ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NOs. 02___-EI, 02___-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: PETITION FOR DETERMINATION OF NEED FOR PROPOSED ELECTRICAL POWER PLANT IN MARTIN COUNTY OF FLORIDA POWER & LIGHT COMPANY

IN RE: PETITION FOR DETERMINATION OF NEED FOR PROPOSED ELECTRICAL POWER PLANT IN MANATEE COUNTY OF FLORIDA POWER & LIGHT COMPANY

TESTIMONY & EXHIBITS OF:

SAMUEL S. WATERS

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF SAMUEL S. WATERS

DOCKET NOS. 02 -EI, 02 -EI

Q. Please state your name and business address.

A. My name is Samuel S. Waters, 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 the Director of Resource Assessment & Planning.

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

A. I manage the group that is responsible for the development of FPL's integrated resource plan and other related activities, such as analysis of demand-side management programs, system production cost projections, development of FPL's demand and energy forecasts, and the administration of wholesale power purchase agreements.

Q. Please describe your education and professional experience.

A. I graduated from Duke University with a Bachelor of Science Degree in Electrical Engineering in 1974. From 1974 until 1985, I was employed by the

Advanced Systems Technology Division of Westinghouse Electric Corporation as a consultant in the areas of Transmission Planning and Power System Analysis Software. While employed by Westinghouse, I earned a Masters Degree in Electrical Engineering from Carnegie-Mellon University in 1976.

I joined what was then the System Planning Department of FPL in 1985, working in the generation planning area. I became Supervisor of Resource Planning in 1986, and subsequently the Manager of Integrated Resource Planning in 1987, a position I held until 1993. At that time, I assumed the position of Director, Market Planning where I was responsible for oversight of regulatory activities for FPL's Marketing Department as well as tracking of marketing-related trends and developments.

In 1994, I became Director of Regulatory Affairs Coordination, where I was responsible for management of FPL's regulatory filings with the FPSC and FERC. In 2000, I assumed my current position. I am a registered Professional Engineer in the States of Pennsylvania and Florida and a Senior Member of the Institute of Electrical and Electronics Engineers, Inc. (IEEE).

Q. Have you previously testified before this Commission?

A. Yes. I have testified in several dockets related to FPL's resource plans including Docket 870197-EI, Petition of Florida Power and Light Company for Non-Firm Load Methodology and Annual Targets; Docket Nos. 890973-EI and 890974-EI, FPL's Petition To Determine Need for the Lauderdale and Martin Projects; Docket Nos. 900709-EQ and 900731-EQ, Joint Petition of Indiantown Cogeneration Limited (ICL) and FPL to Determine Need for the ICL Facility; Docket No. 900796-EI, Petition for Approval of the Purchase of Robert W. Scherer Unit No. 4 from Georgia Power Company; Docket No. 910004-EU, Annual Hearings on Load Forecasts, Generation Expansion Plans and Cogeneration Prices; Docket No. 910816-EI, Petition of Nassau Power Corporation to Determine Need; Docket No. 911103-EI, Complaint of Consolidated Minerals, Inc. (CMI) Against Florida Power & Light Company for Failure to Negotiate Cogeneration Contract; Docket Nos. 920520-EQ and 920648-EQ, Joint Petition to Determine Need for Electric Power Plant to be located in Okeechobee County by Florida Power & Light Company and Cypress Energy Partners, Limited Partnership; and Dockets 900001-EI, 910001-EI, 920001-EI and 930001-EI concerning FPL's Oil Backout Cost Recovery Factor and Capacity Cost Recovery Factor. I also submitted testimony in Docket No. 891049-EU, Revision to Cogeneration Rules. Most recently, I submitted testimony in FPL's rate review, Docket No. 001148-EI.

In addition to appearing on FPL's behalf in the above cases, the PSC Staff submitted my testimony in Docket No. 960409-EI, Tampa Electric Company's Petition to Determine Need for Polk Power Station.

Q. What is the purpose of your testimony?

A. My testimony introduces FPL's Need Study document and identifies the sponsors of each of the sections contained within that document. I also introduce the FPL witnesses in this case and describe the areas of the case they will cover.

In addition to this introductory role, my testimony:

- Describes FPL's system and service area,
- Describes FPL's load forecasting process and presents the forecast used in the analyses,
- Describes FPL's resource planning process,
- Summarizes FPL's need for new resources in the 2005/2006 time frame, the Request for Proposals (RFP) issued by FPL to address those needs, and the results of the solicitation,
- Briefly presents the results of the analysis of bids received in response to the RFP,
- Discusses a number of qualitative factors which are incorporated into FPL's decision making process,
- Discusses the relative merits of the self-build option versus purchase of new resources, and
- Discusses the adverse consequences to FPL's customers if the proposed Martin Unit 8 and Manatee Unit 3 projects are not brought into service by the target dates.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring an exhibit consisting of 6 documents attached to my direct testimony.

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

A. Yes. I am sponsoring the following sections:

Section I Executive Summary

Section II Introduction

Section VII Adverse Consequences of Delay

Section VIII Conclusion

I also co-sponsor Section V with Dr. Sim.

<u>Description of FPL's Need Study document</u>

Q. Please describe FPL's Need Study document supporting its Petitions for Determination of Need for the Martin Unit 8 and Manatee Unit 3 projects.

A. The Need Study document is a comprehensive review of FPL's planning process, of the RFP process used to identify the Martin and Manatee projects as the most cost-effective alternatives for new resources, and of the Martin and Manatee Unit 3 projects. The document consists of eight sections:

Section I Executive Summary

Section II Introduction

Section III	Description of Proposed Power Plants
Section IV	FPL's Need for the Proposed Power Plants
Section V	FPL's Process for Determining the Best Available Options
Section VI	Non-Generating Alternatives
Section VII	Adverse Consequences if the Proposed Capacity Additions are not Added on Schedule
Section VIII	Conclusion

Section I provides a summary of the overall process FPL employed to identify its capacity needs and the results of the process.

Section II describes FPL's existing system and provides the underlying methodologies and assumptions used in the analyses, including the load forecasting methodology.

Section III provides a detailed description of the proposed Martin conversion and Manatee combined cycle projects, including cost and performance expectations.

Section IV describes the analysis which concluded that FPL has a need for 1,722 MW in the 2005/2006 timeframe.

Section V describes in detail FPL's general planning process, the RFP process employed to solicit bids from other parties to meet the identified capacity needs, and the analytical process used to evaluate those bids.

Section VI details the non-generating alternatives considered by FPL prior to determining a need for additional capacity and addresses the potential for additional cost-effective Demand Side Management (DSM) programs.

Section VII discusses the adverse consequences that would result from delay of licensing the Martin Unit 8 and Manatee Unit 3 projects, including a deterioration of system reliability and increased costs.

Section VIII is a summary of the need for the new capacity, the cost-effectiveness of the Martin Unit 8 and Manatee Unit 3 projects and the processes FPL employed to reach these conclusions.

Q. Please summarize the testimony of the other witnesses that will appear on FPL's behalf in this proceeding.

A. Dr. Sim will present the details of FPL's evaluation of bids received in response to the capacity solicitation process. In so doing, he will discuss the need for new capacity in 2005/2006, the RFP solicitation issued by FPL, the self-build options considered by FPL, and the outside proposals received in response to the RFP. He demonstrates that the Martin Unit 8 and Manatee

Unit 3 projects are the most cost-effective alternatives to FPL's customers. Dr. Sim will also present the assumptions used in the analyses, with the exception of the load forecasts. Dr. Sim is sponsoring Section IV and co-sponsoring with me Section V of the Need Study document.

Mr. Taylor will present his view of the RFP and the economic analysis of the alternatives performed by FPL. He will also discuss the results of his independent evaluation of the bids and his conclusion that the Martin Unit 8 and Manatee Unit 3 projects are the most cost-effective alternative for FPL's customers.

Mr. Yeager will present the engineering details of FPL's proposed Martin Unit 8 project, the conversion of two simple-cycle combustion turbines to a new state-of-the art combined cycle unit, and the Manatee Unit 3 project, which involves the construction of a new combined cycle unit. Included in his testimony are the cost and performance specifications of these proposed units, corresponding to the data used in FPL's analysis. Mr. Yeager sponsors Section III of the Need Study Document.

Mr. Brandt's testimony presents the details of FPL's DSM goals, and FPL's DSM programs and plan. He demonstrates that there is not sufficient DSM potential either to defer or avoid the proposed generating units. Mr. Brandt is sponsoring Section VI of the Need Study Document.

<u>Description of FPL's Existing System</u>

Q. Please describe FPL's existing service territory.

A. FPL's service area covers approximately 27,650 square miles within peninsular Florida, ranging from St. Johns County in the north to Dade County in the south, and westward to Manatee County. FPL serves customers in 35 counties within this geographical region.

Q. How many customers receive their electric service from FPL?

A. FPL currently serves more than 3.9 million customers and a population of more than 7.7 million people. It is expected that FPL will cross the 4 million customer mark in 2002.

Q. Of the nearly 4 million customers served by FPL, what is the mix of residential, commercial and industrial customers?

A. FPL's customer mix is approximately 89% residential, 11% commercial, and less than one half of one percent in the industrial and other categories. As a percentage of sales, residential customers represent about 51% of sales, commercial customers represent 43%, and industrial customers represent approximately 4% of total sales. The remainder of sales comes from other consumers.

Q. Please describe FPL's electric system.

A. To serve its customers, FPL has generating resources at 14 sites located throughout its service territory and beyond, including partial ownership of one unit located in Georgia and partial ownership of two units located in Jacksonville. FPL's generating resources are shown in a map attached to my testimony included as Document SSW-1. The bulk transmission system which interconnects these resources comprises 1,107 circuit miles of 500 kV lines, including 75 circuit miles of lines jointly owned with the Jacksonville Electric Authority (JEA) connecting FPL's system to Georgia, and 2,644 circuit miles of 230 kV lines. The network that underlies this bulk transmission system comprises 1,578 circuit miles of 138 kV lines, 717 circuit miles of 115 kV lines and about 164 circuit miles of 69 kV transmission lines. Integration of the generation, transmission and distribution system is achieved through 505 substations. The configuration of FPL's bulk transmission system is shown in Document SSW-2.

Q. Does FPL purchase power from other sources in addition to its own generation resources to meet demand?

A. Yes. FPL purchases from utility/non-utility sources and qualifying facilities (QFs). Over the next 10 years, to meet seasonal peak demand, FPL will purchase from utility/non-utility sources as much as 2,620 MW (winter). By summer of 2010, the purchases are expected to decline to 382 MW. A summary of these power purchases is provided in Document SSW-3. FPL also will purchase as much as 877 MW from QFs within the next 10 years. By the summer of 2010, QF purchases are expected to decline to 640 MW. A schedule of QF purchases is provided in Document SSW-4.

The decline in purchased power and QF purchases is simply a result of the expiration of a number of different contracts. For example, FPL's current Unit Power Sale (UPS) purchases from the Southern Companies terminates in 2010, and FPL has not decided how to replace this capacity at this time. A number of other purchases are shorter-term, intended to help FPL achieve a 20% reserve margin in the near term, but not needed beyond the period FPL's RFP was intended to address.

Q. How much DSM is included in FPL's resource plan?

A. Measured from the summer of 2001, FPL's cumulative DSM goal is to achieve approximately 565 MW of additional summer peak demand reduction, at the meter, through 2009, the end of the current goal setting period. This reduction is in addition to the 3,076 MW of demand reduction at the meter already accomplished by the summer of 2001. This reduction to date, after accounting for reserve margin requirements, translates to an avoidance of more than 3,600 MW of generation requirements, while FPL's goals from 2001 to 2009 represent an additional 725 MW of capacity avoidance.

Q. What were FPL's actual peaks and net energy for load during 2001?

A. FPL experienced a record summer peak of 18,754 MW in 2001, an increase of 5.3% from the 2000 summer peak. The winter peak for 2000/2001 was 18,199 MW, a 6.7% increase from the previous year. Net Energy for Load (NEL) in 2001 was 98,404 GWh, up 2.5% from 2000.

<u>FPL's Load Forecasting Process and Results</u>

Q. What is FPL's process to forecast the level of energy sales?

A. The forecast of the level of energy sales consists of three steps. First, total Net Energy for Load output is projected; next, a line loss factor is applied to this output to arrive at a total customer end-use energy demand of electricity. Finally, revenue class models are developed to distribute the total end-use sales of electricity forecast to the different revenue classes such as residential, commercial, industrial, etc.

FPL develops econometric models to explain and predict the level of energy sales. Explanatory factors, such as the weather, the price of electricity, the economic conditions in Florida, the number of customers and seasonal factors are used to develop the forecast of energy sales. An econometric model is a numerical representation, obtained through statistical estimation techniques, of the degree of relationship between the level of energy sales and the explanatory factors. A change in any of the explanatory factors will result in a corresponding change in the level of energy sales. On a historical basis, econometric models have proven to be highly effective in explaining changes in the level of energy sales.

Predicting the level of sales in a future year first requires assumptions regarding the levels of the explanatory factors. These assumptions are obtained from different sources. For example, the future number of customers typically will depend on population projections produced by the University of Florida's Bureau of Economic and Business Research (BEBR). The projected economic conditions are secured from reputable economic forecasting firms such as Standard and Poors' DRI-WEFA. The weather factors are obtained from the National Oceanographic and Atmospheric Administration (NOAA). The price of electricity is produced internally by FPL and reflects the Commission's approved base rates and adjustment clauses. Seasonal factors in the consumption of electricity come from two sources, the weather seasons and the population seasonal pattern. Substantial analysis is performed in order to ensure that the assumptions regarding the explanatory variables are reasonable. This ensures that the forecast of energy sales is both realistic and rational.

The final end-use energy demand of electricity or billed energy sales is NEL adjusted for line losses and for billing cycle tuning to take into account the difference between when a customer consumes electricity and when the meter is read. Due to this accounting practice, a superior econometric forecasting model is obtained if NEL, instead of billed energy sales, is matched to the explanatory factors. This is because the NEL data do not have to be attuned to account for billing cycle adjustments, which might distort the real time match between the production and consumption of electricity.

To project energy sales by revenue class, separate models for the residential, commercial, and industrial revenue classes are developed. The sum of all revenue classes will result in total energy sales, which is adjusted to coincide with the total energy sales derived from the NEL model. These revenue class models are developed to obtain an objective allocation of the total energy sales among FPL's different revenue classes.

Q. What are the primary inputs to determine the growth in energy sales?

A. The growth in use of electricity comes from the overall growth in per capita use of electricity by all customers and the growth in the number of new customers. The product of per capita use multiplied by the number of customers' yields the NEL for a given period. The per capita use of electricity and the increased numbers of new customers both are linked directly to the performance of the local and national economy. When the economy is booming, use of electricity increases in all sectors: residential, commercial, industrial and others. A strong economy creates new jobs that attract new customers. New households develop, including those of retirees from other states. However, the reverse also holds. If the economy is performing poorly, customers with reduced incomes are more apprehensive as to expenditures, and tend to restrict their consumption of goods and services. Electricity demand and sales slacken when income falls. Job contractions reduce the number of new customers coming to Florida seeking employment opportunities. New household formations are postponed.

FPL relies on the outlook for the local and national economy produced by Standard and Poors' DRI-WEFA and the population growth forecast developed by the University of Florida.

Q. What is FPL's process to forecast peak demand?

A. The rate of absolute growth in FPL system load has been a function of a larger customer base, varying weather conditions, continued economic growth, changing patterns of customer behavior (including an increasing stock of electricity-consuming appliances) and more efficient heating and cooling appliances. FPL developed the Peak Forecast models to capture these behavioral relationships.

The Summer peak forecast is developed using an econometric model. The model is a per customer model that includes: the total number of FPL Summer customers, the price of electricity, real Florida income as an economic driver, and maximum temperature as a weather variable. The model is estimated using an autoregressive term.

Like the system Summer peak model, the Winter peak model is also an econometric model. The Winter Peak model is a per customer model that consists of three weather-related variables: (1) the minimum temperature on the peak day; (2) a weather term which is a product of heating saturation and minimum Winter day temperature; and (3) Heating Degree Hours from the prior day until 9:00 a.m. of the peak day. In addition, the model also has an economic term, Real Florida Income. A dummy variable, which is used to capture the effects of larger homes, is multiplied by the minimum temperature.

Monthly peaks are forecast to provide information for the scheduling of maintenance for power plants and fuel budgeting. The forecasting process is basically the same as for the monthly NEL forecast; and consists of the following actions:

- Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to seasonal peak (Summer = April-October; Winter = November-March).
- Apply the monthly ratios to their respective seasonal peak forecast to drive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

Q. Is FPL's need for power driven by the demand forecast, the sales forecast, or both?

A. FPL's need for resources, i.e. the amount of resources needed, is driven exclusively by the peak demand forecast because FPL's needs are currently determined by a reserve margin criterion, which I will discuss later in my testimony. The sales forecast may have some influence on the type of resource needed.

Q. Is FPL's peak forecast, and its need for power, reduced by a short-term economic forecast that includes recovery from a recession?

A. No, not to any great degree. While an economic downturn may temporarily slow customer growth and result in a permanent loss of some growth, it does not permanently reduce growth rates. FPL will grow again at something closer to its historical rates after the recession passes. Unlike sales, customer usage on the day of the peak is barely influenced by other economic factors such as per capita income or unemployment rates.

For example, in the recession between 1990 and 1992, energy use per customer grew at a negative rate of 0.83% annually. At the same time, peak demand per customer grew at a positive rate of 0.67% annually. Further, in 2001 the summer peak forecast underestimated the peak forecast by 604 MW (+3.3%) while energy sales were over-estimated by 1.3%

Q. How does FPL's projected rate of growth in peak demand compare to its historical growth?

A. Using summer peak as the example, FPL's peak demand grew from 14,661 MW in 1992 to 18,754 MW in 2001, a 2.8% compound annual growth rate. For the forward-looking period, FPL is projecting a peak demand of 22,687 MW by summer of 2010, which is a 2.1% compound annual growth rate.

Looking more specifically at the growth in peak demand for the period resources are needed, FPL projects a peak demand unadjusted for incremental conservation or load management of 21,186 MW in 2006, which is a 2.5% growth rate, slightly below FPL's historical experience since 1992. So while FPL is not projecting peak demand growth as high as it experienced during the booming 1990's, FPL is projecting significant peak demand growth.

Q. Is FPL's load forecast reasonable for planning purposes?

A. Yes. FPL's load forecast is based on reasonable assumptions and is consistent with historical experience.

FPL's Planning Objective and Process

Q. What is the objective of FPL's Integrated Resource Planning process?

The objective of the process is simply to maintain supply system reliability at the lowest cost or rate while considering appropriate strategic issues such as fuel diversity and flexibility to respond to changing conditions. The first part of this statement, maintaining supply system reliability, is of primary importance in the planning process in that it drives the amount and timing of resource needs. FPL attempts to do this by adding cost-effective resources taking into account the long-term costs to customers. This primarily determines which resources are selected to meet an identified need. The selection of resources also may be influenced by the above-mentioned qualitative strategic factors.

Q. **How does the planning process address supply system reliability?**

A. For many years, FPL used the dual planning criteria of reserve margin and loss of load probability (LOLP). Use of this dual criteria approach ensures that adequate resources are available not only to meet the expected annual peak load, but also to meet daily peak conditions throughout the year.

The LOLP criterion used by FPL is 0.1 days per year, alternatively referred to as one day in ten years. Previously, this Commission has approved this standard as reasonable for planning purposes.

Prior to 1997, FPL employed a reserve margin standard of 15% of projected summer peak. This Commission has reviewed and approved this standard in several proceedings. In 1997, responding to Commission concerns over reliability of the peninsular Florida supply system during winter peaks, FPL added a third criterion to its planning, which is a 15% winter peak reserve margin.

In 1999, as part of Docket No. 981890-EU, the Commission's Generic Investigation into the Aggregate Electric Utility Reserve Margins Planned for Peninsular Florida, FPL agreed to use a planning criterion of 20% reserve margin based on annual peak applied to planning years 2004 and beyond. This criterion has been applied in conjunction with LOLP since the 1999 planning cycle.

Q. Has the Commission reviewed and approved FPL's reliability criteria?

A. Yes, on several occasions FPL has presented the dual criteria discussed above, and the Commission has approved them as reasonable, including:

Docket	**Title**
890973-EI/890974-EI	Petition to Determine Need for Electrical Power Plant 1993-96
900709-EQ/900731-EQ	Indiantown Cogeneration, Ltd. Determination of Need
900796-EI	Petition for Approval of Purchase of Scherer Unit No. 4
910004-EU	Annual Hearings on Load Forecasts, Generation Expansion Plans and Cogeneration Process

910816-EQ	Nassau Power Corporation Determination of Need
920520-EQ	Cypress Energy Partners Determination of Need

The Commission has also had the opportunity to address FPL's entire planning process, including the reliability criteria used, in its annual review of utility Ten Year Power Plant Site Plans, as well as two comprehensive reviews during Conservation Goals hearings in 1994 and 1999.

Q. Why did FPL change its reserve margin criterion from 15% to 20%?

A. In 1998 the Commission staff expressed concern over the projected level of reserves in the state. The Commission initiated an investigation of reserve margins and, in that case, FPL and the other Investor-Owned Utilities in peninsular Florida proposed and voluntarily agreed to begin using 20% of annual peak as a reserve margin criterion and to achieve this level of reserves by summer 2004. The Commission approved this stipulation in Order No. PSC-99-2507-S-EU. FPL continues to use a dual criteria approach to assessing system reliability, leaving in place the 0.1 days/year LOLP standard and a reserve margin standard of 15% of annual peak until mid-2004, at which time the reserve margin standard becomes 20% of annual peak.

Q. Which reliability criterion is the primary driver of the need for new resources?

A. Currently, FPL's need for new resources is driven by the reserve margin criterion. Use of LOLP alone would result in a lower level of resource additions. This relationship has reversed from those performed in the late 1980's, when LOLP was the primary driver.

Q. Why is LOLP no longer the primary driver of the need for new resources?

A. There are two reasons for this change over time. The first and leading reason is that FPL has made substantial improvements in the availability of its generating units since the late 1980's. The second reason is, as previously mentioned, that FPL has changed its reserve margin targets from 15% of summer and winter peak to 20% of annual peak by mid-2004. In the interim period until 2004, FPL is working to raise its reserve margins toward the 20% level.

Q. How does improving unit availability reduce the need for new capacity?

A. In simple terms, improving generating unit availability, which reduces LOLP, translates into an increased value for existing generation and a decreased need for new capacity. Each 1% improvement in availability roughly translates into a 1% increase in available capacity. Thus, for 10,000 MW of generating capacity, a 1% availability improvement is equivalent to approximately 100

MW of additional generation. From a planning perspective as long as LOLP is the driver in determining future resource needs, this is 100 MW of new generation FPL would not have to add to meet expected load.

Q. How does the planning process address resource alternative economics?

A. In general terms, the objective of the economic analysis is to identify the combination of resources that results in the lowest cost (i.e., electric rates) to customers. Alternatives may be examined under a number of different scenarios to ensure a robust solution. Other factors, such as technology risk, environmental risk, flexibility to respond to changing conditions, and security of fuel supply also may be examined to differentiate between alternatives when economic differences are small.

The comparison of competing alternatives must reflect all associated quantifiable costs, both direct and indirect. For example, in comparing supply alternatives, such as competing generating units, the direct costs would include capital, fixed Operating and Maintenance (O&M) expenses, variable O & M expenses and fuel costs and, to the extent possible, transmission interconnection and integration costs. An indirect cost would be the change in the fuel costs of other, existing generating units when the new unit is added to the system. This last item might either be a cost (increase in other units' fuel costs) or a benefit (reduction in other units' fuel costs). The total of these costs, referred to as revenue requirements, are compared over time on a cumulative net present value of revenue requirements (CPVRR) basis.

Using competing new generation unit alternatives as an example, the generating alternative with the lowest CPVRR over the life of the project, which is equivalent to providing lowest rates, is favored, although other factors must be considered, as I mentioned above.

Q. You said that transmission interconnection and integration costs are considered to the extent possible. What did you mean?

A. Two components of transmission costs must be included in the evaluation of a new generating resource. Interconnection costs are basically the costs associated with connecting the generating resource to the transmission system. It is not necessary to know how often the unit will run or where power will be sent in order to determine interconnection costs. These costs could be considered the minimum level of costs associated with new generation and are generally associated with costs of equipment up to and including the substation to which the generator will be interconnected.

Integration costs, on the other hand, are determined by knowing when the unit runs and where power from that unit flows. These costs would include upgrades to the system beyond the interconnecting substation.

In both cases, costs depend on the facilities that exist at the time the generator begins service. This is where uncertainty in cost level is introduced.

Q. Why does this relationship to existing facilities increase uncertainty of costs associated with interconnection and integration?

A. To meet the requirements of the Federal Energy Regulatory Commission (FERC) Order No. 888, which establishes the requirements for nondiscriminatory transmission access, generator interconnection and integration requests are placed in a queue in the order in which they are received. In order of receipt each generator is studied and interconnection or integration costs are established. In this process, cost levels obviously depend on the number of generators in the queue at the time the study is done, as well as the location of the generators.

For example, a generator placed in queue position number 5 may have significant interconnection or integration costs imposed if each of the four generators ahead in the queue has requested interconnection to the same substation.

The limitation in the methodology is that all five generators may be competing for the same sale. The additional costs imposed on the fifth generator may make it non-competitive, even if it otherwise provided lower costs. Only one of the five projects actually may come to pass. However, this is not something that can be known to the transmission planner when interconnection and/or integration costs are determined. Thus, interconnection and integration costs are less certain than any of the other costs in the comparison of alternatives. However, these costs must be considered because they can be substantial.

Q. Is the same economic comparison done when the alternatives are demand-side management (DSM) programs?

A. Yes, in the sense that the sum of all quantifiable direct and indirect costs are compared. However, when DSM programs are compared, there also must be a recognition of the fact that, in most cases, kWh sales to participating customers are reduced, shifting the contribution of those sales to existing costs to non-participating customers, thereby increasing their rates. This method of comparison of DSM is known as the Rate Impact Methodology (RIM) test, and it is the methodology employed by FPL. It allows FPL to analyze DSM on an identical basis – impact on electric rates – as is used for generating alternatives.

Q. Has the Commission approved the use of the RIM test for comparison of DSM programs?

A. Yes. The RIM Test has been reviewed thoroughly and approved in Order No. PSC-94-1313-FOF-EG and reaffirmed in Order No. PSC-99-1942-FOF-EG.

Q. Are there other factors that may influence FPL's selection of a generating alternative?

A. Yes. Several other factors need to be considered in the selection of a generating alternative, including:

- Fuel Diversity
- Technology Risk
- Environmental Risk

Other factors to be considered when evaluating other than self-build options include:

- Financial strength of the supplier
- Feasibility of licensing and construction plans
- Delivery risk related to firmness of fuel supply, construction schedule, experience of the seller, etc.
- Degree of control offered, including items such as dispatchability, rights to sell power, etc.

I will discuss these issues about non-FPL options later in my testimony.

Q. Would you please expand on those factors, i.e. fuel diversity, technology risk and environmental risk, that FPL considers when selecting a generating technology?

A. Although these factors do not necessarily override economic considerations, they are important in distinguishing between alternatives that offer relatively similar life-cycle economics.

Fuel diversity is the consideration of whether any one fuel source, such as coal, oil, natural gas or nuclear, provides too much of the overall energy mix. There is no hard and fast guideline as to how much energy any source should provide, but in choosing between for example, a coal source and a gas source, the coal source would be rated higher as contributing to fuel diversity, assuming the existing system used more gas than coal.

Another aspect of fuel diversity concerns diversity of supply for a single fuel type. An example of this might be in the comparison of two gas-fired options, one fed from an existing gas pipeline and the other fed from a new gas pipeline. The alternative fed from a new pipeline might be considered a better contributor to fuel diversity because it develops a new transportation source.

Technology risk is an assessment of the relative maturity of a technology. For example, an alternative based on a new gas turbine still in the prototype stage might be considered a greater risk than a more commercially developed technology.

Environmental risk is simply a recognition that some technologies, coal and nuclear for example, may face a higher hurdle in licensing and run a higher risk of future tightening of controls than a gas option.

Again, these considerations in and of themselves do not override overall economics, but they should be considered in the selection of a generating alternative, to the extent it is meaningful to do so.

Q. Has FPL employed the processes you have described to identify needed resource additions in 2005/2006?

A. Yes. With the 20% reserve margin criterion driving the need for new capacity, FPL has identified a need for approximately 1,722 MW in the 2005/2006 time frame. Economic analysis identified the Martin conversion and Manatee combined cycle projects as the most cost-effective resource options for FPL's customers. The details of these analyses are more thoroughly presented in Dr. Sim's testimony.

<u>FPL's Need for Power and the RFP Process</u>

Q. When did FPL first identify its needs for the 2005/2006 timeframe?

A. For several years, FPL has identified a capacity need in 2005/2006. In its 1999 Ten Year Site Plan, for example, FPL shows the addition of Martin Unit No. 5, a combined cycle unit, in 2006. Subsequent to the issuance of that document, two significant changes increased the need for capacity in those years. The first change, which I have already discussed, was the agreement by FPL and the other peninsular Florida IOU's to use a 20% reserve margin reliability criterion for the years 2004 and beyond.

The second significant change was an increase in the peak load forecast. In the 1999 Ten Year Site Plan, the summer peak forecast for the year 2005 was 19,170 MW. In the 2001 Ten Year Site Plan, the summer peak forecast for the year 2005 was 20,433 MW, an increase of 1,263 MW. This increase was driven primarily by continuing growth above forecast in customer count and increasing use per customer above forecast.

Q. What was the need for power in 2005/2006 shown in the 2001 Ten Year site Plan?

A. To maintain a 20% reserve margin, FPL needed an additional 1,750 MW in the years 2005 and 2006.

Q. How did FPL plan to meet that need?

A. As a result of its year 2000 planning cycle, FPL had identified the following additions in its 2001 Ten Year Site Plan for the years 2005/2006:

Year	Addition
2005	Martin Combined Cycle No. 5
2005	Conversion of Martin CTs to Combined Cycle
2005	Conversion of Ft. Myers CTs to Combined Cycle
2005	Midway Combined Cycle
2006	Martin Combined Cycle No. 6

The concentration of additions in 2005 resulted from the fact that the 1,750 MW of need was split into approximately 1,150 MW in 2005 and 600 MW in 2006.

The 2001 Site Plan, which presents the results of FPL's prior year (2000) planning process, did not show consideration of a new combined cycle unit at its Manatee site. FPL conducted its 2000 planning process under the assumption that the Martin site would remain its preferred location for new combined cycle capacity. Given the availability of the Martin and Midway sites for the 2X1 Combined cycle (2 combustion turbines to 1 heat recovery steam generator) technology evaluated in that planning cycle, Manatee alternatives were not considered to be necessary. As I will explain later in my testimony, FPL developed new technology alternatives and introduced units at its Manatee site in the RFP evaluation.

Q. Would the additional units identified by FPL require licensing under the Power Plant Siting Act (PPSA)?

A. Yes. Each of the new or conversion units would be adding more than 75 MW of steam capacity in its proposed configuration, and therefore would require FPL to pursue licensing under the PPSA, including a Determination of Need filing with this Commission.

Q. Did this licensing requirement trigger a need to issue a request for proposals?

A. Yes. Under the Commission's bidding rule, the need to issue a RFP is tied to the need for licensing a unit or units under the PPSA. Thus, as a result of its 2000 planning process and issuance of the 2001 Ten Year Site Plan, FPL recognized that a RFP would be required before it could pursue licensing or construction of any of the identified capacity additions.

Q. When did FPL decide to issue a RFP?

A. FPL began work on a RFP early in 2001, recognizing that, in order to meet licensing and construction lead times, as well as any possible negotiation lead time, a RFP had to be issued no later than the third quarter of 2001 to meet a projected June 1, 2005 in-service date.

Q. When did FPL issue its RFP?

A. FPL issued an announcement of its RFP on August 13, 2001.

Q. Please summarize the RFP.

A. Based on its RFP experience in 1989 with a highly detailed, lengthy RFP, FPL decided to issue a document with less detail, greatly simplifying the submittal process and, at least in theory, reducing the burden of analyzing the submittals.

The RFP requested up to 1,750 MW of firm capacity in the 2005/2006 time frame. A preference for offerings from 3 to 10 years was stated, but turnkey bids for new units were specifically noted as acceptable. No technology preference was stated; in fact, FPL invited any project of any type that would satisfy FPL's capacity needs. By leaving the timing and technology open, FPL did not preclude sales from other utility systems, construction of new units, or sales from existing units. We did not favor utilities or Independent Power Producers (IPPs). Our intent was to make the solicitation as open as possible.

Q. Did FPL also solicit bids from non-firm energy sources?

A. Yes. FPL's RFP had a separate solicitation for renewable energy.

Q. Did FPL charge bidders to submit responses to the RFP?

A. Yes. FPL's fee structure required a $500 fee to obtain a copy of the RFP and attend a Pre-Bid Workshop. A subsequent $500 payment was required after the bidder's conference to file a Notice of Intent (NOI) to bid. A final $9000 evaluation fee was required with submittal of the final bid. The $9000 evaluation fee was waived for renewable energy bids.

Q. Please describe the Pre-Bid Workshop.

A. All registered bidders were invited to attend a Pre-Bid Workshop held in Miami on August 24, 2001. The workshop was intended to supplement and clarify information contained in the RFP. FPL began by presenting its capacity needs, the RFP forms to be completed, and the schedule for the RFP process. This presentation was followed by a question and answer session during which FPL responded to written questions from the attendees. The questions and answers were later posted to a website accessible to registrants.

Q. How many organizations submitted NOIs to bid?

A. FPL received NOIs from 19 organizations for firm capacity projects totaling approximately 20,000 MW.

Q. How many bids were received in response to FPL's RFP?

A. FPL received firm capacity bids from 15 organizations totaling approximately 14,500 MW. The 15 organizations, along with the type of proposal submitted and the technology, are listed in Document SSW-5.

Q. Did any bidders submit multiple projects?

A. Yes. When multiple proposals are considered, FPL received approximately 30 different proposals. But, when pricing variations, start date and term-of-service were accounted for, FPL actually had 81 discrete alternatives to evaluate. I have listed these 81 alternatives in Document SSW-6.

Q. After the bids were received, did FPL communicate with the bidders?

A. Yes. Before the evaluation started, FPL communicated extensively with the bidders to ask questions about specific aspects of their bids and clarify their proposals. I believe FPL bent over backwards to understand each and every bid submitted, to the point that we significantly delayed the evaluation process and final result.

Q. Do you consider FPL's RFP to have been a successful solicitation for new capacity?

A. Yes. Based on the large number of both respondents and projects proposed, I believe that FPL's RFP was the most successful solicitation in Florida to date.

Q. How many bids did FPL receive for renewable energy projects?

A. FPL received four bids for renewable energy projects, three based on biomass and one on landfill gas. These bids were for energy only and do not compete with the firm capacity bids received.

Q. What is the status of these bids?

A. The bids are being held pending the results of a customer survey to test interest in a green pricing program. If sufficient interest exists among FPL's customers and program feasibility issues can be resolved, the renewable projects will be matched to serve a portion of the electricity requirements of customers who state that they desire to receive power from renewable resources. This customer survey and feasibility work is ongoing.

<u>Results of the RFP Analysis</u>

Q. Please summarize the RFP's economic analysis process.

A. The economic analysis of the outside proposals was carried out through a series of steps. These proposals were evaluated not only compared to one another but also against FPL's self-build options. Details of the process are described more fully in Dr. Sim's testimony. I summarize the steps of the process as follows:

<u>Step 1: Individual Rankings of Options:</u> Perform economic analyses of all individual outside proposals to determine a ranking of these proposals and perform similar economic analyses of all individual FPL construction options to determine an economic ranking of these FPL options.

<u>Step 2: Expansion Plan Analyses</u>: Using the highest ranked individual outside proposals, determine the best "All Outside" proposal expansion plan that is composed solely of outside proposals for 2005 and 2006. Similarly, using the highest ranked individual FPL construction options, determine the best "All FPL" expansion plan that is composed solely of FPL construction options for 2005 and 2006. Finally using the highest ranked individual

outside proposals and FPL construction options, determine the best "Combination" expansion plan that meets FPL's 2005 and 2006 needs.

Step 3: Total Cost Analyses: After identifying the most economic expansion plans from the final Step 2 analyses, factor in additional cost information not include in the expansion plan analyses. These additional costs include: generating unit startup costs, transmission integration costs, and capital costs associated with additional power purchases ("equity penalty" costs). The results of this total cost analysis of the expansion plans are then compared to determine the most cost-effective expansion plan.

Step 4: Review and Adjustments: The final analysis step involved the review of many of the inputs used, the analyses, and the review of the computer model outputs.

Q. Was the analysis independently verified?

A. Yes. Mr. Taylor's firm, Sedway Consulting, Inc., was retained prior to the analysis to run an independent study of the proposals and the FPL options. As he describes in his testimony, he used his own model to perform the analysis.

Q. What are the results of FPL's analysis?

A. The results of FPL's analysis show that the most cost-effective alternative for FPL's customers when all costs are considered is construction of a new combined cycle unit at FPL's Manatee site and conversion of the two simple cycle CTs now at the Martin site to combined cycle operation. There is no plan consisting entirely of non-FPL options that is even remotely competitive with this Manatee/Martin plan. As Dr. Sim shows, the smallest differential between the FPL plan and an all non-FPL plan was approximately $130 million, NPV, without consideration of generator startup costs, transmission integration costs or equity penalty.

The only competitive plans are certain combinations of FPL's Manatee Combined Cycle or Martin conversion and non-FPL alternatives. The best of these combination plans is $12 million, NPV more expensive than the FPL plan.

Q. Do the combination plans provide risk comparable to that of FPL's self-build plan?

A. No. I will address qualitative factors later in my testimony, but all of the most competitive combination plans create serious concerns, particularly in the areas of security of fuel supply and financial viability. I will return to this point later.

Q. What did Mr. Taylor's results show?

A. Mr. Taylor obtained similar results from his studies. According to Mr. Taylor's analysis, FPL's Manatee/Martin plan was better than the best combination plan by $36 million, NPV, and better than the best outside proposal combination by more than $300 million, NPV.

Q. Do you believe that these results provide a reasonable basis for concluding that FPL's Manatee/Martin plan is the most cost-effective alternative available?

A. Yes. Not only has FPL determined that its own self-build options are the most cost effective, but also this result has been independently verified. The analytical process was comprehensive and subject to an internal critical review.

<u>Qualitative and Other Economic Factors to be Considered in Resource Selection</u>

Q. Are there other factors beyond minimization of unit costs that should be taken into account in evaluating the bids?

A. Yes. As I discussed earlier in my testimony, there are a number of other qualitative factors that need to be considered when selecting a capacity alternative. These same factors can be applied to the projects offered in response to the RFP. In addition, there are two quantitative factors that need to be considered when buying capacity: equity penalty costs and transmission integration costs. I will first address the qualitative issues I discussed earlier as they relate to the bids received. Those issues are:

- Fuel Diversity
- Technology Risk, and

- Environmental Risk

which apply to both FPL and non-FPL alternatives, and

- Financial strength of the supplier
- Feasibility of licensing and construction requirements
- Delivery risk related to firmness of fuel supply, construction schedule, experience of the seller, etc.
- Degree of control offered including terms such as dispatchability, rights to sell power, etc.

which are related to a build vs. buy decision.

Q. Was fuel diversity a factor in FPL's selection of an alternative?

A. No. In this case, all of the alternatives offered were fueled by natural gas or were utility system sales. Thus, the system fuel price response to changes in any single fuel price would be relatively similar. Regarding the diversity introduced by alternative sources of supply, i.e. alternative pipelines, this tended to influence the economic results. For example, projects located on one pipeline tended to have better economics than those fed from a competitive pipeline.

Q. Can the FPL and non-FPL alternatives be distinguished based on technology risk, as you have presented it?

A. There is really insufficient information in the bids to be certain, but it would appear that all of the bids, which utilize CTs, have used a technology similar to the GE Frame 7F turbine, or more mature models, so there is no basis to select among competing alternatives using technology risk.

Q. Is environmental risk different for FPL than for non-FPL alternatives?

A. Based on the fact that all bids were based on natural gas as a fuel source, there is very little separation between alternatives based on environmental risk resulting from air emissions. However, there are obvious environmental advantages to adding capacity to a "brownfield" site, i.e. a site with existing generation, versus development of a new "greenfield" site.

Q. Turning to those issues you stated affect a build versus buy decision, please address the first factor, which is financial strength of the bidder.

A. The recent collapse of Enron has brought much more attention to this issue. However, this has always been a concern to FPL, because the long-term financial viability of a project needs to be confirmed to ensure that FPL's customers will receive the benefits of unit operation throughout the expected life of the unit. Any hiccup in performance, whether related to financial viability or not, jeopardizes the ability of FPL to provide an adequate supply of electricity. FPL must evaluate, at least qualitatively, whether a supplier would be able to complete construction and continue operation, regardless of any short-term financial setbacks.

Given the general effect of the Enron situation on the whole independent power producer industry, it is hard for me to imagine anyone arguing that buying power would present less risk than FPL's self-build options. Affiliates of Enron were among the RFP bidders, as were affiliates of other financially weak developers.

Q. Is there a difference in feasibility of licensing and construction requirements between buying and building?

A. There may well be such differences, depending on the proposal. For example, several proposals offered power from combined cycle units which would have to be licensed under Florida's Power Plant Siting Act. Some of these offers proposed to construct the unit or multiple units, but to sell only part of the power to FPL. This type of offer presents significant questions as to whether a unit which is not fully committed to serving Florida customers can be licensed under the PPSA. Thus, even if the project offered the potential for savings to FPL's customers, FPL would have to seriously consider the potential risk to system reliability if licensing efforts should fail.

Another example of licensing risk is where construction of a new combined cycle is proposed with all output committed to FPL, but with a contract for less than the expected life of the unit. Again, under current interpretation of the Power Plant Siting Act, as I understand it, approval of a Determination of Need application may be doubtful.

Q. Please address the relative risks of building versus buying related to firmness of fuel supply, construction schedule and experience of the seller.

A. This is really a diverse set of considerations which I will address briefly in order.

Firmness of fuel supply is an obvious issue with any technology. Proposals that include firm gas transportation and secure sources of the gas commodity are favored over those that do not. FPL's own projects would include firm contracts for transportation and supply. (FPL made it clear in its RFP that it would not accept proposals based on gas-tolling arrangements). A project without firm fuel transportation arrangements would be considered higher risk than one with such arrangements.

Construction schedule relates to the likelihood that a proposal can meet the desired in-service date. For the most part, this is a function of the technology proposed. For example, a nuclear unit would take much longer to complete than a combined cycle unit. If both units were proposed to be constructed over a five-year term, the nuclear proposal would obviously be suspect. This particular issue was not relevant in FPL's RFP process, since all proposals were either combined cycle or combustion turbines, as were FPL's own units.

An assessment of the experience of the seller considers the number of similar projects in which the seller or proposer has participated and, if relevant, whether the proposer has any prior experience dealing with FPL. Obviously, the more positive experience a developer has, the better, and the more favorable past dealings with FPL, the more favorably a proposer would be viewed.

Q. How does FPL evaluate the degree of control, including such issues as dispatchability and rights to sell power?

A. The issue of degree of control relates to how much a proposal allows FPL to duplicate the way it can operate a unit it owns. For example, as owner of a generating unit, FPL has complete control over the level of output of the unit at any point in time, including shutting down the unit or turning it on, within the engineering limits of the unit. FPL also completely controls maintenance scheduling for the unit and has the right to sell power from the unit off-system when the power is not needed, with benefits accruing to the customer. In purchasing power, FPL must attempt to duplicate these rights by contract.

Q. Since FPL has some experience with purchased power contracts, can the rights it has through ownership be duplicated by contract?

A. In my judgment, no, it is not reasonable to expect that a contract can guarantee the same level of control. A contract not only must specify clearly when a unit can be turned on or off, up or down, but also must specify how any performance-based payments are affected by FPL's exercising its contractual rights. Trying to cover every conceivable circumstance explicitly in a contract is difficult if not impossible. Where a difference of opinion exists with respect to the terms of a purchased power contract, exercising control rights that the purchaser believes to exist may require litigation. This represents a risk to customers that is not present with self-build options.

Q. Did any of the qualitative factors that you have discussed influence FPL's decision to pursue the Manatee and Martin projects?

A. Yes. Consideration of qualitative factors was an important factor in FPL's decision to pursue its self-build options. The qualitative considerations I have listed above reinforce the results of FPL's quantitative analysis. Let me address each of the factors in turn.

Financial Strength of the Supplier – The most competitive portfolio to FPL's self-build plan includes an FPL self-build unit, purchase of power from a utility, and power purchases from new units to be constructed by an independent power producer. A qualitative comparison of the proposals that comprise this portfolio favors FPL's own options and purchases from other utilities. Purchases from the IPP would rate lower due to concerns over the financial state of the supplier in question.

Feasibility of Licensing and Construction Requirements – FPL's self-build option requires licensing under the Power Plant Siting Act and a Determination of Need Proceeding at the FPSC. Competitive plans that include an FPL option similarly would require this licensing. Competitive plans that include combustion turbines do not necessarily need to pursue PPSA licensing, and may have shortened licensing times. However, recent actions by certain counties, which include establishment of a moratorium on power plant construction, suggest that even local licensing can produce opposition and delay. Power purchases from other utilities require no licensing, just FERC approval. Thus, since both FPL's self-build option and the most competitive alternative plans, which combined FPL construction with purchases, require PPSA action and offer similar generation technologies, there is not a clear advantage to either approach.

Delivery risk related to firmness of fuel supply, construction schedule, experience of the seller - I will limit my comments here to firmness of fuel supply, since it is the most significant of these factors, given the alternative plans considered. The plans that are most competitive to FPL's self-build option include power purchases from a combustion turbine facility that included neither firm gas supply from FGT or Gulfstream pipelines nor backup fuel. For this proposal, firm supply was to come from an undersea LNG pipeline as yet unlicensed and for which construction has not yet begun. FPL does not believe it would be prudent to purchase power from such a facility under a long-term contract. Therefore, this consideration is a significant disadvantage to the most competitive alternative plans.

Degree of control offered including terms such as dispatchability, rights to sell power - Ultimately, the degree to which this would differentiate FPL's Manatee/Martin self-build options from power purchase alternatives would be determined by the final negotiated contract. However, as I stated before, it is difficult to duplicate ownership rights in a contract. The best that can be expected is that a contract matches ownership rights. Any other contract outcome increases risk of supply reliability. Moreover, under any contract there is a very real potential for litigation, which increases costs to customers.

The combustion turbine facility proposal offered FPL first call rights on the output, but the facility owner retained rights to sell power when not called upon by FPL. Given the proposal's high energy costs, FPL would seldom call on the unit based on economics. Dispatch of the unit to meet system reliability requirements would be costly. This is certainly a lesser degree of control than FPL has with its owned units and translates to additional costs to customers, who would not share any benefit of off-system sales under this arrangement.

Q. Are there any other considerations relevant to FPL's comparison of its self-build options to the most competitive portfolios?

A. Yes. There is one other factor worth noting that falls outside the issues I have discussed. The most competitive portfolio to FPL's self-build option includes a system sale from a Florida utility. Although this sale does not have the negative considerations mentioned above, such an arrangement does not expand available resources for the state of Florida.

Q. What other economic factors, beyond construction and operating costs, should be considered in comparing bids to FPL's self-build options?

A. There are two cost components that are real costs to FPL customers and must be considered in the analysis. These are transmission interconnection and integration costs and the capital costs associated with power purchases.

I have already discussed the nature of transmission and interconnection and integration costs and how they introduce uncertainty in the analysis of alternatives. Uncertainty of costs is certainly no reason to ignore them. A reasonable attempt should be, and has been, made to quantify this cost component.

However, another issue related to transmission costs is how they are paid by customers, and whether they should be included in the costs of a specific project. The issue arises from uncertainty in the application of FERC policy regarding transmission pricing. Specifically, there remains a question as to whether the transmission upgrades and enhancements resulting from the addition of a specific generator should be charged to that generator or rolled into overall transmission rates.

Some would argue that if these costs are rolled into overall transmission rates, they should not be included in the costs of the specific generation when a comparison is made to another alternative. Obviously, this argument is a form of the shell game in which costs are hidden as if they do not need to be paid by anyone. Whether costs are assigned to a specific project or rolled into overall rates, customers will pay those costs. Therefore, for bid comparison purposes, the costs of transmission enhancements must be quantified and should remain with the generator or group of generators that cause the enhancement.

Q. Please describe how transmission integration costs were factored into the RFP analysis?

A. A transmission assessment was performed for the eight most competitive portfolios and the all-FPL portfolio. The total transmission integration estimate for each portfolio that would come in-service in 2005 and 2006 was estimated. For each group of projects the total integration estimate was determined with no attempt made to break out integration estimates for any one individual project in the group. This approach was taken for two reasons.

First, this breakout of the group's total integration cost was unnecessary since FPL was attempting to determine the best expansion plan (i.e., group of projects). Second, any attempt to break out the total integration estimates into separate costs for the individual 2005/2006 projects in an expansion plan would be totally dependent upon an assumption as to which the order in which individual projects would be added.

The transmission integration construction estimates for the groups of 2005 and 2006 projects in each of the eight portfolio expansion plans and the All FPL expansion plan were then converted into annual revenue requirements. The CPVRR of these revenue requirements was then added to the EGEAS and startup costs for each expansion plan.

Q. Please describe the load flow analyses performed.

A. For each competitive portfolio and the All FPL portfolio, FPL performed load flow studies to assess necessary transmission system upgrades. These studies were considered screening type studies since they were not as comprehensive as studies that are normally performed for a request for transmission service. However, the screening type studies are sufficient to provide a reasonable estimate of what facilities may become overloaded as a result of the portfolio options and what incremental transmission facilities may be necessary to mitigate such overload(s).

The load flow data used to determine what incremental transmission facilities may be necessary in order to integrate each plan are publicly available load flow base cases which are developed annually by the Florida Reliability Coordinating Council ("FRCC"). These load flow cases were slightly modified to reflect additional transmission facilities and upgrades and transmission service requests that have been committed to since the time these base cases were developed in April 2001. Once the base cases were developed, each portfolio plan was incorporated into the base cases individually. Subsequently, an assessment was performed to determine if, consistent with NERC, FRCC and FPL criteria and standards, the incorporation of a plan resulted in any overloads of transmission facilities. To the extent such violations were identified for a specific plan, expansion and/or upgrade of certain transmission facilities were deemed necessary in order to mitigate such violations. Due to the limited time available, an exhaustive analysis to determine the most effective alternative was not performed. Additionally, as a result of the limited time provided to perform such study, just one test year was analyzed for each plan. Based on engineering judgment, a year 2007 load flow base case was used since it incorporated the portfolios entering into service throughout years 2005 and 2006.

Q. Please provide a summary of the result of the load flow analysis.

A. Appendix M to the Need Study document contains a list of incremental transmission facilities and upgrades to existing transmission facilities that are necessary to integrate each portfolio. Generally, the results of the load flow analysis indicated that a limited amount of capability exists on the east coast of Florida for integrating new generation before extensive incremental transmission facilities are needed, and that as larger amounts of additional generation are connected on the east coast of Florida, significantly more incremental transmission facilities must be installed. This fact is evidenced by the cost estimates for the different portfolios discussed below.

With respect to portfolios containing projects not directly connected to the FPL system, this analysis did not identify resulting overloads on such non-FPL transmission systems. Thus, the need for incremental transmission facilities was not determined on non-FPL systems.

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 budget estimate for the facilities necessary for integration was developed for each portfolio. Due to the availability of time provided to develop these budget grade estimates, they were based on sound engineering judgment and readily available data. The estimates did not involve any field inspections. Nor did the estimates involve a detailed or exhaustive analysis to determine less costly or more efficient alternatives. Subsequently, the estimated cost of integration for each portfolio was summed, and the total estimated integration cost determined. As discussed above, no estimates were provided for any incremental facilities that may have been deemed necessary because of a project(s) not connected to the FPL transmission system.

Q. Please summarize the cost estimates associated with integration for the eight portfolios and the All FPL portfolio?

A. The estimates provided were in year 2002 dollars. The portfolio designated as Plan 8, which added approximately 450-550 MW on the East Coast of Florida and 1050-1150 MW on the West Coast of Florida, resulted in the lowest integration costs - - $13.5 Million. The second least costly portfolio was the All FPL portfolio which added approximately 800 MW on the East Coast of Florida and 1050-1150 MW on the West Coast of Florida and resulted in about $42 Million in incremental transmission facilities. The other portfolios all resulted in the addition of approximately 1350-2050 MW on the East Coast of Florida and 0-550 MW on the West Coast of Florida results in the need for incremental transmission facilities estimated at $93 Million.

Q. What is the equity penalty and how is it calculated?

A. The equity penalty is a real cost associated with power purchases. The cost is a result of an imputation by rating agencies, such as Standard & Poors (S&P), of additional debt to a purchaser who enters into a power purchase contract. This additional debt assignment would require an additional equity infusion by the purchaser to bring its overall capital structure back to within the limits required to maintain its bond rating. In the absence of such an equity infusion, the purchaser would be viewed as excessively leveraged. The cost of the necessary additional equity to avoid this overleveraging is the equity penalty.

As an example of how this would work, consider the effects of FPL's entering into a ten-year power purchase agreement. First, the cumulative net present value of the fixed portion of contract payments would be calculated. While it may vary, approximately 40-50% of this net present value would be assigned to the purchaser as additional debt. To bring its capital structure back to its pre-purchase ratio, the purchaser would be required to add a comparable amount of equity. The cost of this additional equity would be appropriately assigned as additional cost to the power purchase.

The equity penalty calculations performed in this analysis are set forth in Appendix N of the Need Study document.

Q. Couldn't the argument be made that signing a contract with an independent power producer is less risky than saddling the ratepayers with a long-term obligation in rate base?

A. The argument is made by some, but it is specious. It ignores the fact that commitment through contract is the same as commitment through rate base.

In other words, customers pay for capacity either way, and only the method of cost recovery is different.

This argument is premised on the notion that the utility can contract for capacity on a short-term basis. Customers do not need capacity only in the short-term. When that short-term contract ends, the capacity must be replaced. Beyond this obvious replacement requirement, the fact is that a generating unit built to meet customers needs will be paid for by customers regardless of the recovery mechanism.

Q. Wouldn't a utility be able to find cheaper power at the end of a short-term contract?

A. This is not necessarily so. Prices also might be higher at the end of the short-term contract. When a utility builds a unit, prices are more certain for that unit, and they are based on actual cost for the life of the unit. That cost declines over the life of the unit. At the end of a specified period, customers receive additional value from the unit by continuing to receive power from what is essentially a fully depreciated unit. Any contract renewal, regardless of timing, would likely be at market rates, not cost-based rates, with market rates set by the cost of replacement power that would certainly be higher than power from a depreciated unit.

In simple terms, the price paid by customers for a utility-built unit will be cost based, with cost set in part by the net book value of a generating unit. For a unit under contract, the <u>minimum</u> price paid by customers would be cost based, with prices higher if the market price is higher. If costs are the same for utility and non-utility units, there simply is no savings potential from the non-utility unit.

Q. Is FPL predisposed to build its own units rather than to buy power?

A. No. FPL has a history that demonstrates its willingness to purchase power if that is the most economic alternative to customers. In 1989, prior to establishment of the Commission's bidding rule, FPL issued a RFP. After an evaluation of the bids received in response to that RFP, FPL selected an offer of a Unit Power Sale from the Southern Company as the preferred alternative, with other projects identified as secondary options. FPL's self-build option was not considered to be cost-effective. FPL eventually purchased Scherer Unit No. 4 after discussions with Georgia Power and presented the results of its RFP analysis to the Commission in Docket No. 900796-EI.

In 1992 FPL returned to the Commission as a co-applicant in the Petition to Determine Need for the Cypress Energy Partners, Ltd. Project, Docket Nos. 920520-EQ and 920648-EQ, which consisted of two 400 MW class coal-fired units located near Lake Okeechobee. Although the Commission ultimately found that this project was not the most cost-effective alternative available to

FPL because FPL had not conducted a new RFP, the fact that in both cases FPL brought forward non-FPL options demonstrates that there is no predisposition toward self-building.

Q. Did FPL include an equity penalty and transmission integration costs when it selected the Cypress Energy project?

A. Yes. FPL included \$71 million of equity penalty and \$99 million of transmission integration costs and still found the project to be cost-effective.

Q. Won't units built by unregulated, competitive companies be cheaper than units built by a regulated utility?

A. There is no rational basis for that assertion. The ultimate proof of the ability of a regulated utility to compete with unregulated companies is found in FPL's RFP process. FPL went to the market and was able to beat all comers by offering a very competitive construction plan that saves money for customers.

Beyond this result, FPL has a track record that demonstrates its capabilities to construct new generation. FPL's Martin 3 and 4 projects were completed well under their original budgets.

Q. A bidder might argue, however, that a contract price is firm while the utility's cost is not guaranteed and may exceed the original estimate. How do you respond?

A. Under a traditional approach to utility construction, the utility estimated a cost and actual costs may have been higher or lower than estimated. If higher, the Commission could determine whether the cost overruns were justified. If lower, recovery of only the lower cost amount would be allowed, in effect passing all construction savings back to customers.

Through the RFP process, FPL has demonstrated its own build options are the most cost-effective alternatives to FPL's customers. Any cost savings that FPL experiences would be passed on to customers, unlike cost savings experienced by other developers.

Q. Are there any other qualitative or quantitative factors that should be considered in the comparison that FPL has done?

A. Yes, I can think of two more factors, one quantitative and one qualitative that should be considered: residual value of owned units and the value of additional MW of a portfolio of generation.

The residual value of a generating unit is a quantitative factor and refers to any remaining value in that unit after its useful or expected life has passed. For example, the combined cycle units proposed by FPL have expected lives of 25 years. While this is the life used to calculate depreciation expense for these units, they will have some value beyond their retirement date. It is not unreasonable to assume that they will operate beyond 25 years with reasonable upkeep, and that will have some value in a resale market.

The value of additional MW is a qualitative consideration and refers to the flexibility of a portfolio of generation to meet any load increases or other changes that would require additional generation. For example, FPL's portfolio of Manatee and Martin provides 1,896 MW of generation in 2005/2006 at nearly the same economics as the best competitive plan, which provides 1,722 MW. This alternative plan meets FPL's 20% reserve margin target <u>to the MW</u>, but any change in load forecast or other conditions might require FPL to seek additional resources in those years. FPL's self-build plan offers some protection against any such changes. The quantitative benefits of these additional MW are captured in FPL's EGEAS analysis, but the flexibility they offer is not really quantifiable.

Q. Has FPL quantified the benefit of residual value of its self-build plan?

A. No. FPL has taken a conservative approach and not attempted to quantify residual value. However, there is no question that there is some value left in the units at the end of their depreciable life. Thus, in a situation where the build versus buy economics are similar, the potential for residual value is an additional factor which favors the self-build option.

Adverse Consequences of Delay

Q. Are there any adverse consequences to delaying approval of the Manatee and Martin projects?

A. Yes. Delaying approval could create a threat to system reliability and an increase in system fuel costs and oil burn.

The threat to system reliability would come from FPL's inability to meet its 20% reserve margin target if one or both units failed to meet their proposed June 2005 in-service dates. While falling below a 20% reserve margin does not necessarily result in loss of service to any of FPL's customers, lower reserve margins certainly increase the possibility of outages and increase the probability of load control operations.

Increased system fuel costs would result from any delayed in-service date of the proposed combined cycle units. These units will be highly efficient, state-of-the-art generating units which would displace energy from older, less efficient units. Absence of the new gas-fired units will result in increased operation of FPL's older units, which generally are oil-fired, leading to increased oil use.

Q. Would you please summarize your testimony?

A. The Manatee combined cycle and Martin conversion projects proposed by FPL are the most cost-effective alternatives to meet the future need of FPL's customers. These projects are needed to maintain system reliability in

2005/2006 as measured by FPL's 20% reserve margin criterion. They will provide FPL's customers with an adequate supply of electricity at a reasonable cost.

The Manatee and Martin projects offer economics that are favorable to the best of the competitive offerings from the RFP, as well as a number of advantages, including:

- They are supplied by firm gas transportation and have potential access to multiple pipelines, resulting in greater reliability of supply than competing proposals. The most competitive portfolios included an offer without firm gas transportation costs with a questionable gas supply and without backup fuel.

- Ownership offers more operational flexibility and control than purchased power and reduces the litigation potential resulting from contract administration.

- Ownership presents less financial risk than purchased power from entities that may be financially stressed in the post-Enron era. The most competitive combination portfolios contained a proposal from a developer that is financially distressed.

- FPL's self-build portfolio offers more flexibility to respond to changes in forecast load than the most competitive portfolios.

- There is a residual value in units owned by FPL versus units under contract.

Moreover, there is no reason to believe FPL cannot compete with non-utility bids. FPL's experience in new construction has been extremely successful, as evidenced by its Martin projects.

FPL is not predisposed to building its own generation, as evidenced by its presentation to this Commission of its purchase of Scherer Unit No. 4, which resulted from its 1989 RFP, and the Cypress Energy project Determination of Need.

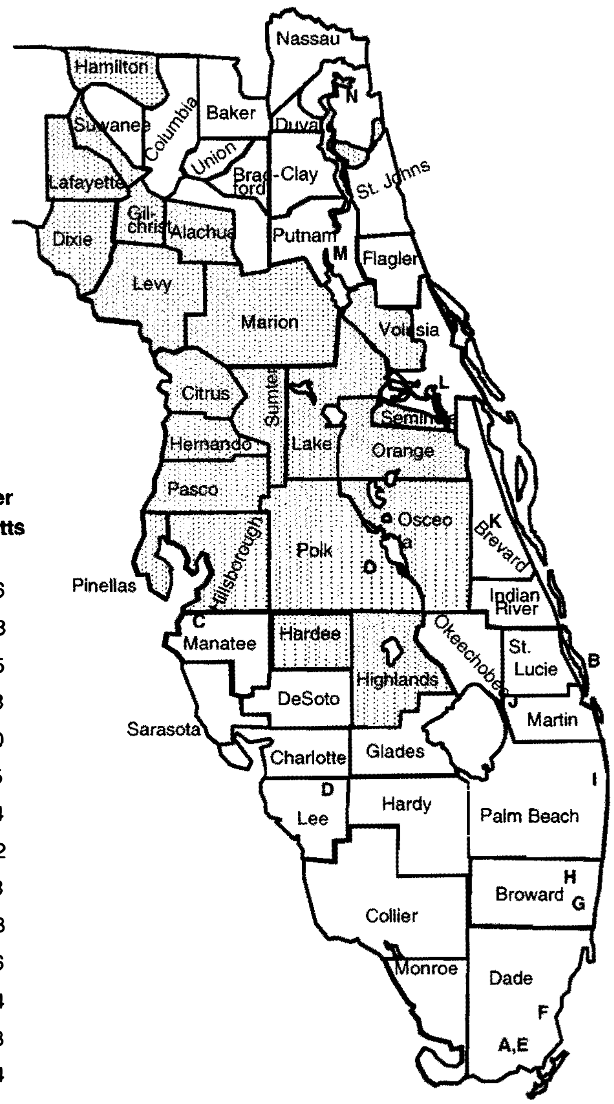
FPL's proposed Manatee and Martin projects meet all of the criteria required by the Commission and should be granted a Determination of Need.

Q. Does this conclude your testimony?

A. Yes.

Capacity Resources
(as of December 31, 2001)

Non-FPL Territory

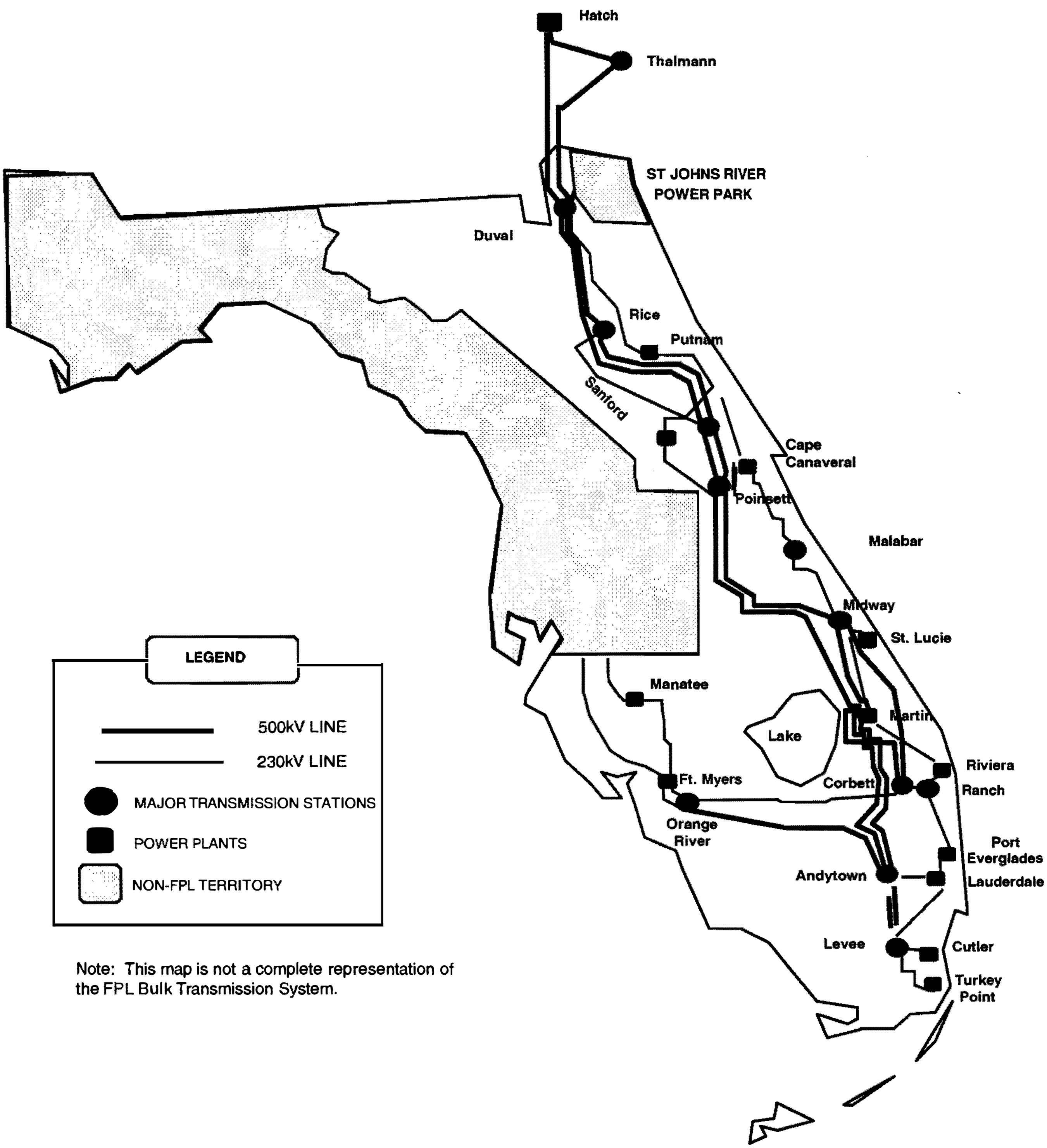


	Unit Name	Unit	Fuel Type	Summer Megawatts
A	Turkey Point	2	Nuclear	1,386
B.	St. Lucie *	2	Nuclear	1,553
C.	Manatee	2	Oil	1,625
D.	Ft. Myers	2	Oil	543
E.	Turkey Point	2	Oil/Gas	810
F.	Cutler	2	Gas	215
G.	Lauderdale	2	Oil/Gas	854
H.	Port Everglades	4	Oil/Gas	1,242
I.	Riviera	2	Oil/Gas	563
J.	Martin	4	Gas/Oil	2,588
K.	Cape Canaveral	2	Oil/Gas	806
L.	Sanford	3	Oil/Gas	914
M.	Putnam	2	Oil/Gas	498
N.	St. Johns River *	2	Coal	254
Scherer **		1	Coal	658
Peaking Units				2,355
FPL Generation				**16,864**

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

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

FPL Substation and Transmission System Configuration



Note: This map is not a complete representation of the FPL Bulk Transmission System.

	FPL's Purchased Power MW (1)							
	UPS		***SJRPP***		***New Firm Capacity Purchases***		***Total***	
Year	***Winter***	***Summer***	***Winter***	***Summer***	***Winter***	***Summer***	***Winter***	***Summer***
2001 (2)	928	928	389	382	0	196	1317	1506
2002	928	928	389	382	50	1093	1367	2403
2003	928	928	389	382	774	1164	2091	2474
2004	928	928	389	382	813	1164	2130	2474
2005	928	928	389	382	1303	447	2620	1757
2006	928	928	389	382	540	447	1857	1757
2007	928	928	389	382	540	0	1857	1310
2008	928	928	389	382	0	0	1317	1310
2009	928	928	389	382	0	0	1317	1310
2010	928	0	389	382	0	0	1317	382
2011	0	0	389	382	0	0	389	382

Note:

(1) Total reflects total resource entitlements resulting from existing agreements between FPL, Southern Companies, JEA, and from new firm purchase agreements.

(2) Values for 2001 are actual

Florida Power & Light Company Firm Capacity and Energy Contracts with Cogeneration/Small Power Production Facilities					
Project	***County***	***Fuel***	***MW Capacity***	***In-Service Date***	***End Date***
Bio-Energy	Broward	Landfill Gas	10.0	5/1/98	1/1/05
Broward South	Broward	Solid Waste	50.6	4/1/91	8/1/09
			1.4	1/1/93	12/31/26
			1.5	1/1/95	12/31/26
			0.6	1/1/97	12/31/26
Broward North	Broward	Solid Waste	45.0	4/1/92	12/31/10
			7.0	1/1/93	12/31/26
			1.5	1/1/95	12/31/26
			2.5	1/1/97	12/31/26
Royster Mulberry	Polk	Waste Heat	8.0	4/1/92	3/31/02
			1.0	12/1/95	3/31/02
Cedar Bay Generating Co.	Duval	Coal (CFB)	250.0	1/25/94	12/31/24
Indiantown Cogen., LP	Martin	Coal (PC)	330.0	12/22/95	12/1/25
Palm Beach SWA	Palm Beach	Solid Waste	43.5	4/1/92	3/31/10
Florida Crushed Stone	Hernando	Coal (PC)	110.0	4/1/92	10/31/05
			11.0	1/1/94	10/31/05
			12.0	1/1/95	10/31/05

List of Organizations Submitting Firm Capacity Proposals

	Organization	Type of Proposal	Technology
1	AES	Purchased Power	CC & CT
2)	Bright Star (Enron)	Purchased Power & Turnkey	CC
3)	Calpine	System Sale	"System" of 4 CC Units
4)	Competitive Power Ventures	Purchased Power & Turnkey	CC
5)	Constellation	Purchased Power	CC
6)	El Paso	Purchased Power	CC
7)	Florida Power Corporation	System Sale	Utility System
8)	Mirant	Purchased Power	CC
9)	PG&E NEG	Purchased Power	CC
10)	Progress Energy Ventures	Purchased Power	CC
11)	Reliant	Purchased Power	CC
12)	Sempra	Purchased Power	CC
13)	Southern Company	Purchased Power	CC
14)	TECO	Purchased Power & System Sale	CC & Utility System
15)	Tractabel	Purchased Power	CC

Summary of Outside Proposals

Firm Capacity Proposal Code Number (FC__)	Location (County)	Incremental Summer Capacity (MW)	Start Date (Year)	Term of Service (No. of Years)
1	Hardee	712	2005	10
2	St.Lucie	618	2005	7
3	Palm Beach	465	2005	25
4	St. Lucie	447	2006	Turnkey
5	Lee	730	2006	6
6	Palm Beach	800	2005	3
7	Manatee	220	2004	10
8	St. Lucie	811	2005	10
9	**Ineligible**	300	2003	9
10	Palm Beach	220	2005	10
11	Utility System	150	2005	5
12	Bradford	576	2005	9
13	Palm Beach	220	2004	10
14	De Soto	490	2006	10
15	St. Lucie	224	2005	20
16	Lee/Indian River/Polk	300	2005	3
17	Palm Beach	811	2005	10
18	Palm Beach	257	2005	25
19	Okeechobee	526	2005	3
20	Dade	242	2005	5
21	St. Lucie	447	2005	Turnkey
22	Broward	811	2005	10
23	Volusia	242	2005	5
24	Bahamas	1,200	2006	10
25	Bahamas	1,200	2005	10
26	Bahamas	1,200	2005	10
27	Bahamas	1,200	2005	10
28	Palm Beach	257	2005	10
29	Palm Beach	220	2005	25
30	St.Lucie	1,236	2005	7
31	St. Lucie	811	2005	Turnkey
32	Palm Beach	811	2005	Turnkey
33	Broward	811	2005	Turnkey

Summary of Outside Proposals

Firm Capacity Proposal Code Number (FC__)	Location (County)	Incremental Summer Capacity (MW)	Start Date (Year)	Term of Service (No. of Years)
34	Manatee/Hillsborough	300	2004	5
35	Manatee/Hillsborough	300	2005	6
36	Hillsborough	250	2004	3
37	Hillsborough	250	2005	3
38	Utility System	150	2005	3
39	Lee/Indian River/Polk	300	2005	10
40	Palm Beach	800	2005	10
41	Lee/Indian River/Polk	300	2005	5
42	Lee/Indian River/Polk	450	2005	3
43	Lee/Indian River/Polk	450	2005	5
44	Lee/Indian River/Polk	450	2005	10
45	Lee/Indian River/Polk	900	2005	5
46	Lee/Indian River/Polk	900	2005	10
47	Hardee	712	2006	10
48	Utility System	150	2006	5
49	Utility System	150	2006	3
50	Palm Beach	800	2006	3
51	Palm Beach	800	2006	10
52	Manatee/Hillsborough	300	2006	6
53	Palm Beach	220	2005	10
54	Manatee	220	2005	10
55	Palm Beach	220	2006	10
56	Manatee	220	2006	10
57	Bradford	576	2006	9
58	Okeechobee	526	2006	3
59	Volusia	242	2006	5
60	Dade	242	2006	5
61	Hillsborough	250	2006	3
62	St.Lucie	811	2006	10
63	Palm Beach	811	2006	10
64	Broward	811	2006	10
65	Palm Beach	465	2006	25
66	Palm Beach	220	2006	10

Summary of Outside Proposals

Firm Capacity Proposal Code Number (FC__)	Location (County)	Incremental Summer Capacity (MW)	Start Date (Year)	Term of Service (No. of Years)
67	Palm Beach	220	2006	25
68	Palm Beach	257	2006	25
69	Palm Beach	257	2006	10
70	St. Lucie	224	2006	20
71	Lee/Indian River/Polk	300	2006	3
72	Lee/Indian River/Polk	300	2006	10
73	Lee/Indian River/Polk	300	2006	5
74	Lee/Indian River/Polk	450	2006	3
75	Lee/Indian River/Polk	450	2006	5
76	Lee/Indian River/Polk	450	2006	10
77	Lee/Indian River/Polk	900	2006	5
78	Lee/Indian River/Polk	900	2006	10
79	Broward	811	2006	Turnkey
80	Palm Beach	811	2006	Turnkey
81	St. Lucie	811	2006	Turnkey