BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120009-EI
FLORIDA POWER & LIGHT COMPANY

MARCH 1, 2012

IN RE: NUCLEAR POWER PLANT COST RECOVERY
FOR THE YEAR ENDING
DECEMBER 2012

TESTIMONY & EXHIBITS OF:

JOHN J. REED

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DIRECT TESTIMONY OF JOHN J. REED

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<u>Section I: Introduction</u>

Q. Please state your name and business address.

A. My name is John J. Reed. My business address is 293 Boston Post Road West, Marlborough, Massachusetts 01752.

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

A. I am the Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. ("Concentric").

Q. Please describe Concentric.

A. Concentric is an economic advisory and management consulting firm, headquartered in Marlborough, Massachusetts, which provides consulting services related to energy industry transactions, energy market analysis, litigation, and regulatory support.

Q. Please describe your educational background and professional experience.

A. I have more than 35 years of experience in the energy industry, having served as an executive in energy consulting firms, including the position of Co-Chief Executive Officer of the largest publicly-traded management consulting firm in the United States and as Chief Economist for the largest gas utility in the United States. I have provided expert testimony on a wide variety of economic and financial issues related to the energy and utility industry on numerous occasions before administrative agencies, utility commissions, courts, arbitration panels and elected bodies across North America. I also have provided testimony on behalf of FPL in its NCRC proceedings in 2008, 2009, 2010, and 2011. A summary of my educational background can be found on Exhibit JJR-1.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibits JJR-1 through JJR-5, which are attached to my direct testimony.

Exhibit JJR-1	Curriculum Vitae
Exhibit JJR-2	Current Testimony of John J. Reed
Exhibit JJR-3	Total Production Cost of Electricity
Exhibit JJR-4	List of the EPU Project's Periodic Meetings
Exhibit JJR-5	PTN 6 & 7 Project Organizational Chart

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to review the benefits of nuclear power and the appropriate prudence standard to be applied to Florida Power & Light's ("FPL" or the "Company") decision-making processes in this Nuclear Cost Recovery Clause ("NCRC") proceeding before the Florida Public Service Commission (the "FPSC" or the "Commission"). In addition, I provide a review of the system of internal controls used by the Company in 2011 during construction phases of the Extended Power Uprate ("EPU") project at the Turkey Point ("PTN") and St. Lucie ("PSL") generating stations (together, the "EPU Project"), and in developing and maintaining the option to construct two new nuclear generating units ("PTN 6 & 7" or "New Nuclear Project") at FPL's existing Turkey Point site. Finally, I provide an opinion as to whether the EPU and PTN 6 & 7 expenditures for which FPL is seeking recovery in this proceeding have been prudently incurred.

Q. Please describe your experience with nuclear power plants, and specifically your experience with major construction programs at these plants.

A. My consulting experience with nuclear power plants spans more than 30 years. My clients have retained me for assignments relating to the construction of nuclear plants, the purchase, sale and valuation of nuclear plants, power uprates and major capital improvement projects at nuclear plants, and the decommissioning of nuclear plants. In addition to my work at FPL's plants, I have had significant experience with those activities at the following plants:

- Big Rock Point
- Callaway
- Darlington
- Duane Arnold
- Fermi
- Ginna
- Hope Creek
- Indian Point
- Limerick
- Millstone
- Monticello
- Nine Mile Point
- Oyster Creek
- Palisades
- Peach Bottom
- Pilgrim
- Point Beach
- Prairie Island
- Salem
- Seabrook
- Vermont Yankee
- Wolf Creek
- Vogtle

I have recently been active on behalf of a number of clients in pre-construction activities for new nuclear plants across the United States and in Canada. Those activities include state and Federal regulatory processes, raising debt and equity financing for new projects and evaluating the costs schedules and economics of new nuclear facilities. Those activities have included detailed reviews of contracting strategies, cost estimation and construction project management activities of other refurbishment and new nuclear projects.

Q. Please summarize your testimony.

A. The remainder of my testimony covers five main topic areas. Section II contains an introduction to the projects and a discussion of the benefits of nuclear power to Florida. Section III describes the appropriate prudence standard that should be applied in this case, and discusses the precedents with respect to the prudence standard in Florida. In Section IV, I discuss the internal controls, processes, and procedures that were the focus of Concentric's review. In Section V, I discuss Concentric's assessment of the EPU Project that is underway at both of FPL's Florida nuclear generating stations, and in Section VI, I present Concentric's review of the New Nuclear Project. My conclusions are provided in Section VII. Each of those topics is summarized below.

FPL's four existing nuclear reactors in Florida have provided, and continue to provide, substantial benefits to Florida customers. Those benefits include virtually no air emissions, increased fuel diversity, reduced exposure to fuel price volatility, fuel cost savings, highly reliable base load capacity, and efficient land use. Additional nuclear capacity is expected to provide more of those same benefits to Florida.

The rule that governs the Commission's review of FPL's nuclear projects calls for an annual prudence determination. The prudence standard encapsulates three main elements. First, prudence relates to decisions and actions, not costs incurred by a utility. Second, the prudence standard includes a presumption of prudence with regard to the utility's actions. Absent evidence to the contrary, a utility is assumed to have acted prudently. Third, the prudence standard excludes hindsight. Thus, the prudence of a utility's actions must be evaluated on the basis of information that was known or could have been known at the time the decision was made.

Finally, Concentric has reviewed the processes and procedures that are used to manage and implement the EPU and PTN 6 & 7 projects. This review has focused on the Company's internal controls that are in place to provide assurance that the Company meets its strategic, financial, and regulatory objectives related to the projects. Our review is premised on a framework developed by Concentric when advising potential investors in new nuclear development projects and our recent regulatory experience.

Q. What are your summary conclusions?

A. Concentric's review found that FPL appropriately and prudently managed the EPU Project and PTN 6 & 7 in 2011. As discussed in more detail later in my testimony, FPL faced challenges in 2011 in its management of the projects, including significant challenges due to external factors outside of the Company's control. However, I found that FPL's policies and procedures put it in a position to appropriately respond to those challenges, and that the Company's oversight and decision making resulted in prudently incurred costs in 2011.

Section II: Introduction to the Projects and Benefits of Nuclear Power to Florida

Q. Please provide a brief introduction to FPL's EPU Project.

A. FPL is implementing an EPU at PSL and PTN. An EPU is the process of modifying and upgrading specific components at a nuclear power plant to increase the maximum power level at which the plant can operate. Once completed, the EPU Project is expected to increase the nuclear generating capacity of PSL and PTN by about 490 megawatts for the benefit of FPL's customers. The final increase in capacity will not be known until all modifications and testing are complete.

Q. Please also generally describe PTN 6 & 7.

A. The PTN 6 & 7 Project remains focused on obtaining the licenses and permits that will provide FPL and its customers the option to construct two nuclear units at the existing PTN site. Specifically, through PTN 6 & 7, FPL continues to develop the option to construct approximately 2,200 megawatts of additional nuclear capacity. The Company's project management strategy is focused on preserving appropriate flexibility and multiple hold points and off-ramps during which PTN 6 & 7's progress can be delayed for further analysis, or progressed to meet the existing schedule. A decision on whether to move forward with development of new units can be made based on the project's ability to achieve a balance of high value to customers and decreased exposure to risk at the point when all relevant permits have been obtained. The option to construct will last for a period of at least 20 years from the date the final license is issued.

Q. Has nuclear power benefited FPL customers?

A. Yes. Nuclear power has a long and successful history of operation in FPL's power generating fleet. The four reactors at FPL's existing PSL and PTN sites have been generating power for an average of over 35 years. Throughout the last three and a half decades, these units have benefited Florida customers by reliably producing emissions-free energy, decreasing total fuel costs, enhancing the diversity of fuels used to generate power and insulating customers from commodity price spikes.

Q. Is it prudent to continue the development of additional nuclear capacity in Florida?

A. Yes, whenever that capacity can be developed on an economic basis over its useful life. One of the most compelling advantages of additional nuclear power is that it emits virtually no carbon dioxide. Whereas the alternative base load power sources in Florida are carbon intensive, nuclear power emits no greenhouse gases ("GHG").

This is especially important in the current federal policy context. Support for a federal cap and trade system of regulating emissions has lost momentum in the past two to three years, partially as a result of challenging economic conditions. However, other Federal regulations of power plant emissions have been creating considerable controversy in Washington. In December 2011, the Environmental Protection Agency finalized a rule establishing national emissions standards for coal- and oil-burning power plants. The rule, known as the "Utility MACT" rule, is expected to have dramatic consequences on operators of fossil-fueled power plants, especially those that burn coal. In order to operate, affected plants will need to install the "maximum achievable control technologies" for certain emissions. The costs of compliance are expected to cause the retirement of many facilities, and will likely make electricity considerably more expensive.

Similarly, the Cross State Air Pollution Rule ("CSAPR"), announced in July 2011, targets power plant emissions that cross state lines. Like the Utility MACT rule, the CSAPR is expected to have a significant effect on fossil-fired generating stations. While a recent ruling in a federal appeals court has temporarily halted implementation of the CSAPR, the specter of stringent regulations on power plant emissions remains a significant risk to power producers.

These federal rules pose the greatest obstacles to coal generation. As a consequence, there will be an implicit promotion of natural gas generation. In many regions, including Florida, a greater emphasis on gas increases the risk that electric customers face from a volatile market that faces increasing demand, both in the U.S. and abroad, and periodic supply constraints. Nuclear power, however, provides much-needed fuel diversity, insulating residents from the market for natural gas. In addition, nuclear power's limited emissions profile essentially eliminates considerable uncertainty with regard to the highly contentious federal rules.

Q. How do trends in the production cost of natural gas-fired generation compare with trends in the price of nuclear power?

A. The cost of nuclear power has been stable due to the fact that fuel represents a comparatively small portion of the production costs of nuclear power facilities. According to the Nuclear Energy Institute ("NEI"), fuel has accounted for approximately 90% of the total production cost of energy from natural gas, whereas fuel costs of nuclear power are only 25-30% of the total production cost.[1]

As shown in Exhibit JJR-3, the production cost of energy from nuclear power remains substantially lower than other sources of base load energy. The electric bills of Florida residents have benefited from lower and much less volatile production costs of nuclear power.

Q. Is it appropriate for the Commission to continue to allow recovery of certain pre-construction costs and construction carrying costs through the NCRC process?

A. Yes. Given the unique nature of nuclear construction and its economics, it is absolutely appropriate to allow for cost recovery through the annual NCRC process. The NCRC is important for both the Company and its customers. With respect to the Company, the NCRC provides FPL's debt and equity investors with some measure of assurance of cost recovery if their investments are used to prudently incur costs. In addition, by allowing recovery of carrying costs during construction, the NCRC eliminates the effect of compound interest on the total project costs, which will reduce customer bills when the facilities are constructed.

Q. Have other utilities considering nuclear development activities noted the necessity of NCRC-like recovery mechanisms?

A. Yes. Utilities such as Duke, SCANA, Georgia Power, Progress Energy and Ameren have publicly acknowledged the benefits and the necessity of cost recovery mechanisms like the NCRC.

Q. Has the financial community commented on the importance of NCRC-like recovery mechanisms?

A. Yes, Standard & Poor's recently commented that "such frameworks can support credit quality and provide utilities with guidelines for dealing with schedule delays, cost overruns, stemming from technical difficulties, or other issues that may arise."[2]

Q. Are there benefits of nuclear power other than those that quantitatively affect the price of electricity?

A. Yes. The comparatively small footprint of a nuclear powered generating station relative to clean, emissions-free alternative technologies is often overlooked. By requiring less land, nuclear power plants limit the degree of forest clearing, wetlands encroachments, and other environmental impacts associated with siting a generating facility.

Section III: The Prudence Standard

Q. Please generally describe the prudence standard as you understand it.

A. The prudence standard is captured by three key features. First, prudence relates to actions and decisions; costs themselves are not prudent or imprudent. It is the decision or action that must be reviewed and assessed, not simply whether the costs are above or below expectations. The second feature is that the standard incorporates a presumption of prudence, which is often referred to as a rebuttable presumption. The burden of showing that a decision is outside of the reasonable bounds falls, at least initially, on the party challenging the utility's actions. The final feature is the total exclusion of hindsight. A utility's decisions must be judged based upon what was known or knowable at the time the decision was made by the utility.

Q. What test for prudence has been adopted by the Commission?

A. The Commission has prohibited the use of hindsight when reviewing utility management decisions and has instead chosen to strictly follow the standard I described above. In 2011, the Commission reaffirmed this approach, quoting its 2009 Order (Order No. PSC-09-0783-FOF-EI):

> The applicable standard for determining prudence is consideration of what a reasonable utility manager would have done in light of conditions and circumstances which were known or reasonably should have been known at the time decisions were made.

__Section IV: Framework of Internal Controls Review__

Q. What is meant by the term "internal control" and what does it intend to achieve?

A. The Committee of Sponsoring Organizations of the Treadway Commission ("COSO") is a global industry organization that provides guidance as to the development, implementation and assessment of systems of internal control. COSO has defined internal control as a process that provides reasonable assurance of the effectiveness of operations, reliability of financial reporting and compliance with applicable laws and regulations. This definition has been further expanded to reflect four critical concepts. First amongst these is that internal control is a process. While internal control may be assessed at specific moments in time, a system of internal control can only be effective if it responds to the dynamic nature of organizations and projects over time. Second, internal control is created by people, and thus the effectiveness of an internal control system is dependent on the individuals in an organization. Third, internal control is specifically directed at the achievement of an entity's goals. Thus, risks that present the greatest challenge to the achievement of those objectives must take priority. Finally, internal control can provide only reasonable assurance. Expectations of absolute assurance cannot be achieved.

Q. Please describe the framework Concentric used to review the Company's system of internal control as implemented by the EPU Project and PTN 6 & 7 in 2011.

A. In order to review and assess the Company's internal controls, Concentric utilized a similar framework to that which it has used previously for FPL's NCRC proceedings. That framework is based upon Concentric's contemporaneous experience advising prospective investors in new nuclear projects and Concentric's regulatory experience.

In summary, the framework has focused on six elements of the Company's internal controls, including:

- Defined corporate procedures;
- Written project execution plans;
- Involvement of key internal stakeholders;
- Reporting and oversight requirements;
- Corrective action mechanisms; and
- Reliance on a viable technology.

Each of these elements was reviewed for five processes including:

- Project estimating and budgeting processes;
- Project schedule development and management processes;

- Contract management and administration processes;
- Internal oversight mechanisms; and
- External oversight mechanisms.

Concentric's work in this proceeding is additive to our work reviewing the projects in prior years. In other words, Concentric's efforts in 2012 reflect the information and understanding of the projects gained during Concentric's reviews in 2008 through 2011.

Q. Please describe how Concentric performed this review.

A. Concentric's review was performed over the period from December 2011 to February 2012. Concentric began by reviewing the Company's policies, procedures and instructions with particular emphasis placed on those policies, procedures or instructions that may have been revised since the time of Concentric's previous review. In addition, Concentric reviewed the current project organizational structures and key project milestones that were achieved in 2011. Concentric then reviewed other documents, conducted several in-person interviews and conducted site tours at PTN and PSL to make certain the EPU Project's and PTN 6 & 7's policies, procedures and instructions were known by the project teams, were being implemented by the projects and have resulted in prudent decisions based on the information that was available at the time of each decision.

Concentric's in person interviews included representatives from each of the following functional areas:

- Project Management;
- Project Controls;

- Integrated Supply Chain Management ("ISC");
- Employee Concerns Program;
- Quality Assurance/Quality Control ("QA/QC");
- Transmission;
- Environmental Services; and
- Licensing and Permitting.

Q. Please describe why you believe it is important for FPL to have defined corporate procedures in place throughout the development of the projects.

A. Defined corporate procedures are critical to any project development process as they detail the methodology with which the project will be completed and make certain that business processes are consistently applied to the project. To be effective, these procedures should be documented with sufficient detail to allow project teams to implement the procedures, and they should be clear enough to allow project teams to easily comprehend the procedures. It is also important to assess whether the procedures are known by the project teams and adopted into the Company's culture, including a process that allows employees to openly challenge and seek to improve the existing procedures and to incorporate lessons learned from other projects into the Company's procedures. Within the EPU Project and PTN 6 & 7, the Project Controls staff is primarily responsible for ensuring the Company's corporate procedures are applied consistently by the various FPL and contractor staff members who are working on the projects. However, it is acknowledged that this is a shared responsibility held by all project team members, including the project managers.

Q. Please explain the importance of written project execution plans.

A. Written project execution plans are necessary to prudently develop a project. These plans lay out the resource needs of the project, the scope of the project, key project milestones or activities and the objectives of the project. These documents are critical as they provide a "roadmap" for completing the project as well as a "yardstick" by which overall performance can be monitored and managed. It is also important for the project sponsor to require its large-value contract vendors to provide similar execution plans. Such plans allow the project sponsor to accurately monitor the performance of these vendors and make certain at an early stage of the project that each vendor's approach to achieving key project milestones is consistent with the project sponsor's needs. These project plans must be updated to reflect changes to the project scope and schedule as warranted by project developments.

Q. Why is it important that key internal stakeholders are involved in the project development process?

A. One of the most challenging aspects of prudently developing a large project is the ability to balance the needs of all stakeholders, including various Company representatives and the Company's customers. This balance is necessary to make certain that the maximum value of the project is realized. By including these stakeholders in a transparent project development process, the project sponsor will be better positioned to deliver on these high-value projects.

Q. Why is it important to have established reporting and oversight requirements?

A. Effective internal and external communications enable an organization to meet its key objectives, and allow employees to effectively discharge their responsibilities. By having an established reporting structure and periodic reporting requirements, the project sponsor's senior management will be well informed on the status of the project's various activities. Reporting requirements give senior management the information it needs to leverage its background and previous experience to prudently direct the many facets of the project. In addition, established reporting requirements ensure that senior management is fully aware of the activities of the respective project teams so management can effectively control the overall project risks. In the case of the EPU Project and PTN 6 & 7, this level of project administration by senior management is prudent considering the large expenditures that will be required to complete the projects and the potential impact of the projects on the Company overall.

In order to be considered robust, these reporting requirements should be frequent and periodic (*i.e.*, established daily, weekly and monthly reporting requirements) and should include varying levels of detail based on the frequency of the report. The need for timely and effective project reporting is well recognized in the industry. To that point, a field guide for construction managers notes:

> Cost and time control information must be timely with little delay between field work and management review of performance. This timely information gives the project manager a chance to evaluate alternatives and take corrective action while an opportunity still exists to rectify the problem areas.[3]

Q. What is the purpose of corrective action mechanisms and why are they important to ensure the Company is prudently incurring costs?

A. A corrective action mechanism is a defined process whereby a learning culture is implemented and nurtured throughout an organization to help eliminate concerns that can interfere with the successful completion of the project. Corrective action mechanisms help identify the root cause of issues, such as an activity that is trending behind schedule, and provide the opportunity to adopt mechanisms that mitigate and correct the negative impact from these issues. A robust corrective action mechanism assigns responsibility for implementing the corrective actions and a means by which these activities are managed. In addition, a corrective action mechanism educates the project team in such a manner as to ensure project risks are prudently managed in the future.

Q. Are there any other elements of the Company's internal controls included in your review?

A. No. There were no other elements of the Company's internal controls included in my review.

Section V: EPU Project Activities in 2011

Q. How is this section of your testimony organized?

A. This section describes my review of the five key processes (*i.e.*, project estimating and budgeting, project schedule development and management, contract management and administration, internal oversight mechanisms, and external oversight mechanisms), described above, as they related to the EPU Project in 2011.

Q. As a preliminary matter, what did your review lead you to conclude with regard to the prudence of FPL's actions in 2011 as they related to the EPU Project?

A. FPL's decision making and management actions as they related to the EPU Project in 2011 were prudent. Those decisions and actions included: making key staffing decisions regarding the organization of the EPU Project and bringing in experienced staff to manage the implementation outages; managing two implementation outages and reassessing the planned schedule for the remaining outages in light of delays in the licensing process, challenges to complete all planning for the outages due to design evolution and complexity, and lessons learned from previous outages; and rigorous oversight and management of the Engineering, Procurement, and Construction ("EPC") vendor, including the establishment of a target price incentive structure at PSL, and bringing in vendors with specialized experience to assist with project management and to subcontract to the EPC. As a consequence, it is my opinion that FPL's 2011 expenditures on the EPU Project have been prudently incurred. Importantly, Concentric continued to note that FPL is a learning organization that effectively incorporates lessons learned from prior EPU outages at both PTN and PSL, other EPU projects, and Concentric's prior reviews.

Q. What period of time did your review of the EPU Project encompass?

A. Our review of the EPU Project was for the period January 1, 2011 through December 31, 2011. Concentric's review of this time period relied upon data that was provided to Concentric in the period from November 2011 to February 2012.

Q. What steps is FPL taking to plan and execute the EPU Project?

A. The EPU Project consists of four overlapping phases: (i) the Engineering Analysis Phase; (ii) the Long Lead Equipment Procurement Phase; (iii) the Engineering Design Modification Phase; and (iv) the Implementation Phase. In 2011, all four phases of the EPU Project were underway concurrently, with the Engineering Analysis Phase and Long Lead Procurement Phase nearing completion. The activities undertaken in each of the four phases presented above are further described in the testimony of FPL Witness Jones.

Q. Please describe the general progress of the EPU Project in 2011 as it pertained to the phases you have identified above.

A. As stated above, the Engineering Analysis and Long Lead Procurement Phases neared completion in 2011, and a substantial amount of work was completed in the Engineering Design Modification Phase in preparation for the 2011 and 2012 implementation outages. Two outages were completed in 2011 as part of the Implementation Phase, one at PSL Unit 2, and one at PTN Unit 4.

Q. Given that all phases of the project were underway, what was the timeline for the implementation of the EPU Project?

A. The EPU Project is scheduled for completion by August 2013, including project close out activities. Activities planned for 2012 include receipt of NRC approval of the EPU License Amendment Requests ("LAR") for PSL Unit 1, PSL Unit 2, and PTN Units 3 and 4, and the completion of the Engineering Analysis Phase, the Long Lead Procurement Phase and the Engineering Design Modifications Phase of the project. As of February 15, 2012, FPL is performing an outage at PSL Unit 1, which it expects to complete in April 2012, and implementation outages are also expected to be performed at the other three units (with the PTN Unit 4 outage extending into 2013). Due to a delay in receiving approval of the PSL Unit 1 LAR from the NRC, FPL expects to perform an additional short, mid-cycle implementation outage at that unit in order to operate the plant at the post-EPU rating. FPL expects to add over 300 MWe in 2012. The PTN Unit 4 outage, expected to be complete in 2013, will be the final implementation outage.

Q. Does that timeline reflect any modifications to the overall schedule made in 2011?

A. Yes, it does. As discussed further below, the planned start date of the PSL Unit 1 2011 outage, as well as the PTN Unit 3 and PSL Unit 2 2012 outages, were all changed due to challenges identified in 2011. Those challenges included the completion of engineering planning for each outage. Allowing for additional time before the start of each outage allows for greater certainty regarding licensing and implementation while keeping within the constraints of FPL's operational fueling requirements.

Q. How was the EPU Project organized in 2011?

A. As it has been since 2009, the EPU Project is organized at the site level, with managers at each site to oversee construction, project controls, licensing, procurement, and other critical functions. Having these functions at both EPU sites is appropriate and necessary given the number of activities that require oversight at each plant. Furthermore, towards the end of the year, the EPU Project added additional oversight at each plant by splitting the role of Implementation Owner – South, and designating an Implementation Owner at each site. That change, which officially took place in January 2012, reflects the fact that the EPU Project is now moving out of the engineering and planning phases and into a mode of almost continuous implementation, in which each site will benefit from the increased focus brought by its directly assigned Implementation Owner.

In Juno Beach, there remains a centralized core project management team providing oversight of the EPU Project from FPL headquarters. The primary centralized positions include: the Nuclear Power Uprate Vice President, responsible for all aspects of project execution, including licensing, design, engineering, cost, implementation and regulatory; the Controls Director, who provides direction, oversight and governance to the Project Control Supervisor at each site and has overall responsibility for the EPU Project control functions including cost control, estimating, scheduling and support activities; the EPU Licensing and Regulatory Interface Director, who is responsible for the oversight, coordination, production and technical quality of the licensing engineering and analysis related to the LARs and other regulatory submittals; and the EPU Nuclear Cost Recovery interface manager, responsible for the overall coordination of the project with the Commission and FPL Regulatory Affairs.

Q. Did the EPU Project team consist of any other centralized management positions?

A. Yes. Throughout 2011, the EPU Project team included a Quality Assurance ("QA") manager at the Company's headquarters. Described in greater detail later in this section of my testimony, this function necessarily acted separately from the functions described above to maintain independence when assessing the EPU Project.

Q. Was the management structure explicitly defined in a Company procedure or instruction?

A. Yes. The management structure is outlined in Extended Power Uprate Project Instruction ("EPPI")-140: Roles and Responsibilities.

Q. What challenges did FPL face in 2011 with regard to employee turnover within the EPU Project?

A. Employee turnover included seven senior employees voluntarily resigning or retiring from the EPU Project in 2011, compared to two employees in 2010, and four employees in 2009. That turnover included the Site Directors at both sites.

Q. What was FPL's response to those challenges?

A. FPL responded by looking both inward and outward to fill key positions with employees who had the requisite experience and qualifications to replace personnel who resigned or retired from the Company. That response included promoting employees from within the EPU Project, and reassigning employees from other areas of NextEra's nuclear business. In that way, FPL ensured continuity on the EPU Project while also incorporating operational experience from NextEra's nuclear fleet. I discuss the value of transferring that operational experience in further detail later in my testimony.

Q. What major milestones were met on the EPU Project in 2011?

A. The EPU Project reached several major milestones in 2011, including: (1) acceptance by the NRC of the PSL Unit 1, PSL Unit 2, PTN 3&4, and PTN Core Operating Limits Report LARs, and the approval by the NRC of the PTN Alternate Source Term and Spent Fuel Criticality LARs; (2) continuation and near completion of the Engineering Analysis Phase and the Long Lead

Equipment Procurement Phase of the project; (3) the completion of two implementation outages, which enabled increased output at PSL Unit 2 of 36 MWe due to the replacement of the low pressure turbine; and (4) continued oversight of the EPC contractor, Bechtel, which included the establishment of a target price incentive mechanism at PSL and negotiations regarding the incentive structure at PTN. That last development (*i.e.*, establishment of a target price mechanism at PSL) represents a significant step for FPL in terms of its management of the EPU Project in general, and its EPC contractor specifically. I will discuss the repercussions of that development further below.

Project Estimating and Budgeting Processes

Q. Please describe the mechanisms utilized to track the project's 2011 budgets and cost estimate.

A. Several budget and cost reporting mechanisms exist to ensure that key decisions related to the EPU Project were prudent and made at the appropriate level of FPL's management structure. Those reporting mechanisms included presentations and status calls as well as periodic reports. That allowed the Company to leverage the experience of its executive team. A list of the EPU Project's periodic meetings can be found in Exhibit JJR-4.

Q. Was the EPU Project's cost estimate modified in 2011?

A. Yes, it was. In fact, in 2011 FPL established a procedure, EPPI-302, "Nonbinding Cost Estimate Range," that calls for an update to the cost estimate range to be performed annually. In 2011, in accordance with that procedure, FPL updated its cost estimate range of direct EPU Project costs of $1,844 to

$2,091 million, to a range of $2,065 to $2,221 million. The range was updated to reflect the evolution of scope of the project and lessons learned to date. As discussed above, FPL also developed a target price structure for the PSL EPC contract with Bechtel in 2011 that resulted in FPL and Bechtel agreeing to a target price estimate that was also reflected in the updated range.

As of December 31, 2011, the EPU Project cost estimate exceeded that range. It is my understanding that FPL plans to update its cost estimate again on or before May 1, 2012 to account for the need for additional modifications, evolution in design engineering, and the need for additional engineers to address scope growth. In addition, as part of its negotiations with Bechtel to establish an incentive structure for the PTN EPU, Bechtel has provided its cost estimate to complete the work. Siemens has similarly proposed increases to costs due to the complexity of scope of the work it is completing for the project. FPL is currently performing due diligence on those areas of potential increase, and it is my understanding that any increase in cost will be reflected in FPL's May 1, 2012 filing and 2012 Feasibility Analysis.

Q. What are the components of FPL's cost estimate?

A. FPL's cost estimate is comprised of a base amount, a weighted allowance for identified risks, and a category called "Undefined Scope." The weighted risk allowance is based on FPL's evaluation of risks to the project, which are each assigned a potential cost estimate that is weighted by FPL's assessment of its probability of occurrence. As new risks are identified, or as existing risks are resolved, FPL depletes or increases, respectively, the Undefined Scope element of the cost estimate.

Q. How was undefined scope accounted for in the EPU Project's cost estimates?

A. Undefined scope was accounted for by a specific line within the EPU Project's cost estimates. In 2011, the EPU Project's allowance for undefined scope was released at times to fund increases in the cost estimate and was brought down to $0 by year end. FPL has recognized that the allowance for unknown scope now needs to be replenished. As in my previous NCRC reviews, it continues to be my opinion that this is an area in which FPL could strengthen its processes and its compliance with its written procedures. However, it is my understanding that, as part of its 2012 analysis of the EPU Project's cost estimate, FPL will revisit and establish a contingency amount in accordance with the Company's procedures.

Q. Did the increase to the cost estimate result from imprudent project management?

A. No, it did not. It is not uncommon for a mega project of this size to require regular updates to its cost estimate, especially given the fact that the EPU Project is currently in the Implementation Phase in which significant new items of scope (referred to as "discovery scope") are revealed. The reason for that is, often, the full scope of a work package cannot be known until the modifications to the facility have begun. At that point, wear and tear on the equipment can be better evaluated, and additional scope identified as necessary. In addition, there are factors external to FPL's control, such as the timing of the NRC reviews and additional analyses required by the NRC, which can have significant effects on the EPU Project's scope and schedule. In fact, as I will explain further below, delays in the NRC's reviews posed a significant challenge for FPL in 2011.

Q. Does management of the target price structure at PSL present any new challenges for the Company?

A. Yes, it does. The target price structure is intended to provide incentives to the EPC contractor to operate efficiently, both from a schedule and cost perspective. The target price is structured so that cost overruns or under-runs, outside of a dead band around the target price, are shared between the Company and the contractor. In that way, the contractor's profit under the contract is at risk. Under such a construct, the project sponsor must diligently manage the contract such that any vendor-proposed scope changes that affect the target price (known as "compensation events") are evaluated to confirm that they are caused by emerging issues, not poor planning on the vendor's part. That can often lead to a series of negotiations between the sponsor and the contractor, and it is important that such negotiations be elevated to the appropriate level of authority. Those are the major new challenges FPL faced in 2011 resulting from the target price structure.

Q. Did FPL institute any new policies in 2011 to mitigate the risks presented by the challenges discussed above?

A. Yes, it did. FPL issued EPPI-250, "Project Target Price Control Process," to establish policies and procedures for managing potential target price changes. That EPPI includes procedures for processing Potential Scope Change /Delay Notices ("PSCDN") and Requests for Change ("RFC") to the target price, establishes a procedure for dispute resolution, and calls for the tracking of

PSCDNs and RFCs in a Target Price Change Log. In addition, as discussed above, FPL established EPPI-302, "Nonbinding Cost Estimate Range," in 2011 in order to document its process for updating its cost estimate and accounting for contingency.

Q. In 2011, how were vendor costs at PTN controlled?

A. Whereas PSL used a target price structure to provide performance incentives to the EPC vendor, PTN used a "report card" incentive structure as well as reviews of overtime and staff augmentation requests. The report card incentive structure involves allotting portions of an incentive fee to performance factors such as safety, quality, and schedule maintenance. If the vendor achieves its goal in a particular performance factor, then it is awarded that portion of the incentive fee. If the vendor achieves only part of the goal, then it is awarded a commensurately lower incentive fee. In my opinion, the report card approach to vendor management was appropriate for PTN in 2011, given the magnitude and complexity of work to be accomplished at the site. The remaining complexity of scope would likely have been built into any target price for PTN in 2011, leading to the potential for higher costs on the project.

Q. In addition to EPPI-250, EPPI-302, and the Target Price Change Log, how were project controls executed by the site teams and the overall project management team to track the EPU Project's 2011 budget?

A. The site team utilized multiple reports and reviews in 2011 to track the EPU Project's budget. These reports included the Monthly Operating Performance Report that categorized the overall performance of the EPU Project as either on budget, budget-challenged, or out of budget. Each site also produced monthly cash flow reports in 2011, which contained monthly actual and forecast capital expenditures as compared to the budget. Those reports were reviewed and discussed during formal project management meetings. The EPU Project recently has increased the detail of its regular reports, which now include current project risks and cost-related performance indicators in addition to budget matters.

Q. In 2011, did anything related to the budgeting and expenditure tracking processes occur that would eliminate the cost effectiveness of the EPU Project?

A. No. In May 2011, the EPU Project was subject to an annual feasibility analysis that included a review of the continued cost effectiveness of the project. However, as mentioned above, Bechtel and Siemens both have both proposed increases to their cost estimates to complete the EPU Project, the effect of which will be evaluated in 2012. Bechtel's Estimate at Completion ("EAC") for PTN was received in November 2011, and is currently not reflected in the cost estimate because FPL is performing due diligence on the amount and challenging Bechtel to find a more cost-effective means of implementing the work. FPL is similarly evaluating Siemens' proposal under the Turbine Generator Installation Agreement for PTN for additional budget to complete its scope of work.

Q. In 2011, how did the EPU Project track and identify risks to the project schedule?

A. In 2011, the EPU Project used a Risk Matrix, referred to as the "Risk Register," to track challenges to the current budgets and cost estimates and to provide a brief explanation of the reasons for the challenges. According to EPPI-340, "EPU Project Risk Management Program," the risk identification process covered identification, assessment and analysis, handling strategy, risk management, categorization, reporting, and mitigation. The Company defined risks as issues that affect nuclear quality, environment, project cost, schedule, safety, security, legal, plant operations, regulatory, and reputation. EPPI-340 was updated on April 22, 2011 to reflect recommendations Concentric previously made about the EPU Project's mechanisms for tracking risk to the project. Specifically, provisions were made for preserving all Risk Mitigation Plans in a central location and for not closing Risk Mitigation Plans until all actions therein had been completed.

Q. In light of internal and external assessments of its risk management process, how has the EPU Project modified its processes?

A. The managers of the EPU Project have recognized the need to modify and improve processes based on progressive experience. To that end, the EPU Project modified 14 of its policy documents during 2011. Many of those changes were minor, but some were in direct response to internal or external assessments. In addition to the EPU Project policies that were modified in 2011, a new EPPI was created to address the adoption of a target price contract with Bechtel, as discussed above.

Q. Did Concentric review the process by which the EPU Project made certain that each plant modification or component replacement is necessary for the completion of the EPU Project?

A. Yes, Concentric reviewed the process by which FPL made certain that the costs being charged to the EPU Project in 2011 are separate and apart from the normal maintenance and operations of PSL and PTN, and, therefore eligible for recovery under the NCRC. This process included a detailed engineering analysis to determine if the component replacement or plant modification is necessary for plant operations under uprated conditions.

Q. Has the Commission previously reviewed and approved this methodology?

A. Yes. In Commission Order PSC-09-0783-FOF-EI the Commission determined that "FPL's separate and apart methodology is reasonable and appropriate for identifying NCRC costs."[4]

Q. Did Concentric have any observations related to the EPU Project's processes used to track cost performance in 2011?

A. Yes. As discussed above, several budget and cost reporting mechanisms exist to ensure that key decisions related to the EPU Project were prudent and made at the appropriate level of FPL's management structure, and the Company added new procedures in 2011 to further its oversight of the project. While it continues to be my opinion that FPL could strengthen its processes and its compliance with its written procedures with regard to accounting for cost contingency, any such variance from established procedures has not resulted in any imprudently incurred costs. In addition, it is my understanding that FPL will revisit and establish a contingency amount in accordance with the Company's procedures in 2012.

Project Schedule Development and Management Process

Q. How did the EPU Project monitor its schedule performance in 2011?

A. In 2011, the EPU Project team continued to utilize several periodic reporting mechanisms including daily, weekly, bi-weekly, and monthly conference calls. In addition, the EPU Project team issued a variety of reports, including a Daily Report. Exhibit JJR-4 provides a listing of the meetings used in 2011 to monitor the EPU Project's schedule performance. A list of the reports used to monitor the EPU Project's schedule performance can be found in the testimony of FPL Witness Jones as Exhibit TOJ-4. Many of those reports included a discussion of the EPU Project's schedule performance as compared to an initial target schedule.

Q. Were any new reports created in 2011 to assist FPL in managing the project?

A. Yes. As discussed above, FPL created a Target Price Change Log to track and aid in the processing of potential scope and cost changes under the target price structure at PSL.

Q. Did the EPU Project use any other methods to monitor schedule performance in 2011?

A. Yes. FPL used an industry standard software package known as Primavera P-6 to review the project schedule based on approved updates on an almost real-time basis. Primavera provides Critical Path Method ("CPM") Scheduling, which uses the activity duration, relationships between activities, and calendars to calculate a schedule for the project. CPM identifies the critical path of activities that affect the completion date for the project or an intermediate deadline, and how these activity schedules may affect the completion of the project. This software package is used by many in the nuclear power industry to schedule refueling outages and major capital projects.

Q. What status reports did the EPU Project's key vendors provide to the Company?

A. In addition to monitoring the EPU Project team's efforts, the Company also required that status reports be provided by its key vendors in 2011. At the beginning of each vendor's scope of work, FPL required the vendors to provide a reasonable target schedule from which future progress would be measured. The vendors were then responsible for providing daily, weekly, and monthly progress reports regarding that schedule depending on outage or non-outage conditions. The Company also received some insight regarding the vendors' progress by monitoring the number of work hours that were included on each monthly invoice. That was done by comparing the number of work hours expended during the prior month with a projection.

Q. How did the EPU Project track and identify risks to the project schedule?

A. In 2011, the EPU Project continued to use the same Risk Register, described earlier, to track challenges to the current schedule and to provide a brief explanation of the reasons for the challenges. Bechtel, the EPC contractor, also provided a Trend Log to FPL to track risks to schedule. The Trend Log is integrated into the Risk Register.

Q. What EPPI governs schedule creation and management?

A. The processes for schedule creation and management were described in EPPI-310: Project Instructions – Development, Maintenance and Update of Schedules.

Q. Was this EPPI modified in 2011?

A. Yes. EPPI-310 was modified in April 2011 to incorporate lessons learned during the project as well as eliminate some unnecessary directives. Such modifications included: clarifying the treatment of activity duration, predicating the use of the phrase "Expected Finish" on the establishment of a firm start date, granting responsibility for issuing Key Performance Indicator reports to the Lead Scheduler, and adding additional steps to check schedule performance, among others. Changes of this type are to be expected with the progression of a project, as past lessons are incorporated and the focus shifts to implementation.

Q. What activities occurred in 2011 that altered the project schedule?

A. As discussed above, the NRC's review of FPL's LARs are taking longer than expected, presenting challenges to FPL's schedule. In addition, to allow for greater certainty regarding the completion of planning and engineering for the upcoming outages, FPL made the decision in 2011 to delay the start of the PSL Unit 1 2011 outage, as well as the 2012 outages at PTN Unit 3 and PSL Unit 2. In addition to those delays, the EPU portion of the PSL Unit 2 2011 outage lasted longer than planned, due to an error by Siemens, the vendor that is performing the turbine generator upgrade work. It is my understanding, however, that the Siemens delay will not cause any change to the overall EPU Project schedule. That incident is discussed in the testimonies of Company Witness Jones and Company Witness Ferrer, and I also discuss it further below.

Q. What outstanding challenges to the timely execution of the EPU Project's schedule existed in 2011?

A. Going forward, as with 2011, the primary schedule challenges lie in licensing and outage implementation. Specifically affected by licensing is the schedule at PTN. As of December 31, 2011, FPL planned to enter into the PTN Unit 3 2012 outage prior to receipt of the PTN LAR. It is important to note that once certain EPU modifications are made at the PTN units, those units cannot start up again until the PTN LAR is approved. For that reason, FPL must enter the 2012 PTN EPU outage with a high degree of certainty that the LAR will be received during or shortly after the outage. However, FPL can only do so with some amount of risk as the alternative (*i.e.*, delaying the EPU modifications until the next scheduled refueling outage) represents potentially greater cost and schedule risks to the Company and its customers.

As to the NRC's delay, it has, in general, resulted from a shift of resources within the NRC in response to a natural disaster in Japan and the earthquake in Virginia. Those events broadly affected the U.S. nuclear industry. Another ongoing risk to schedule is the discovery of additional design modifications that need to be completed during the outages themselves.

Q. Please further explain the effect of the events in Japan and Virginia on the nuclear industry.

A. The earthquake and resulting tsunami that occurred on March 11, 2011 in Japan caused severe accidents at Tokyo Electric Power Co.'s Fukushima Daiichi nuclear power plant that reverberated throughout the world's nuclear industry. That event has lead to action plans by both the NRC and the U.S. nuclear industry that have already begun to affect FPL's licensing processes for both the EPU Project and PTN 6 & 7. The same can be said of the August 23, 2011 earthquake that caused the North Anna nuclear station in Virginia to lose electricity and automatically shut down for a period of time. Those events had two major effects on FPL's licensing efforts: (1) the NRC has become resource limited as it allocated personnel to respond to those events; and (2) the reviews themselves have involved requirements for new analyses. Both of those external factors posed challenges to be managed by FPL in 2011, and they will continue to do so in 2012.

Q. Please describe Concentric's observations related to the EPU Project's schedule development and management in 2011.

A. Concentric observed that FPL has sufficient systems and procedures in place to allow for appropriate oversight of the project schedule development and management process. In addition, in 2011 FPL made reasonable changes to its outage schedule in response to emerging trends and issues.

Contract Management and Administration Processes

Q. In 2011, what processes were used to ensure the EPU Project was prudently managing and administering the Company's procurement functions?

A. Several policies and procedures governed the procurement functions in 2011, including General Operating ("GO") Procedure 705 and Nuclear Policy NP-1100, Procurement Control. In 2011, those policies were administered through the ISC organization and include a significant breadth and depth of procurement processes, including a stated preference for competitive bidding wherever possible, the proper means for conducting a comprehensive solicitation, initial contract formation, and administration of the contract.

Q. Were there cases in 2011 when contracts were executed without first having gone through a competitive bidding process?

A. Yes. Certain situations called for the use of single or sole source procurement methods. The reasons for that included the fact that there were very few suppliers qualified to handle the vast amount of proprietary technical information relied upon when operating or working on a nuclear plant. Additionally, single sourcing was appropriate in certain situations that involved leveraging existing knowledge or expertise or otherwise capitalizing on synergies.

Q. Please describe the procedures involved in the awarding of non-competitively bid contracts.

A. Single and sole source procurements required documented justification for using a single or sole source procurement strategy and senior-level approval. The recommendation of any vendor for a single or sole sourced contract necessitated the completion of a Single/Sole Source Justification ("SSJ") Memorandum. That document must describe the conditions that have given rise to the need to procure outside services, a justification for not seeking competitive bids, and an explanation of the reasonableness of the vendor's costs.

Q. Please describe the Company's competitive bidding process in 2011.

A. While the majority of procurement activities were completed before the start of 2011, in the cases in 2011 where competitive bidding was utilized, the process began with the creation of a purchase requisition. Pursuant to the creation of a purchase requisition, the department that originated the request, in conjunction with ISC, was required to develop a scope of work or technical specification and develop a timeline to ensure it meets the schedule requirements. Once those steps were complete, the originating department was required to provide the purchase requisition to the Nuclear Supply Chain ("NSC") Sourcing Specialist who was a member of ISC.

The NSC Sourcing Specialist, with assistance from the originating department, was responsible for the creation and issuance of the request for proposals ("RFP"), but worked in concert with the originating department when identifying potential bidders and determining the base commercial terms and conditions that were included in the RFP. What followed was the assembly of the RFP package, which incorporated any special terms identified by the originating department, an RFP transmittal letter providing the potential bidders with all specific instructions and requirements, and any applicable attachments.

Upon receipt of proposals, the NSC Sourcing Specialist sorted and distributed all submissions to subject matter experts for technical and commercial analysis. If questions arose during that review process, written requests for clarification or additional information were sent to the bidder for commercial or technical clarifications. After that initial phase, the originating department undertook a side-by-side comparison of the bids' technical information, taking into consideration scope requirements, differences in operational impacts, whether or not any technical exceptions were necessary, and the potential for impacts to the scope of work. At the conclusion of this process, the NSC Sourcing Specialist and the originating department together determined the recommended supplier.

Q. What process was used in 2011 to make certain that the Company and its customers received the full value of the various contracts for services and materials?

A. FPL utilized an invoice review process to make certain that the Company and its customers received the full value of the goods and services being procured for the EPU Project. The process required a review of each invoice by key project team members who worked closely with the vendor on the goods and services for which payment was requested to make certain that the costs being billed were correct and appropriate. Project Controls Supervisors at each site ensured that invoice monitoring reports from approved purchases were up-to-date and accurate. Each invoice review required approval by certain senior project team members based upon the individuals' corporate approval authority. That tiered oversight structure, including technical specialists who are most familiar with the contracted work, ensures that the EPU Project's procured goods and services are providing their full value to the Company and its customers.

Q. What significant decisions did FPL make in 2011 with regards to its EPC contract?

A. In order to ensure that the Company is deriving appropriate value from the EPC contract and implementing the EPU Project in an efficient manner, FPL hired outside contractors to serve as Owner's Representatives to assist with management of the EPC. In addition, FPL directed Bechtel to sub-contract portions of the project for which a specialty provider was able to carve out a portion of the scope for which it had more expertise. That approach, which included engaging industry-recognized vendors such as Babcock & Wilcox, Sargent & Lundy LLC, Shaw/Stone & Webster Inc., Weldtech Services, Westinghouse Electric Company ("WEC"), Williams Group, and Zachry Nuclear Engineering Inc., resulted in a more cost-effective implementation of the project.

Q. Were there any vendor-caused work stoppages in 2011?

A. Yes, there were. As discussed in the testimonies of Company Witness Jones and Company Witness Ferrer, in the spring 2011 outage at PSL Unit 2, it was determined that a tool was left inside the generator stator core by Siemens personnel after work had been completed on that piece of equipment. That tool caused damaged to the equipment during post-modification testing. In addition, in December 2011 during the PSL Unit 1 outage, work was begun by Bechtel personnel on an incorrect motor control center, which resulted in a two day work stand down for Bechtel's electrician staff.

Q. What was FPL's response to those challenges?

A. In regards to the Siemens error, FPL challenged Siemens to review its tooling design to improve its "foreign material exclusion" procedures. In response, Siemens took corrective actions to improve its engineering of the tool. The Company and Siemens agreed to a confidential settlement regarding the incident that was consistent with industry norms for such contracts.

As to the work stand-down for Bechtel staff, numerous training and "job aid" procedures were put in place to avoid similar issues in the future. Thus, for both the Siemens and the Bechtel work stoppage issues in 2011, corrective actions were put in place to prevent future occurrences of similar issues. That is consistent with industry best practices regarding the avoidance of repeat incidents.

Q. Does Concentric have any observations and recommendations related to the processes used to manage the EPU Project's procurement functions in 2011?

A. Yes. Overall, Concentric noted that the EPU Project's procurement functions performed quite well in 2011. FPL instituted incentive mechanisms at both plants that were the result of significant negotiations with the EPC vendor, and required diligent management by the Company.

<u>Internal Oversight Mechanisms</u>

Q. What mechanisms exist for internal oversight and review of the EPU Project?

A. There are three primary mechanisms used to make certain the EPU Project received adequate oversight in 2011. First, the Company has in place senior oversight and management committees, including the Board of Directors, the Nuclear Committee on the Board of Directors, the Company's Nuclear Review Board, and On-Site Review Groups at both PSL and PTN. In addition, the Company's senior management received a briefing of the EPU Project on a periodic basis. The Company's Chief Nuclear Officer also received a briefing on an approximately bi-weekly basis.

Secondly, the EPU Project was subject to an annual review by the FPL Internal Audit Division. Lastly, the FPL QA/QC department was responsible for making certain that the FPL QA program was being implemented by the EPU Project.

In addition, FPL transferred operational experience from NextEra's nuclear fleet. That internal transfer of knowledge allowed FPL to benefit from lessons learned within NextEra that should result in improved efficiency in the implementation of the EPU Project.

Q. With the EPU Project's management effort largely decentralized, how was information communicated from the site-level to the corporate-level in 2011?

A. The centralized management staff that operated from the Company's headquarters included director positions that were responsible for each business function. For instance, the Director of Project Controls oversaw the project controls managers at both sites. Communication between overall project management and management at the sites was facilitated by a formal reporting structure that emphasized the timely and comprehensive transfer of information.

Q. Please describe the Internal Audit division and its functions.

A. The Internal Audit process was a backstop to make certain the EPU Project complied with the Company's internal policies and procedures. The Internal Audit Division did not report to any of the EPU Project team members to protect the Internal Audit employees' independence. Rather, Internal Audit reported to the Senior Vice President Internal Audit and Compliance, who reported directly to the Chairman and CEO of NextEra Energy. Internal Audit's 2011 financial review of the EPU Project ensured that costs were being appropriately charged to the project and that the project complied with the Company's accounting policies.

Q. Is Internal Audit conducting a review of the EPU Project costs charged in 2011?

A. Yes. Costs incurred by the EPU Project in 2011 are being reviewed by the Company's Internal Audit Department, with a final report to be issued by Internal Audit in May 2012.

Q. Please describe the FPL QA/QC function and its purpose.

A. In 2011, the FPL QA/QC function was responsible for implementing the Company's QA Program that was mandated by the NRC in 10 CFR 50, Appendix B. The QA/QC function was separate from the EPU Project and reported to the Company's Chief Nuclear Officer through the Director of Nuclear Assurance. Federal regulations define eighteen criteria for a NRC licensee's QA program. It was the responsibility of the QA/QC function to ensure that FPL's QA program met these criteria.

Q. What quality assurance activities, related to the EPU Project, took place in 2011?

A. Throughout 2011 the QA/QC function oversaw the implementation phase of the EPU Project. As the EPU Project commenced its outages, QA inspectors were assigned to both PTN and PSL. The QA/QC function was also responsible for reviewing certain activities by the EPU Project's vendors, both at the EPU Project sites as well as at certain vendors' manufacturing facilities. These activities included multiple in-person reviews of the project vendors' methodologies, qualifications and QA programs. Finally, the QA/QC function monitored NRC QA activities and suggested changes to the EPU Project to respond to the NRC's findings at other power uprate projects.

Q. What internal operational experience did FPL incorporate into the EPU Project in 2011?

A. In 2011, FPL incorporated operational experience learned from other plants within NextEra's nuclear fleet. That operational experience was transferred directly through meetings and presentations to the EPU Project team, and indirectly through the reassignment of experienced personnel from other plants within NextEra's fleet into key positions on the EPU Project.

Q. Please provide Concentric's observations related to the internal oversight and review mechanisms utilized in 2011.

A. FPL has in place the appropriate internal oversight and audit functions to properly manage and survey the EPU Project, including processes by which to address emerging issues. Those are important functions to have within a mega project organization to ensure prudent execution of the project.

External Oversight Mechanisms

Q. What external oversight mechanisms did the Company utilize in 2011 to ensure the EPU Project had adequate internal controls and were prudently incurring costs?

A. There were several external oversight and review mechanisms in place for the EPU Project, including the retention of my firm, Concentric, to assess the EPU Project's internal control mechanisms, ongoing contact with the project's major vendors' quality oversight functions, industry contacts, and the FPSC Staff's financial and internal controls audits. Additionally, as a publicly traded company, NextEra Energy must undergo an annual company-wide audit of its financial and internal controls.

Q. Please expand on Concentric's role vis-à-vis external oversight and review.

A. Concentric conducted a review of the EPU Project, its procedures, and the various mechanisms in place to ensure compliance with these procedures in 2011. Concentric focused on ensuring that these internal controls were implemented, and as a result, that the EPU Project prudently incurred costs during 2011.

Q. In 2011, did industry contacts provide a form of external oversight and review?

A. Yes. FPL was a member of industry groups that provided further guidance about uprate projects. These groups include the Institute of Nuclear Power Operations, the World Association of Nuclear Operators, the Electric Power Research Institute and NEI, among others. Each of these groups provided the EPU Project team access to a wide breadth and depth of information that was used to enhance the project team's effectiveness. Additionally, the EPU Project team members maintained close relationships with their counterparts at other nuclear power plants around the country. These valuable relationships allowed the EPU Project team to monitor developments or challenges at other plants and leverage those experiences at PSL and PTN.

Q. Did Concentric have any observations related to external oversight and review of the project in 2011?

A. During its review, Concentric noted that FPL appeared to have taken reasonable steps to obtain and implement lessons learned from outside sources in 2011. These lessons learned are vital to the successful execution of the projects.

<u>**Section VI: PTN 6 & 7 Project Activities in 2011**</u>

Q. How is this section of your testimony organized?

A. This section describes my review of the five key processes (*i.e.*, project estimating and budgeting, project schedule development and management, contract management and administration, internal oversight mechanisms, and external oversight mechanisms) as they were applied to PTN 6 & 7 in 2011.

Q. As a preliminary matter, what did your review lead you to conclude with regard to the prudence of FPL's actions in 2011 on the PTN 6 & 7 Project?

A. FPL's decision to continue pursuing PTN 6 & 7 in 2011 was prudent and was expected to be beneficial to customers. In addition, Concentric's review indicates that FPL's management of the PTN 6 & 7 Project over the course of 2011 has resulted in prudently incurred costs. During 2011 FPL continued its methodical approach to achieving its licensing goals, which will allow it to continue to create the option to build new nuclear capacity for the benefit of its customers.

Q. How was PTN 6 & 7 organized in 2011?

A. Since 2008, few changes have occurred in the PTN 6 & 7 Project organization, which is depicted in Exhibit JJR-5. The project organizational structure continued to be developed around two separate, but collaborative business units: Project Development and New Nuclear Projects. While both organizations ultimately report up to NextEra Energy's Chief Operating Officer, their objectives are tied to each group's respective capabilities. That approach allows FPL to ensure the most qualified group is utilized to accomplish the project's objectives.

The Project Development organization was responsible for all aspects of the project not related to the NRC in 2011. In contrast, the New Nuclear Projects organization is responsible for submitting and defending the PTN 6 & 7 COLA. That organization will also be responsible for the engineering, procurement, construction, and subsequent start-up of the project if a decision to proceed is ultimately made.

Q. In 2011, who was responsible for the New Nuclear Projects organization?

A. The New Nuclear Projects organization falls under the leadership of the Executive Vice President of Engineering and Construction, who was supported directly by a Licensing Director. The Licensing Director was supported by multiple Licensing Engineers and Document Control personnel, as well as by a matrix relationship to other departments within FPL.

Q. Who was responsible for the Project Development organization in 2011?

A. The Project Development organization also falls under the leadership of the Executive Vice President of Engineering and Construction. The organization is led on a day-to-day basis by a Senior Project Director who was supported via matrix relationships by a variety of FPL functional departments.

Q. What internal FPL departments supported the New Nuclear and Project Development organizations in 2011?

A. Both organizations received support from FPL's Juno Environmental Services, Law Department, and ISC, among others.

Q. Did Concentric have any observations related to the PTN 6 & 7 organizational structure in 2011?

A. Yes. Concentric believes the organizational structure appropriately assigned responsibility to those employees best equipped to respond to the project needs and properly reflected the project's focus on the licensing and permitting stage that the project is currently in.

Q. What major milestones were achieved by PTN 6 & 7 in 2011?

A. The main focus of the New Nuclear Project in 2011 was the facilitation of the Federal and State licensing reviews. To that end, PTN 6 & 7 achieved several significant milestones.

In September 2011, the project's State Certification Application ("SCA") was determined to be complete, which is a major step in the state licensing process. The transmission portion of the New Nuclear Project had previously achieved completion in December 2010. Preparation of the SCA required thousands of man-hours and more than a year to complete, as did the preparation of responses to numerous information requests made by state agencies since the application was submitted.

The NRC approved an amendment to the Westinghouse AP1000 Design Certification in December 2011. That is a significant achievement for

Westinghouse, and for FPL and the other companies that are pursuing development of projects using the AP1000 reactor.

In addition, after a three month delay for additional regulatory reviews, the New Nuclear Project began drilling an exploratory underground injection control ("UIC") well to demonstrate the required hydro-geologic conditions necessary to obtain approval of planned operating wells from the Florida Department of Environmental Protection.

Q. Were there changes in 2011 that affect expectations for the timing of future regulatory approvals?

A. Yes, two significant changes occurred in 2011 with respect to the timing of regulatory approval of applications made by the New Nuclear Project. First, a revised NRC review schedule was sent to FPL on October 27th, 2011. Under that new schedule, the expected completion of a Final Environmental Impact Statement has been delayed from October 2012 to February 2014. The expected issuance of the Final Safety Evaluation Report has been delayed from December 2012 to November 2013. However, the NRC has also indicated that the duration of hearings related to the PTN 6 & 7 COLA could be reduced. Based on these schedule revisions, the mandatory NRC hearings are now expected to take place in June 2014. The delays in review of the COLA are related to staff and budget challenges at the NRC that have affected other NRC applicants as well, and have also affected the EPU Project. The changes suggest that a COL could be issued as soon as June 2014.

The State of Florida's review of the PTN 6 & 7 SCA has been delayed for similar reasons. FPL currently expects that land-use hearings will be held in September 2012, with approval of the SCA expected in July 2013.

The PTN 6 & 7 Project is currently assessing the effect these scheduling changes will have on the project. This review is expected to be complete by the middle of 2012.

Q. You mentioned that certain challenges facing the NRC have affected the PTN 6 & 7 Project, as well as other new nuclear development projects. Please briefly describe these challenges.

A. As described in my discussion of the EPU Project, the NRC was presented with two considerable challenges in 2011. In March, the disaster at Japan's Fukushima Daiichi Nuclear Generating Station prompted the NRC to shift considerable personnel resources to an emergency Task Force assigned with ensuring that U.S. nuclear facilities are adequately protected from similar seismic events. The earthquake that struck Virginia occurred only months later, and additional NRC engineering staff-members were reassigned to assessing that incident. As a result of these emergent priorities, some members of the teams assigned to review licensing applications for new nuclear projects were reassigned, delaying technical reviews. The PTN 6 & 7 Project is not alone in having been affected by these staffing challenges. Exelon, Tennessee Valley Authority, PSEG, and other projects have received revised review schedules as well. In addition, FPL has been made aware that budget constraints have limited the extent to which the NRC can use contractors, a resource that is typically heavily relied upon by the NRC, to assist in its review of licensing applications.

Q. Please describe what key decisions related to PTN 6 & 7 were made in 2011.

A. FPL determined that continuing to extend PTN 6 & 7's reservation agreement with WEC for the forging of certain ultra-heavy forgings presented the best value to customers. That agreement was entered into in 2008 when the global market for ultra-heavy forging was becoming increasingly constrained. Those constraints have since been greatly alleviated, and thus FPL has continued to maintain flexibility with regard to the agreement by regularly extending the terms while the Company evaluates the risks and benefits of such continuations. In addition, due to the NRC's announced delay in its license review process for PTN 6 & 7, FPL made plans in 2011 to further evaluate its execution schedule for the units. The results of that review are expected in 2012. No other major decisions affecting the direction of the project were made in 2011.

Q. Was PTN 6 & 7 deemed feasible by the Company during the period of your review?

A. Yes. In the second fiscal quarter of 2011, the Company performed a feasibility analysis regarding PTN 6 & 7, concluding that the project continues to be feasible. FPL revisits its feasibility analysis on an annual basis, and will present a revised feasibility analysis in the second quarter of 2012.

Project Estimating and Budgeting Processes

Q. Please describe how the 2011 project budgets were developed for PTN 6 & 7.

A. As in prior years, the PTN 6 & 7 budgets were developed based on feedback from each department supporting the New Nuclear Project. Those budgets included a bottom-up analysis that assessed the resource needs of each department during the year, and included an adequate contingency for undefined scope or project uncertainties. Typically, that contingency is equal to 15% of the project budget, but may be increased or decreased based upon discussions with each business unit lead.

Q. Was the process used by PTN 6 & 7 to develop its budgets consistent with the Company's policies and procedures?

A. Yes, the process utilized by PTN 6 & 7 to develop its 2011 budgets was consistent with FPL's corporate procedures, which outline the process to be used by each business unit when developing annual budgets.

Q. What mechanisms did the PTN 6 & 7 Project team use to monitor budget performance in 2011?

A. The PTN 6 & 7 Project team used numerous reports to manage budget performance. Those reports are more fully described by Company Witness Scroggs on Exhibit SDS-4. Throughout the year on a monthly basis, the PTN 6 & 7 Project management received several reports detailing budget variances by department, with explanations of the variances. Those reports included a description of all costs expended in the current month and quarter as well as year-to-date and total cumulative spending. In addition, the PTN 6 & 7 Project team published quarterly Due Diligence reports for the Company's senior executives. Further, the project management periodically (usually monthly), presented a status update to FPL's senior management. Those presentations included a description and explanation of any budget variances or significant project challenges.

Q. Are those reporting mechanisms consistent with the PTN 6 & 7 Project Execution Plan?

A. Yes, those reporting mechanisms are consistent with the PTN 6 & 7 Project Execution Plan, which was last revised in March 2010.

Q. Within the PTN 6 & 7 Project team, who was responsible for tracking and reporting project expenditures?

A. Responsibility for tracking and reporting project expenditures was held by the PTN 6 & 7 Project Controls Manager, who worked with a Senior Financial Analyst to review and approve significant vendor invoices, and to track the project's expenditures relative to PTN 6 & 7's annual budget. The processes for both approving invoices and tracking project expenditures are well documented within PTN 6 & 7.

Q. Did Concentric have observations related to the PTN 6 & 7 budget processes?

A. Concentric has found that in 2011 the PTN 6 & 7 Project team acted prudently when developing its annual budget and in tracking its performance relative to the annual budget. As in years past, the PTN 6 & 7 Project team developed a series of reports that track budget performance on a cumulative and periodic basis, along with a process for describing variances in actual expenditures relative to the budget. The PTN 6 & 7 budget processes include a variety of mechanisms that ensure that the project's management and the Company's senior management are well informed of the project's performance.

Q. What are your observations regarding the Company's Quarterly Risk Assessments?

A. The Quarterly Risk Assessments, which contain an assessment of key issues in six areas (*i.e.*, NRC License, Army Corps of Engineers Section 404b and Section 10 Permits, State Cite Certification, Underground Injection Control Permit, Miami Dade County Zoning and Land Use, and Development Agreements), along with FPL's mitigation strategy, continue to be an important tool to assist the Company in analyzing, monitoring, and mitigating risks. The Quarterly Risk Assessments also provide the Company with another method of tracking trends in key issues facing the project, as well as the potential impacts to implementation, cost, and schedule.

The Quarterly Reports are one of the methods by which FPL's senior leadership is apprised of the PTN 6 & 7 Project's status. It is, therefore, very important to clearly communicate all risks and the full suite of mitigation strategies being considered for the project. In 2011, I observed several opportunities to improve the Quarterly Risk Assessment, including the identification and explanation of "fall back" or "Plan B" options for listed risks. That opportunity to strengthen the Risk Assessments remains. Including a discussion of alternatives will help executives grasp the importance of properly mitigating risk, and of achieving risk-related milestones. It will also keep the project focused on maintaining and developing the alternative approaches, reducing the overall risk to the project.

Q. Has FPL developed a cost estimate that is sufficiently detailed for the current phase of the project?

A. Yes. However, it is important to note that FPL's cost estimate is currently indicative in nature and will need to be much more definitive before FPL commits to the construction phase of the project. It is my understanding that the Company has plans to obtain a more definitive cost estimate as the project progresses.

Project Schedule Development and Management Processes

Q. Please describe how the PTN 6 & 7 Project team produced and managed the PTN 6 & 7 schedule in 2011.

A. The initial PTN 6 & 7 Project schedule was developed earlier in PTN 6 & 7's life cycle. This schedule continues to be refined and managed using an industry standard software package developed by Primavera Systems, Inc., which I described in the context of the EPU Project's schedule development.

State and federal review schedules have changed significantly over the past year. Those changes extended the review process into the early construction periods of the current project schedule. As discussed above, FPL is in the process of evaluating the effect those schedule adjustments will have on project timelines, including the assessment of whether early construction phases can be condensed to capture lost time from extended regulatory reviews.

Q. What procedures or project instructions existed in 2011 to govern the development and refinement of the PTN 6 & 7 schedule?

A. New Nuclear Project, Project Instruction 100 governs the development, refinement and configuration of the project schedule.

Q. What mechanisms were in place to ensure that the PTN 6 & 7 Project team prudently managed its schedule performance?

A. The PTN 6 & 7 Project team proactively monitored and managed its schedule performance on a weekly and monthly basis. The PTN 6 & 7 Project team has incorporated similar reporting requirements into its contracts with key vendors such as Bechtel. As a result, Bechtel was required to submit monthly progress reports detailing its progress to date, including any projected delays.

Q. Did Concentric have any observations related to how the PTN 6 & 7 Project team managed and reported its schedule performance in 2011?

A. Yes. Concentric believes PTN 6 & 7 has taken appropriate steps to prudently manage and report on its schedule performance, which include keeping executive management apprised of the project's progress against its schedule plans.

Contract Management and Administration Processes

Q. Did PTN 6 & 7 require the use of outside vendors in 2011?

A. Yes. In order to avoid the need to recruit, train and retain the significant number of employees required to complete the COLA, SCA and other project activities, and respond to interrogatories from Federal, State, and local agencies, FPL used, and will continue to use, a number of outside vendors. Those vendors were utilized to produce the COLA and SCA and provide ongoing post-submittal support, among other tasks. In addition, a limited number of individual contractors were utilized to augment the project staff and fill vacancies where appropriate. FPL's use of outside vendors and contractors is consistent with general industry trends and was clearly anticipated by the PTN 6 & 7 Project Execution Plan.

Q. How did the PTN 6 & 7 Project team make certain that it is prudently managing and administering its procurement processes?

A. As discussed in my review of the EPU Project, FPL has a number of GO Procedures related to the procurement function. In addition, ISC, which has overall responsibility for managing FPL's commercial interactions with vendors, produced a desktop Procurement Process Manual that provides more detailed instructions for implementing the GOs, while also containing nuclear-specific procurement procedures. The GOs, along with the Procurement Process Manual, are sufficiently detailed to ensure that ISC prudently manages the vast number of procurement activities that must take place to support an endeavor such as PTN 6 & 7. Additionally, those procedures clearly state a preference for competitive bidding except in instances where no other supplier can be identified, in cases of emergencies or when a compelling business reason not to seek competitive bids exists.

Q. Did Concentric review examples of how these processes were implemented throughout 2011?

A. Yes. Concentric reviewed information related to each of the new contracts, purchase orders and change orders listed on Schedule T-7A of the Company's Nuclear Filing Requirements. Relative to early phases of the project, PTN 6 & 7 entered into comparatively few new contracts in 2011. PTN 6 & 7 executed 14 contracts in 2011 that related to extensions or expansions of scope for PTN 6 & 7's existing vendors. For the remaining eleven contracts executed in 2011, FPL utilized single or sole source justifications to acquire a specific skill or proprietary technology eight times. One contract was competitively bid, and the remaining two contracts were for less than $25,000.

In a past review, Concentric observed an opportunity to improve procurement processes, and recommended that competitive bids received in response to an RFP for in excess of $5 million be reviewed by ISC roughly contemporaneously and with at least two people participating in the review process. FPL implemented a new Procurement Guideline to address this observation, and followed that new guideline for bids received for UIC construction work in early 2011.

Q. Does the PTN 6 & 7 Project team expect the number of goods and services procured on a single or sole source basis to grow in the future?

A. Yes. This results from the fact that many of the future goods and services that must be procured relate to proprietary design information that is specific to a single vendor. Thus, it will often be impossible to locate another vendor that is capable of providing those goods or services without re-creating thousands of man-hours to replicate the initial plant designs.

Q. What processes were in place to ensure that PTN 6 & 7 received the full value for the goods and services that were procured in 2011 and that appropriate charges were invoiced to the project?

A. In order to ensure that the Company and its customers received the full value of the goods and services that were procured, the PTN 6 & 7 Business Manager and his staff were responsible for reviewing each invoice received from the major PTN 6 & 7 Project vendors. To perform that review, the Business Manager's staff received the invoices from each of the project's vendors. Upon receipt, an Invoice Review/Verification Form that detailed which technical or functional representative was responsible for reviewing each section of the invoice was attached to the invoice. That form and the respective invoice were then sent to each reviewer to verify that the appropriate charges were included in the invoice and that the work product met PTN 6 & 7's needs and contractual provisions prior to payment. When discrepancies were identified, FPL sought a credit on a future invoice or deducted the amount from the current invoice depending on discussions with the vendor. Similar processes are utilized by the FPL departments that support PTN 6 & 7.

Q. Were there instances in 2011 where project vendors were found to be including inappropriate charges in their invoices?

A. Yes. For example, early in 2011 FPL was charged for warranty work that was performed by Bechtel. Those charges were discovered by the invoice review process. Upon discovery of the charges, FPL withheld payment of the aggregate overcharge when completing payment of the monthly invoice. From time-to-time, FPL also discovered and challenged minor, inappropriate expenses from other vendors.

Q. Does Concentric have any observations related to FPL's management of the contract management and administration processes?

A. Yes. FPL managed the contract management and administration process according to its corporate procedures and guidelines in 2011. In addition, the Company continued to follow recommendations that Concentric has made in prior years with respect to contracts and ISC management.

Internal Oversight Mechanisms

Q. What internal reporting mechanisms were used to inform the Company's senior management of PTN 6 & 7's status and key decisions?

A. As I discuss above, the PTN 6 & 7 Project team used a number of periodic reports to inform the project management team and the Company's executive management of progress with PTN 6 & 7. Those reports are described in greater detail in the direct testimony of Company Witness Scroggs and are used to make certain that the costs PTN 6 & 7 is incurring are the result of prudent decision-making processes. Those reports included monthly reports that detailed key budget and schedule performance.

Q. What other internal oversight and review mechanisms exist for the New Nuclear Project?

A. PTN 6 & 7 is subject to FPL's corporate GO procedures, but is being developed external to the FPL Nuclear Division. Thus, PTN 6 & 7 is not automatically subject to the Nuclear Division's policies. To address this condition, and to remain in compliance with the NRC's QA requirements, the FPL QA/QC department developed a procedure, QI-2-NNP-01, that identifies which FPL Nuclear Division polices are applicable to PTN 6 & 7. In response to Concentric's 2009 recommendation, QA/QC staff created a regular update schedule to revise and update this procedure in order to adapt to the dynamic nature of the project.

Similarly, during 2011, PTN 6 & 7 continued to develop its own set of New Nuclear Project Instructions that relate to the following activities:

- Internal controls policies (*e.g.*, the monthly closing process);
- Purchase order and invoice processing;
- ISC policies;
- Contracting policies; and
- The New Nuclear Project Desktop Guide.

Additionally, there were two primary active internal oversight and review mechanisms for PTN 6 & 7: the FPL Internal Audit Department and the FPL QA/QC division.

Q. Please describe the FPL Internal Audit Department and its function.

A. FPL's Internal Audit Department, described earlier, performs regular audits of PTN 6 & 7, not only focusing on the eligibility of the costs being recorded to the NCRC for recovery from customers, but also considering internal controls as part of its procedures, and commenting to PTN 6 & 7 if it finds areas for improvement. In 2011, the FPL Internal Audit Department performed an audit of PTN 6 & 7 to test whether charges billed to the project were appropriate and that those charges were being accounted for correctly. Very often, findings are resolved during the course of the audit, and any unresolved items are tracked within a database to make sure they are completed on schedule.

In 2011, PTN 6 & 7 received an audit rating of "Good," which is the highest rating used by Internal Audit. The audit report included only very minor suggestions to improve project controls, such as providing additional guidance to staff about the level of detail to include on expense reports so that the appropriateness of costs is easier to verify.

Q. Is Internal Audit conducting a review of the New Nuclear Project costs charged in 2011?

A. Yes. Costs incurred by the New Nuclear Project in 2011 are being reviewed by the Company's Internal Audit Department, with a final report to be issued by Internal Audit in May 2012.

Q. Please describe the FPL QA/QC function and its purpose.

A. The FPL QA/QC function has a similar mandate with regard to PTN 6 & 7 as it does with regard to the EPU Project, which was discussed earlier in my testimony.

Q. What quality assurance activities related to PTN 6 & 7 took place in 2011?

A. In 2011, QA/QC performed an audit of Bechtel's processes for responding to NRC Requests for Additional Information ("RAI"). That audit was conducted at Bechtel's offices in Frederick, Maryland, and involved extensive review of work product samples and in-person interviews. The results of the audit confirmed that the Bechtel QA program is being implemented and followed properly.

QA/QC also conducted an audit of quality control processes for the PTN 6 & 7 Project overall. The audit revealed that the project complies with NRC requirements specified for COLA and preconstruction projects, and that appropriate measures have been established and implemented for procurement and contracting policies. In addition, PTN 6 & 7 was found to have an effective correction action program.

Q. Does the Company maintain other internal oversight and review mechanisms for PTN 6 & 7?

A. Yes. The Company maintains other internal oversight mechanisms that are available to help ensure that PTN 6 & 7 is prudently incurring costs. The first of those mechanisms is the FPL Corporate Risk Committee. This committee consists of FPL director-level and other senior employees, and is charged with ensuring that the project appropriately considers risks when making key project decisions. That committee is available to the project when necessary as an additional oversight tool.

Q. Did Concentric have any observations related to PTN 6 & 7's internal oversight mechanisms?

A. Yes. While the suggestions for improvement that were made in 2011 through internal oversight mechanisms were relatively minor, the PTN 6 & 7 Project has already implemented these recommendations.

External Oversight Mechanisms

Q. What external review mechanisms were used by the PTN 6 & 7 Project team in 2011 to ensure that the Company is prudently incurring costs?

A. PTN 6 & 7 and FPL have been subject to several external reviews. These reviews are utilized to make certain industry best practices are incorporated into PTN 6 & 7 and to improve overall project and senior management performance. These reviews include Concentric's review of the Company's activities and project controls, and the FPSC Staff's financial and internal controls audits. Those reviews are in addition to NextEra Energy's company-wide audit of its financial and internal controls, discussed earlier.

Q. Are there other external information sources relied upon by the PTN 6 & 7 Project team?

A. Yes. In 2011, FPL maintained membership in several industry groups that relate to the development of new nuclear projects. Those groups include the NuStart Consortium, APOG (the AP 1000 owners group), the Electric Power Research Institute, and NEI, among others. Each of those groups provides the PTN 6 & 7 Project team with access to a breadth and depth of information that can be used to enhance the PTN 6 & 7 Project team's effectiveness. For instance, those industry groups were utilized during the preparation of the PTN 6 & 7 COLA to identify and analyze potential areas of concern by the NRC and the appropriate response to the NRC's RAIs.

Q. Did Concentric have any observations related to the external oversight mechanisms utilized by FPL in 2011?

A. Based on Concentric's review to date, Concentric believes the PTN 6 & 7 Project team is proactively seeking to incorporate best practices into the management of PTN 6 & 7. That is being achieved by retaining outside experts to review and comment on certain aspects of the project, and by soliciting external information sources that can provide useful guidance to the project team.

Section VII: Conclusions

Q. Please summarize your conclusions.

A. It is my conclusion that there were no imprudently incurred costs or project management deficiencies that led to imprudently incurred costs for the EPU Project and PTN 6 & 7 in 2011. FPL faced challenges in 2011 in its management of the projects, including significant challenges due to external factors outside of the Company's control. However, I found that FPL's policies and procedures put it in a position to appropriately respond to those challenges, and that the Company's oversight and decision making resulted in prudently-incurred costs. In addition, it is important to note that for over three decades nuclear power has provided a number of substantial benefits to utility customers in Florida. Those benefits include electric generation with virtually no GHG emissions, fuel cost savings, fuel diversity, reduced exposure to fuel price volatility and more efficient land use. As a result, it is prudent for FPL to develop additional nuclear capacity for the benefit of its customers. In order to do so, FPL is carefully managing the EPU Project and PTN 6 & 7 through capable project managers and directors who are guided by detailed company procedures and appropriate management oversight.

Q. Does this conclude your testimony?

A. Yes, it does.

Endnotes:

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[1] Production cost is equal to operating and maintenance costs plus fuel costs, and excludes all capital-related costs.

[2] Global Credit Portal, RatingsDirect, Standard & Poor's, "The U.S. Nuclear Power Industry Takes A Giant Leap Forward," February 15, 2012, p. 3.

[3] Sears, Keoki S., Glenn A. Sears, and Richard H. Clough, Construction Project Management: A Practical Guide to Field Construction Management. 5th Edition, John Wiley & Sons, Hoboken, NJ, 2008, at 20.

[4] Florida Public Service Commission Order No. PSC-090783-FOF-EI.

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John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 30 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 150 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join Concentric as Chairman and Chief Executive Officer.

REPRESENTATIVE PROJECT EXPERIENCE

Executive Management

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 25 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

Financial and Economic Advisory Services

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

Litigation Support and Expert Testimony

Provided expert testimony on more than 150 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Have been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets. Represented the interests of the gas distributors (the AGD and UDC) and participated actively in developing and presenting position papers on behalf of the LDC community.

Resource Procurement, Contracting and Analysis

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

Strategic Planning and Utility Restructuring

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies (LDCs), pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to many of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Chairman and Chief Executive Officer

CE Capital Advisors (2004 – Present)
Chairman, President, and Chief Executive Officer

Navigant Consulting, Inc. (1997 – 2002)
President, Navigant Energy Capital (2000 – 2002)
Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988 – 1997)
Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983 – 1988)
Vice President

Stone & Webster Management Consultants, Inc. (1981 – 1983)
Senior Consultant
Consultant

Southern California Gas Company (1976 – 1981)
Corporate Economist
Financial Analyst
Treasury Analyst

EDUCATION AND CERTIFICATION

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, and 24 Licenses

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BOARDS OF DIRECTORS (PAST AND PRESENT)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

AFFILIATIONS

National Association of Business Economists
International Association of Energy Economists
American Gas Association
New England Gas Association
Society of Gas Lighters
Guild of Gas Managers

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alaska Public Utilities Commission				
Chugach Electric	12/86	Chugach Electric	Docket No. U-86-11	Cost Allocation
Chugach Electric	6/87	Enstar Natural Gas Company	Docket No. U-87-2	Tariff Design
Chugach Electric	12/87	Enstar Natural Gas Company	Docket No. U-87-42	Gas Transportation
Chugach Electric	11/87, 2/88	Chugach Electric	Docket No. U-87-35	Cost of Capital
California Energy Commission				
Southern California Gas Co.	8/80	Southern California Gas Co.	Docket No. 80-BR-3	Gas Price Forecasting
California Public Utility Commission				
Southern California Gas Co.	3/80	Southern California Gas Co.	TY 1981 G.R.C.	Cost of Service, Inflation
Pacific Gas Transmission Co.	10/91, 11/91	Pacific Gas & Electric Co.	App. 89-04-033	Rate Design
Pacific Gas Transmission Co.	7/92	Southern California Gas Co.	A. 92-04-031	Rate Design
Colorado Public Utilities Commission				
AMAX Molybdenum	2/90	Commission Rulemaking	Docket No. 89R-702G	Gas Transportation
AMAX Molybdenum	11/90	Commission Rulemaking	Docket No. 90R-508G	Gas Transportation
Xcel Energy	8/04	Xcel Energy	Docket No. 031-134E	Cost of Debt
CT Dept. of Public Utilities Control				
Connecticut Natural Gas	12/88	Connecticut Natural Gas	Docket No. 88-08-15	Gas Purchasing Practices
United Illuminating	3/99	United Illuminating	Docket No. 99-03-04	Nuclear Plant Valuation
Southern Connecticut Gas	2/04	Southern Connecticut Gas	Docket No. 00-12-08	Gas Purchasing Practices
Southern Connecticut Gas	4/05	Southern Connecticut Gas	Docket No. 05-03-17	LNG/Trunkline

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Southern Connecticut Gas	5/06	Southern Connecticut Gas	Docket No. 05-03-17PH01	LNG/Trunkline
Southern Connecticut Gas	8/08	Southern Connecticut Gas	Docket No. 06-05-04	Peaking Service Agreement
District Of Columbia PSC				
Potomac Electric Power Company	3/99, 5/99, 7/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts
Fed'l Energy Regulatory Commission				
Safe Harbor Water Power Corp.	8/82	Safe Harbor Water Power Corp.		Wholesale Electric Rate Increase
Western Gas Interstate Company	5/84	Western Gas Interstate Company	Docket No. RP84-77	Load Fcst. Working Capital
Southern Union Gas	4/87, 5/87	El Paso Natural Gas Company	Docket No. RP87-16-000	Take-or-Pay Costs
Connecticut Natural Gas	11/87	Penn-York Energy Corporation	Docket No. RP87-78-000	Cost Alloc./Rate Design
AMAX Magnesium	12/88	Questar Pipeline Company	Docket No. RP88-93-000	Cost Alloc./Rate Design
Western Gas Interstate Company	6/89	Western Gas Interstate Company	Docket No. RP89-179-000	Cost Alloc./Rate Design, Open-Access Transportation
Associated CD Customers	12/89	CNG Transmission	Docket No. RP88-211-000	Cost Alloc./Rate Design
Utah Industrial Group	9/90	Questar Pipeline Company	Docket No. RP88-93-000, Phase II	Cost Alloc./Rate Design

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Iroquois Gas Trans. System	8/90	Iroquois Gas Transmission System	Docket No. CP89-634-000/001; CP89-815-000	Gas Markets, Rate Design, Cost of Capital, Capital Structure
Boston Edison Company	1/91	Boston Edison Company	Docket No. ER91-243-000	Electric Generation Markets
Cincinnati Gas and Electric Co., Union Light, Heat and Power Company, Lawrenceburg Gas Company	7/91	Texas Gas Transmission Corp.	Docket No. RP90-104-000, RP88-115-000, RP90-192-000	Cost Alloc./Rate Design Comparability of Svc.
Ocean State Power II	7/91	Ocean State Power II	ER89-563-000	Competitive Market Analysis, Self-dealing
Brooklyn Union/PSE&G	7/91	Texas Eastern	RP88-67, et al	Market Power, Comparability of Service
Northern Distributor Group	9/92	Northern Natural Gas Company	RP92-1-000, et al	Cost of Service
Canadian Association of Petroleum Producers and Alberta Pet. Marketing Comm.	10/92	Lakehead Pipe Line Co. L.P.	IS92-27-000	Cost Allocation, Rate Design
Colonial Gas, Providence Gas	7/93, 8/93	Algonquin Gas Transmission	RP93-14	Cost Allocation, Rate Design
Iroquois Gas Transmission	94	Iroquois Gas Transmission	RP94-72-000	Cost of Service and Rate Design
Transco Customer Group	1/94	Transcontinental Gas Pipeline Corporation	Docket No. RP92-137-000	Rate Design, Firm to Wellhead
Pacific Gas Transmission	2/94, 3/95	Pacific Gas Transmission	Docket No. RP94-149-000	Rolled-In vs. Incremental Rates; rate design

DOCKET NO. 120009-EI
CURRENT TESTIMONY OF JOHN J. REED
EXHIBIT JJR-2, PAGE 3 OF 24

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Tennessee GSR Group	1/95, 3/95, 1/96	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs
PG&E and SoCal Gas	8/96, 9/96	El Paso Natural Gas Company	RP92-18-000	Stranded Costs
Iroquois Gas Transmission System, L.P.	97	Iroquois Gas Transmission System, L.P.	RP97-126-000	Cost of Service, Rate Design
BEC Energy - Commonwealth Energy System	2/99	Boston Edison Company/ Commonwealth Energy System	EC99-___-000	Market Power Analysis – Merger
Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	10/00	Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	Docket No. EC00-___	Market Power 203/205 Filing
Wyckoff Gas Storage	12/02	Wyckoff Gas Storage	CP03-33-000	Need for Storage Project
Indicated Shippers/Producers	10/03	Northern Natural Gas	Docket No. RP98-39-029	Ad Valorem Tax Treatment
Maritimes & Northeast Pipeline	6/04	Maritimes & Northeast Pipeline	Docket No. RP04-360-000	Rolled-In Rates
ISO New England	8/04 2/05	ISO New England	Docket No. ER03-563-030	Cost of New Entry
Transwestern Pipeline Company, LLC	9/06	Transwestern Pipeline Company, LLC	Docket No. RP06-614-000	

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Portland Natural Gas Transmission System	6/08	Portland Natural Gas Transmission System	Docket No. RP08-306-000	Market Assessment, natural gas transportation; rate setting
Portland Natural Gas Transmission System	5/10, 3/11, 4/11	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Business risks; extraordinary and non-recurring events pertaining to discretionary revenues
Morris Energy	7/10	Morris Energy	Docket No. RP10-	Affidavit re: Impact of Preferential Rate
Florida Public Service Commission				
Florida Power and Light Co.	10/07	Florida Power & Light Co.	Docket No. 070650-EI	Need for new nuclear plant
Florida Power and Light Co.	5/08	Florida Power & Light Co.	Docket No. 080009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/09	Florida Power & Light Co.	Docket No. 080677-EI	Benchmarking in support of ROE
Florida Power and Light Co.	3/09, 5/09, 8/09	Florida Power & Light Co.	Docket No. 090009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/10; 5/10, 8/10	Florida Power & Light Co.	Docket No. 100009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/11, 7/11	Florida Power & Light Co.	Docket No. 110009-EI	New Nuclear cost recovery, prudence

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Florida Senate Committee on Communication, Energy and Utilities				
Florida Power and Light Co.	2/09	Florida Power & Light Co.		Securitization
Hawaii Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/00	Hawaiian Electric Light Company, Inc.	Cause No. 41746	Standby Charge
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/01	Northern Indiana Public Service Company	Docket No. 99-0207	Valuation of Electric Generating Facilities
Northern Indiana Public Service Company	01/08, 03/08	Northern Indiana Public Service Company	Cause No. 43396	Asset Valuation
Northern Indiana Public Service Company	08/08	Northern Indiana Public Service Company	Cause No. 43526	Fair Market Value Assessment
Iowa Utilities Board				
Interstate Power and Light	7/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. SPU-05-15	Sale of Nuclear Plant
Interstate Power and Light	5/07	City of Everly, Iowa	Docket No. SPU-06-5	Municipalization
Interstate Power and Light	5/07	City of Kalona, Iowa	Docket No. SPU-06-6	Municipalization
Interstate Power and Light	5/07	City of Wellman, Iowa	Docket No. SPU-06-10	Municipalization
Interstate Power and Light	5/07	City of Terril, Iowa	Docket No. SPU-06-8	Municipalization
Interstate Power and Light	5/07	City of Rolfe, Iowa	Docket No. SPU-06-7	Municipalization

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Maine Public Utility Commission				
Northern Utilities	5/96	Granite State and PNGTS	Docket No. 95-480, 95-481	Transportation Service and PBR
Maryland Public Service Commission				
Eastalco Aluminum	3/82	Potomac Edison	Docket No. 7604	Cost Allocation
Potomac Electric Power Company	8/99	Potomac Electric Power Company	Docket No. 8796	Stranded Cost & Price Protection
Mass. Department of Public Utilities				
Haverhill Gas	5/82	Haverhill Gas	Docket No. DPU #1115	Cost of Capital
New England Energy Group	1/87	Commission Investigation		Gas Transportation Rates
Energy Consortium of Mass.	9/87	Commonwealth Gas Company	Docket No. DPU-87-122	Cost Alloc./Rate Design
Mass. Institute of Technology	12/88	Middleton Municipal Light	DPU #88-91	Cost Alloc./Rate Design
Energy Consortium of Mass.	3/89	Boston Gas	DPU #88-67	Rate Design
PG&E Bechtel Generating Co./ Constellation Holdings	10/91	Commission Investigation	DPU #91-131	Valuation of Environmental Externalities
Coalition of Non-Utility Generators		Cambridge Electric Light Co. & Commonwealth Electric Co.	DPU 91-234 EFSC 91-4	Integrated Resource Management
The Berkshire Gas Company Essex County Gas Company Fitchburg Gas and Elec. Light Co.	5/92	The Berkshire Gas Company Essex County Gas Company Fitchburg Gas & Elec. Light Co.	DPU #92-154	Gas Purchase Contract Approval

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Boston Edison Company	7/92	Boston Edison	DPU #92-130	Least Cost Planning
Boston Edison Company	7/92	The Williams/Newcorp Generating Co.	DPU #92-146	RFP Evaluation
Boston Edison Company	7/92	West Lynn Cogeneration	DPU #92-142	RFP Evaluation
Boston Edison Company	7/92	L'Energia Corp.	DPU #92-167	RFP Evaluation
Boston Edison Company	7/92	DLS Energy, Inc.	DPU #92-153	RFP Evaluation
Boston Edison Company	7/92	CMS Generation Co.	DPU #92-166	RFP Evaluation
Boston Edison Company	7/92	Concord Energy	DPU #92-144	RFP Evaluation
The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Company	11/93	The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Co.	DPU #93-187	Gas Purchase Contract Approval
Bay State Gas Company	10/93	Bay State Gas Company	Docket No. 93-129	Integrated Resource Planning
Boston Edison Company	94	Boston Edison	DPU #94-49	Surplus Capacity
Hudson Light & Power Department	4/95	Hudson Light & Power Dept.	DPU #94-176	Stranded Costs
Essex County Gas Company	5/96	Essex County Gas Company	Docket No. 96-70	Unbundled Rates
Boston Edison Company	8/97	Boston Edison Company	D.P.U. No. 97-63	Holding Company Corporate Structure
Berkshire Gas Company	6/98	Berkshire Gas Mergeco Gas Co.	D.T.E. 98-87	Merge approval
Eastern Edison Company	8/98	Montaup Electric Company	D.T.E. 98-83	Marketing for divestiture of its generation business.
Boston Edison Company	98	Boston Edison Company	D.T.E. 97-113	Fossil Generation Divestiture

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Boston Edison Company	98	Boston Edison Company	D.T.E. 98-119	Nuclear Generation Divestiture
Eastern Edison Company	12/98	Montaup Electric Company	D.T.E. 99-9	Sale of Nuclear Plant
NStar	9/07, 12/07	NStar, Bay State Gas, Fitchburg G&E, NE Gas, W. MA Electric	DPU 07-50	Decoupling, risk
NStar	6/11	NStar, Northeast Utilities	DPU 10-170	Merger approval
Mass. Energy Facilities Siting Council				
Mass. Institute of Technology	1/89	M.M.W.E.C.	EFSC-88-1	Least-Cost Planning
Boston Edison Company	9/90	Boston Edison	EFSC-90-12	Electric Generation Mkts
Silver City Energy Ltd. Partnership	11/91	Silver City Energy	D.P.U. 91-100	State Policies; Need for Facility
Michigan Public Service Commission				
Detroit Edison Company	9/98	Detroit Edison Company	Case No. U-11726	Market Value of Generation Assets
Consumers Energy Company	8/06, 1/07	Consumers Energy Company	Case No. U-14992	Sale of Nuclear Plant
WE Energies	12/11	Wisconsin Electric Power Co	Case No. U-16830	Economic Benefits/Prudence
Minnesota Public Utilities Commission				
Xcel Energy/No. States Power	9/04	Xcel Energy/No. States Power	Docket No. G002/GR-04-1511	NRG Impacts
Interstate Power and Light	8/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. E001/PA-05-1272	Sale of Nuclear Plant

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Northern States Power Company d/b/a Xcel Energy	11/05	Northern States Power Company	Docket No. E002/GR-05-1428	NRG Impacts on Debt Costs
Northern States Power Company d/b/a Xcel Energy	09/06	NSP v. Excelsior	Docket No. E6472/M-05-1993	PPA, Financial Impacts
Northern States Power Company d/b/a Xcel Energy	11/06	Northern States Power Company	Docket No. G002/GR-06-1429	Return on Equity
Northern States Power	11/08, 05/09	Northern States Power Company	Docket No. E002/GR-08-1065	Return on Equity
Northern States Power	11/09 6/10	Northern States Power Company	Docket No. G002/GR-09-1153	Return on Equity
Northern States Power	11/10, 5/11	Northern States Power Company	Docket No. E002/GR-10-971	Return on Equity
Missouri Public Service Commission				
Missouri Gas Energy	1/03	Missouri Gas Energy	Case No. GR-2001-382	Gas Purchasing Practices; Prudence
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case Nos. ER-2004-0034 HR-2004-0024	Cost of Capital, Capital Structure
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case No. GR-2004-0072	Cost of Capital, Capital Structure
Missouri Gas Energy	11/05	Missouri Gas Energy	Case Nos. GR-2002-348 GR-2003-0330	Capacity Planning
Missouri Gas Energy	11/10, 1/11	KCP&L	Case No. ER-2010-0355	Natural Gas DSM
Missouri Gas Energy	11/10, 1/11	KCP&L GMO	Case No. ER-2010-0356	Natural Gas DSM

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Laclede Gas Company	5/11	Laclede Gas Company	Case No. CG-2011-0098	Affiliate Pricing Standards
Union Electric Company d/b/a Ameren Missouri	2/12	Union Electric Company	Case. No. ER-2012-0166	ROE/earnings attrition/regulatory lag
Montana Public Service Commission				
Great Falls Gas Company	10/82	Great Falls Gas Company	Docket No. 82-4-25	Gas Rate Adjust. Clause
Nat. Energy Board of Canada				
Alberta-Northeast	2/87	Alberta Northeast Gas Export Project	Docket No. GH-1-87	Gas Export Markets
Alberta-Northeast	11/87	TransCanada Pipeline	Docket No. GH-2-87	Gas Export Markets
Alberta-Northeast	1/90	TransCanada Pipeline	Docket No. GH-5-89	Gas Export Markets
Indep. Petroleum Association of Canada	1/92	Interprovincial Pipe Line, Inc.	RH-2-91	Pipeline Valuation, Toll
The Canadian Association of Petroleum Producers	11/93	Transmountain Pipe Line	RH-1-93	Cost of Capital
Alliance Pipeline L.P.	6/97	Alliance Pipeline L.P.	GH-3-97	Market Study
Maritimes & Northeast Pipeline	97	Sable Offshore Energy Project	GH-6-96	Market Study
Maritimes & Northeast Pipeline	2/02	Maritimes & Northeast Pipeline	GH-3-2002	Natural Gas Demand Analysis
TransCanada Pipelines	8/04	TransCanada Pipelines	RH-3-2004	Toll Design
Brunswick Pipeline	5/06	Brunswick Pipeline	GH-1-2006	Market Study
TransCanada Pipelines Ltd.	3/07, 04/07	TransCanada Pipelines Ltd.: Gros Cacouna Receipt Point Application	RH-1-2007	Toll Design
Repsol Energy Canada Ltd	3/08	Repsol Energy Canada Ltd	GH-1-2008	Market Study

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Maritimes & Northeast Pipeline	7/10	Maritimes & Northeast Pipeline	RH-4-2010	Regulatory policy, toll development
New Brunswick Energy and Utilities Board				
Atlantic Wallboard/JD Irving Co	1/08	Enbridge Gas New Brunswick	MCTN #298600	Rate Setting for EGNB
Atlantic Wallboard/Flakeboard	09/09, 6/10, 7/10	Enbridge Gas New Brunswick	NBEUB 2009-017	Rate Setting for EGNB
NH Public Utilities Commission				
Bus & Industry Association	6/89	P.S. Co. of New Hampshire	Docket No. DR89-091	Fuel Costs
Bus & Industry Association	5/90	Northeast Utilities	Docket No. DR89-244	Merger & Acq. Issues
Eastern Utilities Associates	6/90	Eastern Utilities Associates	Docket No. DF89-085	Merger & Acq. Issues
EnergyNorth Natural Gas	12/90	EnergyNorth Natural Gas	Docket No. DE90-166	Gas Purchasing Practices
EnergyNorth Natural Gas	7/90	EnergyNorth Natural Gas	Docket No. DR90-187	Special Contracts, Discounted Rates
Northern Utilities, Inc.	12/91	Commission Investigation	Docket No. DR91-172	Generic Discounted Rates
New Jersey Board of Public Utilities				
Hilton/Golden Nugget	12/83	Atlantic Electric	B.P.U. 832-154	Line Extension Policies
Golden Nugget	3/87	Atlantic Electric	B.P.U. No. 837-658	Line Extension Policies
New Jersey Natural Gas	2/89	New Jersey Natural Gas	B.P.U. GR89030335J	Cost Alloc./Rate Design

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New Jersey Natural Gas	1/91	New Jersey Natural Gas	B.P.U. GR90080786J	Cost Alloc./Rate Design
New Jersey Natural Gas	8/91	New Jersey Natural Gas	B.P.U. GR91081393J	Rate Design; Weather Norm. Clause
New Jersey Natural Gas	4/93	New Jersey Natural Gas	B.P.U. GR93040114J	Cost Alloc./Rate Design
South Jersey Gas	4/94	South Jersey Gas	BRC Dock No. GR080334	Revised levelized gas adjustment
New Jersey Utilities Association	9/96	Commission Investigation	BPU AX96070530	PBOP Cost Recovery
Morris Energy Group	11/09	Public Service Electric & Gas	BPU GR 09050422	Discriminatory Rates
New Jersey American Water Co.	4/10	New Jersey American Water Co.	BPU WR 1040260	Tariff Rates and Revisions
Electric Customer Group	01/11	Generic Stakeholder Proceeding	BPU GR10100761 and ER10100762	Natural gas ratemaking standards and pricing
New Mexico Public Service Commission				
Gas Company of New Mexico	11/83	Public Service Co. of New Mexico	Docket No. 1835	Cost Alloc./Rate Design
New York Public Service Commission				
Iroquois Gas. Transmission	12/86	Iroquois Gas Transmission System	Case No. 70363	Gas Markets
Brooklyn Union Gas Company	8/95	Brooklyn Union Gas Company	Case No. 95-6-0761	Panel on Industry Directions
Central Hudson, ConEdison and Niagara Mohawk	9/00	Central Hudson, ConEdison and Niagara Mohawk	Case No. 96-E-0909 Case No. 96-E-0897 Case No. 94-E-0098 Case No. 94-E-0099	Section 70, Approval of New Facilities

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Central Hudson, New York State Electric & Gas, Rochester Gas & Electric	5/01	Joint Petition of NiMo, NYSEG, RG&E, Central Hudson, Constellation and Nine Mile Point	Case No. 01-E-0011	Section 70, Rebuttal Testimony
Rochester Gas & Electric	12/03	Rochester Gas & Electric	Case No. 03-E-1231	Sale of Nuclear Plant
Rochester Gas & Electric	01/04	Rochester Gas & Electric	Case No. 03-E-0765 Case No. 02-E-0198 Case No. 03-E-0766	Sale of Nuclear Plant; Ratemaking Treatment of Sale
Rochester Gas and Electric and NY State Electric & Gas Corp	2/10	Rochester Gas & Electric NY State Electric & Gas Corp	Case No. 09-E-0715 Case No. 09-E-0716 Case No. 09-E-0717 Case No. 09-E-0718	Depreciation policy
Oklahoma Corporation Commission				
Oklahoma Natural Gas Company	6/98	Oklahoma Natural Gas Company	Case PUD No. 980000177	Storage issues
Oklahoma Gas & Electric Company	9/05	Oklahoma Gas & Electric Company	Cause No. PUD 200500151	Prudence of McLain Acquisition
Oklahoma Gas & Electric Company	03/08	Oklahoma Gas & Electric Company	Cause No. PUD 200800086	Acquisition of Redbud generating facility
Ontario Energy Board				
Market Hub Partners Canada, L.P.	5/06	Natural Gas Electric Interface Roundtable	File No. EB-2005-0551	Market-based Rates For Storage
Pennsylvania Public Utility Commission				
ATOC	4/95	Equitrans	Docket No. R-00943272	Rate Design, unbundling

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ATOC	3/96	Equitrans	Docket No. P-00940886	Rate Design, unbundling
Rhode Island Public Utilities Commission				
Newport Electric	7/81	Newport Electric	Docket No. 1599	Rate Attrition
South County Gas	9/82	South County Gas	Docket No. 1671	Cost of Capital
New England Energy Group	7/86	Providence Gas Company	Docket No. 1844	Cost Alloc./Rate Design
Providence Gas	8/88	Providence Gas Company	Docket No. 1914	Load Forecast., Least-Cost Planning
Providence Gas Company and The Valley Gas Company	1/01	Providence Gas Company and The Valley Gas Company	Docket No. 1673 and 1736	Gas Cost Mitigation Strategy
The New England Gas Company	3/03	New England Gas Company	Docket No. 3459	Cost of Capital
Texas Public Utility Commission				
Southwestern Electric	5/83	Southwestern Electric		Cost of Capital, CWIP
P.U.C. General Counsel	11/90	Texas Utilities Electric Company	Docket No. 9300	Gas Purchasing Practices, Prudence
Oncor Electric Delivery Company	8/07	Oncor Electric Delivery Company	Docket No. 34040	Regulatory Policy, Rate of Return, Return of Capital and Consolidated Tax Adjustment
Oncor Electric Delivery Company	6/08	Oncor Electric Delivery Company	Docket No.35717	Regulatory policy
Oncor Electric Delivery Company	10/08, 11/08	Oncor, TCC, TNC, ETT, LCRA TSC, Sharyland, STEC, TNMP	Docket No. 35665	Competitive Renewable Energy Zone

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CenterPoint Energy	6/10 10/10	CenterPoint Energy/Houston Electric	Docket No. 38339	Regulatory policy, risk, consolidated taxes
Oncor Electric Delivery Company	1/11	Oncor Electric Delivery Company	Docket No. 38929	Regulatory policy, risk
Texas Railroad Commission				
Western Gas Interstate Company	1/85	Southern Union Gas Company	Docket 5238	Cost of Service
Atmos Pipeline Texas	9/10; 1/11	Atmos Pipeline Texas	GUD 10000	Ratemaking Policy, risk
Utah Public Service Commission				
AMAX Magnesium	1/88	Mountain Fuel Supply Company	Case No. 86-057-07	Cost Alloc./Rate Design
AMAX Magnesium	4/88	Utah P&L/Pacific P&L	Case No. 87-035-27	Merger & Acquisition
Utah Industrial Group	7/90	Mountain Fuel Supply	Case No. 89-057-15	Gas Transportation Rates
AMAX Magnesium	9/90	Utah Power & Light	Case No. 89-035-06	Energy Balancing Account
AMAX Magnesium	8/90	Utah Power & Light	Case No. 90-035-06	Electric Service Priorities
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Benchmarking in support of ROE
Vermont Public Service Board				
Green Mountain Power	8/82	Green Mountain Power	Docket No. 4570	Rate Attrition
Green Mountain Power	12/97	Green Mountain Power	Docket No. 5983	Cost of Service
Green Mountain Power	7/98, 9/00	Green Mountain Power	Docket No. 6107	Ratae development

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Wisconsin Public Service Commission				
WEC & WICOR	11/99	WEC	Docket No. 9401-YO-100 Docket No. 9402-YO-101	Approval to Acquire the Stock of WICOR
Wisconsin Electric Power Company	1/07	Wisconsin Electric Power Co.	Docket No. 6630-EI-113	Sale of Nuclear Plant
Wisconsin Electric Power Company	10/09	Wisconsin Electric Power Co.	Docket No. 6630-CE-302	CPCN Application for wind project

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American Arbitration Association				
Michael Polsky	3/91	M. Polsky vs. Indeck Energy		Corporate Valuation, Damages
ProGas Limited	7/92	ProGas Limited v. Texas Eastern		Gas Contract Arbitration
Attala Generating Company	12/03	Attala Generating Co v. Attala Energy Co.	Case No. 16-Y-198-00228-03	Power Project Valuation; Breach of Contract; Damages
Nevada Power Company	4/08	Nevada Power v. Nevada Cogeneration Assoc. #2		Power Purchase Agreement
Sensata Technologies, Inc./EMS Engineered Materials Solutions, LLC	1/11	Sensata Technologies, Inc./EMS Engineered Materials Solutions, LLC v. Pepco Energy Services	Case No. 11-198-Y-00848-10	Change in usage dispute/damages
Commonwealth of Massachusetts, Suffolk Superior Court				
John Hancock	1/84	Trinity Church v. John Hancock	C.A. No. 4452	Damages Quantification
State of Colorado District Court, County of Garfield				
Questar Corporation, et al	11/00	Questar Corporation, et al.	Case No. 00CV129-A	Partnership Fiduciary Duties
State of Delaware, Court of Chancery, New Castle County				
Wilmington Trust Company	11/05	Calpine Corporation vs. Bank Of New York and Wilmington Trust Company	C.A. No. 1669-N	Bond Indenture Covenants

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Illinois Appellate Court, Fifth Division				
Norweb, plc	8/02	Indeck No. America v. Norweb	Docket No. 97 CH 07291	Breach of Contract; Power Plant Valuation
Independent Arbitration Panel				
Alberta Northeast Gas Limited	2/98	ProGas Ltd., Canadian Forest Oil Ltd., AEC Oil & Gas		
Ocean State Power	9/02	Ocean State Power vs. ProGas Ltd.	2001/2002 Arbitration	Gas Price Arbitration
Ocean State Power	2/03	Ocean State Power vs. ProGas Ltd.	2002/2003 Arbitration	Gas Price Arbitration
Ocean State Power	6/04	Ocean State Power vs. ProGas Ltd.	2003/2004 Arbitration	Gas Price Arbitration
Shell Canada Limited	7/05	Shell Canada Limited and Nova Scotia Power Inc.		Gas Contract Price Arbitration
International Court of Arbitration				
Wisconsin Gas Company, Inc.	2/97	Wisconsin Gas Co. vs. Pan-Alberta	Case No. 9322/CK	Contract Arbitration
Minnegasco, A Division of NorAm Energy Corp.	3/97	Minnegasco vs. Pan-Alberta	Case No. 9357/CK	Contract Arbitration
Utilicorp United Inc.	4/97	Utilicorp vs. Pan-Alberta	Case No. 9373/CK	Contract Arbitration
IES Utilities	97	IES vs. Pan-Alberta	Case No. 9374/CK	Contract Arbitration

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State of New Jersey, Mercer County Superior Court				
Transamerica Corp., et. al.	7/07, 10/07	IMO Industries Inc. vs. Transamerica Corp., et. al.	Docket No. L-2140-03	Breach-Related Damages, Enterprise Value
State of New York, Nassau County Supreme Court				
Steel Los III, LP	6/08	Steel Los II, LP & Associated Brook, Corp v. Power Authority of State of NY	Index No. 5662/05	Property seizure
Province of Alberta, Court of Queen's Bench				
Alberta Northeast Gas Limited	5/07	Cargill Gas Marketing Ltd. vs. Alberta Northeast Gas Limited	Action No. 0501-03291	Gas Contracting Practices
State of Rhode Island, Providence City Court				
Aquidneck Energy	5/87	Laroche vs. Newport		Least-Cost Planning
State of Texas Hutchinson County Court				
Western Gas Interstate	5/85	State of Texas vs. Western Gas Interstate Co.	Case No. 14,843	Cost of Service
State of Texas District Court of Nueces County				
Northwestern National Insurance Company	11/11	ASARCO LLC	No. 01-2680-D	Damages

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State of Utah Third District Court				
PacifiCorp & Holme, Roberts & Owen, LLP	1/07	USA Power & Spring Canyon Energy vs. PacifiCorp. et. al.	Civil No. 050903412	Breach-Related Damages
U.S. Bankruptcy Court, District of New Hampshire				
EUA Power Corporation	7/92	EUA Power Corporation	Case No. BK-91-10525-JEY	Pre-Petition Solvency
U.S. Bankruptcy Court, District Of New Jersey				
Ponderosa Pine Energy Partners, Ltd.	7/05	Ponderosa Pine Energy Partners, Ltd.	Case No. 05-21444	Forward Contract Bankruptcy Treatment
U.S. Bankruptcy Court, No. District of New York				
Cayuga Energy, NYSEG Solutions, The Energy Network	09/09	Cayuga Energy, NYSEG Solutions, The Energy Network	Case No. 06-60073-6-sdg	Going concern
U.S. Bankruptcy Court, So. District Of New York				
Johns Manville	5/04	Enron Energy Mktg. v. Johns Manville; Enron No. America v. Johns Manville	Case No. 01-16034 (AJG)	Breach of Contract; Damages

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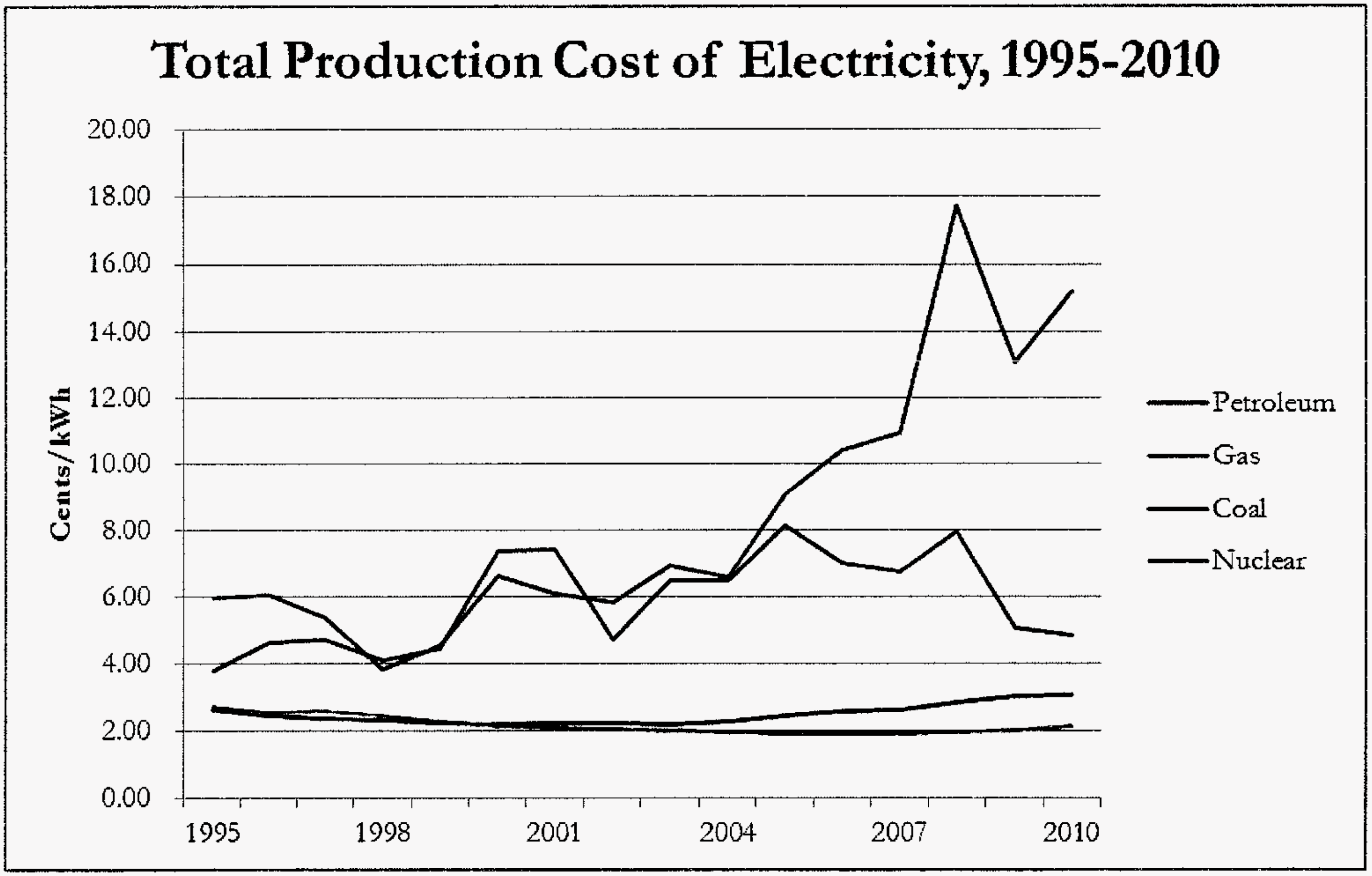
U.S. Bankruptcy Court, Northern District Of Texas				
Southern Maryland Electric Cooperative, Inc. and Potomac Electric Power Company	11/04	Mirant Corporation, et al. v. SMECO	Case No. 03-4659; Adversary No. 04-4073	PPA Interpretation; Leasing
U. S. Court of Federal Claims				
Boston Edison Company	7/06, 11/06	Boston Edison v. Department of Energy	No. 99-447C No. 03-2626C	Spent Nuclear Fuel Litigation
Consolidated Edison of New York	08/07	Consolidated Edison of New York, Inc. and subsidiaries v. United States	No. 06-305T	Leasing, tax dispute
Consolidated Edison Company	2/08, 6/08	Consolidated Edison Company v. United States	No. 04-0033C	SNF Expert Report
Vermont Yankee Nuclear Power Corporation	6/08	Vermont Yankee Nuclear Power Corporation	No. 03-2663C	SNF Expert Report
U. S. District Court, Boulder County, Colorado				
KN Energy, Inc.	3/93	KN Energy vs. Colorado GasMark, Inc.	Case No. 92 CV 1474	Gas Contract Interpretation
U. S. District Court, Northern California				
Pacific Gas & Electric Co./PGT PG&E/PGT Pipeline Exp. Project	4/97	Norcen Energy Resources Limited	Case No. C94-0911 VRW	Fraud Claim

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U. S. District Court, District of Connecticut				
Constellation Power Source, Inc.	12/04	Constellation Power Source, Inc. v. Select Energy, Inc.	Civil Action 304 CV 983 (RNC)	ISO Structure, Breach of Contract
U. S. District Court, Massachusetts				
Eastern Utilities Associates & Donald F. Pardus	3/94	NECO Enterprises Inc. vs. Eastern Utilities Associates	Civil Action No. 92-10355-RCL	Seabrook Power Sales
U. S. District Court, Montana				
KN Energy, Inc.	9/92	KN Energy v. Freeport MacMoRan	Docket No. CV 91-40-BLG-RWA	Gas Contract Settlement
U.S. District Court, New Hampshire				
Portland Natural Gas Transmission and Maritimes & Northeast Pipeline	9/03	Public Service Company of New Hampshire vs. PNGTS and M&NE Pipeline	Docket No. C-02-105-B	Impairment of Electric Transmission Right-of-Way
U. S. District Court, Southern District of New York				
Central Hudson Gas & Electric	11/99, 8/00	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Electric restructuring, environmental impacts
Consolidated Edison	3/02	Consolidated Edison v. Northeast Utilities	Case No. 01 Civ. 1893 (JGK) (HP)	Industry Standards for Due Diligence
Merrill Lynch & Company	1/05	Merrill Lynch v. Allegheny Energy, Inc.	Civil Action 02 CV 7689 (HB)	Due Diligence, Breach of Contract, Damages

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U. S. District Court, Eastern District of Virginia				
Aquila, Inc.	1/05, 2/05	VPEM v. Aquila, Inc.	Civil Action 304 CV 411	Breach of Contract, Damages
U. S. District Court, Portland Maine				
ACEC Maine, Inc. et al.	10/91	CIT Financial vs. ACEC Maine	Docket No. 90-0304-B	Project Valuation
Combustion Engineering	1/92	Combustion Eng. vs. Miller Hydro	Docket No. 89-0168P	Output Modeling; Project Valuation
U.S. Securities and Exchange Commission				
Eastern Utilities Association	10/92	EUA Power Corporation	File No. 70-8034	Value of EUA Power
Council of the District of Columbia Committee on Consumer and Regulatory Affairs				
Potomac Electric Power Co.	7/99	Potomac Electric Power Co.	Bill 13-284	Utility restructuring

DOCKET NO. 120009-EI
EXPERT TESTIMONY OF JOHN J. REED
COURTS AND ARBITRATION
EXHIBIT JJR-2, PAGE 24 OF 24


Total Production Cost of Electricity, 1995-2010
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Cents/kWh
1995
1998
2001
2004
2007
2010
Petroleum
Gas
Coal
Nuclear

Index of the EPU Projects' Periodic Meetings

Meetings

1. EPU Executive Steering Committee Meeting
    a. Occurs: quarterly
    b. Attendees: EPU Executive Steering Committee
    c. Purpose: overview of major project issues, costs, schedule and budget
2. Plan of the Day Accountability Meeting
    a. Occurs: daily
    b. Attendees: Site representatives
    c. Purpose: review and report daily work plans
3. Engineering and Construction Trend Review Meeting (PSL & PTN)
    a. Occurs: weekly
    b. Attendees: managers
    c. Purpose: review and approve Change/Trend at site level
4. Monthly Cost Reviews
    a. Occurs: monthly
    b. Attendees: FPL management
    c. Purpose: review incurred and forecasted project costs
5. Risk Review
    a. Occurs: weekly (PSL & PTN)
    b. Attendees: managers
    c. Purpose: review and track identified project risks
6. EPU Leadership Meeting
    a. Occurs: weekly
    b. Attendees: FPL leadership and the major vendors managers
    c. Purpose: discussion of project strategies and progress
7. Plant Change Modifications
    a. Occurs: weekly
    b. Attendees: Engineering Supervision

   c. Purpose: 8-week look ahead meeting

8. FPL – Siemens meeting
   a. Occurs: weekly
   b. Attendees: EPU Management
   c. Purpose: review status of Siemens EPU scope
9. Bechtel Schedule and Cost Performance meeting
   a. Occurs: weekly (daily during outages)
   b. Attendees: Bechtel and EPU management
   c. Purpose: review of Bechtel's CPIs and SPIs
10. Integrated Supply Chain meeting
    a. Occurs: weekly
    b. Attendees: Senior management
    c. Purpose: review status of EPU project procurements
11. FPL Senior Management Meeting (Morning Call)
    a. Occurs: daily
    b. Attendees: VP, Implementation Owners, Site Directors, LAR Director, Controls Director, NCRI Manager, Project Controls Supervisors & invitees
    c. Purpose: discussion of progress and issues
12. Project and Plant Integration meeting (PTN & PSL)
    a. Occurs: weekly
    b. Attendees: EPU project management and plant management
    c. Purpose: project and plant integration

13. Key Supplier Meeting
    a. Occurs: Quarterly
    b. Attendees: Senior FPL management and senior management from major vendors
    c. Purpose: first time quality and interfacing between vendors
14. CNO Meeting
    a. Occurs: Monthly
    b. Attendees: EPU Senior management
    c. Purpose: report project status
15. Lead Team Meeting (PTN)
    a. Occurs: Daily
    b. Attendees: FPL Site EPU leadership team
    c. Purpose: review progress and project execution
16. Task Readiness Review Meeting (PTN)
    a. Occurs: As required per the project schedule
    b. Attendees: FPL and Bechtel supervisors and engineers
    c. Purpose: ensure implementation plan for modification is ready
17. NRC EPU LAR Status meeting
    a. Occurs: Weekly
    b. Attendees: EPU LAR Director, EPU LAR Managers and NRC Project Manager
    c. Purpose: review status and issues related to LAR review
18. Project Manager Review Meeting (PTN)
    a. Occurs: weekly
    b. Attendees Sr. Project Managers, All EPU Project Managers
    c. Purpose: Review Bechtel POD, Site POD, EPU Daily Reports and Project status
19. Outage Turnover Meeting
    a. Occurs twice per day during outage period
    b. Attendees: Team Room Lead, Night / Day shift PM, Construction Manager
    c. Purpose: Review status from one shift to the next

JJR-5

CONCENTRIC ENERGY ADVISORS

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PTN 6 & 7 Organization Charts
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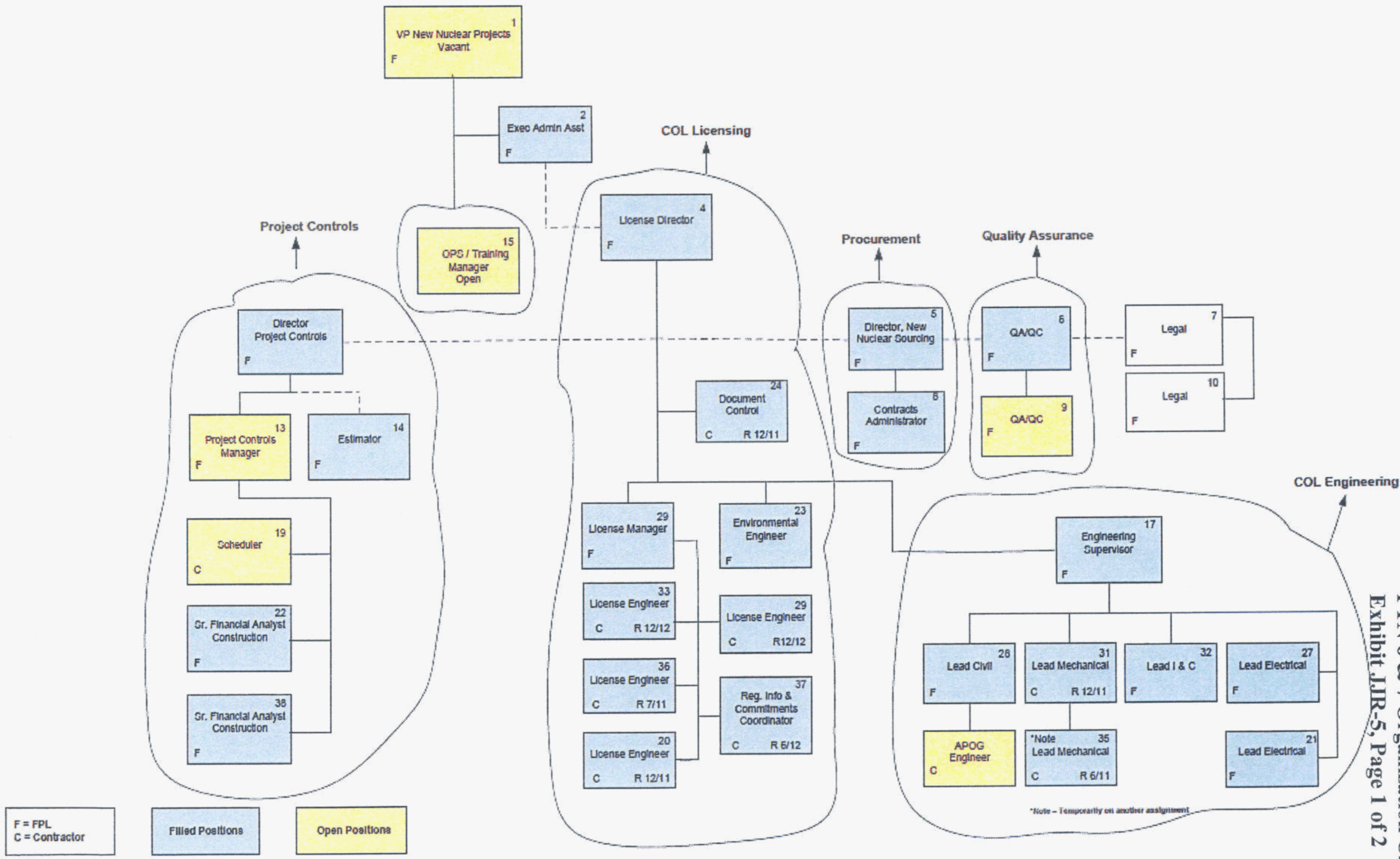
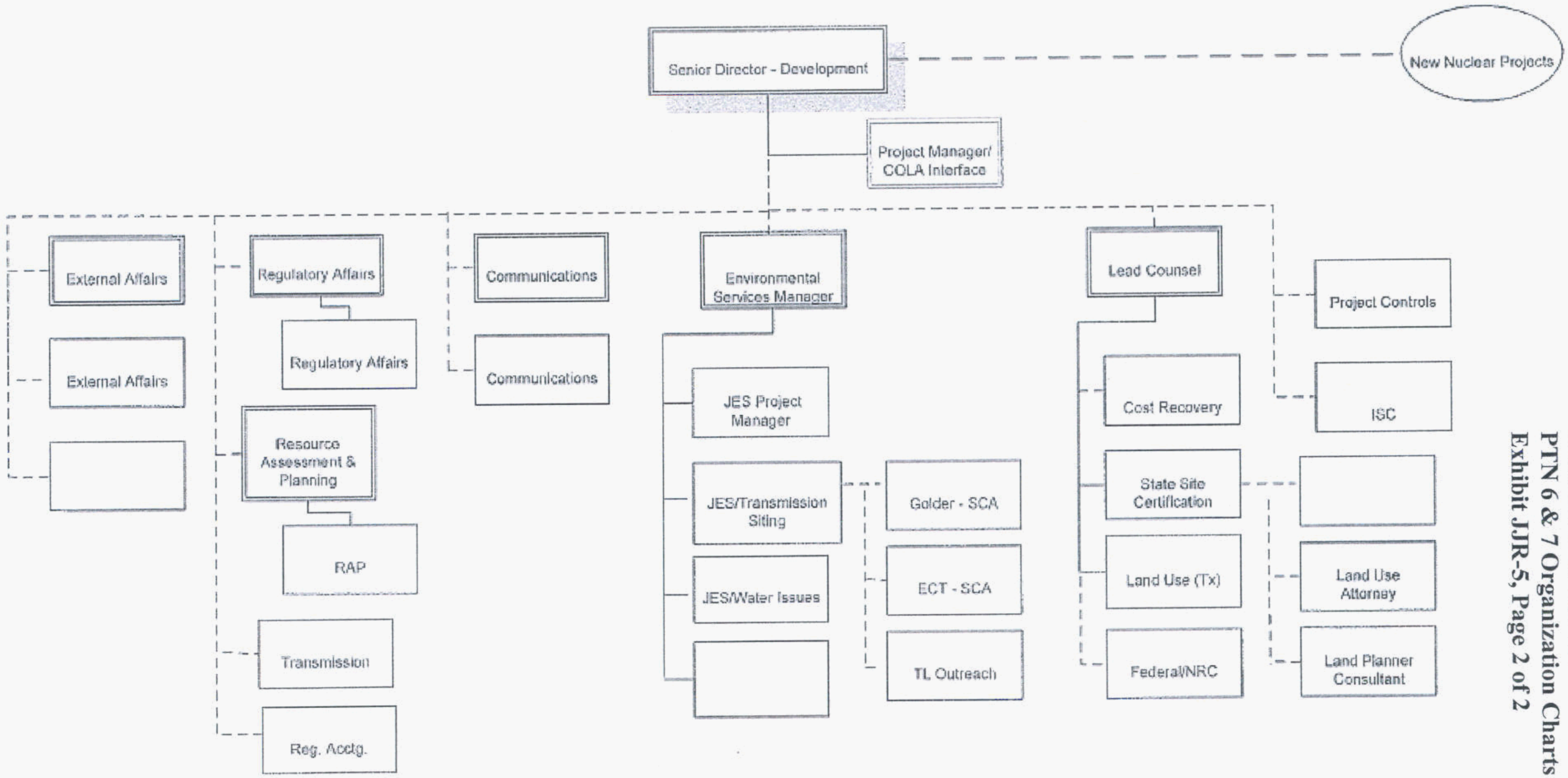


Turkey Point 6 & 7
Development Project Organization
Licensing Phase



Docket No. 120009-EI
PTN 6 & 7 Organization Charts
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