BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110009-EI

In the Matter of:

NUCLEAR COST RECOVERY CLAUSE.
_______________________________/

VOLUME 5

Pages 649 through 808

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: CHAIRMAN ART GRAHAM
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Wednesday, August 10, 2011

TIME: Commenced at 4:25 p.m.
Concluded at 5:09 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: JANE FAUROT, RPR
Official FPSC Reporter
(850) 413-6734

APPEARANCES: (As heretofore noted.)

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I N D E X

WITNESSES

NAME:	PAGE NO.
TERRY JONES	
Direct Examination by Mr. Anderson	652
Prefiled Direct Testimony Extended Power Uprate 2009	655
Prefiled Direct Testimony Extended Power Uprate 2010	694
Prefiled Direct Testimony Nuclear Power Plant Cost Recovery, 2011 and 2012	732
Errata Sheet	772
Prefiled Supplemental Direct Testimony	773
Cross Examination by Ms. Kaufman	780
Cross Examination by Mr. McGlothlin	796
Redirect Examination by Mr. Anderson	804

EXHIBITS

NUMBER:	ID.	ADMTD.
49 through 75		806

P R O C E E D I N G S

(Transcript continues in sequence from Volume 4.)

CHAIRMAN GRAHAM: You can call your next witness.

MR. ANDERSON: Thank you.

FPL would call as its next witness Terry Jones. Mr. Jones has not been in the room to be sworn. I'm sorry, I am told he was. And I remember that now, too.

TERRY JONES

was called as a witness on behalf of Florida Power and Light Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. ANDERSON:

Q. Mr. Jones, if you could just look up when you are settled and ready to go, we'll proceed.

Thank you. It has been noted on the record that you have been sworn as a witness. Would you please state your name and your business address?

A. My name is Terry Jones. My business address is 700 Universe, Juno Beach, Florida.

Q. By whom are you employed and in what capacity?

A. I'm employed by Florida Power and Light; I'm the Vice-President for the Extended Power Uprate Project.

Q. Have you prepared and caused to be filed 39 pages of Prefiled Direct Testimony in this proceeding on March 1, 2011, entitled Extended Power Uprates, 2009?

A. Yes, I have.

Q. Did you prepare and caused to be filed 38 pages of Prefiled Direct Testimony in this proceeding on March 1, 2011, entitled Extended Power Uprates, 2010?

A. Yes, I have.

Q. Have you prepared and caused to be filed 40 pages of Prefiled Direct Testimony in this proceeding on May 2nd, 2011, entitled Nuclear Power Plant Cost-Recovery for the Years Ending December 2011 and 2012?

A. Yes, I have.

Q. Did you also cause to be filed one page of errata on June 10, 2011?

A. That's correct.

Q. Did you prepare and cause to be filed four pages of Prefiled Supplemental Direct Testimony on July 15th?

A. That is correct.

Q. Do you have any other changes or revisions to your Prefiled Direct Testimony?

A. No, I do not.

Q. If I asked you the same questions contained in your Prefiled Direct Testimony, would your answers be the same?

A. Yes, they would.

MR. ANDERSON: Mr. Chairman, Florida Power and Light Company asks that the Prefiled Direct Testimony be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert Mr. Jones' Prefiled Direct Testimony into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TERRY O. JONES

DOCKET NO. 110009-EI

MARCH 1, 2011

Q. Please state your name and business address.

A. My name is Terry O. Jones, and my business address is 700 Universe Boulevard, Juno Beach, FL 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as Vice President, Nuclear Power Uprate.

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

A. In my current role, I report directly to the Chief Nuclear Officer. I am responsible for the management and execution of the Extended Power Uprate ("EPU" or "Uprate") Project.

Q. Please describe your educational background and professional experience.

A. I was appointed Vice President, Nuclear Power Uprate on August 1, 2009. In my current position I provide executive leadership, governance and oversight to ensure the safe and reliable implementation of the EPU Projects for the four FPL nuclear units.

I joined FPL in 1987 in the Nuclear Operations Department at Turkey Point. Since then, my positions at FPL have included Vice President, Operations, Midwest Region; Vice President, Nuclear Plant Support; Vice President, Special Projects; Vice

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President, Turkey Point Nuclear Power Plant; Plant General Manager; Maintenance Manager; Operations Manager and Operations Supervisor. Prior to my employment at FPL, I worked for the Tennessee Valley Authority at the Browns Ferry Nuclear Plant and served in the US Nuclear Navy. I hold a Bachelors of Science degree and an MBA from the University of Miami.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits which are incorporated herein by reference:

- Exhibit TOJ-1, T-Schedules, 2009 EPU Construction Costs, containing schedules T-1 through T-7A. Page 2 of Exhibit TOJ-1 contains a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Powers and myself.
- Exhibit TOJ-2, 2009 Extended Power Uprate Project Instructions (EPPI) Index as of December 31, 2009
- Exhibit TOJ-3, 2009 Extended Power Uprate Project Organization Chart
- Exhibit TOJ-4, Extended Power Uprate Project Reports - 2009
- Exhibit TOJ-5, St. Lucie Low Pressure (LP) Turbine Rotors
- Exhibit TOJ-6, St. Lucie Low Pressure (LP) Turbine Rotor Rings
- Exhibit TOJ-7, St. Lucie Low Pressure (LP) Turbine Rotor Ring Testing
- Exhibit TOJ-8, Plant Change Modification (PCM) Status as of December 31, 2009
- Exhibit TOJ-9, Extended Power Uprate Equipment List as of December 31, 2009
- Exhibit TOJ-10, Extended Power Uprate Project Schedule as of December 31, 2009
- Exhibit TOJ-11, Summary of 2009 Extended Power Uprate Construction Costs

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain the EPU project, key management decisions and Uprate project activities that occurred in 2009, FPL's 2009 construction expenditures, and the procedures, processes and controls that ensure that those expenditures are reasonable and the result of prudent decision making. My testimony also explains the careful engineering-based process employed by FPL to ensure that it is including only nuclear uprate costs that are "separate and apart" from other costs, such as those for base rate nuclear operations and maintenance or capital projects that are unrelated to the nuclear Uprates.

Q. Please summarize your testimony.

A. The EPU project is a complex undertaking to safely increase the capacity of FPL's four existing nuclear units – St. Lucie (PSL) Units 1 & 2 and Turkey Point (PTN) Units 3 & 4 – which will provide significant and quantifiable benefits for customers without expanding the footprint of FPL's existing nuclear power plant sites. Upon completion, FPL estimates that approximately 450 megawatts electric power (MWe) of baseload, non-greenhouse gas emitting generation will be provided by the EPU project for FPL's customers, and that customers will realize significant fuel cost savings as a result.

The project team is in the process of performing design engineering, procuring long lead equipment and materials, obtaining regulatory approvals, and implementing plant modifications to support the uprate conditions in multiple refueling outages for each of the nuclear units. This process is supported by robust and overlapping project schedule and cost controls, along with rigorous risk management. Additionally, the EPU team manages the Uprate work in a manner that ensures that only the costs necessary for the Uprates are expended and included in the Nuclear Cost Recovery process.

Significant progress was made in 2009, including continued engineering evaluation and analyses in support of EPU License Amendment Request (LAR) submittals to the Nuclear Regulatory Commission (NRC), the submittal of the PTN Alternative Source Term (AST) LAR to the NRC, activities and quality inspections related to the manufacture of long lead equipment, the management and implementation of the Engineering Procurement and Construction (EPC) contract, and detailed reviews of the modification installation planning and EPU outage schedules. Also, FPL made adjustments to the project organizational structure reflecting a shift of responsibilities to the individual sites, revised several project instructions, and continued with project staffing. Overall, FPL prudently incurred approximately $238 million in EPU costs during 2009, as compared to the May 1, 2009 actual/estimated amount of approximately $259 million.

Q. Please describe how the remainder of your testimony is organized.

A. My testimony includes the following sections:

1. 2009 Project Summary
2. Project Management Internal Controls
3. Procurement Processes and Controls
4. Internal/External Audits and Reviews
5. "Separate and Apart" Considerations
6. 2009 Project Activities

7. 2009 Construction Costs

8. Conclusion

2009 PROJECT SUMMARY

Q. What is the EPU Project?

A. The EPU project will increase FPL's nuclear generating capacity from its four existing nuclear units by fitting the units with higher capacity and more efficient turbines and other necessary equipment to accommodate increased steam flow that will result from loading fuel with increased reactivity into each reactor. This involves the modification or outright replacement of a large number of components and support structures within FPL's operating nuclear power plants. Each modification/replacement is considered a project in and of itself. In the case of some major modifications, some permanent plant equipment will have to be removed and then reinstalled as a part of the construction process.

Because the project will modify FPL's operating nuclear plants, it is a much different construction project than constructing a new combined cycle generating unit at a greenfield site. FPL plans to perform the modifications during the units' pre-planned refueling outages. Performing the Uprate work during the refueling outages minimizes the amount of time that these low fuel-cost generators are off line.

Upon completion, the Uprates will produce a minimum of 399 MWe and could produce a theoretical maximum of up to 463 MWe for FPL's customers. The minimum reflects FPL's need determination assumption (414 MWe), less the St. Lucie Unit 2 co-owners' share of the output. The maximum reflects the turbine vendor's estimate of the turbine generator's performance (approximately 500 MWe) if the "best case scenario" of plant parameters are achieved, less the co-owners' share of PSL Unit 2 and increased plant electrical requirements. Taking into account the current uncertainty of whether "best case" plant parameters will be achieved, FPL's current estimate is that a total of about 450 MWe will be produced by the uprated units for FPL's customers.

Q. How will customers benefit from the EPU project?

A. Among other benefits, this increase in nuclear power will: (i) enhance system reliability and integrity by diversifying FPL's fuel mix; (ii) provide energy and baseload capacity to FPL's customers with zero greenhouse gas emissions; and (iii) provide significant fuel cost and environmental compliance cost savings. Some of these benefits will be realized as early as 2011, when the replacement of a low pressure turbine generator at St. Lucie Unit 2 with a more efficient low pressure turbine generator will result in a projected total increased electrical power output of approximately 20 MWe and FPL's customers are projected to receive approximately 17 MWe of this increased output. Quantification of these types of benefits will be provided along with an updated project feasibility analysis in FPL's May 2011 testimony.

Q. Please describe the general approach to the EPU project.

A. In 2007, FPL prepared an initial conceptual engineering study for performing an EPU at St. Lucie and Turkey Point which included a conceptual cost estimate based on a preliminary scope. This study provided the basis for FPL's request for a determination of need. In 2008, Shaw Stone & Webster (Shaw) performed a scoping study which included an order-of-magnitude estimate for part of the preliminary scope. The 2008 Shaw order-of-magnitude estimate was confirmatory of the 2007 FPL conceptual estimate.

The EPU project is currently being implemented in four overlapping phases.

1. In the Engineering Analysis Phase, the analyses that support the LAR are performed. During this phase, the major modifications required to implement the EPU are identified and confirmed, the LARs are prepared and submitted to the NRC for review, the NRC approves a license amendment for each plant (or unit, as applicable), and the conceptual scope is better defined.
2. In the Long Lead Equipment Procurement Phase, the major long lead equipment is procured. During this phase, purchase specifications are developed, vendor quotes are requested, vendor proposals are received and evaluated, contracts are awarded, and the cost of long lead equipment is better defined.
3. In the Engineering Design Modification Phase, the detailed modification packages are prepared. During this phase, calculations are prepared, construction drawings are issued, some equipment and materials are procured, general installation instructions are provided, and high level testing requirements are identified. These

activities provide the basis for preparing detailed estimates of the implementation costs.

4. The final Implementation Phase consists of two major parts. The first is planning and scheduling. Planning is the process to convert the design packages into detailed work orders for implementation. During this part of the implementation, revisions to the design may be warranted based on constructability. Scheduling is the process that takes the detailed work orders and converts them into a detailed integrated implementation schedule which ultimately is the point at which the final outage durations are determined. The second part of the final implementation is actual execution of the physical work in the plant including extensive testing and systematic turnover to operations.

Q. Are some activities being performed in parallel?

A. Yes. FPL is performing many activities in parallel in order to bring the benefits of additional nuclear power generation to its customers as soon as practical. The current project schedule is approximately 5 years long, and all necessary work is being performed prior to a particular unit's outage. On the other hand, if FPL had worked through each phase of the project in sequence (i.e., by performing all LAR analyses for all units first, then procuring all equipment for all units next, etc.) the EPU project would have taken many more years. Additionally, by performing EPU work in this manner, Floridians will receive the benefit of approximately 20 additional electrical megawatts of nuclear power from St. Lucie Unit 2 in 2011 – prior to the unit operating at its final uprated level – by virtue of the installation of a more efficient low pressure turbine generator. FPL's customers are projected to receive approximately 17 MWe of this increased output.

Q. Does FPL include industry best practices into the work being performed for the EPU project?

A. Yes. For example, the FPL project team members participate in nuclear industry working groups organized by the Institute of Nuclear Plant Operations (INPO) and the Nuclear Energy Institute (NEI) and benefit from lessons learned. This is supplemented with direct engagement with our industry peers through benchmarking trips to other nuclear sites which have performed similar scopes of work to incorporate best practices. These sources help ensure project decisions are supported by the best information currently available.

Q. Please briefly describe the status of the project in 2009.

A. Through 2009, the EPU project was well into the Engineering Analysis Phase and about half-way through the Long Lead Procurement phase, and only in the early stages of Engineering Design Modification and Implementation. The project scope was not (and is not at the date of this testimony) fully defined and thus definitive cost estimates were not completed – nor were they expected to be completed.

Q. Will project scope continue to evolve as the project moves forward?

A. Yes. Even after completion of the engineering analyses required for the LAR submittal, the potential exists that additional scope will be required by the NRC. After the NRC approves the LARs, the project scope will be further defined and, commensurate with engineering design modification progress, the cost estimate range will be further adjusted. Once the modification packages are final and the work order planning is complete, the implementation scope will be fully defined allowing the final refinement of the detailed implementation cost estimates and schedule durations. These activities lead to increased cost certainty with the achievement of each milestone.

Q. Please provide a brief overview of 2009 activities and costs.

A. Several key activities occurred in 2009, including: (i) continued forward-looking project management which included modification of the EPU project management organization and adjustments to project procedures; (ii) submittal of the AST LAR to the NRC in support of the Turkey Point Units 3 and 4 uprate and continued engineering analyses in support of submitting the EPU LARs; (iii) the execution of vendor contracts for long lead equipment and quality inspections of long lead equipment; (iv) modification engineering for the St. Lucie and Turkey Point units; (v) rigorous management of the EPC vendor and consideration of EPC alternatives; and (vi) detailed reviews of the modification installation planning and EPU outage modification assignments. In total, FPL spent approximately $238 million in 2009 (as compared to the $259 million that was previously estimated) to carry out these key activities and proceed with the development of the Uprate projects, all of which work was subject to the robust project planning, management, and cost control processes that FPL has in place and continuously works to improve.

FPL's EPU activities and expenditures, as well as its internal processes and controls, are described in more detail below.

PROJECT MANAGEMENT INTERNAL CONTROLS

Q. Please describe the EPU project management organization during 2009.

A. As described below, FPL has robust project planning, management, and execution processes in place. These efforts are spearheaded by personnel with significant experience in project management within the nuclear industry. Additionally, the EPU project uses guidelines and Project Instructions to assist project personnel in the performance of their assigned duties. Exhibit TOJ-2, Extended Power Uprate Project Instructions (EPPI) Index as of December 31, 2009 is provided to illustrate the types of instructions that were used.

FPL has a dedicated Nuclear Power Uprate team within the NextEra Energy, Inc. Nuclear Division that is responsible for monitoring and managing the uprate project, schedule, and costs. During the earliest stages of the project through mid-2009, the organization was largely centralized, with support from smaller EPU Project groups at the respective St. Lucie and Turkey Point Sites. This organizational structure was appropriate – and indeed effective – for the solicitation and execution of major contracts and preliminary project-planning activities.

As would be expected for a continuously evolving project, in June 2009, it was appropriate to transition from an organization that was centralized to a decentralized organization as the project progressed into the Implementation Phase. The move would allow for better alignment and integration of EPU activities with operating plant processes. This organizational change was implemented in conjunction with a broader Nuclear Division reorganization. As implemented in 2009, and continuing today, there is an EPU Site Director and an EPU organization at each site responsible for the efficient and effective engineering and implementation of the EPU project modifications. Exhibit TOJ-3, Extended Power Uprate Project Organization Chart, illustrates the organizational structure after it was modified effective August 2009, as the project entered a new stage of execution.

There is also a separate Nuclear Business Operations (NBO) group that provides accounting and regulatory oversight for the EPU Project. This organization is independent of the EPU Project team and reports to the Nuclear Division Controller.

Q. Please describe the role of the NBO group in more detail.

A. As described in EPPI-150, NBO provides accounting and regulatory oversight for the EPU Project. It is independent of the EPU Project team and reports to the Nuclear Division Controller. NBO's primary responsibilities include:

- Review, approval, and recording of monthly accruals prepared by the Site Cost Engineers;
- Conducting monthly detail transaction reviews to ensure that labor costs recorded to the EPU Project are only for those FPL personnel authorized to charge time to the EPU Project;
- Conducting on-going analysis to evaluate project costs to ensure they are "separate and apart";

- Creating monthly variance reports that include cost figures used in the EPU Monthly Operating Performance Report;
- Performing analyses of the costs being incurred by the project to ensure that those costs are appropriately allocated to the correct Capital Expenditure Requisitions established for each nuclear unit's outages;
- Assisting in the classification of Property Retirement Units;
- Setting up and maintaining the EPU Project account coding structure;
- Providing accounting guidance and training to the EPU Team;
- Working closely with FPL's Accounting and Regulatory Accounting Departments to determine which costs related to the EPU Project are capital and which are O&M;
- Managing internal and external financial audit requests and ensuring that findings and recommendations are dispositioned, as appropriate; and
- Providing oversight and guidance to the EPU Project Team in developing and maintaining accounting-related project instructions to ensure compliance with corporate policies and procedures and Sarbanes Oxley processes.

Q. What other schedule and cost monitoring controls were in place during 2009?

A. FPL utilizes a variety of mutually reinforcing schedule and cost controls and draws upon the expertise provided by employees within the project team, employees within the separate NBO group, and executive management. Within the organization of the Vice President, Nuclear Power Uprate is a Controls Group. The Controls Director provides functional leadership, governance and oversight. Each site has a dedicated EPU Project Controls group lead by a Project Controls Supervisor. The site Project Controls organization provides cost and schedule analysis and associated performance indicators on a routine and forward-looking basis thus allowing Project Management to make informed decisions. Exhibit TOJ-4 lists many of the reports that are a direct result of the information the Controls organization provides, analyzes and produces.

FPL's efforts to meet the desired completion date of each uprate is tracked through the use of Primavera P-6 scheduling software, enabling FPL to track the schedule daily and update the schedule weekly. This allows project management to monitor and report schedule status on a periodic basis. Updates to the schedule and scope of project are made as such changes are approved by management. FPL's use of this scheduling software system allows management to examine the project status at any time as well as request the development and generation of specialized reports to facilitate informed decision making. When FPL identifies a scheduled milestone date that may have a high probability of missing its schedule date, a mitigation plan is prepared, reviewed, approved, and implemented with increased management attention to restore the scheduled milestone date or mitigate any impact of missing the scheduled date.

As part of the site Project Controls Group there are several highly experienced Cost Engineers assigned to monitor, analyze, and report project costs associated with the Uprate Projects. Governed by well established procedures and work instructions, the Cost Engineer receives contractor invoices and forwards them to technical representatives to ensure the scope of work has been completed and the deliverables have been accepted. For fixed-price contracts, the Cost Engineer matches the invoice amount to the correct amount and the deliverable work received from the subject matter expert, which is then sent to the appropriate personnel for approval and payment. The Cost Engineer also prepares accruals and reviews variance reports monthly for each of the sites, to monitor and document expenditures and commitments to the approved budget. The Project Controls organization operates in a transparent manner and its accountability is clear in providing sound analysis based on all available information at their disposal.

Q. What periodic reviews were conducted in 2009 to ensure that the project and key decisions were appropriately analyzed and vetted?

A. Regularly scheduled meetings are held to help effectively manage the uprate project and communicate the performance of the project in terms of quality, schedule and costs. In 2009, these included the following:

- Daily meetings to mutually share lessons learned information from each of the projects and to coordinate project activities;
- Weekly project management, project controls, and risk meetings to review the status of the schedules and project costs, and to identify areas needing attention;
- Biweekly meetings with the Chief Nuclear Officer; Vice President, Power Uprate; Implementation Owner South; and other project leaders to review project progress and work through any identified risks to schedules or costs;
- Routine, usually monthly, FPL Executive Steering Committee meetings where project management presents the status of the project. Strategy discussions take place to help improve management of risk areas;
- Monthly Project Meetings involving FPL and individual major vendors during which the project schedules and challenges are discussed; and

- Quarterly Project Meetings involving FPL and its major vendors during which strategy discussions take place to help improve management of risk areas.

The EPU Project also produces several reports. Exhibit TOJ-4, Extended Power Uprate Project Reports, is a listing of reports generated by the project during 2009 with a brief description, the periodicity, and the intended audience of each report. Generally, the project reports provide a status of the project, scope changes, schedule and cost adherence/variance, safety, quality, risks, risk mitigation, and a path forward as appropriate. The information provided by these reports assists in the overall management of the EPU Project.

Finally, the project is annually reviewed to assess its continued economic feasibility. This analysis is conducted in a similar manner to the analysis that supported the affirmative need determination by the Commission, but it is updated to reflect engineering progress and what is currently known regarding project scope and project cost, project schedule, and the cost and viability of alternative generation technologies. The analyses submitted by FPL Witness Sim in 2008 and 2009 demonstrated that the EPU project continued to present a significant economic advantage in a majority of fuel and environmental compliance cost scenarios. An updated feasibility analysis will be provided on May 1, 2011.

Q. **Please describe the risk management process for the EPU project.**

A. FPL's risk management process is governed by EPPI-340 and EPPI-345. FPL's risk management process is used to identify and manage potential risks associated with the

Uprates. A Project Risk Committee, consisting of site project directors and subject matter experts reviews and evaluates initial cost and schedule projections and any potential significant variances. This committee enables senior managers to critically assess and discuss risks faced by the EPU projects from different departmental perspectives. The committee also ensures that actions are taken to mitigate or eliminate identified risks. When an identified risk is evaluated as high, a risk mitigation action plan is prepared, approved, and executed. The high risk item is monitored through this process until it is reduced or eliminated. Additionally, an EPU Project Risk Management report is presented at meetings with senior management, identifying potential risks by site, unit, priority, probability, cost impact, and the unit or persons responsible for mitigating or eliminating the risk. These steps ensure continuous, vigilant identification of and response to potential project risks that could pose an adverse impact on cost or schedule performance of the project.

Q. Please describe the risk management process as it applies to Operational risk.

A. EPU Project work will be performed during normal plant operations and during planned refueling outages. The amount of work that can be safely performed during these plant conditions is dependent upon the minimum required systems or components needed to support the plant operating condition. Extreme care in the planning, scheduling, and execution of the work activities is required to ensure the plant is operated in accordance with applicable NRC regulatory and plant technical specification requirements. This requires proper sequencing of work activities that can be safely performed during normal plant operations or those that must be performed during planned refueling outages, including work activities that can be safely performed in parallel and those that must be performed in series. This operational risk management accomplishes two major objectives: first is to ensure the equipment is in a state that makes it safe for workers to perform the work, and secondly that the plant systems and components are properly maintained to ensure public safety. This operational risk management through the careful planning, scheduling and execution of work activities, adds to the complexity of the implementation phase of the EPU project.

PROCUREMENT PROCESSES AND CONTROLS

Q. Please describe the contractor selection and contractor management procedures that applied to the EPU projects in 2009.

A. The contractor selection procedures applicable to the uprate project are found in General Operating Procedure 705 and Nuclear Fleet Policy NP-1100, Procurement Control. As explained in those policies, the standard approach for the procurement of materials or services with a value in excess of $25,000 is to use competitive bidding. During 2009, the majority of the equipment and work contracted out for the EPU project was competitively bid. However, the use of single source, sole source, and Original Equipment Manufacturer (OEM) providers is also necessary in certain situations. FPL's policies require proper documentation of justifications and senior-level management approval of single or sole source procurements.

Over the course of 2009, and in response to considerations raised by the Commission in the 2008 NCRC proceedings, FPL identified opportunities to improve the documentation of its procurement practices and began implementing enhanced measures late in 2008. FPL has maintained its focus on the process of documenting and approving single and sole source procurements, to ensure compliance with NP-1100 and to facilitate review by third parties who are not directly involved in the nuclear procurement process. Training is provided to personnel responsible for having Single and Sole Source Justifications (SSJs) prepared, the SSJ expectations are included in appropriate project instructions, and all new applicable personnel assigned to the EPU Project are required to review and understand the SSJ expectations.

With respect to vendor management, the EPU Project Directors at each site assure vendor oversight is provided by the Site Senior Project Managers, Project Managers, the site Technical Representative, and Contract Coordinators. Together, these representatives provide management direction and coordinate vendor performance reviews while the vendors are on site. The Site Technical Representative verifies that the vendor has met all obligations and determines whether any outstanding deliverable issues exist using a Contract Compliance Matrix. In addition to assisting with the development and administration of contracts, Nuclear Sourcing and Integrated Supply Chain (ISC) groups complete updates as necessary to a Project Contract Log and report the status of contracts to project management. EPU management also holds quarterly vendor integration meetings as mentioned above.

Q. What is FPL's approach to contracting for the EPU project?

A. FPL structures its contracts and purchase orders to include specific scope, deliverables, completion dates, terms of payment, commercial terms and conditions, reports from the vendor, and work quality specifications. Project Management has several types of contracts available depending on how well the scope of work and the risk associated with the work scope can be defined. Fixed price or lump sum contracts are used where practical. An example would be where project work scope is well-defined and risk is limited. Project Management will use a time and material contract where project work scope is not well-defined and where there is greater risk to completing the work scope. These and other contract provisions help ensure the contractors perform the right work at the right time for the right price, which benefits FPL's customers.

INTERNAL/EXTERNAL AUDITS AND REVIEWS

Q. Are FPL's financial controls and management controls audited?

A. Yes. Several audits have been conducted to ensure compliance with applicable project controls.

Q. What internal audits or reviews have been conducted to ensure the project controls are adequate and costs are reasonable?

A. In 2010, Jefferson Wells on behalf of the FPL Internal Audit Department conducted an internal audit of the 2009 expenses charged to the EPU project. Specifically, the audits focused on whether costs charged to the project are actually for the EPU project and are recorded in accordance with FPSC Rule 25-6.0423. Independent testing of expenses charged to the EPU project for the period January 1, 2009 to December 31, 2009 was conducted. The overall opinion was that the controls over the EPU project are adequate and Jefferson Wells identified no significant issues.

Q. What external audits or reviews have been conducted to ensure the project controls are adequate and costs are reasonable?

A. FPSC staff completed two audits in 2009 – a financial audit and an internal controls audit. FPL also engaged Concentric Energy Advisors to conduct a review of project management in 2009. Witness Reed discusses Concentric's review of the EPU Project in his testimony.

"SEPARATE AND APART" CONSIDERATIONS

Q. Would any of the EPU costs included in FPL's filing have been incurred if the FPL nuclear generating units were not being uprated?

A. No. The construction costs and associated carrying charges and recoverable Operations & Maintenance (O&M) expenses for which FPL is requesting recovery through the NCRC process were caused only by activities necessary for the Uprate projects, and would not have been incurred otherwise. I note that as explained in FPL Witness Powers' testimony and schedules, only carrying costs and recoverable O&M expenses are requested for recovery for the EPU Projects, consistent with the Commission's NCRC rule.

Q. Please explain the processes utilized by FPL to ensure that only those costs necessary for the implementation of the Uprates are included for NCRC purposes.

A. FPL conducted engineering analyses to identify major components that must be modified or replaced in order to enable the units to function safely and reliably in the uprated condition. However, as inspections, LAR engineering analyses, and design engineering modifications are performed, the need for additional modifications or replacements necessary for the Uprate may be identified. Likewise, it may be determined that certain modifications previously identified as necessary to the Uprate project are determined not to be necessary for the Uprate and can be removed from the scope.

Further, FPL considered whether any of the major component modifications or replacements required for the Uprates were already required as a condition of receiving its NRC license renewals. FPL reviewed the "License Renewal Action Items" issued by the NRC and compiled by FPL in conjunction with the approval of FPL's requested license renewals. In doing so, it verified that none of the major component modifications or replacements identified by FPL as necessary for the EPU project were duplicative of the activities required by the NRC for license renewals. FPL also confirmed that none of the EPU activities were previously planned as regular O&M or capital improvement. Additionally, when a scope change is required, a review of the NRC License Renewal Action Items and the seven year capital expenditure plan is conducted to ensure the proposed scope change is separate and apart. FPL's 2009 EPU activities, and their associated costs, were "separate and apart" as required by the NCRC process.

2009 PROJECT ACTIVITIES

Q. What key activities occurred in 2009 in execution of the uprate projects?

A. Several key activities occurred in 2009, including: (i) submittal of the AST LAR to the NRC in support of the Turkey Point Units 3 and 4 uprate and continued engineering analyses in support of submitting the EPU LARs; (ii) the execution of vendor contracts for long lead equipment and quality inspections of long lead equipment; (iii) modification engineering for the St. Lucie and Turkey Point units; (iv) rigorous management of the EPC vendor; and (v) detailed reviews of the modification installation planning and EPU outage modification assignments.

Q. Please describe the Project Management structure for the EPU Project.

A. The management structure that was in place from project inception through the first half of 2009 was appropriate for the earliest stages of the project. The management structure that was in place for the last half of 2009 was appropriate as the EPU Project moved into the implementation phases at each of the sites. These changes permit EPU project personnel to more efficiently integrate with the site unit staff for planning and scheduling the installation of EPU modifications. These activities include, but are not limited, to the following:

- arrival and safe storage of EPU components and equipment;
- any baseline inspections or testing needed in support of the EPU project;
- direct management and oversight of the EPC contractor and other vendors used in preparing engineering modifications or specification development;
- FPL engineering reviews and acceptance of vendor prepared documents;

- work order planning of the modifications;
- implementation of the modifications;
- accurate accounting for the EPU costs being incurred; and
- development of scope changes necessary for the success of the EPU Project.

Q. Did FPL incur any imprudent costs in the reorganization of the EPU project team or the broader Nuclear Division reorganization discussed previously?

A. No. FPL did not incur any imprudent costs as a result of the project reorganization. To the contrary, reorganizing project management by shifting more responsibilities to the sites was the prudent course of action as the project enters its implementation stage. With respect to the Nuclear Division reorganization, this change did not affect the types or amounts of costs incurred for the EPU project.

Q. Please describe the license amendment preparation and submittal activities in 2009.

A. FPL submitted to the NRC the AST LAR for Turkey Point Units 3 and 4 on June 25, 2009. The NRC accepted the AST LAR for review on September 25, 2009, and the review and approval process was expected to take approximately 12 months. As of the time of this filing, the NRC had not completed its review. The AST LAR includes uprate conditions information and is required by the NRC prior to submitting the EPU LAR. The potential exists that additional EPU project scope may be required as a result of the NRC's AST LAR review process.

FPL also continued to manage the engineering analyses and preparations of the EPU LARs to the NRC and respond to NRC Requests for Additional Information (RAIs) in a timely manner. There is one EPU LAR submittal for Turkey Point and two EPU LARs for St. Lucie (one for each unit). One EPU LAR for each St. Lucie unit is required due to the differences in the plant design bases and the nuclear fuel used in each of the units. Work was conducted in 2009 to support the planned submittal of the three EPU LARs in 2010.

Q. Please describe the engineering analyses in support of License Amendment Requests in more detail.

A. The EPU LARs contain nuclear fuels, mechanical, electrical, chemical and material engineering evaluations required for NRC review and approval of the uprated condition. For example, the engineering analyses conducted in 2009 included a review of the Nuclear Steam Supply System (NSSS) design bases using the power uprate parameters to ensure the original design safety margins could be maintained, or are not challenged, when a plant is operated in the uprate condition.

Q. Who is performing these analyses?

A. Engineering analyses for the St. Lucie and Turkey Point EPU LARs are being performed by the following major organizations: Westinghouse, which is an OEM for the NSSS and is one of the fuel suppliers (PTN 3 and 4 and PSL 1); Shaw Stone & Webster, which is performing the secondary or Balance of Plant (BOP) analyses; Areva, which is an OEM for portions of the NSSS and is one of the fuel suppliers (PSL 2); and FPL, which reviews engineering materials prepared by the contracted companies.

Q. Were any state regulatory approvals sought or obtained in 2009?

A. Yes. Agreement on the Conditions of Certification for the Turkey Point Site Certification Amendment was reached with the South Florida Water Management District on October 14, 2009, favorably closing out this issue.

Q. Please describe activities related to the Long Lead Procurement phase in 2009.

A. The engineering analysis was completed for major equipment and components in 2009. Several increased capacity heat exchangers, pumps, and motors were specified and contracted. Adjustments to the milestone payments for some of the long lead equipment items resulted in fewer payments being made in 2009 and orders for equipment were rescheduled as a result of the adjusted outage modification assignments.

Significant progress was made in 2009 on the manufacturing of items previously contracted, including the turbine closed cooling heat exchangers, high pressure (HP) feedwater heat exchangers, moisture separator reheaters, main feedwater pumps, feedwater heat exchangers, main condensers, turbine plant cooling water heat exchangers, feedwater isolation valves, and other components. The St. Lucie main turbine low pressure (LP) rotors were forged and machined in 2009. Exhibits TOJ-5 through TOJ-7 are pictures of the manufacturing process for the St. Lucie LP Rotor and illustrate the size and nature of these major forgings. Exhibit TOJ-5 is a picture of the machined St. Lucie LP turbine rotors. Exhibit TOJ-6 is a picture of the St. Lucie LP turbine rotor rings that will hold the turbine blades.

Q. Please describe the quality inspections related to the manufacture of long lead equipment for the EPU Project.

A. FPL Quality Assurance (QA) personnel witnessed various portions of the manufacturing process and performed vendor audits of the manufacturer's processes to ensure vendor quality control processes were adhered to and specifications were being met. For example, Exhibit TOJ-7 is a picture of a vendor technician performing ultrasonic testing to evaluate the integrity of one of the St. Lucie LP turbine rotor rings. This process was witnessed by FPL QA personnel. QA verified that the individual performing the testing was qualified to operate the equipment and perform the testing and that the instrumentation was properly calibrated. QA prepares reports of their inspections/audits.

Q. Please describe the management of the major EPU project vendors in 2009.

A. At all times EPU management exercises vigilant oversight of its vendors, including routine visits to its vendors' headquarters, and adherence to the internal management controls and vendor oversight controls discussed above. Throughout 2009, FPL particularly focused on the staffing projections being provided by its EPC vendor to begin the engineering for the Plant Change Modifications (PCM). A PCM will include as necessary the mechanical, electrical, civil, instrumentation and control requirements, requirements for removing interferences, and requirements for installing and pre-operational or operational testing of the equipment as appropriate. When a PCM nears completion, a more definitive cost for that modification can be estimated for use in project management and budgeting. Early in 2009, the EPC vendor proposed mobilization staffing and personnel ramp-up that would have resulted in costs that were greater than originally estimated.

Q. How did FPL respond to the EPC vendor's proposals?

A. The EPU site organizations challenged these projections by requiring the EPC vendor to justify each position for mobilization. The site organizations then approved mobilization of only those positions that were appropriate for that stage of the project, including EPC management and engineering staff. Additionally, the corporate EPU organization entered into blanket contracts with three specialty vendors that perform nuclear project estimating with the intent of using their estimating expertise on portions of the EPU project if needed.

During the second quarter of 2009, the EPU project team determined there was a need to more aggressively explore and implement ways to test, validate, and report cost projection information such as that which the Company had begun to receive from its EPC vendor, especially for the out-years of the Uprate project. Also, executive management directed the EPU team to continue challenging the EPC vendor's estimates, to consider alternative EPC vendors for at least a portion of the work, and to engage third party estimating support to assist in advancing the project cost estimate and to use as a tool in challenging vendor estimates. Following several iterations of vendor negotiations and challenges by the site EPU project organizations and EPU management, the EPC vendor's projected staffing levels were adjusted downward, and continue to be adjusted from time to time as appropriate.

Q. What was the effect on the total EPU project cost forecast?

A. The fluctuating vendor proposals were reflected in the standard project cost reports and varied the total project cost forecast at completion from month to month. The project cost forecasts represent a snapshot of current trends but do not necessarily represent everything known about the project. For example, while a particular month's forecast may have incorporated a recent EPC vendor staffing estimate, it would not have reflected the fact that EPU management was considering EPC vendor alternatives with the potential to reduce costs. Due to the extensive project management activity in mid- to late-2009, and considerations that put both upward and downward pressure on potential total project costs, FPL had an insufficient basis upon which to revise its non-binding cost estimate for the EPU project. This topic is also discussed by FPL Witness Art Stall.

Q. Was there any effect on the 2009 EPU project costs?

A. No. The cost uncertainty discussed above concerned future year projections, not current or near-term expenditures. No imprudent costs were incurred in 2009.

Q. What was the status of the Plant Change Modification packages as of December 31, 2009?

A. Exhibit TOJ-8, Plant Change Modification (PCM) Status as of December 31, 2009, is a chart that illustrates the number of identified engineering modifications as of December 31, 2009, the number of PCMs that were initiated, and those that reached 30%, 90%, and final completion. As can be seen in this exhibit, there were 185 PCMs identified of which only 4 were finalized and approved for issuance. This exhibit demonstrates that the Project was in the very early stages of the implementation engineering.

Q. Does FPL have a list of the equipment modifications planned for the EPU project?

A. Yes. Exhibit TOJ-9, Extended Power Uprate Equipment List, provides a listing of the equipment modifications or replacements, a description as to why it is needed for the uprate conditions, current vendors and contract Purchase Orders (PO) where available, and the source document identifying the equipment modification or replacement, as of December 31, 2009.

Q. Please describe the modification installation planning and EPU outage modification assignments performed by project personnel.

A. In 2009 the project team analyzed which modifications should be performed in which outages based on the long lead equipment schedule for delivery, the sequencing of the outages, vendor capabilities, and the amount of EPU modification work that was proposed for each outage. Discussions took place with executive management, each of the site's outage and operations management, FPL's nuclear fuels department, the major equipment suppliers, and the EPC vendor to determine the impact of changing the implementation sequence of EPU modifications, and an adjustment to the outage assignments was made.

There are some risks associated with adjusting outage modification assignments, including the need to accommodate any additional modifications that result from the NRC's LAR reviews and the ability of the project vendors to integrate outage sequencing with their other work commitments. But there are several potential benefits to the adjusted outage modification assignments as well. The outage modification assignments will permit an earlier increase in the electrical generation from one of the units, and may also reduce total off-line time which would benefit customers through additional cost savings. Also, because the initial EPU outages will now have more limited scope, the site implementation teams will be able to use initial outage experience to enhance second outage performance, when there will be more scope. Finally, the reassignment provides for more time to develop more of the EPU engineering modifications and installation packages now that they will be implemented during the second outage for each unit. It should be expected, however, that as the LAR reviews, design engineering, and implementation planning progresses, additional changes to outage modification assignments may occur.

Q. As of December 31, 2009, what was the overall EPU project schedule?

A. Exhibit TOJ-10, Extended Power Uprate Project Schedule as of December 31, 2009, illustrates the LAR, long lead material, engineering design, and implementation schedule for the EPU Project. Underlying this high-level schedule are tens of thousands of individually-scheduled activities. These scheduled activities provide a roadmap for the project. Activities are logically-tied to ensure a sequence of activities needed to support a future activity are completed prior to the future activity being started or completed, as required. FPL's overall project schedule in 2009 included the following:

- The LAR analyses were scheduled to be completed and submitted to the NRC with sufficient time for an extended NRC review before the license amendment approval is needed by FPL to increase the power output at the completion of the second EPU outage for each of the units.

- Long lead material items were scheduled to arrive on site prior to the outage during which the equipment will be installed.
- PCM engineering design for each of the 185 identified modifications was scheduled to be approved for implementation prior to the unit outage when each modification will be implemented.
- Implementation of the EPU modifications was scheduled to be completed during the scheduled refueling outages for each of the units.

Q. Did FPL conduct a "feasibility analysis" of the EPU project in 2009?

A. Yes. FPL Witness Steve Sim conducted a feasibility analysis in 2009, which demonstrated that in all nine combinations of projected fuel cost and environmental compliance cost scenarios the EPU project was the cost-effective choice for FPL's customers. Dr. Sim's analysis and results were discussed in detail in the testimony provided in Docket No. 090009-EI and approved by the Commission.

2009 CONSTRUCTION COSTS

Q. What type of costs did FPL incur for the uprate project in 2009?

A. As demonstrated in Exhibit TOJ-1, Schedule T-6 and T-4, and summarized on Exhibit TOJ-11, Tables 1 through 9, costs were incurred in the following categories: License Application; Engineering and Design; Permitting; Project Management; Power Block Engineering, Procurement, Etc.; Non Power Block Engineering, Procurement, Etc.;

and Recoverable O&M. These costs were the direct result of the prudent project management, decision making, and actions described in detail above. Each category reflects some variance against what was originally estimated and budgeted, which is to be expected, particularly given the relatively early stage of the project. The overall variance in 2009 is driven primarily by the reduced payments for long lead equipment items, downward adjustments to engineering and EPC contractor resources due to the vendor oversight efforts described above, and downward adjustments to staff resources due to the adjusted EPU outage modification assignments. Staffing levels will be increased later in the project to provide appropriate staffing for the EPU long duration outages. Exhibit TOJ-11, 2009 Extended Power Uprate Construction Costs contains summaries of the EPU expenditures in 2009 for each of the NFR schedule categories. Table 1 to Exhibit TOJ-11 is a summary of each of the categories showing the actual expenditure amounts prior to any adjustments.

Q. Please describe the costs incurred in the License Application category and the variance, if any, from the 2009 actual/estimated costs in this category.

A. Licensing Costs consist primarily of charges for consulting and contractor services rendered in support of preparing the LARs. The primary contractors that provide services in this category are Westinghouse, Areva, and Shaw Stone & Webster. FPL incurred $66.9 million in this category in 2009, which was $7.9 million more than the actual/estimated amount. This was primarily attributable to the preparation of more analyses than expected and a longer period of contractor mobilization in performing the NSSS/Fuel Engineering work. The longer period of mobilization and the increased quantity of analyses are due to additional scope identified during the initial phases of these evaluations.

Q. Please describe the costs incurred in the Engineering and Design category and the variance, if any, from the actual/estimated costs in this category.

A. Engineering & Design Costs consist primarily of costs for FPL personnel and contractor personnel in the FPL engineering organizations at both sites and in the central organization. Some of these personnel provide management, oversight and review of the LAR activities, while others are oriented towards management, oversight and review of the detail design activities being performed by the EPC contractor. FPL incurred $12.6 million in this category in 2009, which is $1.9 million more than the actual/estimated amount. This was primarily attributable to LAR scope growth and actual costs required to manage the EPC contractor engineering effort.

Q. Please describe the costs incurred in the Permitting category and the variance, if any, from the actual/estimated costs in this category.

A. Permitting Costs are primarily attributable to the State of Florida Site Certification Application for the St. Lucie and Turkey Point sites. This consists of consulting services related to environmental work for the Site Certification Application (SCA) and Compliance of Certification (CoC), and FPL employee support. FPL incurred $512,725 in this category in 2009, which was $410,295 more than the actual/estimated amount. This was primarily due to more than expected costs to reach closure on the manner in which FPL would comply with the CoC for the Turkey Point SCA. Specifically, resources were required to develop the scope of the Turkey Point Cooling Canal monitoring program required by the CoC.

Q. Please describe the costs incurred in the Project Management category and the variance, if any, from the actual/estimated costs in this category.

A. Project Management Costs relate to overall project oversight including project and construction management, project controls and non-NRC regulatory compliance. These oversight activities are performed by personnel located at both sites; and by the EPU central organization and by non-EPU organizations such as NBO, New Nuclear Accounting, and Regulatory Affairs. FPL incurred $15.5 million in this category in 2009 which was $4.7 million less than the actual/estimated amount. This was primarily attributable to the movement of more field management responsibilities to the EPC vendor. In addition, the ramp up of EPU project staff was revised to support the adjusted outage modification assignments.

Q. Please describe the costs incurred in the Power Block Engineering, Procurement, Etc. category and the variance, if any, from the actual/estimated costs in this category.

A. The majority of these costs continue to be for milestone payments for long lead equipment items. This includes payments to Siemens for turbines and generator rotors, and payments to TEI for feedwater heaters and moisture separator reheaters, main condensers, and increased capacity heat exchangers and pumps required to support the uprate conditions. These costs also include the EPC vendor contract for the engineering and design of modifications of currently identified project scope. In addition, FPL completed the modifications to the St. Lucie Unit 2 Turbine Gantry Crane in 2009 and incurred most of the expected project costs. On December 4, 2009, FPL filed a petition to include costs associated with the St. Lucie Unit 2 Turbine Gantry Crane in base rates.

FPL incurred $141.2 million in this category in 2009 which is $26.6 million less than the actual/estimated amount. The majority of the variance is attributable to less than expected utilization of the EPC contractor and deferral of some milestone payments to vendors for the long lead procurement equipment. A contributing factor was the adjusted outage modification assignments which moved some plant modifications between the outages. In 2009, this resulted in a less intensive EPC engineering effort and a less pronounced EPC organization ramp up, and later delivery requirements for certain major equipment.

Q. Please describe the costs incurred in the Power Block Engineering, Procurement, Etc. category for the completed modifications to the St. Lucie Unit 2 Turbine Gantry Crane.

A. The St. Lucie Unit 2 Turbine Gantry Crane upgrade field implementation started in August 2009. Performance testing was completed and the PSL Unit 2 Turbine Gantry Crane was placed in service on December 22, 2009.

The St. Lucie Plant has two Turbine Gantry Cranes, one for each unit. During the initial evaluations of the proposed schedule for implementation of the EPU modifications, the Turbine Gantry Crane activities became the critical path during implementation of the EPU modifications. An engineering evaluation of each Turbine Gantry Crane was performed resulting in proposed modifications to each crane for increased efficiency and precision in removing and installing the many pieces of heavy equipment. The modifications to each Turbine Gantry Crane can be performed during normal plant operation, saving plant outage time. The modifications were performed on the PSL Unit 2 Turbine Gantry Crane in 2009. Some of the modifications performed included installing bridge and trolley motors and hoists capable of infinitely variable speed control from the operator's cab or from a pendant control that can be used by the crane operator outside of the cab on the turbine deck at the same level as the load being moved.

The cost of the PSL 2 Turbine Gantry Crane upgrades was $2,856,822, as of the fourth quarter of 2009, as reflected in Appendix A of Exhibit TOJ-1. On December 4, 2009, FPL filed a petition with the Commission to include the St. Lucie Unit 2 Turbine Gantry Crane modification costs associated with the EPU Project in Base Rates (Docket No. 090529-EI). That request was granted on March 16, 2010.

Q. Please describe the costs incurred in the Non-Power Block Engineering, Procurement, Etc. category and the variance, if any, from the actual/estimated costs in this category.

A. Non-Power Block Engineering Costs consist primarily of costs for facilities for engineering and project staff at site locations and the simulator upgrades required to reflect the uprate conditions. FPL incurred $535,251 in this category in 2009. This represents $445,101 more than the actual/estimated amount. The variance is primarily attributable to costs for the simulator modifications being incurred earlier than planned.

Q. Please describe the costs incurred as Recoverable O&M.

A. FPL incurred $498,077 in recoverable O&M. This represents a variance of $69,923 less than the actual/estimated amount. Consistent with FPL's capitalization policy, the commodities that make up these expenditures consist primarily of non-capitalizable computer hardware and software, and office furniture and fixtures needed for new project-bound hires – all of which are segregated for EPU Project personnel use only – incremental staff, and augmented contract staff. In addition, with the completion of the St. Lucie Unit 2 Turbine Gantry Crane modification in late 2009, Recoverable O&M also includes the write-off of inventory rendered obsolete because of EPU modifications. Through 2009, $18,864 in inventory has been written off.

Q. Please describe the costs incurred in the Transmission category.

A. The expenditures in Transmission include line engineering, substation engineering, and line construction and totaled $368,559. The cost is $659,565 less than the actual/estimated amount. The variance is the result of revising the schedule for substation and transmission construction activities. FPL moved some of the substation construction activities originally scheduled for 2010 to outages scheduled in 2011 and 2012. This shift resulted in reduced 2009 substation engineering costs. Additionally, due to restrictions in removing certain transmission lines from service in 2009, part of the transmission line engineering and construction costs scheduled during the PSL Unit 2 spring 2009 outage were deferred to the PSL Unit 1 spring 2010 outage.

CONCLUSION

Q. Were FPL's 2009 EPU expenditures prudently incurred?

A. Yes. FPL incurred costs of approximately $238 million in 2009. FPL's actual costs were less than its estimate for the reasons described above. All of FPL's expenditures were necessary so that the uprate work can be performed during the planned outages. Through experienced personnel's application of the robust internal schedule and cost controls, careful vendor oversight, and the ability to continuously adjust based on lessons learned and the project's evolving needs, FPL is confident that its EPU management decisions are well-founded and prudent. All costs incurred in 2009 were the product of such decisions, were reasonable and prudently incurred, and should be approved.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TERRY O. JONES

DOCKET NO. 110009-EI

MARCH 1, 2011

Q. Please state your name and business address.

A. My name is Terry O. Jones, and my business address is 700 Universe Boulevard, Juno Beach, FL 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as Vice President, Nuclear Power Uprate.

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

A. In my current role, I report directly to the Chief Nuclear Officer. I am responsible for the management and execution of the Extended Power Uprate ("EPU" or "Uprate") Project.

Q. Please describe your educational background and professional experience.

A. I was appointed Vice President, Nuclear Power Uprate on August 1, 2009. In my current position I provide executive leadership, governance and oversight to ensure the safe and reliable implementation of the EPU Projects for the four FPL nuclear units.

I joined FPL in 1987 in the Nuclear Operations Department at Turkey Point. Since then, my positions at FPL have included Vice President, Operations, Midwest Region; Vice President, Nuclear Plant Support; Vice President, Special Projects; Vice

President, Turkey Point Nuclear Power Plant; Plant General Manager; Maintenance Manager; Operations Manager and Operations Supervisor. Prior to my employment at FPL, I worked for the Tennessee Valley Authority at the Browns Ferry Nuclear Plant and served in the US Nuclear Navy. I hold a Bachelors of Science degree and an MBA from the University of Miami.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits which are incorporated herein by reference:

- Exhibit TOJ-12, AE Schedules, 2010 EPU Construction Costs, containing schedules AE-1 through AE-7B. Page 2 of Exhibit TOJ-12 contains a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Powers and myself.
- Exhibit TOJ-13, T-Schedules, 2010 EPU Construction Costs, containing schedules T-1 through T-7B. Page 2 of Exhibit TOJ-13 contains a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Powers and myself.
- Exhibit TOJ-14, 2010 Extended Power Uprate Project Instructions (EPPI) Index as of December 31, 2010
- Exhibit TOJ-15, 2010 Extended Power Uprate Project Site Centered Organization Chart
- Exhibit TOJ-16, Extended Power Uprate Project Reports - 2010
- Exhibit TOJ-17 Plant Change Modification (PCM) Status as of December 31, 2010
- Exhibit TOJ-18, Extended Power Uprate Equipment List as of December 31, 2010
- Exhibit TOJ-19, Extended Power Uprate Project Schedule as of December 31, 2010

- Exhibit TOJ-20, Summary of 2010 Extended Power Uprate Construction Costs

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain the EPU project, key management decisions and Uprate project activities that occurred in 2010, FPL's 2010 Uprate construction expenditures, and the procedures, processes and controls that ensure that those expenditures are reasonable and the result of prudent decision making. My testimony also explains the careful engineering-based process employed by FPL to ensure that it is including only nuclear uprate costs that are "separate and apart" from other costs, such as those for base rate nuclear operations and maintenance or capital projects that are unrelated to the nuclear Uprates.

Q. Please summarize your testimony.

A. The EPU project is a complex undertaking to safely increase the capacity of FPL's four existing nuclear units – St. Lucie (PSL) Units 1 & 2 and Turkey Point (PTN) Units 3 & 4 – which will provide significant and quantifiable benefits for customers without expanding the footprint of FPL's existing nuclear power plant sites. Upon completion, FPL estimates that approximately 450 megawatts electric power (MWe) of baseload, non-greenhouse gas emitting generation will be provided by the EPU project for FPL's customers, and that customers will realize significant fuel cost savings as a result.

The project team is in the process of performing design engineering, procuring long lead equipment and materials, obtaining regulatory approvals, and implementing plant modifications to support the uprate conditions in multiple refueling outages for each of the nuclear units. This process is supported by robust and overlapping project schedule and cost controls, along with rigorous risk management. Additionally, the EPU team manages the Uprate work in a manner that ensures that only the costs necessary for the Uprates are expended and included in the Nuclear Cost Recovery process.

Progress in 2010 included the following: the successful completion of the first of two EPU outages at St. Lucie Unit 1 and Turkey Point Unit 3; continuance of the LAR engineering evaluations along with the submittal of two EPU LARs and a Spent Fuel Criticality LAR for Turkey Point; EPC vendor work towards completing the engineering design of approximately 207 plant design modification packages; continued scheduling and planning for implementation of the modifications in proper sequence; and a decision to revise the planned outage durations. FPL prudently incurred approximately $319 million of EPU costs during 2010, as compared to the May 2, 2010 actual/estimated amount of approximately $321 million.

Q. Please describe how the remainder of your testimony is organized.

A. My testimony includes the following sections:

1. 2010 Project Summary
2. Project Management Internal Controls
3. Procurement Processes and Controls
4. Internal/External Audits and Reviews
5. "Separate and Apart" Considerations
6. 2010 Project Activities
7. 2010 Construction Costs
8. Conclusion

2010 PROJECT SUMMARY

Q. What is the EPU Project?

A. The EPU project will increase FPL's nuclear generating capacity from its four existing nuclear units by fitting the units with higher capacity and more efficient turbines and other necessary equipment to accommodate increased steam flow that will result from loading fuel with increased reactivity into each reactor. This involves the modification or outright replacement of a large number of components and support structures within FPL's operating nuclear power plants. Each modification/replacement is considered a project in and of itself. In the case of some major modifications, some permanent plant equipment will have to be removed and then reinstalled as part of the construction process.

Because the project will modify FPL's operating nuclear plants, it is a much different construction project than constructing a new combined cycle generating unit at a greenfield site. FPL plans to perform the modifications during the units' pre-planned refueling outages. Performing the Uprate work during the refueling outages minimizes the amount of time that these low fuel-cost generators are off line.

Upon completion, the Uprates will produce a minimum of 399 MWe and could produce a theoretical maximum of up to 463 MWe for FPL's customers. The minimum reflects FPL's need determination assumption (414 MWe), less the St. Lucie

Unit 2 co-owners' share of the output. The maximum reflects the turbine vendor's estimate of the turbine generator's performance (approximately 500 MWe) if the "best case scenario" of plant parameters are achieved, less the co-owners' share of PSL Unit 2 and increased plant electrical requirements. Taking into account the current uncertainty of whether "best case" plant parameters will be achieved, FPL's current estimate is that a total of about 450 MWe will be produced by the uprated units for FPL's customers.

Q. How will customers benefit from the EPU project?

A. Among other benefits, this increase in nuclear power will: (i) enhance system reliability and integrity by diversifying FPL's fuel mix; (ii) provide energy and baseload capacity to FPL's customers with zero greenhouse gas emissions; and (iii) provide significant fuel cost and environmental compliance cost savings. Some of these benefits will be realized as early as 2011, when the replacement of a low pressure turbine generator at St. Lucie Unit 2 with a more efficient low pressure turbine generator will result in a projected total increased electrical power output of approximately 20 MWe and FPL's customers are projected to receive approximately 17 MWe of this increased output. Quantification of these types of benefits will be provided along with an updated project feasibility analysis in FPL's May 2011 testimony.

Q. Please describe the general approach to the EPU project.

A. In 2007, FPL prepared an initial conceptual engineering study for performing an EPU at St. Lucie and Turkey Point which included a conceptual cost estimate based on a preliminary scope. This study provided the basis for FPL's request for a determination of need. In 2008, Shaw Stone & Webster (Shaw) performed a scoping study which included an order-of-magnitude estimate for part of the preliminary scope. The 2008 Shaw order-of-magnitude estimate was confirmatory of the 2007 FPL conceptual estimate.

The EPU project is currently being implemented in four overlapping phases.

1. In the Engineering Analysis Phase, the analyses that support the LAR are performed. During this phase, the major modifications required to implement the EPU are identified and confirmed, the LARs are prepared and submitted to the NRC for review, the NRC approves a license amendment for each plant (or unit, as applicable), and the conceptual scope is better defined.
2. In the Long Lead Equipment Procurement Phase, the major long lead equipment is procured. During this phase, purchase specifications are developed, vendor quotes are requested, vendor proposals are received and evaluated, contracts are awarded, and the cost of long lead equipment is better defined.
3. In the Engineering Design Modification Phase, the detailed modification packages are prepared. During this phase, calculations are prepared, construction drawings are issued, some equipment and materials are procured, general installation instructions are provided, and high level testing requirements are identified. These activities provide the basis for preparing detailed estimates of the implementation costs.
4. The final Implementation Phase consists of two major parts. The first is planning and scheduling. Planning is the process to convert the design packages into

detailed work orders for implementation. During this part of the implementation, revisions to the design may be warranted based on constructability. Scheduling is the process that takes the detailed work orders and converts them into a detailed integrated implementation schedule which ultimately is the point at which the final outage durations are determined. The second part of the final implementation is actual execution of the physical work in the plant including extensive testing and systematic turnover to operations.

Q. Are some activities being performed in parallel?

A. Yes. FPL is performing many activities in parallel in order to bring the benefits of additional nuclear power generation to its customers as soon as practical. The current project schedule is approximately 5 years long, and all necessary work is being performed prior to a particular unit's outage. On the other hand, if FPL had worked through each phase of the project in sequence (i.e., by performing all LAR analyses for all units first, then procuring all equipment for all units next, etc.) the EPU project would have taken many more years. Additionally, by performing EPU work in this manner, Floridians will receive the benefit of approximately 20 additional electrical megawatts of nuclear power from St. Lucie Unit 2 in 2011 – prior to the unit operating at its final uprated level – by virtue of the installation of a more efficient low pressure turbine generator. FPL's customers are projected to receive approximately 17 MWe of this increased output.

Q. Does FPL include industry best practices into the work being performed for the EPU project?

A. Yes. For example, the FPL project team members participate in nuclear industry working groups organized by the Institute of Nuclear Plant Operations (INPO) and the Nuclear Energy Institute (NEI) and benefit from lessons learned. This is supplemented with direct engagement with our industry peers through benchmarking trips to other nuclear sites which have performed similar scopes of work to incorporate best practices. These sources help ensure project decisions are supported by the best information currently available.

Q. Please briefly describe the status of the project in 2010.

A. Through 2010, the EPU project was nearing completion of the Engineering Analysis Phase, well into the Long Lead Procurement Phase, and progressing with the Engineering Design Modification and Implementation Phases in support of each outage. The project scope was not (and is not at the date of this testimony) fully defined and thus definitive cost estimates were not completed – nor were they expected to be completed. FPL developed a non-binding cost estimate range in 2010 that recognized the uncertainties of the early stage of the project and quantified the associated project risks based on known information.

Q. Will project scope continue to evolve as the project moves forward?

A. Yes. Even after completion of the engineering analyses required for the LAR submittal, the potential exists that additional scope will be required by the NRC. After the NRC approves the LARs, the project scope will be further defined and, commensurate with engineering design modification progress, the cost estimate range will be further adjusted. Once the modification packages are final and the work order planning is complete, the implementation scope will be fully defined allowing the final refinement of the detailed implementation cost estimates and schedule durations. These activities lead to increased cost certainty with the achievement of each milestone.

Q. Please provide a brief overview of 2010 activities and costs.

A. In 2010, FPL continued work on the overlapping phases of the project. Several of the key activities that occurred in 2010 include: (i) submittal of the St. Lucie Unit 1 EPU LAR, the Turkey Point Units 3 and 4 EPU LAR, and the Turkey Point Spent Fuel Criticality LAR to the NRC for review and approval of the engineering evaluation and analyses, and the progress of activities related to the St. Lucie Unit 2 EPU LAR; (ii) the progress of modification engineering for the St. Lucie and Turkey Point Units; (iii) the execution and quality inspections of the vendor contracts for long lead procurement equipment as well as inspection, receipt, and storage of long lead procurement items; (iv) continued vigilant oversight and management of vendors; (v) preparation for and successful execution of implementation activities during the St. Lucie Unit 1 spring outage and the Turkey Point Unit 3 fall outage; (vi) receipt of an independent third party estimate of implementation man-power requirements and costs; and (vii) continued forward-looking project management resulting in adjustments to outage durations, project plans and procedures. In total, FPL spent approximately $319 million in 2010 (as compared to the $321 million that was previously estimated) to carry out these key activities and proceed with the development of the uprate projects, all of which work was subject to the robust project planning, management, and cost control processes that FPL has in place and continuously works to improve.

FPL's EPU activities and expenditures, as well as its internal processes and controls, are described in more detail below.

PROJECT MANAGEMENT INTERNAL CONTROLS

Q. Please describe the EPU project management organization during 2010.

A. As described below, FPL has robust project planning, management, and execution processes in place. These efforts are spearheaded by personnel with significant experience in project management within the nuclear industry. Additionally, the EPU project uses guidelines and Project Instructions to assist project personnel in the performance of their assigned duties. Exhibit TOJ-14, Extended Power Uprate Project Instructions (EPPI) Index as of December 31, 2010 is provided to illustrate the types of instructions that were used.

FPL has a dedicated Nuclear Power Uprate team within the NextEra Energy, Inc. Nuclear Division that is responsible for monitoring and managing the uprate project, schedule, and costs. Exhibit TOJ-15, EPU Project Site Centered Organization, illustrates the organizational structure in place during 2010. In addition to some centralized project oversight, there is an EPU Site Director and an EPU organization at each site responsible for the efficient and effective engineering and implementation of the EPU project modifications. This decentralized management structure is appropriate as the EPU Project enters the implementation phases at each of the sites to better integrate EPU activities with plant operating activities.

There is also a separate Nuclear Business Operations (NBO) group that provides accounting and regulatory oversight for the EPU Project. This organization is independent of the EPU Project team and reports to the Nuclear Division Controller.

Q. Please describe the role of the NBO group in more detail.

A. As described in EPPI-150, NBO provides accounting and regulatory oversight for the EPU Project. It is independent of the EPU Project team and reports to the Nuclear Division Controller. NBO's primary responsibilities include:

- Review, approval, and recording of monthly accruals prepared by the Site Cost Engineers;
- Conducting monthly detail transaction reviews to ensure that labor costs recorded to the EPU Project are only for those FPL personnel authorized to charge time to the EPU Project;
- Conducting on-going analysis to evaluate project costs to ensure they are "separate and apart";
- Creating monthly variance reports that include cost figures used in the EPU Monthly Operating Performance Report;
- Performing analyses of the costs being incurred by the project to ensure that those costs are appropriately allocated to the correct Capital Expenditure Requisitions established for each nuclear unit's outages;
- Assisting in the classification of Property Retirement Units;
- Setting up and maintaining the EPU Project account coding structure;
- Providing accounting guidance and training to the EPU Team;

- Working closely with FPL's Accounting and Regulatory Accounting Departments to determine which costs related to the EPU Project are capital and which are O&M;
- Managing internal and external financial audit requests and ensuring that findings and recommendations are dispositioned, as appropriate; and
- Providing oversight and guidance to the EPU Project Team in developing and maintaining accounting-related project instructions to ensure compliance with corporate policies and procedures, and Sarbanes Oxley processes.

Q. What other schedule and cost monitoring controls were in place during 2010?

A. FPL utilizes a variety of mutually reinforcing schedule and cost controls and draws upon the expertise provided by employees within the project team, employees within the separate NBO group, and executive management. Within the organization of the Vice President, Nuclear Power Uprate is a Controls Group. The Controls Director provides functional leadership, governance and oversight. Each site has a dedicated EPU Project Controls group lead by a Project Controls Supervisor. The site Project Controls organization provides cost and schedule analysis and associated performance indicators on a routine and forward-looking basis thus allowing Project Management to make informed decisions. Exhibit TOJ-16 lists many of the reports that are a direct result of the information the Controls organization provides, analyzes and produces.

FPL's efforts to meet the desired completion date of each uprate is tracked through the use of Primavera P-6 scheduling software, enabling FPL to track the schedule daily and update the schedule weekly. This allows project management to monitor and report schedule status on a periodic basis. Updates to the schedule and scope of project are made as such changes are approved by management. FPL's use of this scheduling software system allows management to examine the project status at any time as well as request the development and generation of specialized reports to facilitate informed decision making. When FPL identifies a scheduled milestone date that may have a high probability of missing its schedule date, a mitigation plan is prepared, reviewed, approved, and implemented with increased management attention to restore the scheduled milestone date or mitigate any impact of missing the scheduled date.

As part of the site Project Controls Group, there are several highly experienced Cost Engineers assigned to monitor, analyze, and report project costs associated with the Uprate Projects. Governed by well established procedures and work instructions, the Cost Engineer receives contractor invoices and forwards them to technical representatives to ensure the scope of work has been completed and the deliverables have been accepted. For fixed-price contracts, the Cost Engineer matches the invoice amount to the correct amount and the deliverable work received from the subject matter expert, which is then sent to the appropriate personnel for approval and payment. The Cost Engineer also prepares accruals and reviews variance reports monthly for each of the sites, to monitor and document expenditures and commitments to the approved budget. The Project Controls organization operates in a transparent manner and its accountability is clear in providing sound analysis based on all available information at their disposal.

Q. **What periodic reviews were conducted in 2010 to ensure that the project and key decisions were appropriately analyzed and vetted?**

A. Regularly scheduled meetings are held to help effectively manage the uprate project and communicate the performance of the project in terms of quality, schedule and costs. These include the following:

- Daily meetings to mutually share lessons learned information from each of the projects and to coordinate project activities;
- Weekly project management, project controls, and risk meetings to review the status of the schedules and project costs, and to identify areas needing attention;
- Biweekly meetings with the Chief Nuclear Officer; Vice President, Power Uprate; Implementation Owner South; and other project leaders to review project progress and work through any identified risks to schedules or costs;
- Routine, usually quarterly, FPL Executive Steering Committee meetings where project management presents the status of the project. Strategy discussions take place to help improve management of risk areas;
- Monthly Project Meetings involving FPL and individual major vendors during which the project schedules and challenges are discussed; and
- Quarterly Project Meetings involving FPL and its major vendors during which strategy discussions take place to help improve management of risk areas.

The EPU Project also produces several reports. Exhibit TOJ-16, Extended Power Uprate Project Reports, is a listing of reports generated by the project during 2010 with a brief description, the periodicity, and the intended audience of each report. Generally, the project reports provide a status of the project, scope changes, schedule and cost adherence/variance, safety, quality, risks, risk mitigation, and a path forward as appropriate. The information provided by these reports assists in the overall management of the EPU Project.

Finally, the project is annually reviewed to assess its continued economic feasibility. This analysis is conducted in a similar manner to the analysis that supported the affirmative need determination by the Commission, but it is updated to reflect engineering progress and what is currently known regarding project scope and project cost, project schedule, and the cost and viability of alternative generation technologies. The analyses submitted by FPL Witness Sim in 2010 demonstrated that the EPU project continued to present a significant economic advantage in a majority of fuel and environmental compliance cost scenarios. An updated feasibility analysis will be provided in May, 2011.

Q. Please describe the risk management process for the EPU project.

A. FPL's risk management process is governed by EPPI-340 and EPPI-345. FPL's risk management process is used to identify and manage potential risks associated with the uprates. A Project Risk Committee, consisting of site project directors and subject matter experts reviews and evaluates initial cost and schedule projections and any potential significant variances. This committee enables senior managers to critically assess and discuss risks faced by the EPU projects from different departmental perspectives. The committee also ensures that actions are taken to mitigate or eliminate identified risks. When an identified risk is evaluated as high, a risk mitigation action plan is prepared, approved, and executed. The high risk item is monitored through this process until it is reduced or eliminated. Additionally, an EPU

Project Risk Management report is presented at meetings with senior management, identifying potential risks by site, unit, priority, probability, cost impact, and the unit or persons responsible for mitigating or eliminating the risk. These steps ensure continuous, vigilant identification of and response to potential project risks that could pose an adverse impact on cost or schedule performance of the project.

Q. Please describe the risk management process as it applies to Operational risk.

A. EPU Project work will be performed during normal plant operations and during planned refueling outages. The amount of work that can be safely performed during these plant conditions is dependent upon the minimum required systems or components needed to support the plant operating condition. Extreme care in the planning, scheduling, and execution of the work activities is required to ensure the plant is operated in accordance with applicable NRC regulatory and plant technical specification requirements. This requires proper sequencing of work activities that can be safely performed during normal plant operations or those that must be performed during planned refueling outages, including work activities that can be safely performed in parallel and those that must be performed in series. This operational risk management accomplishes two major objectives: first is to ensure the equipment is in a state that makes it safe for workers to perform the work, and secondly that the plant systems and components are properly maintained to ensure public safety. This operational risk management through the careful planning, scheduling and execution of work activities, adds to the complexity of the implementation phase of the EPU project.

PROCUREMENT PROCESSES AND CONTROLS

Q. Please describe the contractor selection and contractor management procedures that applied to the EPU projects in 2010.

A. The contractor selection procedures applicable to the uprate project are found in General Operating Procedure 705 and Nuclear Fleet Guideline BO-AA-102-1008, Procurement Control. As explained in those procedures, the standard approach for the procurement of materials or services with a value in excess of $25,000 is to use competitive bidding. Excluding Original Equipment Manufacturer (OEM) work, the majority of the equipment and work contracts initiated for the EPU project in 2010 were competitively bid. However, the use of single source, sole source, and OEM providers is also necessary in certain situations. FPL's policies require proper documentation of justifications and senior-level management approval of single or sole source procurements.

In response to considerations raised by the Commission in the 2008 NCRC proceedings, FPL has maintained its focus on the process of documenting and approving single and sole source procurements, to ensure compliance with BO-AA-102-1008 and to facilitate review by third parties who are not directly involved in the nuclear procurement process. Training is provided to personnel responsible for having Single and Sole Source Justifications (SSJs) prepared, the SSJ expectations are included in appropriate project instructions, and all new applicable personnel assigned to the EPU Project are required to review and understand the SSJ expectations.

With respect to vendor management, the EPU Project Directors at each site assure vendor oversight is provided by the Site Senior Project Managers, Project Managers, the site Technical Representative, and Contract Coordinators. Together, these representatives provide management direction and coordinate vendor performance reviews while the vendors are on site. The Site Technical Representative verifies that the vendor has met all obligations and determines whether any outstanding deliverable issues exist using a Contract Compliance Matrix. In addition to assisting with the development and administration of contracts, Nuclear Sourcing and Integrated Supply Chain (ISC) groups complete updates as necessary to a Project Contract Log and report the status of contracts to project management. EPU management also holds quarterly vendor integration meetings as previously mentioned.

Q. What is FPL's approach to contracting for the EPU project?

A. FPL structures its contracts and purchase orders to include specific scope, deliverables, completion dates, terms of payment, commercial terms and conditions, reports from the vendor, and work quality specifications. Project Management has several types of contracts available depending on how well the scope of work and the risk associated with the work scope can be defined. Fixed price or lump sum contracts are used where practical. An example would be where project work scope is well-defined and risk is limited. Project Management will use a time and material contract where project work scope is not well-defined and where there is greater risk to completing the work scope. These and other contract provisions help ensure the contractors perform the right work at the right time for the right price, which benefits FPL's customers.

INTERNAL/EXTERNAL AUDITS AND REVIEWS

Q. Are FPL's financial controls and management controls audited?

A. Yes. Several audits have been conducted to ensure compliance with applicable project controls.

Q. What internal audits or reviews have been conducted to ensure the project controls are adequate and costs are reasonable?

A. Jefferson Wells is in the process of performing an audit of 2010 expenses on behalf of the FPL Internal Audit Department. Specifically, the audit is focusing on whether costs charged to the project are actually for the EPU project and are recorded in accordance with FPSC Rule 25-6.0423. Independent testing of expenses charged to the EPU project for the period January 1, 2010 to December 31, 2010 is being conducted. The 2010 audit will be available for Commission review upon completion.

Q. What external audits or reviews have been conducted to ensure the project controls are adequate and costs are reasonable?

A. FPSC staff is conducting two audits related to 2010 – a financial audit and an internal controls audit. The 2010 FPSC staff financial and internal controls audits will be provided to the Commission when completed. FPL also engaged William Derrickson to conduct a review of project management in 2010 as the project entered the early stages of implementation. Witness Derrickson discusses his review in his testimony.

"SEPARATE AND APART" CONSIDERATIONS

Q. Would any of the EPU costs included in FPL's filing have been incurred if the FPL nuclear generating units were not being uprated?

A. No. The construction costs and associated carrying charges and recoverable Operations & Maintenance (O&M) expenses for which FPL is requesting recovery through the NCRC process were caused only by activities necessary for the Uprate projects, and would not have been incurred otherwise. I note that as explained in FPL Witness Powers' testimony and schedules, only carrying costs and recoverable O&M expenses are requested for recovery for the EPU Projects, consistent with the Commission's NCRC rule.

Q. Please explain the processes utilized by FPL to ensure that only those costs necessary for the implementation of the Uprates are included for NCRC purposes.

A. Consistent with EPPI-180, FPL conducted engineering analyses to identify major components that must be modified or replaced in order to enable the units to function safely and reliably in the uprated condition. However, as inspections, LAR engineering analyses, and design engineering modifications are performed, the need for additional modifications or replacements necessary for the Uprate may be identified. Likewise, it may be determined that certain modifications previously identified as necessary to the Uprate project are determined not to be necessary for the Uprate and can be removed from the scope.

Further, FPL considered whether any of the major component modifications or replacements required for the Uprates were already required as a condition of receiving its NRC license renewals. FPL reviewed the "License Renewal Action Items" issued by the NRC and compiled by FPL in conjunction with the approval of FPL's requested license renewals. In doing so, it verified that none of the major component modifications or replacements identified by FPL as necessary for the EPU project were duplicative of the activities required by the NRC for license renewal. FPL also confirmed that none of the EPU activities were previously planned as regular O&M or capital improvement. Additionally, when a scope change is required, a review of the NRC License Renewal Action Items and the seven year capital expenditure plan is conducted to ensure the proposed scope change is separate and apart. FPL's 2010 EPU activities, and their associated costs, were "separate and apart" as required by the NCRC process.

2010 PROJECT ACTIVITIES

Q. What key activities occurred in 2010 in execution of the EPU project?

A. Several key activities occurred in 2010, including: (i) submittal of the St. Lucie Unit 1 EPU LAR, the Turkey Point Units 3 and 4 EPU LAR, and the Turkey Point Spent Fuel Criticality LAR to the NRC for review and approval, and continued engineering analyses in support of submitting the St. Lucie Unit 2 EPU LAR; (ii) the execution of vendor contracts for long lead procurement equipment, as well as quality inspection, receipt, and storage of long lead procurement items; (iii) modification engineering for the St. Lucie and Turkey Point Units and continued management of the EPC vendor; (iv) receipt of independent third party estimate of implementation man-power requirements and costs; (v) preparation for, and successful execution of, implementation activities during the St. Lucie Unit 1 spring 2010 outage and the Turkey Point Unit 3 fall 2010 outage; and (vi) adoption of revisions to the planned future outage durations.

Q. **Was the 2010 organizational structure appropriate for the project in 2010?**

A. Yes. Exhibit TOJ-15, EPU Site Centered Organization, is a graphic representation of the 2010 EPU Project organizations for PSL and PTN, which continued to support authority and responsibility for the four overlapping phases of the project at the site organizations.

Q. **Please describe the license amendment preparation and submittal activities in 2010.**

A. FPL submitted two EPU LARs to the NRC in 2010, as well as one additional LAR – a Spent Fuel Criticality LAR for Turkey Point. The St. Lucie Unit 1 EPU LAR was submitted on April 16, 2010, and the Turkey Point Plant EPU LAR was submitted on October 21, 2010. Both EPU LARs were prepared and filed consistent with historical NRC expectations. Nonetheless, FPL had to withdraw and resubmit its St. Lucie Unit 1 EPU LAR in November 2010, as described below. The St. Lucie Unit 2 EPU LAR was planned for submittal to the NRC in February 2011; accordingly, FPL's efforts in 2010 included the continuing engineering analyses in support of that submittal. Additionally, the NRC continued its review of the Turkey Point AST LAR in 2010, which FPL submitted on June 16, 2009. FPL has responded to NRC requests for additional information in a timely manner. The NRC is expected to accept the Turkey Point EPU LAR for review once the Turkey Point AST LAR is approved. The NRC review and approval time for each EPU LAR is estimated to be approximately 14 months following LAR submittal for review.

Q. Please explain the status of the St. Lucie Unit 1 EPU LAR in 2010.

A. During the NRC acceptance review of the St. Lucie Unit 1 LAR, NRC staff changed its expectations for spent fuel storage pool criticality analyses, even though the methodology used by FPL was an NRC-approved design basis methodology. The NRC also required additional analyses in the areas of spent fuel criticality, a reactor control rod withdrawal event, and a station blackout event – each of which was outside the St. Lucie Unit 1 design basis and therefore exceeded the reasonably expected scope of a typical EPU LAR review.

On August 13, 2010, following meetings with the NRC, FPL management withdrew the St. Lucie Unit 1 LAR to ensure the new NRC expectations would be satisfied and incorporated into the LAR prior to the NRC's formal review. Choosing not to withdraw the LAR and work with the NRC likely would have delayed NRC approval substantially. After it had withdrawn the St. Lucie Unit 1 LAR, FPL met with the NRC on August 18, 2010 to discuss a path forward for the engineering analysis methodology the NRC decided it would now require for the spent fuel pool criticality analyses, as well as additional detail concerning the station blackout and control rod withdrawal scenarios. The St. Lucie Unit 1 LAR was re-submitted to the NRC on

November 22, 2010, reflecting the information learned from the NRC in the previous meetings.

Ultimately, FPL must comply with the NRC's expectations, whether it has advance notice of those expectations or not. These events provide a good example of the types of project activity risks and costs that are beyond FPL's control. FPL manages such emergent issues rigorously and prudently when they arise.

Q. Were any state regulatory approvals sought or obtained in 2010?

A. Yes. On March 23, 2010, FPL submitted a Substantial Revision Application for Increasing Discharge Temperature to the Florida Department of Environmental Protection (FDEP) for the St. Lucie Plant. FPL successfully obtained an amendment to the St. Lucie Industrial Wastewater Permit, issued on December 23, 2010, favorably resolving a risk that FPL might be prevented from operating the plant at full capacity during certain times of the year. The amendment requires FPL to perform additional ambient, thermal and pre- and post- EPU biological monitoring in the Atlantic Ocean.

Q. Please describe activities related to the Long Lead Procurement phase in 2010.

A. In 2010, FPL contracted for several major pieces of long lead equipment, including heat exchangers, generator stator core equipment, and main steam turbine controls.

Several long lead procurement items were received, inspected, and stored or prepared for installation at the St. Lucie and Turkey Point plants. These items include steam turbine and generator rotors, and feedwater heaters. FPL also conducted several quality assurance reviews at the equipment manufacturing or testing locations.

Q. Please describe the management of the EPC vendor and the progress in modification engineering made in 2010.

A. The EPC vendor continued its efforts to prepare the detailed modification packages in 2010. During this phase, calculations are prepared, construction drawings are issued, some equipment and materials are procured, general installation instructions are provided, and high level testing requirements are identified. These activities provide the basis for preparing detailed estimates of the implementation costs. By the end of 2010, 48 of approximately 207 packages were completed.

FPL continued to manage the EPC vendor to ensure the costs expended for the EPC work are reasonable and appropriate, including challenging estimates of future staffing requirements. For example, FPL conducted a senior-level management meeting in Frederick, Maryland at the vendor's headquarters to address then-current trends and metrics. The EPC vendor responded to that meeting with a formal proposal for managing trends and improving metrics in November, 2010. FPL also awarded scopes of EPC work at St. Lucie to another vendor, Day & Zimmermann NPS (DZNPS), which is FPL's on-site construction vendor. These assignments were made as part of FPL's continuing effort to control costs.

FPL also contracted with one of the cost estimating experts that was the subject of a blanket PO issued by EPU management in early 2009, and used the output of that estimating work product to continue to manage and challenge its EPC vendor on cost control.

Q. Please describe the use of a third party cost estimator in more detail.

A. Late in 2009, FPL contracted with a third party vendor, High Bridge Associates, with expertise in detailed estimating of nuclear project work, particularly with respect to the implementation of modifications. The Turkey Point Unit 3 EPU outage work was chosen for this estimating effort because more engineering design modification packages had been completed in preparation for the 2010 fall outage. High Bridge identified additional modifications that may be necessary as a result of those planned, and then quantified and priced all aspects of the project costs, such as equipment, shipping costs, and materials, as well as craft labor, supervisors, and overhead. This estimating effort was completed in June 2010. The results provided an independent implementation cost estimate that could be used by FPL to ensure the EPC vendor implementation man-power requirements and cost estimates were reasonable, and to use as a tool for continued EPC vendor management. Additionally, the independent implementation estimate provided additional information that could be used in considering the total EPU Project nonbinding cost estimate range.

Q. Did FPL adjust its non-binding cost estimate in 2010?

A. Yes. By early 2010, enough progress had been achieved (i.e., in terms of EPC vendor negotiations, LAR engineering analyses, and the beginning of modification engineering) that a revision to the non-binding cost estimate was warranted. However, because the project was still in the early stages of modification engineering and an expected level of uncertainty remained, it was appropriate to provide such a revision in terms of a non-binding cost estimate range, totaling $2,050 million to $2,300 million.

Q. What was the status of the Plant Change Modification packages as of December 31, 2010?

A. Exhibit TOJ-17, Plant Change Modification (PCM) Status as of December 31, 2010, is a chart that illustrates the number of identified engineering modifications as of December 31, 2010, the number of PCMs that have been initiated, and those that have reached 30%, 90%, and final completion. As can be seen in this exhibit, there were 207 PCMs identified of which 48 were finalized and approved for issuance. This exhibit demonstrates that the Project was still in the early stages of the implementation engineering.

Q. Please discuss the outage work that was successfully completed.

A. St. Lucie Unit 1 and Turkey Point Unit 3 successfully completed their first EPU outages in 2010. The activities at the units included instrumentation installations for baseline testing and future power uprate testing, feedwater heater inspections and modifications, upgrades to the St. Lucie Unit 1 Turbine Gantry Crane, and feedwater heater drain valve installations. During each unit outage transmission and substation upgrade work was performed in preparation for the increased electrical output from the power uprates. FPL completed all scheduled EPU work during the duration of these two outages as planned.

Q. Did FPL continue to adjust modification assignments in 2010?

A. Yes, but to a much lesser extent than occurred in 2009. FPL adjusted a few modifications out of the St. Lucie Unit 1 spring 2010 outage into the fall 2011 outage, and out of the Turkey Point Unit 3 fall 2010 outage into the spring 2012 outage.

Additionally, some transmission and substation work was moved to outages in 2011 and 2012.

Q. Did the adjustments to modification assignments affect the equipment placed in service in 2010?

A. Yes. FPL decided to perform a large amount of Turkey Point Unit 3 feedwater heater work during the unit's 2012 outage rather than the 2010 outage because the main stream line break analysis showed that NRC approval would first be required prior to operating the plant with the new feedwater heaters. Additionally, several other Turkey Point Unit 3 modifications were initiated during the 2010 outage, with other portions of the modifications planned for completion during the 2012 outage. The impact of these changes on base rate revenue requirements is discussed in Witness Powers' testimony.

Q. Were other project planning assumptions revised in 2010?

A. Yes. FPL determined in 2010 that the outage durations planned for 2011 and 2012 needed to be adjusted. The adjustments to the planned outage durations were necessary in order to accommodate the refined work scope assigned to each outage, which scope reflects the modifications previously made to outage assignments as well as increased project scope overall. FPL uses a variety of inputs to plan outages, including industry and fleet work experience from earlier outages where similar work activities were completed, refined engineering modifications scope and requirements, previous inspection results, and proper sequencing of the EPU modifications which must be coordinated with the NRC approval of the EPU LARs. As always, FPL must also factor into its planning and scheduling the safety of personnel performing work, e.g., securing system electrical, mechanical, and thermal energy sources, and ensuring that the plant is operated safely in accordance with the operating license issued by the NRC.

Q. As of December 31, 2010, what was the overall EPU project schedule?

A. Exhibit TOJ-19, Extended Power Uprate Project Schedule as of December 31, 2010, illustrates the LAR, long lead material, engineering design, and implementation schedule for the EPU Project. Underlying this high–level schedule are tens of thousands of individually-scheduled activities. FPL's overall project schedule reflected the following:

- The LAR analyses were scheduled to be completed and submitted to the NRC, but NRC review before the license amendment approval is needed by FPL to increase the power output at the completion of the second EPU outage for St. Lucie Unit 1 was challenged. Review and approval prior to completion of the second outage for the other units was still expected.
- Long lead material items were scheduled to arrive on site prior to the outage during which the equipment will be installed.
- PCM engineering design for each of the identified modifications was scheduled to be approved for implementation prior to the unit outage when each modification will be implemented.
- Implementation of the EPU modifications was scheduled to be completed during the revised durations of the scheduled refueling outages for each of the units.

Q. Did FPL conduct a "feasibility analysis" of the EPU project in 2010?

A. Yes. FPL Witness Steve Sim conducted a feasibility analysis in 2010 using the high end of FPL's 2010 revised non-binding cost estimate range, which demonstrated that the EPU project was projected to be solidly cost-effective for FPL's customers. Specifically, a resource plan that included the EPU project was projected to cost less than a resource plan that did not include the EPU project in seven out of seven scenarios of fuels cost forecasts and environmental compliance cost forecasts. FPL also conducted 14 sensitivity analyses examining the effect of a higher cost of capital and/or lower than expected EPU electrical output, 13 of which continued to support the cost-effectiveness of the EPU project.

2010 CONSTRUCTION COSTS

Q. Did FPL perform a partial year true-up of 2010 costs in 2010?

A. Yes. The schedules presenting FPL's actual/estimated 2010 costs as of May 2010 are attached hereto as Exhibit TOJ-12. These schedules reflected actual costs through February 2010, and an estimate for the remainder of the year.

Q. Please describe how FPL developed its 2010 actual/estimated costs.

A. The 2010 projected costs were developed from Project Controls forecasts for all known project activities in 2010. Included in the forecasts are the vendor long-lead materials contracts that have scheduled milestone payments in 2010, which are cash flowed based upon the latest fabrication and delivery schedule information. Each major labor related services vendor forecast is based upon the most recent cumulative purchase order value, which would include the original awarded value and all approved changes. Added to this would be an estimate of any known pending changes to arrive at a best forecast at completion for each vendor. Owner engineering and project management support forecasts are derived from detailed staffing plans. Each approved position is cash flowed for the expected assignment duration and expected overtime, where applicable. The large construction related vendor forecasts are based upon previous experience, known scope(s) of work, productivity factors related to outage conditions and prevailing pertinent wage rates. Items identified in the Risk Register are cash flowed based upon anticipated engineering, material procurement and outage implementation time horizons.

Q. Were FPL's 2010 actual/estimated costs reasonable?

A. Yes. Careful vendor oversight, continued use of competitive bidding when appropriate, and the application of the robust internal schedule and cost controls and internal management processes all support a finding that FPL's actual/estimated 2010 expenditures were reasonable.

Q. What type of costs did FPL incur for the uprate projects in 2010?

A. As demonstrated in Exhibit TOJ-13, Schedule T-6 and T-4, and summarized on Exhibit TOJ-20, Tables 1 through 9 (all reflecting the true-up of actual 2010 costs), costs were incurred in the following categories: License Application; Engineering and Design; Permitting; Project Management; Power Block Engineering, Procurement, Etc.; Non Power Block Engineering, Procurement, Etc.; and Recoverable O&M. These costs were the direct result of the prudent project management, decision making, and actions described in detail above. Each category reflects some variance against what was originally estimated and budgeted, which is to be expected, particularly given the relatively early stage of the project. The overall variance in 2010 is driven primarily by the reduced payments for long lead equipment items, adjustments to engineering and EPC contractor resources, and adjustments to staff resources due to the EPU outage modification assignments made in 2009 and 2010. Exhibit TOJ-20, 2010 Extended Power Uprate Construction Costs contains summaries of the EPU expenditures in 2010 for each of the NFR schedule categories. Table 1 is a summary of each of the categories showing the actual expenditure amounts. The amounts shown in the exhibits are slightly different than the NFR schedules as footnoted on the exhibit.

Q. Please describe the costs incurred in the License Application category and the variance, if any, from the 2010 actual/estimated costs in this category.

A. 2010 Licensing Costs consist primarily of charges for consulting and contractor services rendered in support of preparing the NRC LARs. The primary contractors are Westinghouse, Areva and Shaw Stone & Webster. FPL incurred $26.3 million in this category in 2010, which was $3.1 million less than the actual/estimated amount. This variance was primarily attributable to fact that NRC review costs were less than expected. The costs associated with the additional NRC-required engineering analyses and evaluations for St. Lucie Unit 1 are also included in this category.

Q. Please describe the costs incurred in the Engineering and Design category and the variance, if any, from the actual/estimated costs in this category.

A. Engineering & Design Costs consist primarily of costs for FPL personnel and contractor personnel in the FPL engineering organizations at both sites and in the central organization. Some of these personnel provide management, oversight and review of the LAR activities, while others are oriented towards management, oversight and review of the detail design activities being performed by the EPC contractor. FPL incurred $19.8 million in this category in 2010, which is $7.8 million more than the actual/estimated amount. This was primarily attributable to LAR scope growth and the costs required to manage the EPC contractor's engineering and implementation efforts for the PSL Unit 1 and PTN Unit 3 2010 outages.

Q. Please describe the costs incurred in the Permitting category and the variance, if any, from the actual/estimated costs in this category.

A. Permitting Costs reflect costs attributable to the State of Florida Site Certification Application for the St. Lucie and Turkey Point sites and the Substantial Revision Application for Increasing Discharge Temperature to the FDEP for the St. Lucie Plant. These costs consist primarily of consulting services related to environmental work for site certification, compliance certification, FDEP application preparation, and FPL employee support. FPL incurred $274,880 in this category in 2010, which was $98,818 more than the actual/estimated amount. This was primarily attributable to environmental work in the preparation of the Substantial Revision Application for Increasing Discharge Temperature to the FDEP for the St. Lucie Plant.

Q. Please describe the costs incurred in the Project Management category and the variance, if any, from the actual/estimated costs in this category.

A. Project Management Costs relate to overall project oversight including project and construction management, and project controls and non-NRC regulatory compliance. These oversight activities are performed by personnel located at both sites, and by the

EPU central organization and by non-EPU organizations such as NBO, New Nuclear Accounting and Regulatory Affairs. FPL incurred $22.6 million in this category in 2010 which was $2.6 million more than the actual/estimated amount. This was primarily attributable to an increase in FPL project and construction management oversight of the EPC vendor.

Q. Please describe the costs incurred in the Power Block Engineering, Procurement, Etc. category and the variance, if any, from the actual/estimated costs in this category.

A. The majority of the costs in this category reflect payments to the EPC vendor for the successful completion of the EPU outages at PSL Unit 1 and PTN Unit 3 in 2010, the continued engineering efforts to prepare for the 2011 and 2012 outages, payments to Siemens for turbines and generator rotors, and payments to TEI for feedwater heaters and moisture separator reheaters, main condensers, and increased capacity heat exchangers and pumps required to support the uprate conditions. This category also includes the cost to contract with High Bridge for the purpose of conducting a specific scope of project cost estimating, as described above.

Additionally, this category includes the cost to complete the modifications to the St. Lucie Unit 1 Turbine Gantry Crane in 2010. An engineering evaluation of each Turbine Gantry Crane was performed resulting in proposed modifications to each crane for increased efficiency and precision in removing and installing the many pieces of heavy equipment. The modifications to each Turbine Gantry Crane are performed during normal plant operation thus saving plant outage time. On October

7, 2010, FPL filed a petition with the Commission to include the costs of the St. Lucie Unit 1 Turbine Gantry Crane and other equipment placed into service in 2010 associated with the EPU Project in base rates, and on January 11, 2011, the FPSC voted to grant the base rate increase. The only salvageable equipment from the St. Lucie Unit 1 Turbine Gantry Crane was the trolley assembly. The salvage value of the trolley assembly was $13,010, and it was disposed of in July 2010 and was applied back to the EPU project appropriately.

FPL incurred $222.0 million in this category in 2010, which is $18.4 million less than the actual/estimated amount. The primary contributor to this variance was the adjusted outage modification assignments which moved some plant modifications between the outages, deferring some costs to a later year. This variance was partially offset by utilization of the EPC contractor due to work scope increase identified in the licensing and engineering design modification phases. Further outage modification adjustments will be necessary as the LAR reviews, design engineering, and implementation planning activities progress.

Q. Please describe the costs incurred in the Non-Power Block Engineering, Procurement, Etc. category and the variance, if any, from the actual/estimated costs in this category.

A. Non-Power Block Engineering Costs consist primarily of costs for facilities for engineering and project staff at site locations and the simulator upgrades required to reflect the uprate conditions. FPL incurred $6.2 million in this category in 2010. This represents $1.2 million less than the actual/estimated amount. The variance is primarily attributable to costs for the simulator modifications being moved to later than originally planned.

Q. Please describe the costs incurred as EPU Recoverable O&M.

A. Recoverable O&M expenses in 2010 were $7.2 million. This represents a variance of $4.0 million more than the actual/estimated amount. Consistent with FPL's capitalization policy, the commodities that make up these expenditures consist of non-capitalizable computer hardware and software and office furniture and fixtures needed for new project-bound hires, all of which are segregated for EPU Project personnel use only, as well as incremental staff and augmented contract staff. Additionally, costs necessary to preserve adequate laydown space for the EPU project at Turkey Point were included in this category. Also, with the completion of the St. Lucie Unit 1 Turbine Gantry Crane modifications in late 2010, Recoverable O&M also includes the write-off of inventory rendered obsolete because of the modifications. Through 2010, $18,864 in inventory has been written off.

Q. Please describe the costs incurred in the Transmission category.

A. Transmission Costs were $14.6 million in 2010, which is $5.8 million more than the actual/estimated amount. The expenditures in the Transmission category include plant engineering, line engineering, substation engineering, and line construction. This variance is a result of the reclassification of the plant engineering for the procurement and installation of the new main transformer at PSL 2. Part of the substation construction originally scheduled for 2010 at Turkey Point was deferred to 2011 at the request of the Nuclear Security Department to give them additional time to review design changes they had requested. Additionally, favorable transmission line construction bids obtained for 2010 work resulted in overall costs lower than originally budgeted for the non-plant engineering Transmission work.

CONCLUSION

Q. Were FPL's 2010 EPU expenditures prudently incurred?

A. Yes. FPL incurred costs of approximately $319 million in 2010. FPL's costs were less than its estimate for the reasons described above. All of FPL's expenditures were necessary so that the uprate work can be performed during the planned outages. Through experienced personnel's application of the robust internal schedule and cost controls, careful vendor oversight, and the ability to continuously adjust based on lessons learned and the project's evolving needs, FPL is confident that its EPU management decisions are well-founded and prudent. All costs incurred in 2010 were the product of such decisions, were reasonable and prudently incurred, and should be approved.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TERRY O. JONES

DOCKET NO. 110009-EI

MAY 2, 2011

Q. Please state your name and business address.

My name is Terry O. Jones, and my business address is 700 Universe Boulevard, Juno Beach, FL 33408.

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

A. I am employed with Florida Power & Light Company (FPL) as Vice President, Nuclear Power Uprates.

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. Are you sponsoring any exhibits to this testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit TOJ-21 consists of 2011 P Schedules and 2011 TOR Schedules. The NFR Schedules contain a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Powers, and me, respectively. FPL has included the 2011 P Schedules as they are the basis for determining the reasonableness of the true-up of FPL's 2011 AE Schedules. The 2011 TOR Schedules present a summary of costs that are the basis for the revenue requirements being recovered in 2011.

- Exhibit TOJ-22 consists of 2011 AE Schedules, 2012 P Schedules, and 2012 TOR Schedules. The NFR Schedules contain a table of contents listing the schedules that are sponsored and co-sponsored by FPL Witness Powers and me, respectively.
- TOJ-23, Extended Power Uprate Project Schedule as of April 2011
- TOJ-24, 2011 Extended Power Uprate Work Activities
- TOJ-25, EPU Actual/Estimated 2011 Summary Cost Tables
- TOJ-26, 2012 Extended Power Uprate Work Activities
- TOJ-27, EPU Projected 2012 Summary Cost Tables

Q. Please describe how your testimony is organized.

A. My testimony includes the following sections:

1. Project Status and Schedule
2. Project Management Internal Controls
3. 2011 Actual/Estimated Construction Activities and Costs
4. 2012 Projected Construction Activities and Costs
5. True-Up to Original Cost and Updated Cost Estimate Range
6. Long Term Feasibility

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's Extended Power Uprates (EPU or Uprate) project at its St. Lucie (PSL) and Turkey Point (PTN) power plants, the reasonableness of FPL's 2011 actual/estimated EPU costs, and the reasonableness of FPL's 2012 projected EPU costs. The activities and expenditures for these years are described in separate sections below. My testimony also presents the True-up to Original Projections for the Uprate project for the years 2008 through 2013, provides an updated total project cost estimate range, and summarizes FPL's updated EPU feasibility analysis, which continues to demonstrate that the project is a cost-effective generation addition for FPL's customers. FPL Witness Dr. Steven R. Sim describes the economic feasibility analysis in detail in his testimony and exhibits.

Q. Would you please provide an overview of the expected benefits of the EPU project for FPL's customers?

A. Yes. Taking into account the updated project information related in this testimony, FPL expects that the EPU project will:

- Provide estimated fuel cost savings for customers of approximately $106 million in the first full year of operation;
- Provide estimated fuel cost savings for FPL's customers over the life of the plants of approximately $4.6 billion (nominal);
- Diversify FPL's fuel sources by decreasing reliance on natural gas by 2% beginning in the first full year of operation;
- Provide a total amount of energy that is equivalent to the usage of approximately 209,500 residential customers;
- Reduce annual fossil fuel usage by the equivalent of 5 million barrels of oil or 29 million mmBTU of natural gas annually; and
- Reduce CO_2 emissions by an estimated 31 million tons over the life of the plants, which is the equivalent of operating FPL's entire generating system with zero CO_2 emissions for 9 months.

These quantifications are set forth in FPL Witness Dr. Sim's testimony and Exhibit SRS-1.

Q. Please summarize your testimony.

A. FPL is working to deliver the substantial benefits of additional nuclear generating capacity to its customers, without expanding the footprint of its existing nuclear generating plants, by performing an extended power uprate of its existing St. Lucie Units 1 & 2 and Turkey Point Units 3 & 4. Upon completion, FPL estimates that approximately 450 megawatts electric power (MWe) of baseload, non-greenhouse gas emitting generation will be provided by the EPU project for its customers, and that customers will realize significant fuel cost savings as a result. In addition, the benefits to FPL's customers from additional nuclear generation will be realized through the EPU project at least a decade earlier than if additional nuclear generation were to be delivered solely through new nuclear units.

The EPU project is of extraordinary managerial and technical difficulty. FPL's EPU project represents one of the largest and most complex nuclear design, engineering and construction projects undertaken in the nuclear industry since the construction of the last generation of U.S. nuclear plants. As of May 2011, FPL estimates that the project will require the orchestration and management of approximately 1 million total hours of design engineering and total EPU project work of approximately 10 million hours. This is the equivalent of approximately 500 person-years of design engineering time and

5,000 person-years of total EPU work time. All of this work is being conducted on four operating nuclear units with live steam, electrical and nuclear fuel equipment and systems. FPL is committed to efficiently managing all of this work in a way that maximizes the benefits of the EPU project for FPL's customers and in a manner than maintains nuclear and industrial safety.

The project team is in the process of performing design engineering, procuring long lead equipment and materials, obtaining regulatory approvals, and implementing plant modifications to support the uprate conditions in multiple refueling outages for each of the nuclear units. This process is supported by robust and overlapping project schedule and cost controls, along with rigorous risk management. Additionally, the EPU team manages the Uprate work in a manner that ensures that only the costs necessary for the Uprates are expended and included in the Nuclear Cost Recovery Clause (NCRC).

As detailed in this testimony and accompanying exhibits, FPL plans to invest a total of approximately $610 million during 2011 and approximately $799 million during 2012 in the Uprate project. FPL also plans to place certain Uprate project systems into service. The estimated equipment in-service amounts for 2011 are approximately $218 million, and for 2012 are approximately $1,186 million. (Please note that the dollar values in my testimony are the forecasted EPU resource requirements, and do not include certain accounting adjustments made by FPL Witness Powers, unless noted otherwise.) The 2011-2012 EPU project carrying costs on its capital investments, Operations & Maintenance expenses, and revenue requirements for in-service components contribute to a total Company request to recover approximately $196 million in 2012, as described by FPL Witness Powers. This equates to a residential customer monthly bill impact of $2.09 per 1,000 kWh.

FPL has updated its nonbinding total cost estimate range to reflect the progress made on the project and information learned through the beginning of 2011 to approximately $2,324 million to $2,479 million (including transmission and carrying costs) and has utilized the high end of this range as the starting point for an economic feasibility analysis performed consistent with the direction of the Commission. While the current nonbinding cost estimate range is slightly higher than the high-end of the total nonbinding cost estimate range used in the economic analyses conducted last year, the testimony and exhibits of FPL Witness Dr. Sim show that the EPU project continues to result in substantial economic benefits for FPL's customers and continues to be in the best interest of customers to pursue. For example, FPL Witness Dr. Sim's Exhibit SRS-8 shows that in the Medium Fuel Cost, Environmental II cost scenario, the project is currently expected to reduce costs to customers by more than $622 million in cumulative present value of revenue requirements compared to a plan without the EPU project.

FPL's EPU activities, the reasonableness of its 2011 and 2012 costs, and its updated nonbinding cost estimate range and feasibility analysis are described in more detail below.

PROJECT STATUS AND SCHEDULE

Q. **Please provide an overview of the current status of the Uprate Project.**

A. As described in my March 1, 2011 testimony addressing 2009 and 2010 activities and costs, the EPU is being achieved in four overlapping phases. Those four phases are explained in detail in my March testimony. In 2011, FPL expects to complete the Engineering Analysis Phase. FPL will also continue the Long Lead Procurement, Engineering Design Modification, and Implementation phases of the project to support the planned unit outages in 2011 and 2012. FPL is committed to approximately 95% of its long lead procurement items for the St. Lucie units and approximately 80% of its long lead procurement items for the Turkey Point units. FPL is currently performing the Engineering Design Modification Phase, and has successfully completed two of eight planned EPU outages in the Implementation Phase. FPL has also amended its contract with Bechtel, the Engineering, Procurement & Construction (EPC) vendor, for the St. Lucie scope of work to include a target price, better aligning FPL's and Bechtel's project goals.

Q. **Please describe the Federal licensing needed for the EPU Project.**

A. FPL must obtain a license amendment to the renewed operating licenses for St. Lucie Unit 1, St. Lucie Unit 2, Turkey Point Unit 3 and Turkey Point Unit 4 in order to operate at the EPU conditions. The Turkey Point EPU License Amendment Request (LAR) was submitted to the Nuclear Regulatory Commission (NRC) in October 2010 and the St. Lucie Unit 1 EPU LAR was resubmitted to the NRC in November 2010, as described in my March testimony addressing 2010 activities and costs. The St. Lucie Unit 2 EPU LAR was submitted to the NRC in February 2011.

The St. Lucie Unit 1 and Turkey Point EPU LARs were accepted for technical review by the NRC on March 9 and 11, 2011, respectively. According to NRC projections, each of these submittals will take approximately 12 months from acceptance for the NRC to review, request additional information, and approve. Also, as a result of the LAR review process, the NRC may require additional modifications or analyses to be performed. EPU project management is monitoring the progress of the NRC LAR reviews and is prepared to address any questions or issues that may arise during the NRC's review.

Q. Please explain the timing of the LAR approvals and their effect on the operation of the uprated units in more detail.

A. Each plant is unique with respect to the effect of the timing of the NRC approvals. At Turkey Point, the units cannot be restarted following their second (final) EPU outage unless the NRC has approved the EPU LAR. At

St. Lucie, the units can be restarted with the EPU modifications completed (with the exception of the instrumentation setpoints and software changes), but would be operated at existing reactor power levels as opposed to the uprated power levels if FPL has not received approval of the St. Lucie Unit EPU LARs. The St. Lucie units would operate at a slightly increased electrical power output due to the more efficient equipment being operated at existing reactor power levels. In such a scenario, after receipt of NRC approvals for the St. Lucie uprates, FPL may be required to modify the instrumentation setpoints during an off-cycle shutdown to enable the plant to operate at the uprate condition.

Q. Are there any remaining Local and/or State permits needed for the EPU Project?

A. No. State and local permitting has been completed for the EPU Projects. Requirements of the revised permits are being implemented.

Q. Please describe the current EPU project schedule.

A. Exhibit TOJ–23, Extended Power Uprate Project Schedule as of April 2011, is the schedule of the EPU Project and the overlapping phases of the work activities presently proposed to take place. This schedule reflects the outage assignment revisions and the outage duration revisions that were discussed in my March 1, 2011 testimony. Additionally, this schedule reflects a 2011 decision to change several of the outage start dates. This project schedule continues to support a project completion date in early 2013.

Q. Please describe the modification installation planning process and the assignment of modifications to particular outages.

A. A critical component to the modification installation planning is the assignment of particular modifications, and the associated construction work, to particular outages and within those outages. This concept was discussed in my March 1, 2011 testimony, and outage assignments continue to be refined. Consideration is given to several aspects of each of the modifications, such as whether the time provided for the engineering of the modification is sufficient to support the needed reviews, approvals, and planning by the unit's outage management; whether the equipment will arrive at the site early enough before the outage to allow for inspections and preparation work prior to installation; whether there is a sufficient labor force to support the amount of work planned; and whether the modification work can be performed in parallel with other work or if it needs to be performed in a series of critical activities.

Q. Did the reassignment of certain modifications to different outages affect FPL's 2011 EPU costs?

A. Yes. As a result of FPL's 2010 outage assignment review, FPL's actual/estimated 2011 costs being presented in this docket are more than what FPL projected its 2011 costs would be last year in Docket No. 100009-EI. FPL moved a significant amount of work planned for St. Lucie in 2010 to 2011, thereby shifting construction costs out of 2010 and into 2011. Additionally, due to this reassignment, the carrying charges for 2011 increased. The revenue requirement computations are sponsored by FPL Witness Powers.

Q. Please explain the benefits of changing outage start dates.

A. The benefits resulting from adjusting outage dates are the maximization of nuclear fuel "burnup" and the minimization of the off-line time of the nuclear units. FPL recently evaluated the need to adjust outage start dates primarily to maximize nuclear fuel burnup and increase the certainty that the EPC vendor will complete the engineering design phase and the first part of the implementation phase – the planning, scheduling, and constructability reviews of modifications – for the successful execution of the implementation performed during each outage. Additionally, project management continues to assess and work with its EPC vendor to ensure it has the right support and resources to complete its work in a timely manner.

Q. Were there any unanticipated schedule changes this year?

A. Yes. The EPU portion of the St. Lucie Unit 2 spring 2011 outage lasted longer than planned, due to an error by Siemens, the vendor who is performing the turbine generator upgrade work.

It was determined that a small tool – an alignment pin – had been left inside the generator stator core by Siemens personnel. When the stator core was tested for performance, the alignment pin caused damage. As a result, the replacement of some of the stator core iron was required to repair the damage caused by the pin, and this work caused the outage to be extended.

Q. Was FPL prudent in the hiring and oversight of Siemens?

A. Yes. Siemens is the Original Equipment Manufacturer and therefore owns all the intellectual property necessary to perform this scope of work. Siemens is highly specialized and has an excellent track record with similar work on other FPL projects. Moreover, it has a robust system of practices and procedures that have resulted in successful projects over the years. FPL contracted with Siemens in 2008, which was subject to the Commission's prudence review of 2008 decisions and costs in 2009.

FPL reviewed and benchmarked Siemens's performance at other locations to validate those practices and procedures, and continues to be diligent in its oversight of Siemens.

Q. Was there any effect on the cost of the project?

A. It is FPL's position that Siemens is required to repair the damage at no cost to FPL, and that is currently being pursued. However, as with any major nuclear outage work contract, there are limits to Siemens's liability, and recovery of replacement generation and fuel costs on FPL's system is not provided for by the contract. Such limitations on liability are industry-standard, and in fact necessary as no vendor would agree to such cost exposure, and such vendors are necessary to perform this type of nuclear outage work. These system costs are not included in FPL's Nuclear Cost Recovery request.

Q. Will the earthquake and tsunami in Japan, and resulting effects on the nuclear power plants there, affect the EPU project?

A. It is too soon to tell whether or how the events in Japan will affect the EPU project. It is likely that those events will have operational, regulatory and political ramifications for the U.S. nuclear industry in general. FPL Witness Dr. Nils Diaz addresses this topic in his May 2, 2011 testimony. It is also possible that the events in Japan will affect the EPU LAR approval process and the total cost of the project if the NRC requires additional analyses or modifications. However, it is not possible to quantify such effects at this time.

PROJECT MANAGEMENT INTERNAL CONTROLS

Q. Please describe the project management internal controls that FPL has in place to ensure that the project is effectively managed.

A. As described in detail in my March 1, 2011 testimony, FPL has robust project planning, management, and execution processes in place. FPL utilizes a variety of mutually reinforcing schedules and cost controls, and draws upon the expertise provided by employees within the project team, employees within the separate Nuclear Business Operations group, and executive management. Those controls continue to be utilized in 2011.

One of the key project management tools utilized by the EPU team is the project Risk Register. Risk matrices, such as EPU's Risk Register, are a common project management tool. The Risk Register allows for identified risks – including potential increases to scope – to be logged and assessed in terms of cost and probability. Resolutions are also tracked in the Risk Register, which may include avoidance or mitigation of the identified risk, or incorporation of the particular item within the project scope. Periodic presentations are made to executive management where risks, costs, and schedules are discussed.

Q. Have there been any changes in the project management system FPL is using to ensure that the 2011 actual/estimated and 2012 projected costs are reasonable?

A. Yes. The EPU project management processes are adjusted to implement and use industry best practices through self-assessment, peer reviews, independent third party reviews, internal and external audits, and executive oversight and direction. In 2011, FPL made adjustments to controls related to site report generation; staffing ramp levels; work scope assignments, and outage implementation interface.

Q. Are any internal audit activities underway?

A. Yes. The annual internal audit of the EPU financials is currently being conducted, which provides a review of project expenditures through 2010. FPL anticipates that this audit will be completed this summer. An internal audit will be conducted next year to review 2011 expenditures.

2011 ACTUAL/ESTIMATED CONSTRUCTION ACTIVITIES AND COSTS

Q. Please summarize the activity planned for 2011.

A. In 2011, FPL submitted the third and final EPU LAR to the NRC, and has shifted from performing the engineering analyses and developing the LARs to supporting the NRC's review of the LARs. The Long Lead Equipment procurement phase will continue as necessary equipment is delivered to support the outages in 2011 and 2012. The Engineering Design Modification Phase will continue with the EPC vendor preparing modification packages, and performing support activities for outage modifications. The Implementation Phase will continue with the EPC vendor performing implementation activities, the planning and scheduling of EPU outage activities, and the execution of activities during the 2011 outages. There are three EPU outages scheduled to commence in 2011: the St. Lucie Unit 2 outage which will be completed in May 2011, the Turkey Point Unit 4 spring outage which started in March 2011, and the St. Lucie Unit 1 outage which is scheduled to start in November 2011. The return to service from the St. Lucie Unit 2 outage will result in an increase of approximately 20 MWe in the output of the unit due to the installation of a more efficient low pressure turbine rotor during the outage, approximately 17 MWe of which will be for the benefit of FPL's customers. The additional electrical output resulting from more efficient equipment does not require prior NRC license amendment approval.

Q. Did FPL project its 2011 EPU costs for these types of activities in 2010?

A. Yes. FPL prepared and filed a projection of 2011 costs in Docket No. 100009-EI. FPL's previously-projected 2011 costs are provided in Exhibit TOJ-21.

Q. Please describe how FPL developed its projections of 2011 costs for the NFRs submitted in 2010.

A. The 2011 projected costs were developed from Project Controls forecasts derived from the best available information for all known project activities in 2011. Included in the forecasts are the vendor long lead material contracts that have scheduled milestone payments in 2011. Cash flows are based upon the latest fabrication and delivery schedule information. Each major labor related services vendor forecast is based upon the original awarded value and all approved changes. Added to this, where applicable, would be an estimate of any known pending changes to arrive at a best forecast at completion for each vendor. Owner engineering and project management support forecasts are derived from approved detailed staffing plans. Cash flows are developed for each approved position based on the expected assignment duration and expected overtime, where applicable. The large construction related vendor forecasts are based upon previous experience, known scope(s) of work, productivity factors related to outage conditions and prevailing pertinent wage rates. Cash flow projections for items identified in the Risk Register are based upon anticipated engineering, material procurement, and outage implementation time horizons.

Q. Were FPL's projected 2011 costs reasonable?

A. Yes. Careful vendor oversight, use of competitive bidding when appropriate, and the application of the robust internal schedule and cost controls and internal management processes all helped ensure that FPL's projected 2011 expenditures were reasonable.

Q. Has FPL trued up these projections to develop 2011 Actual/Estimated costs?

A. Yes. Exhibit TOJ-22 presents FPL's 2011 Actual/Estimated costs.

Q. Please describe how FPL developed its 2011 Actual/Estimated costs.

A. On a monthly basis, a detailed project cost review is held, in which project management reviews actual and estimated costs. Each major category is examined and, where applicable, performance measurement tools are analyzed. Schedule Performance Index (SPI) and Cost Performance Index (CPI) tools are used along with Earned Value Progress Measurement reporting as appropriate.

The 2011 actual/estimated costs were developed from Project Controls forecasts as described above.

Actual 2011 costs come from a monthly download of project charges from the FPL accounting system. These charges are for materials and services from multiple vendors and are applied to the total project cost on an ongoing basis. Each charge is applied using a coding structure which defines which of the units the charges apply to. For project management purposes, the charges are subsequently broken down by major vendor or appropriate cost control grouping which ultimately supports project management analysis and forecasting.

Q. What types of costs does FPL plan to incur for the Uprate Project in 2011?

A. Schedule AE-6 of Exhibit TOJ-22 breaks the 2011 actual/estimated total costs of $569,779,321 down into the following categories: License Application $19,797,804; Engineering and Design $20,251,942; Permitting $45,451; Project Management $33,835,035; Power Block Engineering, Procurement, Etc. $489,873,573; and Non-Power Block Engineering, Procurement, Etc. $5,975,515. Exhibit TOJ-25, EPU Actual/Estimated 2011 Costs Tables, includes 9 tables summarizing the EPU Project 2011 Actual/Estimated (A/E) costs by NFR category which includes post in-service amounts.

Q. Please describe the 2011 activities in the License Application category.

A. For the period ending December 31, 2011, License Application costs are estimated to be $19,797,804 as shown on Line 3 of Schedule AE-6 of Exhibit TOJ-22. These license application costs consist primarily of payments to vendors for the preparation of the PSL Unit 2 LAR, responding to the NRC Requests for Additional Information (RAIs) as necessary in 2011, and NRC fees. This was approximately $9.4 million more than projected due to increased scope and a longer duration for completing the licensing effort.

Q. Please describe the 2011 activities in the Engineering and Design category.

A. For the period ending December 31, 2011, Engineering and Design costs are estimated to be $20,251,942 as shown on Line 4 of Schedule AE-6 of Exhibit TOJ-22. This amount consists primarily of FPL's engineering and design work in support of review and approval of the engineered design modification packages prepared for the St. Lucie and Turkey Point sites by Bechtel, FPL's EPC vendor on the EPUs. This was approximately $11 million more than projected due to the need for additional resources to support the increased scope for design engineering.

Q. Please describe the 2011 activities in the Permitting category.

A. For the period ending December 31, 2011, Permitting costs are estimated to be $45,451 as shown on Line 5 of Schedule AE-6 of Exhibit TOJ-22. This amount consists primarily of environmental studies and application preparation and submittal to modify the PSL discharge permit. This is approximately $105,000 less than projected due to the completion of the permitting efforts. This amount does not include required permit compliance ordered stipulations, which include monitoring and reporting.

Q. Please describe the 2011 activities in the Project Management category and how those activities help ensure that the Uprate Project will be completed on a reasonable schedule and at a reasonable cost.

A. For the period ending December 31, 2011, Project Management costs are estimated to be $33,835,035 as shown on Line 6 of Schedule AE-6 of Exhibit

TOJ-22. This category includes FPL and contractor management personnel at each of the sites and those in the Juno Beach Office. This work and the associated costs are required to ensure the uprate project is managed in an efficient and cost-effective manner. This is approximately $9.9 million more than projected due to additional support needed for the implementation of the three EPU outages scheduled for 2011.

Q. Please describe the 2011 activities in the Power Block Engineering, Procurement, Etc. category.

A. For the period ending December 31, 2011, Power Block Engineering and Procurement costs are estimated to be $489,873,573 as shown on Line 9 of Schedule AE-6 of Exhibit TOJ-22. This amount is primarily for the development of the engineering design modification packages and for the implementation of the scheduled work for the three outages scheduled for 2011. This work includes preparation of the modification packages (part of the Engineering Design Modification Phase); the development of directions for the removal, replacement and/or modification of components, equipment, systems and structures as needed to support the uprate condition, and the performance of field walkdowns by Bechtel. This also includes certain implementation activities, including the preparation of work orders for implementation and integration of modifications into the unit outage schedule. The second part of this phase is the physical execution of the work, some of which will occur in the three scheduled 2011 outages.

Some modifications can be performed when the units are operating, reducing the complexity of the outage and limiting the outage duration. FPL evaluates the risk to the continued operation of the unit and if determined to be an acceptable risk, the modifications will be performed while the unit is on line. One such modification is the modification of the Turkey Point turbine gantry crane. Modifications to the crane are necessary for increased capacity and efficiency in removing and installing, with precise movements, many pieces of heavy equipment. The needed modifications to this crane will be performed while the respective unit is operating thus saving plant outage time.

Procurement costs include the purchase of long lead equipment items and progress payments to manufacturing vendors. FPL is continuing to execute on contracts for the procurement of major pieces of equipment which include steam turbines, main generator rotors, pumps, motors, valves, and heat exchangers of various specifications. This is approximately $1.4 million less than projected due to scope being deferred to the second PSL1 EPU outage to be completed in 2012.

Q. Please describe the 2011 activities in the Non-Power Block Engineering, Procurement, Etc. category.

A. For the period ending December 31, 2011, Non-Power Block Engineering costs are estimated to be $5,975,515 as shown on Line 10 of Schedule AE-6 of Exhibit TOJ-22. This category consists primarily of the following:

engineering, permitting, and construction of temporary facilities; upgrades to training simulators; and additional dry cask storage for spent fuel.

A fabrication area used to pre-fabricate piping and valves reduces the outage time because work can be performed prior to the outage and at the same time as other work, instead of in a series sequence of field activities during the outage. A warehouse is used to store and stage delivered materials for the EPU project prior to installation and to provide an area for the training and qualification of craft labor. A site training and qualification area is necessary to ensure Turkey Point has the needed qualified craft labor support to perform the many tasks needed to remove, install or modify plant equipment.

This category also includes the modifications to each site's operator training simulators. The training simulators require modifications to reflect the equipment and operating parameters in the uprate condition. Additionally, this category includes costs associated with increased scope for six dry cask storage containers, which scope was added to the project in December 2010. This category of costs is approximately $1.1 million more than projected, primarily due to the addition of the dry cask storage containers.

Q. **Please describe the 2011 activities in the Transmission category.**

A For the period ending December 31, 2011, Transmission costs are estimated to be $18,066,007 as shown on Line 34 of Schedule AE-6 of Exhibit TOJ-22. This amount is primarily related to costs associated with the upgrades to the main transformers and plant yard electrical components at the sites. This is approximately $10.2 million more than projected due to the purchase of the transformers with some transmission outage work accelerated and some deferred due to line and switchyard availability.

Q. Please describe the 2011 actual/estimated recoverable O&M costs.

A. Actual/Estimated recoverable O&M costs for the EPU project in 2011 include $12,701,007 for EPU, shown on Line 19 of Schedule AE-4 of Exhibit TOJ-22, and $5,909 for Transmission, as shown on Line 28 of Schedule P-4 of Exhibit TOJ-22. Recoverable O&M primarily consists of costs for performing inspections of the 1 through 4 feedwater heaters at PSL Unit 2 and PTN Unit 4 and an estimate of obsolete materials that will be expensed as a result of modifications completed in 2011. Additionally, costs for commodities that do not meet FPL's capitalization policy are included. This is approximately $8.6 million more due to an increased scope of required equipment inspections which do not meet capitalization criteria.

Q. Please describe the equipment going into service in 2011.

A. Exhibit TOJ-24, 2011 Extended Power Uprate Work Activities, is a listing by outage of major 2011 work activities for PSL Unit 1, PSL Unit 2 and PTN Unit 4. To the extent the work activities are subject to capitalization as units of property and the modification is completed in 2011, the plant components will be placed into service. The items going into service include, but are not limited to, feedwater heater drain valves, main generators, and isophase bus duct modifications. Certain Transmission and Distribution equipment will also be placed in service in 2011 which includes a main transformer and main transformer cooler upgrades.

Q. Are the 2011 actual/estimated costs presented in your testimony "separate and apart" from other nuclear plant expenditures?

A. Yes, the 2011 actual/estimated costs presented are "separate and apart" from other nuclear plant expenditures. The construction costs and associated carrying charges and recoverable O&M expenses for which FPL is requesting recovery through this proceeding were caused only by activities necessary for the EPU, and would not have been incurred otherwise. As explained in my testimony submitted in this docket on March 1, 2011, FPL's identification of the major components that must be modified or replaced to enable the units to function properly and reliably in the uprated condition is based on engineering analyses. A review of historical site planning documents and the License Renewal Action Items compiled in conjunction with the NRC's approval of FPL's requested license renewals confirmed that the uprate costs were "separate and apart" from other planned nuclear activities and expenditures. FPL has continued to carefully follow all of the safeguards in this respect, which the Commission has previously reviewed and found to be reasonable and appropriate.

Q. Are FPL's actual/estimated 2011 EPU costs reasonable?

A. Yes. The majority of FPL's 2011 expenditures are for (i) payments to long lead equipment manufacturers pursuant to competitively bid contracts; (ii) payments to the competitively bid EPC vendor; (iii) payments to original equipment manufacturers for LAR engineering analyses; and (iv) the implementation costs associated with three EPU outages.

Careful vendor oversight, continued use of competitive bidding when appropriate, and the application of the robust internal schedule and cost controls and internal management processes all support a finding that FPL's actual/estimated 2011 expenditures are reasonable.

2012 PROJECTED CONSTRUCTION ACTIVITIES AND COSTS

Q. Please summarize the construction activities projected for 2012.

A. In 2012, for the EPU LAR Engineering Analysis phase, FPL will continue to support the NRC review process, including, responding to NRC RAIs and interfacing with the NRC Staff. The Long Lead Equipment Procurement Phase will be completed, including equipment for the modifications in the 2012 outages. The Engineering Design Modification Phase will continue with modification package preparation for the final EPU outages in 2012. Implementation will be worked for each of the three outages in 2012: the PTN Unit 3 and PSL Unit 2 spring outages, and the PTN Unit 4 fall outage. Each outage requires long lead equipment, planning, schedule integration, and the actual execution of the physical work in the plants, including extensive testing and systematic turnover to operations. Exhibit TOJ-26, 2012 Extended Power

Uprate Work Activities, includes the unit outage, the work activity, and a description of why it is necessary for the EPU Project.

Q. **Please describe how FPL developed its projections of 2012 costs for its NFRs?**

A. The 2012 projected costs were developed from Project Controls forecasts as described above.

Q. **What types of costs does FPL project to incur for the Uprate Project in 2012?**

A. Schedule P-6 of Exhibit TOJ-22 breaks the 2012 projected total costs of $708,960,295 down into the following categories: License Application $5,312,846; Engineering and Design $11,091,593; Permitting $0; Project Management $26,330,854; and Power Block Engineering, Procurement, Etc. $665,777,875; and Non-Power Block Engineering, Procurement, Etc. $447,127. Exhibit TOJ-27, EPU Project 2012 Projected Costs Tables, provides a summary of the projected EPU Project costs for the NFR categories which includes post in-service amounts.

Q. **Please describe the activities in the License Application category for 2012.**

A. For the period ending December 31, 2012, License Application costs are projected to be $5,312,846 as shown on Line 3 of Schedule P-6 of Exhibit TOJ-22. These amounts consist primarily of vendor payments necessary for responding to NRC RAIs, FPL support and interface with NRC staff, and NRC review fees.

Q. **Please describe the activities in the Engineering and Design category.**

A. For the period ending December 31, 2012, Engineering and Design costs are projected to be $11,091,593 as shown on Line 4 of Schedule P-6 of Exhibit TOJ-22. The amounts consist primarily of FPL engineering activities in support of the review and approval of the engineered modification packages.

Q. Please describe the activities in the Project Management category and how those activities help to ensure that the Uprate Project will be completed on a reasonable schedule and at a reasonable cost.

A. For the period ending December 31, 2012, Project Management costs are projected to be $26,330,854 as shown on Line 6 of Schedule P-6 of Exhibit TOJ-22. This category includes the project management costs associated with the oversight and management of the engineering of modification packages, and implementation of modifications during the planned outages at PSL Unit 2, PTN Unit 3, and PTN Unit 4 occurring in 2012. This work and the associated costs are required to ensure the uprate project is managed in a safe, efficient, and cost-effective manner.

Q. Please describe the 2012 activities in the Power Block Engineering, Procurement, Etc. category.

A. For the period ending December 31, 2012, Power Block Engineering and Procurement costs are projected to be $665,777,875, as shown on Line 9 of Schedule P-6 of Exhibit TOJ-22. This amount consists of milestone payments made to manufacturers of long lead materials and payments made to the EPC vendor for the vast work associated with the implementation of the engineered modification packages in the three planned 2012 outages. This includes final known payments to vendors following installation and testing of the equipment supplied for the Uprates completed through 2012.

The St. Lucie Unit 2 spring 2012 outage is the second of the two planned EPU outages for the unit. Some of the modifications planned for the spring 2012 outage are: condensate pump replacement, High Pressure turbine rotor replacement, feedwater heater 5A and 5B replacement, feedwater heater drain pumps and valves replacements, and Moisture Separator Reheater (MSR) replacements.

The Turkey Point Unit 3 spring 2012 outage is the second of the two planned EPU outages for the unit. Some of the modifications planned for the 2012 outage are: main turbine upgrades, main generator rewind, MSR replacements, main condenser replacement, condensate pumps and motors replacements, and replacement of feedwater heaters 5A and B and 6A and B.

The Turkey Point Unit 4 fall 2012 outage is the second of the two EPU outages planned for the unit. Some of the modifications planned for the fall 2012 outage are: main turbine upgrades, main generator rewind, MSR replacements, main condenser replacement, condensate pumps and motors replacements, and replacement of feedwater heaters 5A and B and 6A and B, and feedwater heater 5 drain piping upgrade.

Q. Please describe the activities in the Non-Power Block Engineering, Procurement, Etc. category.

A. For the period ending December 31, 2012, Non-Power Block Engineering costs are estimated to be $447,127 as shown on Line 10 of Schedule P-6 of Exhibit TOJ-22. This category consists primarily of costs for simulator upgrades and temporary facilities needed to support the project.

Q. Please describe the 2012 activities in the Transmission category.

A. For the period ending December 31, 2012, Transmission costs are projected to be $27,238,132 as shown on Line 34 of Schedule P-6 of Exhibit TOJ-22. This amount is required primarily for the following: Replacement of transformers, transformer cooler upgrades, switchyard breaker replacement with higher capacity breakers, and line and breaker monitoring equipment.

Q. Please describe the 2012 projected recoverable O&M costs.

A. Projected recoverable O&M costs for the EPU project in 2012 total $5,611,503 as shown on Line 19 of schedule P-4 of Exhibit TOJ-22. Recoverable O&M primarily consists of costs for performing equipment inspections and an estimate of obsolete materials that will be expensed as a result of modifications completed in 2012. Additionally, commodities and consumables that do not meet FPL's capitalization policy are included.

Q. Please describe the items going into service in 2012.

A. Exhibit TOJ-26, Extended Power Uprate Work Activities for 2012, is a listing of equipment and control devices that are planned for installation; many of which are planned to be placed into service in 2012. This extensive list includes the Transmission upgraded items and items such as the main generator rotors, high pressure turbine rotors, main transformers and cooler modifications, feedwater heaters, condensate pumps, and main condensers, among others.

Q. Are the 2012 cost projections presented in your testimony "separate and apart" from other nuclear plant expenditures?

A. Yes. The 2012 cost projections presented are "separate and apart" from other nuclear plant expenditures. As explained in my testimony submitted in this docket on March 1, 2011, FPL's identification of the major components that must be modified or replaced to enable the units to function properly and reliably in the uprated condition is based on engineering analyses. A review of historical site planning documents and the License Renewal Action Items compiled in conjunction with the NRC's approval of FPL's requested license renewals confirmed that the uprate costs were "separate and apart" from other planned nuclear activities and expenditures. FPL has continued to carefully follow all of the safeguards in this respect, which the Commission has previously reviewed and found to be reasonable and appropriate.

Q. Are FPL's projected 2012 EPU costs reasonable?

A. Yes. FPL's projected 2012 costs reflect the significant amount of implementation work that is planned to occur in that year and the large number of systems going into service, as the project nears completion. Project staffing levels, including vendor staffing, will be higher to support the modification package engineering design, implementation, and outage support. The majority of FPL's costs, however, will continue to flow from the many ongoing contracts introduced and reviewed in prior proceedings. Careful vendor oversight, continued use of competitive bidding when appropriate, and the application of the robust internal schedule and cost controls and internal management processes, all demonstrate that FPL's projected 2012 expenditures are reasonable.

TRUE-UP TO ORIGINAL COST AND UPDATED COST ESTIMATE RANGE

Q. Did FPL prepare a true-up of the total project costs in 2010?

A. Yes. FPL's 2010 True-up to Original schedule is included in TOJ-22.

Q. Have you prepared a current true-up of the total project costs through the current reporting period?

A. Yes. Exhibit TOJ-22 includes the 2012 TOR schedules that compare the current projections to FPL's originally filed Project costs. The 2012 TOR schedules provide information on the project costs through the end of 2013. The 2012 TOR schedules provide the best information currently available for the cost recovery period through 2013.

Q. Has FPL updated its total nonbinding cost forecast for the project?

A. Yes. Pursuant to the Commission's direction in Order No. PSC-09-0783-FOF-EI, FPL has updated its capital cost forecast. FPL has developed an updated cost forecast range for the EPU project that reflects increased scope that is necessary to support NRC regulatory requirements, power generation in the uprate condition, and implementation support. The updated cost estimate range is approximately $2,324 million to $2,479 million, including transmission costs and carrying costs, as shown on NFR Schedule TOR-2.

Q. **Why is FPL providing a nonbinding range instead of a single point estimate?**

A. The progression of project activities over the last several years provides FPL with additional insight to revise its nonbinding cost forecast. However, the project is still in the design engineering phase and there remains an expected level of uncertainty with respect to project scope. Accordingly, it is only appropriate to provide the total project cost in terms of a range.

This approach is consistent with generally accepted project management best practices. For example, the Project Management Institute's "A Guide to the Project Management Body of Knowledge" states the following at page 161:

> The accuracy of a project estimate will increase as the project progresses through the project life cycle. For example, a project in the initiation phase could have a rough order of magnitude (ROM) estimate in the range of -50% to +100%. Later in the project, as more information is known, estimates could narrow to a range of -10% to +15%.

As activities such as final design engineering analyses, associated NRC reviews, and construction planning progress, FPL will be able to provide additional certainty to the total project cost forecast.

Q. **Please describe the development of the current non-binding cost estimate range for the EPU Project.**

A. The low end of the non-binding cost estimate range represents the current forecast, approximately $2.324 million, at this stage of the project based on the following status of tasks: i) the completion of the LAR engineering effort; ii) the approximately 95% committed costs for long lead equipment, which represents approximately $250 million of $510 million of these costs (as of March 2011); iii) the approximately 50% completion of the design modification phase of the project, which represents approximately 625,000 hours of 940,000 hours of this phase (as of April 2011); and iv) an estimate of implementation costs. The LAR analyses and design modification engineering activities have added work scope to the project. The high end of the range reflects the current forecast, an evaluation of the existing trends for weighted risks, and undefined scope. This resulted in a high end non-binding cost estimate range amount of approximately $2,479 million.

Q. Please compare the current cost estimate range of the EPU Project to the nonbinding cost estimate presented in FPL's Need Filing.

A. FPL's need filing in September 2007 for the EPU Project included a nonbinding cost estimate of $1,798 million. This initiation phase estimate was based on FPL's preliminary feasibility and scoping studies and reflected the best information available at that time. (Please note that FPL's original non-binding cost estimate included the participant's share of St. Lucie Unit 2.)

Q. Please describe the primary reasons why the current nonbinding cost estimate range is higher than the nonbinding cost estimate previously provided.

A. The major reason for the higher cost estimate is the increase in project scope that can be categorized into three areas: Regulatory and Safety Margin, Power Generation, and Implementation Support. For example, in the Regulatory and Safety Margin area, the applicant must demonstrate through engineering analyses submitted to the NRC that the increased operating conditions meet regulatory safety criteria. In many instances, in performing the LAR engineering analyses, the need for a modification to a system, structure, or component to obtain acceptable results was identified. As more modifications are identified by the NRC LAR review process, costs for labor and non-labor resources increase.

With respect to Power Generation, modification design engineering has identified additional scope that is required for the units to operate in the power uprate conditions. For example, the replacement of the main steam isolation valve assemblies and the heater drain pressure re-rate could only be identified through design engineering.

Additionally, increases in Implementation Support costs reflect increased project complexity. The EPC vendor is responsible for detailed design of the modifications, procurement of components, and the implementation of modifications. As described above, the EPC vendor, Bechtel, is performing the modification design engineering process and estimating the additional resources required for planning and implementation. These reviews indicate that modification implementation will be more complex than originally anticipated. This complexity is primarily related to the following:

- Structural Integrity
- Limited Work and Staging Space
- Rigging of Equipment
- Operating Plant Environment
- Work Order Planning and Integration with Routine Outage Activities

Q. Please describe how these components impact projected costs.

A. Structural integrity refers to the existing structures, secondary plant floor elevations and their ability to accommodate heavier and/or larger pieces of equipment supported from the existing structure. Detailed engineering evaluations of the structures are required to support removal, transport and placement of the equipment. Such detailed engineering evaluations had not been performed at the time that the initial non-binding cost estimate was developed. The two components of the additional costs are the engineering analyses needed to assess structural integrity and the resultant plant modifications.

In regards to limited work and staging space, the secondary plant equipment being modified for the EPU Project is located on all of the floors of the secondary plant which includes below grade areas with minimal space for removal, replacement, or modification work. Typically, the modification or replacement of a piece of equipment during a normal refueling outage can be accomplished while routine work is scheduled to minimize interference with a planned major modification. The EPU Project replaces or modifies numerous major pieces of equipment during a single refueling outage. This work increases the complexity, planning, scheduling, and duration of the outage. EPU modification engineering, work order planning and scheduling activities are integrated with routine outage activities to optimize outage performance. The two components of the additional costs are the engineering analyses needed to assess the limited work and staging space and the resultant plant modifications.

In regards to rigging of equipment, some of the equipment being replaced or modified weighs up to approximately 185 tons. This equipment must be stored, staged, and carefully moved into proper location with precise execution. These heavy lifts, including moving existing equipment out of the way to allow new equipment to be installed, requires individual detailed rigging plans. A rigging plan defines the lifting devices to be used, where the equipment can be landed, and the safe load path for moving the equipment. These rigging plans are then integrated into the work orders and the schedule for crane usage, space, and qualified craft labor availability. The additional costs are associated with the engineering analyses, the additional planning, and implementation of resultant engineered lifts.

In regards to operating plant environment, performing work at an operating plant requires strict adherence to federal, state, and local regulations including industrial safety practices, nuclear safety practices, security requirements, and plant technical specifications. All of these requirements are considered and factored into the integrated planning and scheduling when working in an operating plant environment, and result in additional planning and implementation costs.

Work order planning and integration with routine outage activities is particularly challenging. Planned modifications are assigned to an outage to accomplish the work in a prescribed sequence of removing, installing, or modifying the equipment in preparation for operation in the uprate condition. Once the design engineering modification packages are completed, work orders delineating a step-by-step process for performing the work are prepared. The work orders may include equipment clearance orders to ensure equipment is isolated from mechanical energy and electrically de-energized, confined space entry permits requiring additional safety personnel, and hot work permits which may require a fire watch for grinding and welding activities for equipment being removed, installed or modified. These activities are then integrated into the outage schedule for proper sequencing in a manner that maintains the plant in a safely shutdown condition while accomplishing the needed modifications. Schedule integration includes when and what equipment will be moved by the cranes, where equipment will be staged for supporting the work activity, when a confined space can be entered safely, and ensuring regulations are met. All of these requirements are considered and factored into the integrated planning, scheduling, and implementation of outages, resulting in additional costs.

LONG TERM FEASIBILITY

Q. What total project cost did FPL use for purposes of the economic feasibility analysis?

A. FPL performed its feasibility analysis with an estimated going forward project cost figure of $1,780 million, which includes transmission and carrying costs. Thus, FPL conservatively assumed the high end of its current nonbinding cost estimate range in order to evaluate project feasibility. Pursuant to Order No. PSC-09-0783-FOF-EI, the amount used accounts for sunk costs.

Q. What assumed megawatt output did FPL use for purposes of the economic feasibility analysis?

A. FPL assumed that the Uprate would provide an additional 450 MWe for feasibility analysis purposes – more than the 399 MWe assumed during the need determination process. The best case scenario for FPL's customers would be an increase in output of approximately 463 MWe. However, it remains to be seen whether the target steam parameters supporting such output will be achieved at each unit. Accordingly, FPL used 450 MWe in its feasibility analysis, in order to provide feasibility results that are conservative and not reliant upon this best case scenario.

Q. Please summarize the results of the EPU economic feasibility analysis.

A. As discussed in detail by FPL Witness Dr. Sim, the most current feasibility analysis affirms the cost-effectiveness and benefits associated with the Uprate project.

Q. Has FPL examined other aspects of project feasibility?

A. Yes. FPL continuously assesses the financial, technical, and regulatory aspects of the EPU project, and the project remains feasible at this time. This assessment is reflected in the numerous reports and tracking tools used by the project.

Q. Is it technically feasible to accomplish the Uprate Project?

A. Yes. The Project remains technically feasible. The LAR engineering analyses revealed challenges to the Uprates, but the challenges are being addressed. Further, Bechtel has demonstrated that it is capable of performing both the necessary engineering design and implementation scope of work.

Q. Is it feasible to finance the Uprate Project?

A. Yes. The Uprate Project is financed by the general capital FPL raises each year, and FPL's finance department expects that adequate amounts of capital will be obtained to complete the project.

Q. Is it feasible to obtain all necessary licenses and permits?

A. Yes. As described above, FPL has completed the state licensing/permitting process. FPL also has submitted all necessary LARs to the NRC, and expects that they will be approved. Timing consideration related to these approvals were discussed previously in this testimony.

Q. Are there other aspects to feasibility that FPL has examined?

A. Yes. Inherent to the project management process is the recognition of factors such as resource availability/constraints, potential cost escalations, and industry-critical events such as the cancellation of the Yucca Mountain spent fuel disposal project and the recent events in Japan following the March 2011 earthquake and tsunami. FPL monitors these and other factors. None of these issues has caused the project to cease being feasible.

Q. Are these items required to be included in the feasibility analysis set forth in Rule 25-6.0423(c)5, F.A.C.?

A. No. FPL's economic feasibility analysis sponsored by Witness Dr. Sim is being provided in satisfaction of Rule 25-6.0423(c)5, F.A.C. On February 4, 2010, Commission Staff requested that FPL address these feasibility-related topics. Accordingly, FPL has summarized its assessment of the non-economic topics related to feasibility in response to Staff's request.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Power Plant Cost Recovery Clause	))	DOCKET NO. 110009-EI FILED: JUNE 10, 2011

ERRATA SHEET

TESTIMONY OF TERRY O. JONES, MAY 2, 2011

EXHIBIT TOJ-25, 2011 EPU Summary of Construction Costs

REVISED PAGE #	LINE #	COL	
4	Table 8	first	Change "PTN Independent Spent Fuel Storage Installation (ISFSI) Pad Relocation" to "PTN Spent Fuel Dry Cask Loading"

DOCUMENT NUMBER-DATE
04024 JUN 10 =
FPSC-COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLMENTAL TESTIMONY OF TERRY O. JONES

DOCKET NO. 110009-EI

JULY 15, 2011

Q. Please state your name and business address.

My name is Terry O. Jones, and my business address is 700 Universe Boulevard, Juno Beach, FL 33408.

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

A. I am employed with Florida Power & Light Company (FPL) as Vice President, Nuclear Power Uprates.

Q. Have you previously filed testimony in this docket?

A. Yes. I provided testimony on March 1, 2011 related to the Extended Power Uprate (EPU) project activities and costs in 2009, testimony on March 1, 2011 related to the EPU project activities and costs in 2010, and testimony on May 2, 2011 related to anticipated EPU project activities and costs in 2011 and 2012. This is a supplement to my May 2, 2011 testimony.

Q. What is the purpose of this supplement to your testimony?

A. The purpose of this supplement is to provide the Florida Public Service Commission (Commission), Commission Staff, and all parties with an update on three aspects of the EPU project: (i) the outage schedules; (ii) the increased output currently being realized from St. Lucie Unit 2, following the work that was performed earlier this year during the

St. Lucie Unit 2 spring outage; and (iii) the acceptance or approval of two License Amendment Requests.

Q. Please provide the update related to the outage schedules.

A. Several changes have been made to the outage schedules since my May 2, 2011 testimony. These changes have been fully vetted and approved for the EPU project. First, as stated in my testimony at pages 11-12, the St. Lucie Unit 2 spring 2011 outage lasted longer than planned, and the outage was not complete at the time my testimony was filed. The outage concluded and the unit was returned to service on May 8, 2011.

Second, we are now planning for longer durations for the remaining four EPU outages. As stated in my May 2, 2011 testimony at page 4, "[a]s the engineering analyses continue and as modification designs are finalized and construction plans are developed, FPL will be able to refine the planned outage durations, implementation resource requirements, and the total project cost". Since the preparation of my testimony, FPL has in fact adjusted the planned outage durations. Each of the outages has been extended, for planning purposes at this time, between 10 and 40 days, for a total of 85 additional days. FPL determined that additional time needed to be assumed to allow for construction and logistical discovery during implementation. This decision reflects the operating experience gained from completing the implementation of the first FPL EPU outages and non-FPL EPU outages, as well as progress that has been made in the engineering design phase and implementation phase – specifically, the planning and constructability reviews for the implementation of the EPU modifications. The longer planned duration outages also include time for pre-operational and functional testing of modifications prior to turnover to operations.

Third, the start dates of the remaining St. Lucie Unit 2 and Turkey Point Unit 4 outages have been pushed back slightly, while the start date for the Turkey Point Unit 3 outage has advanced slightly. The start dates were adjusted to minimize the overlap of generating unit outages (not just nuclear unit outages) on FPL's system and to maximize the usage of nuclear fuel.

Q. Please provide the update related to the increased output being realized from St. Lucie Unit 2.

A. As stated in my testimony at page 15, FPL anticipated that the return to service from the St. Lucie Unit 2 outage would result in an increase of approximately 20 MWe in the output of the unit due to the installation of a more efficient low pressure turbine rotor, and that approximately 17 MWe of that increased output would be for the benefit of FPL's customers (after accounting for the co-owners' share). As mentioned above, St. Lucie Unit 2 was returned to service on May 8, 2011. Preliminary testing indicates that there is an increase of approximately 34 MWe, 29 MWe of which is for the benefit of FPL's customers.

Q. Please provide the update related to the progress of FPL's License Amendment Requests (LARs.)

A. FPL has accomplished two major milestones in its licensing phase of the project. On June 23, 2011, the Nuclear Regulatory Commission (NRC) accepted FPL's St. Lucie Unit 2 EPU LAR for review. Also on June 23, 2011, the NRC approved FPL's Turkey

Point Alternate Source Term LAR – a prerequisite to approval of the Turkey Point EPU LAR.

Q. Do these EPU project changes affect the feasibility analyses performed by Dr. Sim?

A. The outage schedule changes and the increased output of St. Lucie Unit 2 affect Dr. Sim's feasibility analyses. The LAR accomplishments do not. Dr. Sim is providing supplemental testimony and exhibits demonstrating the effects of the outage schedule and St. Lucie Unit 2 output changes on the feasibility analyses, as well as the effects of other system resource planning assumptions that have recently changed. As Dr. Sim explains in his supplemental testimony, the EPU project remains solidly cost-effective for customers.

Q. Does that complete your supplement?

A. Yes.

BY MR. ANDERSON:

Q. Mr. Jones, you are sponsoring exhibits to your direct testimony?

A. Yes, I am.

Q. These are Exhibits TOJ-1 through TOJ-27, also shown as Exhibits 49 through 75 on staff's exhibit list?

A. That is correct.

MR. ANDERSON: The exhibits have been premarked, Mr. Chairman.

CHAIRMAN GRAHAM: Uh-huh.

BY MR. ANDERSON:

Q. Mr. Jones, would you please provide a summary of your testimony for the Commission?

A. Yes, I will.

Good afternoon, Chairman Graham and Commissioners. FPL's project team is safely and cost-effectively implementing the extended power uprate project at St. Lucie and Turkey Point Nuclear Power Plants. I am responsible for the management and execution of FPL's extended power uprate project. An extended power uprate project is the largest and most complex uprate that can be approved by the Nuclear Regulatory Commission. It requires the replacement or modification of a significant number of nuclear plant components and systems in order to generate and accommodate higher electrical output. When completed, the EPU project will provide FPL's customers with an additional 450 megawatts of clean zero-emission electrical generation without expanding the footprints of these plants.

This project will add approximately one-half of the electrical output of a new nuclear unit and will provide significant fuel cost savings to our customers. Our customers began benefiting from fuel savings this past spring following the outage at St. Lucie Unit 2 where a new more efficient low-pressure turbine was installed for the extended power uprate, adding approximately 19 megawatts of nuclear generated electrical output.

By design, the extensive license, engineering, equipment procurement, design modification engineering, and implementation work all overlap with major construction being incorporated into scheduled refueling outages for FPL's nuclear units. We chose this methodology to bring the benefits of additional nuclear generation to FPL's customers as early as practical.

Let me briefly describe FPL's EPU work during the 2009 to 2012 time period under review in this proceeding. During 2009 and 2010, FPL worked on Nuclear Regulatory Commission licensing, procured major equipment, performed detailed design engineering for required modifications, and prepared and implemented many modifications required to increase nuclear generation for our customers. In 2010, FPL also completed two EPU implementation outages at St. Lucie and Turkey Point.

So far in 2011, we have made good progress on obtaining the required NRC licensing approvals. We received NRC approval on one of our license amendments with three others accepted for approval. We have also successfully completed two more EPU implementation outages, including the St. Lucie outage that I mentioned earlier resulting in an increase of 29 megawatts of electrical output for FPL's customers.

During 2012, FPL will continue its engineering, design implementation and construction work, complete additional outages at the plant, and support the NRC's continued licensing review.

It's a big job. We are employing over ten million manhours of work, or to put it another way, more than 5,000 person years of work to complete the EPU project. The costs incurred in 2009 and 2010 and those projected for 2011 and 2012 for the EPU project are prudent and reasonable. FPL's investment in additional nuclear generation approved by this Commission is creating thousands of jobs and will provide fuel cost savings for FPL customers for decades. This concludes my summary.

MR. ANDERSON: Mr. Jones is available for cross-examination.

CHAIRMAN GRAHAM: Thank you. Who's up first?

MS. KAUFMAN: I guess it's me.

CHAIRMAN GRAHAM: Ms. Kaufman.

MS. KAUFMAN: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q. Good afternoon, Mr. Jones.

A. Good afternoon.

Q. When did you -- you are currently Vice-President of Uprates, is that correct?

A. That is correct.

Q. When did you come into that position?

A. I officially assumed the position August 1st, 2009.

Q. So that was obviously right before the September 2009 nuclear cost-recovery hearing, is that correct?

A. That is correct.

Q. Did you have any involvement in the September 2009 hearing?

A. No, I did not.

Q. Now, in your testimony -- you have several sets of testimony, so let me get this right. In your March 1, 2011, testimony you address the activities of the extended power uprate in 2009, correct?

A. That is correct.

Q. But most of this information -- would you agree most of the activity occurred prior to your assuming your position as VP of Uprates?

A. The activity that occurred in 2007, 2008, and up until August 1 of 2009 were before I officially took over the project. In my prior position as Vice-President for Operations for the Midwest, we're doing extended power uprate across the enterprise, six of the eight reactors. And so I was involved quite a bit in the extended power uprate as it affected the utility company. So I was very much aware of what was going on in the extended power uprate in Florida, because at the time it was a corporate, largely corporate-centric organization.

Q. You referenced your prior position and your involvement with uprates. Where were you located prior to coming to FPL Juno Beach?

A. Prior to coming to FPL Juno Beach, I was located at Turkey Point Nuclear Power Plant, and I came to Juno Beach in January of 2007.

Q. You referenced your experience in the midwest. Where were you located then?

A. As the Vice-President of Operations for the Midwest Region, I was located in Juno Beach, Florida. And also as part of that function, it is mentioned in some of the discovery documents about the technical challenge and review boards of which I chaired in regards to scope additions and scope deletions for the Florida units that preceded me taking over as Vice-President of the Extended Power Uprates.

Q. If you would turn to Page 15 of your March testimony we have just been talking about.

A. Is that the March 2011?

Q. The March 1 -- yes, 2011 extended power uprate, 2009, Page 15. Are you there?

A. I'm there.

Q. Okay. If you look at the question beginning on Line 7, you are discussing periodic reviews conducted in 2009 regarding key decisions about the EPU project, is that correct?

A. I want to make sure that we have the same --

Q. I know, you have many sets of testimony. It's March 1, 2011; EPU 2009. Mine has a purple cover, if that's any help.

A. Okay. Page 15, and the question is whether this is in regard to the answer to the question what periodic reviews were conducted?

Q. Yes.

A. That says conducted in 2010. Hold on. Let me go back one. Sorry.

CHAIRMAN GRAHAM: That's all right.

BY MS. KAUFMAN:

Q. Are you with me?

A. I'm with you.

Q. Okay. So we are looking at the question on Page 7 about the periodic reviews conducted in 2009. And you talk about regularly scheduled meetings in regard to the uprate project and performance. Do you see that?

A. Not on page -- Page 15, Line 7, correct?

Q. That's the question.

A. Got it.

Q. And the following answer, and beginning on Line 9 you talk about regularly scheduled meetings. Do you see where I am?

A. I do.

Q. Okay. Now that we're at the right place, my question is in regard to those regularly scheduled meetings, prior to your assuming the position of VP

Uprates, did you attend any of those meetings?

A. No, I did not.

Q. So the information that's contained in the -- let's say from Line 12 where the bullets start over to the next page, any information in there that refers to prior to your assuming the VP Uprates, you received that information from other FPL members, staff members?

A. I received that information from other FPL staff members on the projects, as well as an examination of the company's records and documentations, and we provided those in discovery.

Q. Does FPL have a witness that discusses what went on in these meetings prior to your taking over? Have they presented a witness on that topic in this hearing that you are aware of?

A. In this hearing?

Q. Yes.

A. I'm sorry, are you asking me is there a witness that was present in those meetings here at this hearing?

Q. Yes. Is there a witness that was there and can tell us what occurred in those meetings?

A. There is no witness that is here that was in those meetings, but I as a witness through an examination of the documents from those meetings know what occurred in those meetings, based on a review of the documents. Although I cannot obviously account for 100 percent of what occurred or was said in each one of those meetings, not actually having been present.

MR. ANDERSON: FPL would also just indicate that Mr. Stall, our Chief Nuclear Officer at the time, is a witness in this case.

BY MS. KAUFMAN:

Q. If you turn to Page 27 of that same set of testimony, and if you would look at Line 12. The question asks you about the management of major EPU project vendors in 2009, is that correct?

A. Correct.

Q. Did you have any personal involvement in managing vendors in 2009 prior to your assumption of the VP uprate position?

A. I did not have personal direct involvement in managing the vendors prior to August 1, 2009. Again, similar to the other question, the same senior people who are on the project, those same people are the ones that were primarily responsible for managing the vendors.

Q. And those individuals are not witnesses in this case, correct?

A. No, I represent them.

Q. Turn over to Page 28. Beginning on Line 12, you're talking about activities occurring in the second quarter of 2009. Do you see that?

A. That is correct.

Q. You weren't personally involved in those activities, were you?

A. Yes, I got involved with the project in July. Well, July is not in the second quarter. So, no, I wasn't directly involved. My involvement was a continuation of those efforts from the second quarter, and that was a part of our transition and turnover as we reorganized the project team.

Q. Okay. I'm going to switch to another set, and I want to see if we can get on the same page, and that is your EPU 2010 testimony. Mine has a green cover, if that helps.

I'm sorry, I gave you the wrong reference. I'm going to look at May 2011. I'm sorry. And I'm going to look at Page 11, which has to do with schedule change.

CHAIRMAN GRAHAM: Ms. Kaufman, would you say that reference again?

MS. KAUFMAN: Yes. It's May 2011, nuclear power plant cost-recovery for the years ending December 2011 and 2012. And it's Page 11. It has a tan cover.

THE WITNESS: May 2, 2011, Page 11.

BY MS. KAUFMAN:

Q. And let's wait until everybody gets with us.

Beginning on Line 14, there is a question about unanticipated schedule changes this year. Do you see that? The question is, "Were there any unanticipated schedule changes this year?"

A. Yes.

Q. And your answer discusses an outage at the St. Lucie Unit, correct?

A. That is correct.

Q. How long was this outage?

A. I don't recall the exact duration, so I would need to check that, but it was on the order of about, about 120 days.

Q. And you tell us in your testimony here that the outage was related to an incident involving the Siemens' personnel, is that correct?

A. That is correct. We had a work stoppage due to a human error during the generator rewind, that is correct.

Q. And Siemens in this instance is the vendor working on the turbine generator, is that correct?

A. Yes. The turbine generators at our Florida units, the original equipment manufacturer is the Siemens Corporation, and so they are the -- quite frankly, they supply these machines worldwide, and they were the vendor that we contracted to do the uprate on the machines. In this particular case, the scope of the work was to replace both the low-pressure turbines which drive the generator, and do a complete rewind and rotor replacement on the generators. So it's quite extensive work, very labor intensive, and these are the experts that do this for a living.

Q. And there was an issue as you describe it there that required this outage, correct?

A. There was a human error made where as a part of the generator rewind process, they change out a portion of what is called the generator core iron. There is literally thousands of these laminate sheets that make up the generator core, and they can only be removed and installed by hand. And in that process, they have a tool that they use which looks simply no different than a round bar about a half-inch diameter and about 18 inches long to align in the process.

And, unfortunately, the worker pushed it down one of the ventilation holes and didn't notice it, and then on the close-out inspection it was missed. And so when we performed an electrical test, because that pin was in there, it caused damage to the generator core iron, and so that had to be repaired.

Q. And so when you say human error, we are talking about a mistake that one of the vendor's employees made on the project as you just described it?

A. That is correct. And like I said, Siemens, they're the equipment experts. And as typical, not only us, but standard industry practice is you would bring in the OEM for this type of work. It involves hundreds of workers, actually, 24/7 type of operation for over two months to do just this scope of work. And obviously it would not be practical for us to employ that number of people and turn them into turbine generator experts. So the standard practice is to bring in the expert.

We do provide oversight, and logistic support, and audits of their procedures and their training and things like that to ensure quality work. But, as with any major construction project, you cannot totally eliminate human error. The standard of perfection is just not achievable. The best you do is provide intrusive oversight and minimize the risk.

Q. This 120-day outage, is that going to result in some costs that is unanticipated?

A. Yes, there are -- certainly there's a cost impact with the extent of the outage. There is the cost impact to the project itself. There is cost associated to the plant, because obviously they are in support of the outage, as well as Siemens had some costs involved in that. And --

Q Excuse me.

A Go ahead.

Q. I was going to ask if you could provide us with an estimate of what you think the cost of this 120-day outage was?

MR. ANDERSON: I'm going to object. The question is based on facts not in evidence. There was a 120-day refueling outage. A portion of it was extended due to this item, and this is being continually referred to as if it were a 120-day outage caused by this personnel error. And I have listened to it a couple of times. With the third time, I will just ask that the questions reflects accurately what the witness has stated, which is it was a little bit of an outage extension and go from there.

CHAIRMAN GRAHAM: Ms. Kaufman, can you restate your question.

MS. KAUFMAN: Yes. I apologize. I thought I was repeating what the witness said, which was 120 days.

THE WITNESS: Can I clarify?

MS. KAUFMAN: Excuse me.

THE WITNESS: The refueling outage, which obviously involved refueling the reactor, as well as all the preventative maintenance, as well as this uprate that we are doing with other planned major projects that we had not related to EPU, that outage duration was about 120 days. The work stoppage and this human error, recovery from that did impact that outage duration. We estimated it about 23 days.

MS. KAUFMAN: Okay. Thank you for that clarification.

BY MS. KAUFMAN:

Q. So the outage time that was related to the human error and the unanticipated schedule change you are talking about was about 23 days, correct?

A. I wish it were that simple. There's other activities that are also -- you know, other activities, other maintenance, other delays that are occurring in parallel. If other things would have gone exactly according to plan, let's just say that the impact to Siemens was definitely 23 days. They were definitely on the project 23 days longer than what they anticipated and longer than what we had anticipated. There was other drivers in the outage that determined the overall duration that are outside of the EPU scope.

Q. And I just want to discuss with you the

Siemens issue only, so that will make our discussion more clear, I hope.

A. Okay.

Q. And I think you agreed earlier that there obviously is a cost to the 23 days, correct?

A. That is correct.

Q. Have you or FPL estimated what that cost is?

A. Yes, we have.

Q. And what is that?

A. We're in commercial negotiations right now with Siemens over what we think Siemens is liable for and what they should have to pay. So I'm a little hesitant to put those numbers out there. I can say this, that as a part of the EPU project we have what we call a risk register, and so anyone, either internal or external, can identify an issue or problem that could have an impact on schedule, quality costs, any number of factors, and we will capture that in our risk register. And so we identified a potential risk of as much as $15 million impact. At this stage it's going to be quite a bit less than that, but as I said, we are still in commercial discussion with Siemens over the claim.

Is that a sufficient answer?

Q. Yes. And I'm certainly not intending to have you divulge anything that is confidential in a public forum. And let me just ask you this: In regard to the amount that is in contention with Siemens as to who would bear that risk, is it Florida Power and Light's view that the risk of that amount rests with Siemens?

A. There is definitely an amount that goes back to Siemens as standard industry practice. As I mentioned refueling outages, set EPU aside, refueling outages, a big complex refueling outage is typically 30 to 40 days involving hundreds of supplemental workers and contractors. And to do those outages in a short period -- in as short a practical period of time, you bring in the OEMs to do things like the refueling portion, to the things like --

MS. KAUFMAN: Chairman Graham, I hate to interrupt, but I think my question was a lot simpler than where Mr. Jones wants to go.

CHAIRMAN GRAHAM: Ms. Kaufman, I actually have to disagree with you. Having lived through many, many outages myself, I know just because you schedule one outage and something else happens arbitrarily to that, it's kind of hard to pinpoint and directly align that. And I think what he is trying to do is explain his answer to you; you may want to be more concise about the question you ask.

BY MS. KAUFMAN:

Q. Were you finished? I think the Chairman --

A. Okay. What was the question? Could you repeat the question?

Q. Yes.

I will just try to be more concise, Mr. Chairman.

Between the amount that is in dispute between FPL and Siemens as to this human error incident, just the incident involving the tool that you have explained, is it Florida Power and Light's view that the risk of that is on Siemens rather than on Florida Power and Light?

A. A portion of the risk is on Siemens, a portion is on Florida Power and Light.

Q. And that is an area that you are attempting to continue to work with Siemens on?

A. That is correct. And all I wanted to add to, if I may, is that there are limits of liability on all of these contracts and major contract vendors. Obviously, it is not practical for me to have a workforce of 3,000 people at a nuclear plant to just accommodate periodic refueling outages. So we bring in the OEMs for the refueling portion and the turbine generator portion, and they all have LDs because they couldn't possibly accept the risk of lost generation or generation replacement. It would put them out of business. Thank you.

MR. ANDERSON: Just for clarification, could the witness say what LDs are?

THE WITNESS: Limits to liability.

BY MS. KAUFMAN:

Q. Do you know if it is the company's intent to come and seek whatever portion of the amount it is that flows to Florida Power and Light from this incident, to seek that from ratepayers?

A. I will only speak to the EPU scope, if I may, and that is that that portion that we are able to hold Siemens liable for, they will be liable for. And the balance of that is a part of project risk and project expense and, therefore, it is our view, is recoverable.

CHAIRMAN GRAHAM: Did that answer your question?

MS. KAUFMAN: Yes.

BY MS. KAUFMAN:

Q. So the answer to my question is, yes, you would try to recover that from ratepayers?

A. Yes.

MS. KAUFMAN: Thank you, Mr. Chairman, for indulging me. That's all I have.

CHAIRMAN GRAHAM: That's fine. I didn't really mean to interrupt, but I have lived that life. Any other intervenors?

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q. Hello, Mr. Jones.

A. Hello.

Q. You indicated that you assumed your position of vice-president of uprates in August 2009, is that correct?

A. That's correct.

Q. Now, in earlier portions of the hearing today with the prior witnesses, references were made to the July meeting, or the executive steering committee, and to certain estimates, or revised estimates of capital costs that were the subject of that meeting.

As the incoming Vice-President of Uprates, you would have participated in the presentation to the executive steering committee that was packaged in August and presented in September 2009, were you not?

A. Yes, but I want to be clear in regards to my presentation -- my participation is that I was present for the meeting. I did not participate in the preparation of the material for the meeting.

Q. Are you familiar with the material that was prepared for that meeting?

A. Yes, I am.

Q. Is it true that the project managers revised the estimated capital costs beyond the increase that was reflected in the July presentation?

A. I'm sorry, could you repeat the question?

Q. Yes. There has been testimony about the revised estimates that Mr. Reed, among others, has described, increasing the estimated capital costs associated with the EPU by $300 million.

My question to you is isn't it true that when the project managers prepared a presentation in August of 2009 that estimate was revised upwards again?

A. To which August presentation are you referring to?

Q. The August presentation to the executive steering -- the August presentation prepared for the meeting of the executive steering committee that occurred on, I think, August or September 9th, 2009?

A. Okay. I wasn't -- to the best of my recollection, there was no August ESC presentation. So are you referring to a presentation that was presented on September 9th?

Q. Prepared in August, presented in September.

A. Prepared in August, presented in September.

The answer to that question is yes, and I would like to clarify that the preliminary numbers to which due diligence was in progress for from the July meeting, those preliminary numbers were retained as a part of the project forecast going forward while the project team continued their due diligence, and so there was scope added and scope deleted and other changes that were captured as a part of that project forecast going forward. So, yes, it would be expected and did occur that those numbers were different for the September 9 presentation.

Q. They were different and they were higher than July, correct?

A. That is correct. I'd also like to point out that those numbers in July, there was at least $200 million of scope that had not been through enough engineering analysis to have management review or approval, which is an example of the due diligence that I am referring to that had been ongoing from July, and we did not complete until April of 2010.

Q. And when that was completed in April of 2010, did the numbers turn out to be higher than they were either in August or July?

A. Yes. We revised the nonbinding cost estimate in April of 2010 following our due diligence in regards to decisions on whether to continue with that particular engineering procurement contractor, whether to split part of that work out from the EPC self-perform part of the work, and advanced CERT (phonetic) engineering analysis to determine what scope would be retained and what scope would be eliminated.

Q. The net effect of which was to increase the estimates in July, again in September, and again in April, correct?

A. Yes. And to be clear, the project forecast really changes on a week-to-week basis, but we don't revise the nonbinding cost estimate. And I mentioned the risk register before, and there's risk register meetings on a weekly basis to which people identify risks associated with the project, and you quantify that, and so that forecast fluctuates on a weekly basis. It is true that at the end of the month we close the book on the project forecast, and it is what it is. And that is what we communicate to the senior executives with appropriate qualification of the certainty of those numbers. If you examine the September executive steering committee presentation, which has been provided in discovery, you will see that we qualified those costs as only about 30 percent of those numbers in our view were certain, and that 7 percent were still not very well-defined, and that was based on engineering progress.

Q. Thirty percent was certain -- only 30 percent were certain because that represented the status of design engineering at the time, correct?

A. Not entirely. The status of engineering design, status of identification of long-lead material, and the costs associated with that material, and certainty around near term staffing for the upcoming work.

Q. It is true, however, is it not, that price certainty increases as the design engineering process progresses?

A. It is true that cost certainty does increase as design engineering progresses and construction and planning and implementation advances.

Q. At Page 32 of your May testimony, and I'm looking at the answer that begins at Line 6, you say the progression of project activities over the last several years provides FPL with additional insight to revise its nonbinding cost forecast. However, the project is still in the design engineering phase, and there remains an expected level of uncertainty with respect to project scope. Do you see that?

A. Yes.

Q. If you would, briefly define what you mean by designing engineering?

A. Yes. Design engineering is that process which you have identified the need to modify or replace a component to be able to accommodate the higher energy or maybe accommodate a larger structural component, whatever that modification may be. And so you will have a team of design engineers work through calculations and produce the design similar to if you were going to have a house built. You would go to an architectural engineer who would design the home and produce the detailed drawings and calculations to support the building of the house. And that's what I mean by design engineering.

Q. And what percentage of design engineering of the EPU has been completed, as we sit here today?

A. Approximately 70 percent.

Q. And expressed in what terms, Mr. Jones?

A. That 70 percent is derived at by looking at the total forecasted hours it would take to complete all the modifications, which is roughly on the order of about 960,000 engineering hours, and roughly 70 percent of those hours have been earned. There's several ways to measure engineering progress, and I can explain it in three sentences, if you want.

Q. Let me pose a couple of questions that I think will give you that opportunity. Seventy percent in terms of hours earned, that unit does not differentiate between those modifications that are completed, those modifications that are partially completed, and those modifications that are yet to be initiated, correct?

A. That is correct. There are over 200 modifications that have been identified as needed to support the extended power uprate, and so those modifications are all in some stage of completion. Does that answer your question?

Q. Yes. And to the extent that design engineering has not been completed, it is possible, then, that as that work progresses additional scope may be identified, correct?

A. Yes, it is possible as design engineering progresses that additional scope could be identified. And so, to that point, here's two of the considerations when we prioritize the engineering that we want done and when. We want the engineering done in time to support those modifications that we want to make in the next outage, and so those have the highest priority. The next highest priority of modifications are those that have the biggest risk to either schedule or cost, or the most complex, and we want to advance that engineering as soon as possible because, again, that brings greater certainty to cost and schedule. And so I really think I need to describe really briefly how we measure engineering progress, if I may.

MR. McGLOTHLIN: Commissioner, he has answered my question. I'm ready to go on.

CHAIRMAN GRAHAM: Okay. Please continue.

MR. McGLOTHLIN: I have a handful of additional questions, but I need a bit of guidance from counsel for FPL. During of the deposition of Mr. Jones, I posed some questions that relate to the nature and aspects of the EPC contract. I know that FPL filed a request for confidentiality for at least some of that transcript. I don't have the redacted portion, so I'm not clear as to whether those particular questions and answers were treated as confidential. And I don't want to tread on anything that is shielded, and I make this offer. I'm perfectly happy to deal with this by excerpting that portion of the transcript of the deposition and treat that as my cross-examination of the witness. And I could do that tonight, if you prefer.

MR. ANDERSON: We appreciate that offer. We have reviewed and determined the redaction, and we don't have that here, but I think that is a very streamlined and appropriate way to proceed. We accept that offer.

MR. McGLOTHLIN: Then I have no further questions.

CHAIRMAN GRAHAM: Okay.

SACE.

MR. WHITLOCK: No questions, Mr. Chairman.

CHAIRMAN GRAHAM: Anybody else? Okay. Staff?

MR. YOUNG: No questions.

CHAIRMAN GRAHAM: Commission board? Okay.

Redirect.

REDIRECT EXAMINATION

BY MR. ANDERSON:

Q. Mr. Jones wants to explain how do you measure engineering certainty, and I am very interested to know, too, so that is my question.

CHAIRMAN GRAHAM: Why did I know that you were going to ask that question? (Laughter.)

Mr. Jones.

A The reason I really wanted to explain that is because the executive steering committee slides, you've got to remember they are for the senior executives of the company and not necessarily the people that run construction projects, and there has just been so many occasions where things are taken out of context off the PowerPoint slide, which is not a detailed project control book.

We measure engineering progress several ways. As I mentioned, there is roughly 215 modification packages required, and we are implementing this EPU over a number of outages, so we want those engineering modification packages completed for the upcoming outage. And so, for example, for the St. Lucie Unit 1 outage coming up around November the 27th, 33 of the 47 are complete. Actually what I would call done done. And that is one way to measure progress.

The other way is that for every single modification there is a detailed analysis or forecast on the number of engineering hours it should take to complete that modification. And it will involve mechanical, civil, electrical, INC engineering disciplines. And you create mileposts that says for 100 hours worth of engineering, you should have completed so many calculations, or for 1,000 hours of engineering. So some of these design packages we require maybe 20,000 hours of work to complete. And so we use an earned value measurement; and, that is, for the number of hours you have expended on the project, have you actually earned those hours? So when I say 70 percent complete, that is based on the actual hours earned, actual progress as compared to those milestones. Thank you.

CHAIRMAN GRAHAM: Mr. Anderson.

MR. ANDERSON: FPL has nothing further, but we have some exhibits to offer. FPL offers into evidence what have been premarked on Staff's Exhibit List as Exhibits 49 to 75, please.

CHAIRMAN GRAHAM: Forty-nine has already been added, but we will do 50 through 79 (sic), but we have already done 60 and 61, and 69 and 70.

MR. YOUNG: Yes, and 49, I think.

CHAIRMAN GRAHAM: I'm sorry?

MR. YOUNG: And 49.

(Exhibits 49 through 75 admitted into evidence.)

CHAIRMAN GRAHAM: Yes. Mr. Anderson, anything else?

MR. ANDERSON: No, sir, there is not. And we have our next witness prepared to proceed.

CHAIRMAN GRAHAM: And this witness is coming back as well for rebuttal?

MR. ANDERSON: This witness, Mr. Jones, is returning for rebuttal. Yes, he has rebuttal, so he is coming back. He is shaking his head and smiling at me wishfully.

CHAIRMAN GRAHAM: Thank you, sir, for your testimony.

THE WITNESS: Thank you.

(Transcript continues in sequence in Volume 7.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 15th day of August, 2011.

JANE FAUROT, RPR
Official FPSC Hearings Reporter
(850) 413-6732