portfolios. The economic impact of transmission losses for each portfolio was determined as the present value of the estimated cost of transmission loss impacts for 2007 and for the following 25 years. For each year losses were calculated to support the estimation of two cost components: a capacity component reflecting the cost of new generation capacity required to compensate for the additional losses during peak load conditions and the cost of energy losses throughout the year. The necessary loss calculations for each portfolio were performed by FPL transmission planning engineers under my direction. The loss results were then forwarded to FPL's RAP department, which calculated cost differentials between portfolios by applying appropriate capacity and energy costs to the loss values provided.

Q. Please describe the methodology applied in the evaluation of transmission loss costs.

A. Before the publication of the RFP, I worked with FPL transmission planning engineers and personnel in FPL's RAP department to define a calculation process that could fairly evaluate the differences in economic impact of portfolios caused by transmission loss effects. Let me briefly address some of the key issues of this calculation process.

When a new power source is integrated into the system, the power flows and the losses in the transmission system will be impacted whenever this resource is dispatched. Therefore, the impact on losses of a capacity addition, and more generally a portfolio of capacity additions, will depend both on where the new capacity resources are located and the characteristics of the resources. While low cost resources may be operating and impacting transmission losses most of the time, more expensive resources tend to operate and impact losses only at higher load levels.

Given the load pattern throughout the year and the availability and operating cost of resources, the impact of losses can be evaluated by load flow calculations assuming that generation resources will be dispatched economically. This evaluation can be performed with reasonable precision for the year 2007. However, for 2008 and beyond, increasing load will require additional capacity resources, the location and composition of which are unknown at this time. The expansion of the transmission system beyond 2008 is also unknown. Therefore, the impact of a particular portfolio on losses becomes progressively more uncertain with time.

To deal with this uncertainty in a consistent fashion, it was assumed that the loss impacts for the year 2008 and beyond would be identical to the loss impacts calculated for the year 2007. For portfolios where a capacity option terminated prior to the study period (25 years after 2007), that capacity was presumed replaced by a combined cycle plant located such that the incremental loss impact of this plant would equal the average year-round losses on the FPL transmission system. A combined cycle plant was used as a replacement for a terminating capacity option whether the terminating option was base load generation or peaking capacity so as not to bias the results toward a particular type of capacity option.

While the accuracy of the losses applied in this analysis can only be ascertained in retrospect after the actual resource and transmission system expansions over the 25 year period is known, I believe that the methodology developed is reasonable and that it produces a fair assessment of the differences in the cost of transmission losses between portfolios. In this context it is important to note that the contribution to the present value of the cost of the loss impacts is greatest for the initial years when the uncertainties in future capacity resource and transmission expansion are the lowest.

Q. Please describe how the load flow analysis was applied to calculate losses.

A. For each portfolio, transmission losses were calculated for the year 2007. In addition, with respect to portfolios with one or more capacity options terminating prior to 2031, losses were recalculated assuming that the terminated capacity options were replaced by a generic combined cycle plant of equal capacity. Losses were calculated for summer peak load conditions and for average system load conditions. Losses calculated for summer peak load conditions were used to estimate the cost of additional capacity required each year to compensate for transmission losses. Energy losses for each year were calculated as 10% of the summer peak losses plus 90% of the losses at a load level representing FPL's average load.

Peak load losses for the year 2007 were determined using the same load flow representation applied in the transmission integration studies. That is, the system model included the representation of the transmission upgrade facilities and new facilities required by the portfolio. Also, all FPL resources, other firm resources and the capacity options in the portfolio were assumed to be dispatched economically. The losses calculated under this methodology reflected the transmission losses only on FPL transmission equipment.

Peak losses for a future year after a capacity option was terminated used the same 2007 load flow model but with dispatches adjusted to reflect the replacement of the terminated capacity option with a generic combined cycle unit as discussed earlier.

Losses for average load conditions used the same system model as for peak load conditions but with resources dispatched economically to the lower load level. CTs included as a capacity option in a portfolio were dispatched at the peak load level but not at the average load level.

This consistently applied procedure allowed efficient calculation of key loss parameters. I believe the results fairly capture the basic differences in transmission loss impacts between portfolios. Also, I believe the level of precision is appropriate considering the uncertainties associated with expansion of capacity resources and the transmission system over a 25-year period.

Q. Please indicate in general terms how the portfolios compare in terms of transmission losses.

A. Comparison of the cost impacts of transmission losses can only be made based on the final cost estimates for capacity additions required to compensate for losses during peak conditions and the cost estimates for energy losses, the latter being a function of the calculated losses at both peak and average load conditions. The FPL RAP department calculated these costs. Aggregate energy losses are not a meaningful quantity by itself since the cost of energy varies as a function of load level. However, some indication of the loss impacts can be observed in Document NDR-3 in Exhibit_____, which lists the peak load level losses and average load level losses for portfolios relative to Portfolio 1 for the year 2007.

The 2007 peak load losses are highest for Portfolios 3, 4, 7, and 8, which all include the 1,220 MW combined cycle plant between Martin and Midway. During average load level conditions, the losses are highest for portfolios 2, 6, and 10, which all include the 4 CTs at Turkey Point totaling 648 MW and the 4 CTs on the west coast totaling 447 MW. While the ranking of portfolios by losses after termination of one or more capacity options is different, the 2007 losses displayed in Document NDR-2 are the dominating contributors to the present value cost estimates of transmission loss impacts.

III. Costs Associated with Increased Operation of Peaking Units in Southeast Florida

Q. What was the rationale for including the operating costs arising from the uneconomic dispatch of peaking units in Southeast Florida as a transmission related cost?

A. If no capacity resources are added in Southeast Florida, economic dispatch of the FPL system will result in a gradual increase of power import into Southeast Florida from the north and west. For certain hours of the year, particularly during planned and forced outages of generation in Southeast Florida, economic operation will be restricted by the maximum amount of power that can be imported over the transmission system into Southeast Florida without violating reliability criteria. When this occurs, in order to maintain reliable operation, it is necessary to run more expensive gas turbines located at Fort Lauderdale and at Port Everglades even though less expensive resources are available outside of Southeast Florida. The uneconomic dispatch and operation of gas turbines under these conditions increases the cost of operation of the FPL system.

The amount of energy that has to be generated by more expensive gas turbines in Southeast Florida when less expensive generation is available elsewhere in FPL's system is reduced if new resources are located in Southeast Florida or if the transmission system is strengthened to allow greater imports. Because the portfolios differ in these attributes, there is a definite and real cost impact associated with each portfolio that needs to be accounted for and included in the economic evaluation of the portfolio.

Q. Please describe the methodology used to determine the cost of increased operation of gas turbines in Southeast Florida.

A. Calculations were performed using a relatively simple, custom-made spreadsheet model. This model addresses the essential aspects of the problem, and reflects actual operating practice and operating experience. For each portfolio, the model estimates the annual energy (MWh) of gas turbine operation in Southeast Florida that would occur at times when less expensive resources are available elsewhere in the FPL system. The most important characteristics and assumptions are as follows:

The likelihood of gas turbine operation increases with planned generation outages and forced outages in Southeast Florida. The planned outage schedules assumed were representative of FPL practices. Forced outages were simulated recognizing the statistical nature of forced outages of individual generating units as represented by their forced outage rates. Based on past operating experience, it was assumed that uneconomic dispatch of gas turbines because of import limitations would most often occur during periods of the year that are subject to planned generation outages. Thus, increased operating costs arising from gas turbine operation during the peak load periods January 1 to February 28 and June 1 to September 30 were not considered.

The transmission import limit, calculated by load flow analysis for each portfolio, is an input to the model. In all cases, the limiting condition was the requirement to avoid voltage collapse in Southeast Florida for a sudden outage of one of the Turkey Point nuclear units. In addition, import limits were reduced to account for expected operational outages of transmission facilities in Southeast Florida. Conforming to operating experience, this reduction in import limit was assumed to vary with the amount of generation on planned outages and other generation maintenance outages.

The estimated annual cost of uneconomic gas turbine operation in Southeast Florida because of the import limitation into this area was determined by multiplying the MWh of gas turbine operation by a representative differential cost. This differential cost is representative of the difference in cost of operating gas turbines at Fort Lauderdale and Port Everglades plants and the marginal cost of resources outside of Southeast Florida at times when the import into Southeast Florida is limited. The differential costs, supplied by FPL's RAP department, varied from $44.71/MWh in 2007 to $5.59/MWh in 2031.

The cost impacts of portfolios were expressed as the present value over the 25 years from 2007 to 2031 of the increased cost of uneconomic dispatch of gas turbines in Southeast Florida because of the import limitation into the area. Since the expansion of resource capacity and the transmission system is uncertain beyond the defined condition for 2007, the increased MWh of gas turbine operation from 2012 and the years beyond were assumed equal to the value calculated for 2011. This allowed application of 5 years of different but representative planned outage schedules while avoiding speculations as to future capacity additions and transmission reinforcements.

Q. Please summarize the results of the analysis.

A. The present value of uneconomic dispatch of gas turbines in Southeast Florida because of import limitations into this area is listed in Document NDR-3. The costs are given for each portfolio relative to Portfolio 1, which has one 1,144 MW combined cycle unit in Southeast Florida. The import limit for each portfolio is also displayed. Note that Portfolios 3, 4, 7, and 8, all with a 1,220 MW generating plant outside of Southeast Florida, have significantly higher import capabilities than the other portfolios. This is caused by transmission reinforcements required to meet reliability criteria when integrating these portfolios into the FPL system. Because of the increased import capabilities, these portfolios have expected costs of uneconomic operation of gas turbines in Southeast Florida that are comparable to Portfolios 2 and 10, which both have substantial generation additions in Southeast Florida. The costs of uneconomic dispatch of gas turbines in Southeast Florida for these portfolios are all approximately $15 million higher than for Portfolio 1. Portfolio 6, consisting of 4 CTs and a small coal fired unit in Southeast Florida and 4 CTs on the west coast, has the lowest present value of uneconomic dispatch cost ($11.4 million) relative to Portfolio 1.

IV. Transmission-Related Costs for Portfolio 1

Q. Please describe the transmission system integration requirements for the proposed combined cycle plant at Turkey Point in Portfolio 1.

A. Several existing 230 kV transmission line segments in the Turkey Point area in Southeast Florida need to be upgraded to accommodate the proposed plant. These upgrades and the estimated cost of each upgrade are listed in Document NDR-1 under Portfolio 1. The total direct cost of the upgrades is estimated at $4.5 million. All upgrades are necessitated because of thermal overloads for single contingencies.

The major portion of the upgrades involves the partial rebuild of transmission facilities on the two parallel 230 kV lines from Turkey Point to the Flagami Substation. Here, rebuilds are required on the Turkey Point to Galloway Tap and the Turkey Point to Killian line segments. The rebuilds are necessary to meet National Electric Safety Code clearance requirements at the higher conductor currents resulting for the additional generating capacity at Turkey Point.

Thermal upgrades are also required on the Killian to Miller line segment on the 230 kV line from Turkey Point to Flagami and on the 230 kV line from Turkey Point to the Florida City substation via McGregor. These line segments can be upgraded without major construction work.

Q. Please summarize the transmission impacts of the Turkey Point plant in Portfolio 1 relative to the other portfolios.

A. The estimated cost of transmission upgrades and new transmission facilities required of Portfolio 1 (about $4.5 million) is approximately the same as for Portfolios 3, 4, 7, and 8, which all have a 1220 MW combined cycle plant on the 500 kV line between Midway and Martin. However, the integration cost for Portfolio 1 is only one tenth of the integration costs for Portfolios 2, 6, and 10. The reason for this cost differential is the new 230 kV line on the west coast and the upgrade of the 230 kV west-east connection, which both are required to accommodate the 447 MW CT plant on the west coast.

Because Turkey Point Unit 5 is located relatively near the load centers in Southeast Florida, transmission losses are significantly lower for Portfolio 1 than for any of the other portfolios. Also, because the Turkey Point plant is located in the Southeast Florida load pocket, the need to run gas turbines uneconomically in the area at times when less expensive units are available elsewhere in the FPL system is greatly reduced. This results in an estimated operating cost saving relative to the other portfolios in the range of $11.4 to $15.5 million.

Q. Do you have an opinion as to whether each and every one of these analyses is necessary and appropriate in performing an economic evaluation of the transmission-related costs for competing resources?

A. Yes, I do. It is my opinion that these analyses provide reasonable estimates of the real transmission-related costs arising from each portfolio and that all such costs should be captured in performing an economic evaluation of competing capacity options under the RFP. These analyses and costs should be relied upon by the Commission, as they were by FPL and the independent evaluator, Mr. Taylor, in the analysis and comparison of which portfolio provides the most cost-effective alternative to meet FPL's 2007 generation need requirement.

Q. Please summarize your testimony.

A. My testimony provides a description of the evaluation of transmission related costs associated with 8 portfolios of capacity options defined by the FPL RAP department. The following three aspects of transmission related costs were evaluated:

- The cost of new transmission facilities and upgrades of existing transmission facilities required to integrate the capacity options in each portfolio into the FPL system.
- Transmission losses during peak load and average load conditions considering the transmission improvements required for each portfolio and the operating characteristics of the capacity options within the portfolio.
- Increased operating costs with each portfolio associated with the need to run more expensive gas turbines in Southeast Florida when transmission capabilities limit import of power from less expensive generator units outside the area.

Each of these transmission related cost impacts were included in the economic comparison of proposed capacity options. Inclusion of these costs is necessary and appropriate to capture a reasonable estimate of the transmission-related costs arising from the competing capacity options.

Finally, I compared the transmission related costs of Portfolio 1, which consists of the Turkey Point 1,144 MW combined cycle plant proposed by FPL, to the other portfolios. Based on the evaluation performed, Portfolio 1 has the lowest transmission losses and the lowest operating cost because of uneconomic dispatch of gas turbines in Southeast Florida of any of the portfolios evaluated. The transmission integration cost for Portfolio 1 was either equal to or lower than the integration cost of the other portfolios.

Q. Does this conclude your testimony?

A. Yes.

Summary of Requirements and Cost for Upgrades or New Construction

(Overnight construction cost, 2007 dollars)

[illegible]	[illegible] Option [illegible]		Summer capability for capacity options in portfolio [illegible] (MW)					
[illegible]	[illegible] Location [illegible]	MW	Port 1	Port 2	Port 3/4	Port 6	Port 7/8	Port 10
[illegible]	Turkey Point 230 kV substation	1144	1144					
[illegible]	Turkey Point 230 kV substation	648		648		648		648
[illegible]	HST Lucy 230 kV substation	50				50	50	
[illegible]	Midway-Martin 500 kV line	1220			1220		1220	
[illegible]	230 kV substation in Southwest Florida	447		447		447		447
[illegible]	Malabar-Midway/Emerson 230 kV lines	252						252
Total summer capability for portfolio (MW)			1144	1095	1220	1145	1270	1347

[illegible]	kV	[illegible]	Integration cost by facility required to meet reliability criteria [illegible] ($000)					
Turkey Pt - Galloway Tap	230	Upgrade	2,196					
Turkey Pt - McGregor - Fla City	230	Upgrade	101	101				101
Turkey Pt-Killian	230	Upgrade	2,178					
Killian - Miller	230	Upgrade	59					
Charlotte - Orange Rv	230	New Line		22,963		22,963		22,963
Orange Rv - Alva - Corbett	230	Upgrade		21,554		21,554		21,554
Riviera - Roebuck	138	Upgrade			1,436		1,436	
W. Palm Bch-Westward	138	Upgrade			74		74	
Westward-Roebuck	138	Upgrade			263		263	
Laudania-Pt. Everglades	230	Upgrade			14		14	
55 MVAR Cap at Arch Creek	138	Cap. Bank			751		751	
55 MVAR Cap at Biscayne	138	Cap. Bank			751		751	
55 MVAR Cap at Miami Shores	138	Cap. Bank			707		707	
55 MVAR Cap at Opa Locka	138	Cap. Bank			697		697	
55 MVAR Cap at Hallandale	138	Cap. Bank			697			
Total Integration Cost ($,000)			4,534	44,618	5,390	44,517	4,693	44,618

Transmission Loss Estimates

Portfolio	Transmission losses for the year 2007relative to Portfolio 1 (MW)	
	2007 Peak load level	2007 average load level
Portfolio 2	27	19
Portfolio 3/4	32	6
Portfolio 6	17	15
Portfolio 7/8	29	2
Portfolio 10	21	10

Increased Operating Cost Estimates in Southeast Florida

Portfolio	Import Limit (MW)	Present value of increased operating cost of gas turbines because of import limitations into Southeast Florida, relative to Portfolio 1 (Millions of 2003 dollars)
1	7307	0
2	7174	15.5
3/4	7827	15.4
6	7225	11.4
7/8	7798	14.8
10	7184	15.3