BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130009-EI
FLORIDA POWER & LIGHT COMPANY

MARCH 1, 2013

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

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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, 2011 and 2012. 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 2012 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 creating the opportunity 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 recently have 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 six 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 precedent 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 nearing completion 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 the reasonableness of 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 the use of 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. That 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 2012.

<u>Section II: Introduction to the Projects and Benefits of Nuclear Power to Florida</u>

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 512 to 526 megawatts electric ("MWe") for the benefit of FPL's customers, which is 22 to 36 MWe greater than the expected increase at this time last year, and 113 to 127 MWe greater than the original plan of 399 MWe for the EPU Project. 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 create the opportunity to construct approximately 2,200 MWe 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 and continues to play a crucial role in FPL's power generating fleet. The four reactors at FPL's existing PSL and PTN sites have been in operation for an average of over 36 years. Throughout the last three and a half decades, these units have provided numerous and substantial benefits to Florida customers by reliably producing carbon-free energy, enhancing fuel diversity and insulating customers from commodity price spikes.

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

A. Yes. It is prudent to continue the development of additional nuclear capacity in Florida whenever that capacity can be developed on an economic basis over its full life-cycle.

Q. What are the advantages of using nuclear power as a base load energy source?

A. One of the greatest advantages to additional nuclear power is that it has virtually no carbon dioxide emissions. Unlike alternative, carbon-intensive base load sources in Florida, nuclear energy does not burn fossil fuels and, therefore, emits no greenhouse gases ("GHG"). Based upon FPL's 2011 generation data and the Environmental Protection Agency's ("EPA") eGrid tool, the four nuclear units FPL operates in Florida currently avoid between 9 and 10 million tons of CO_2 emissions per year compared to an average natural gas-fired, combined cycle generating station.[1] The magnitude of avoided emissions is even greater when compared to other carbon-based fuels (*e.g.*, oil, coal) that produce the same amount of energy.

In addition to its environmental benefits, nuclear power provides a vital source of diversification to the electric generation mix. In recent years, Florida has become increasingly dependent on natural gas as a fuel source for electric generating facilities. According to the Florida Reliability Coordinating Council's 2012 Load and Resource Plan, natural gas generation could approach 58% by 2021.[2] Utilities in the state should continue to develop alternatively-fueled facilities in order to mitigate the incremental dependence on natural gas-fired generation. This will help limit the state's exposure to natural gas price spikes and potential supply disruptions.

Q. Do lawmakers have plans to address carbon emissions anytime soon?

A. Legislation aimed at curtailing carbon emissions has been introduced on several occasions. The current administration has voiced support for carbon emissions regulation that would cover existing power plants as well as new ones, though it plans to pursue such action through its executive agencies rather than Congressional legislation. In 2009, the EPA declared CO_2 and several other GHGs to be dangerous to public health and welfare, and began a process to enact federal regulations on the emission of these gases.[3] This "endangerment finding" has been applied to various sources of GHGs, including power plants and large vehicles. In March 2012, the EPA proposed a Carbon Pollution Standard Rule, which would establish CO_2 emission limits for new fossil-fuel electric generating units. The U.S. Court of Appeals for the D.C. Circuit has upheld the EPA's authority to regulate CO_2 like other hazardous pollutants under the Clean Air Act. However, plans to enact this type of regulation have not yet been finalized. In the absence of federal standards, state and regional programs such as the Regional Greenhouse Gas Initiative in the northeast and the Western Climate Initiative in the northwest have been put in place to address carbon emissions.

Although the scope and severity of restrictions remains uncertain, it is likely that these laws will affect industrial emitters, including utilities, over the next several years. Regulations may potentially require installation of new environmental controls, which can lead to the retirement of coal units if technology conversion is deemed uneconomic.

Q. How does the current price of natural gas compare with recent trends in natural gas prices?

A. Although the price of natural gas is currently on the low end of what we have observed in recent years, it has been subject to significant swings. From 2002-2008 spot natural gas prices nearly tripled from $3.68 to $9.15 per million British Thermal Units before falling to current levels in response to new supply discoveries and advances in technologies used to recover gas from shale formations.[4] While the wholesale price of gas remains below historical levels, it is important to consider the long-term outlook for the price of natural gas when evaluating the benefits of resource diversity over the anticipated 60-year life-span of a nuclear facility.

Q. How does resource diversity benefit customers in Florida?

A. Resource diversification provides numerous benefits to Florida residents by mitigating exposure to any single fuel source. This concept, as explained in modern portfolio theory, is based on the idea that a group of diverse assets may collectively lower the risks relative to holding any individual asset or type of asset. Despite currently low natural gas prices, overdependence on natural gas can expose Florida's generation portfolio to volatility in fuel prices. Diversification of fuel sources—through added nuclear power and additional renewables—insulates consumers from commodity price fluctuations and reduces the risk profile of Florida's electric generation mix.

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

A. Costs associated with nuclear power have remained stable due to the fact that fuel represents a comparatively small portion of nuclear facility operating costs. According to the Nuclear Energy Institute ("NEI"), fuel accounts for approximately 90% of the total production cost of electric energy from natural gas, whereas fuel costs of nuclear power are only 25-30% of the total production cost.[5] With fuel being the single greatest expense for gas plants, costs of production are exceedingly dependent on the price of natural gas. As a result, fuel commodity price swings have a much greater impact on gas plants than they do on nuclear plants. Nuclear plants can help insulate customers from the effects of gas price volatility.

Exhibit JJR-3 provides a simplified analysis showing that the production cost of energy from nuclear power is substantially lower than other sources of base load energy. Nuclear production costs have declined more than 30% in the last ten years to an average of 2.0 cents per kilowatt-hour.[6] While a comparison of competing resources for resource planning purposes should be analyzed in a more comprehensive resource planning environment, Exhibit JJR-3 indicates that, as a result of lower production costs of nuclear power, the electric bills of Florida residents are and have been lower and much less subject to fuel price volatility.

Q. Is it appropriate for the Commission to continue to allow recovery of certain pre-construction costs and construction carrying costs prior to the units entering into service?

A. Yes. It is appropriate to allow for cost recovery through the annual NCRC process given the magnitude of the potential benefits of additional nuclear capacity. The NCRC is important for both the Company and its customers. It 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 permitting recovery of carrying costs associated with construction, the NCRC eliminates the effect of compound interest on the total project costs, which will reduce customer bills when the facilities are fully implemented.

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

A. Yes. One benefit of nuclear generation that is often overlooked is its relatively small footprint compared to other clean, emissions-free technologies. Nuclear power plants require less land, and thus limit the degree of forest clearing, wetlands encroachments, and other environmental impacts associated with siting a generating facility.

<u>**Section III: The Prudence Standard**</u>

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 2012, the Commission reaffirmed this approach, referring to "longstanding Commission practice" (Order No. PSC-12-0650-FOF-EI):

> [T]he standard for determining prudence is consideration of what a reasonable utility manager would have done, in light of the conditions and circumstances which were known, or should have been known, at the time the decision was 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 among 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 2012.

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 review of the EPU Project's and PTN 6 & 7's 2012 activities incorporates the information and understanding of the projects gained during Concentric's reviews of FPL's activities from 2008 through 2011.

Q. Please describe how Concentric performed this review.

A. Concentric's review was performed over the period from December 2012 to February 2013. 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 2012. Concentric then reviewed other documents and conducted several in-person interviews of personnel from both FPL's corporate office and the plant sites 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");
- Internal Audit;
- 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: (1) documented with sufficient detail to allow project teams to implement the procedures; (2) clear enough to allow project teams to easily comprehend the procedures; and (3) should be revisited and revised as the project evolves and as lessons are learned. 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 direct prudently 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.[7]

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 2012

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 2012.

Q. As a preliminary matter, what did your review lead you to conclude with regard to the prudence of FPL's actions in 2012 as they related to the EPU Project?

A. FPL's decision making and management actions as they related to the EPU Project in 2012 were prudent. Those decisions and actions included: management and receipt of the necessary NRC license amendment request ("LAR") approvals for both the PTN and PSL sites; management of five implementation outages, including one mid-cycle outage; incorporation of lessons learned from earlier outages into the design, engineering, and implementation of subsequent outages; and the re-assignment of work scope from the Engineering, Procurement, and Construction ("EPC") vendor to other, qualified specialist firms in order to efficiently manage the multiple outages, along with rigorous oversight and management of those vendors. As a consequence, it is my opinion that FPL's 2012 expenditures on the EPU Project have been prudently incurred.

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, 2012 through December 31, 2012. Concentric's review of this time period relied upon data that was provided to Concentric in the period from December 2012 to February 2013.

Q. What steps has FPL taken 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 2012, the Engineering Analysis Phase was completed with receipt from the NRC of four LAR approvals (PSL Unit 1, PSL Unit 2, PTN Units 3 and 4, and the PTN Core Operating Limits Report). The Long Lead Equipment Procurement Phase and the Engineering Design Modification Phase were also essentially completed in 2012. In the Implementation Phase, four outages were completed in 2012, and a fifth (the final EPU implementation outage, at PTN Unit 4) began. As of December 31, 2012, the PTN Unit 4 outage was expected to be completed in April 2013. The activities undertaken in each of the four phases presented above are further described in the testimony of FPL Witness Jones.

Q. As of the end of 2012, what activities remain in the EPU Project?

A. The remaining activities as of the end of 2012 include the completion of the final implementation outage at PTN Unit 4, and the conclusion of close out activities. As of December 31, 2012, the EPU Project was scheduled for completion in 2013, including project close out activities. FPL added approximately 365 MWe in 2012, representing FPL's owner net share, subject to final testing. An additional 115 to 123 MWe is expected to be gained in 2013 from PTN Unit 4.

Q. Were there any modifications to the overall EPU outage schedule in 2012?

A. No. While FPL made the decision to delay the start of the 2012 outages at PTN Unit 3 and PSL Unit 2 by approximately one month each, and those outages both took longer than originally forecasted, those increased outage lengths did not affect the overall EPU Project schedule in 2012. The final PTN Unit 4 outage was still expected to be completed in April 2013, as of December 31, 2012.

Q. How was the EPU Project organized in 2012?

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, the EPU Project implemented 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 has moved 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. By the end of the year, with the PSL implementation outages complete, FPL was able to reassign the PSL Implementation Owner outside of the EPU Project.

In Juno Beach, there remained a centralized core project management team providing oversight of the EPU Project from FPL headquarters. The primary centralized positions included: 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 Licensing and Regulatory Interface Manager, 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; a Manager of Nuclear Sourcing, responsible for purchasing at the EPU sites, 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. The EPU Project team also included a Quality Assurance ("QA") manager at the Company's headquarters. Described in greater detail later in my testimony, this function necessarily acted separately from the functions described above to maintain independence when assessing the EPU Project.

Q. Is 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 major milestones were met on the EPU Project in 2012?

A. The EPU Project reached several major milestones in 2012, including receipt of all required LAR approvals for the project, completion of four implementation outages, and the commencement of the eighth and final implementation outage.

Project Estimating and Budgeting Processes

Q. Please describe the mechanisms utilized to track the project's 2012 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 2012?

A. Yes. In adherence with FPL procedure EPPI-302, "Nonbinding Cost Estimate Range," which calls for an update to the cost estimate range to be performed annually, FPL performed a review and update to its cost estimate in 2012. Specifically, FPL updated its cost estimate range for direct EPU Project costs of $2.32 billion to $2.48 billion, to a new range of $2.96 billion to $3.15 billion. The range was updated to reflect the evolution of scope of the project and lessons learned to date. As of December 31, 2012, the EPU Project cost forecast exceeded that range. The result of the cost forecast exceeding the estimated range was that the EPU Project had $0 contingency in its cost forecast as of December 31, 2012. Given the fact that the EPU Project is nearing completion, which decreases uncertainty related to the final cost of the project, I do not consider this level of contingency to be a material issue. In addition, it is my understanding that FPL plans to update its cost estimate again on or before May 1, 2013, incorporating any remaining changes based on the final EPU implementation outage at PTN Unit 4.

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

A. No, it did not. The EPU Project is large and multifaceted, and due to the nature of nuclear operations and attendant safety considerations, the scope and schedule can reasonably be expected to expand and be extended as the outage teams go through first time implementation of complex modifications. As I have stated previously, it is not uncommon for a mega project of this size to require regular updates to its cost forecast, 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.

Q. What steps did FPL take to control costs of the EPU Project in 2012?

A. First, FPL worked closely with its vendors to focus them on productivity, safety, and performance. Second, the Company sought concessions from vendors that are working on the EPU Project, including reductions in labor rates and daily living allowances, as well as the elimination of the EPC vendor's (*i.e.*, Bechtel's) incentive fee. Third, as discussed in more detail later in my testimony, FPL reassigned portions of the scope on the PTN Unit 4 outage from Bechtel to other, highly-qualified industry experts, including PCI Energy Services ("PCI"), Shaw Stone & Webster ("Shaw"), and WeldTech.

Q. Were there any changes to the structure of the contract between FPL and its EPC vendor in 2012?

A. Yes. FPL and Bechtel (the EPC vendor) had instituted a target price structure in 2011 that was set aside in 2012. The reason the target price structure was set aside is that FPL found that management personnel spent a considerable amount of time negotiating with the EPC vendor regarding proposed changes to the project's scope and whether those changes would result in changes to the target price. Setting aside the target price eliminated the distraction of such negotiations, and allowed FPL and Bechtel to focus on performance, safety, and productivity.

Q. Were there additional costs associated with setting aside the target price structure?

A. No. Legitimate additions to scope based on scope discoveries would affect the project cost under both a target price structure and a time and materials structure, so setting aside the target price would not affect the overall cost of the project. In addition, as discussed above, FPL negotiated concessions from Bechtel in 2012, which included elimination of its incentive fee, and reductions in hourly rates and daily living allowance rates.

Q. How were project controls executed by the site teams and the overall project management team to track the EPU Project's 2012 budget?

A. The site team continued to use multiple reports and reviews in 2012 to track the EPU Project's budget. Those 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 continued to produce monthly cash flow reports in 2012 that contained monthly actual capital expenditures as compared to the budget, and explanations of any increases or decreases. Those reports were reviewed and discussed during formal project management meetings.

Q. Did the EPU Project perform an analysis of its cost effectiveness in 2012?

A. Yes. In May 2012, the EPU Project was subject to an annual feasibility analysis that included a review of the cost effectiveness of completing the project.

Q. In 2012, how did the EPU Project track and identify risks to the project schedule?

A. As in prior years, the EPU Project continued to use 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.

Q. Did the EPU Project modify any of its processes in 2012?

A. Yes. 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 15 of its policy documents during 2012. Given the late stage of the project, however, most of those updates were editorial in nature. In addition to the EPU Project policies that were modified in 2012, two new EPPIs were created in 2012: (1) EPPI-190, "Human Performance," the purpose of which is to provide guidance to EPU personnel regarding the proper implementation of the Human Performance program; and (2) EPPI-235, "Work Hours Validation Sampling Program," the purpose of which is to provide a mechanism for performing random validation of contractor invoiced hours.

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 2012 are separate and apart from the normal maintenance and operations of PSL and PTN, and, therefore eligible for recovery under the NCRC. This process, which was previously reviewed and approved by the Commission,[8] included a detailed engineering analysis to determine if the component replacement or plant modification is necessary for plant operations under uprated conditions.

Q. What is your conclusion with regard to the EPU Project's processes used to track cost performance in 2012?

A. My conclusion is that the EPU Project has a robust set of policies and procedures in place to track and control cost performance. While the cost forecast for the overall Project increased in 2012, it is my opinion that such an increase is not unexpected for a mega project such as the EPU Project that involves complex modifications performed on short schedules in confined spaces that are generally inaccessible during operating cycles.

Project Schedule Development and Management Process

Q. How did the EPU Project team monitor its schedule performance in 2012?

A. In 2012, the EPU Project team continued to utilize daily, weekly, bi-weekly, monthly, and quarterly conference calls and meetings. Presentations and reports were developed to facilitate many of these conference calls and meetings. Exhibit JJR-4 provides a listing of the meetings used in 2012 to monitor the EPU Project's schedule performance, and 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-12. 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 2012 to assist FPL in managing the project?

A. Yes. With the completion of the implementation outages at PSL, FPL created a project closeout metrics package in October 2012 that tracks project closeout activities and is reviewed weekly. At PTN, daily and weekly reports were created to track schedule and cost performance for two major vendors, Bechtel and Shaw.

Q. Did the EPU Project use any other methods to monitor schedule performance in 2012?

A. Yes. FPL continued to use an industry standard software package known as Primavera P6 Professional Project Management to review the project schedule based on approved updates on an almost real-time basis. Primavera P6 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 2012. Prior to the commencement of work, FPL required its 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. During outage conditions, vendors were required to provide status updates on a daily basis and a recovery plan was required for significant deviations from the target schedule.

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

A. In 2012, 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 the 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 that EPPI modified in 2012?

A. No, it was not.

Q. What activities occurred in 2012 that altered the project schedule?

A. The overall EPU Project implementation schedule was not altered in 2012. However, the starting dates of the 2012 outages at PTN Unit 3 and PSL Unit 2 were delayed by approximately one month each. That decision was made to compensate for NRC delays related to LAR approval and to allow for greater certainty regarding the completion of planning and engineering for the upcoming outages.

In addition, as discussed earlier in my testimony, the PSL Unit 1 and the PTN Unit 3 2012 outages both took longer than originally forecasted due to evolution of the project scope that was caused by discovery and complexity associated with first time implementation of modifications at those units. Moreover, the Company was able to incorporate lessons learned from the outage at PSL Unit 1 into its outage at PSL Unit 2 and completed that outage three days ahead of schedule, and the Company projects that lessons learned from the PTN Unit 3 outage will shorten the PTN Unit 4 outage, which is in progress and was expected to finish in April 2013 as of December 31, 2012.

Q. What outstanding challenges to the timely execution of the EPU Project remain?

A. With construction complete at PSL and construction nearing completion at PTN, the Company does not foresee any significant challenges to the timely execution of the EPU Project. Risks do still exist; however, as additional issues may be discovered as equipment is tested and started up towards the end of the outage.

Q. Please describe Concentric's observations related to the EPU Project's schedule development and management in 2012.

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 2012, FPL incorporated lessons learned from the initial implementation outage at each site to the subsequent outage at each site to maintain the EPU Project on its overall implementation schedule.

Contract Management and Administration Processes

Q. In 2012, what processes were used to ensure the EPU Project was prudently managing and administering the Company's procurement functions?

A. The procurement function continued to be governed by several well-defined policies and procedures in 2012. Those policies continued to be administered through the ISC organization and included 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 2012 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 necessitates 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. Were there any changes to the process for competitive bidding process in 2012?

A. No. That process, which involves a coordinated effort between the department that originates a purchase request and ISC, continued as it has in previous years. Specifically, each competitively-bid purchase involves a purchase requisition from the originating department and the issuance of a request for proposals ("RFP") package.

Upon receipt of proposals, a Nuclear Supply Chain ("NSC") Sourcing Specialist sorts and distributes all submissions to subject matter experts for technical and commercial analysis. The originating department undertakes a side-by-side comparison of 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 determine the recommended supplier.

Q. What process was used in 2012 to make certain that the Company and its customers received the full value of the various contracts for services and materials?

A. FPL continued to utilize 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. That process requires 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 ensure that invoice monitoring reports from approved purchases are up-to-date and accurate. Each invoice review requires 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 2012 with regards to its EPC contract?

A. As discussed previously, FPL made the significant decision to reassign certain portions of Bechtel's scope to other experienced vendors for the PTN Unit 4 outage. For example, Shaw was awarded all modifications in the radioactive containment at the unit, PCI was assigned pre-outage work on the Unit 4 spent fuel pool, and Weldtech was awarded welding implementation and installation services work.

Q. Was that a reasonable decision made by FPL?

A. Yes. Reassigning certain portions of the scope provided many advantages to the EPU Project. First, with the increase in length of the PTN Unit 3 outage in 2012, the reassignment of Bechtel's scope allowed Bechtel to focus on completing its Unit 3 scope while other vendors could focus on preparing for Unit 4. Moreover, having PCI perform the Unit 4 spent fuel pool work allowed that work to be accelerated to the pre-outage period. Second, the reassignment of scope to experienced vendors allowed FPL additional opportunities to control costs. For instance, the spent fuel pool work completed by PCI was done on a fixed price basis after a competitive bidding process, and the welding scope was won by WeldTech also following a competitive bidding process.

Q. Were there any vendor-caused stand downs in 2012?

A. Yes. There were several vendor safety stand downs in 2012 to correct worker practices and mitigate safety events. None of the stand downs materially affected either the project schedule or cost. Such stand downs are important and strengthen the project, offering the EPU Project team the opportunity to reinforce safety standards and prevent potentially larger issues from occurring.

Q. Does Concentric have any observations and recommendations related to the processes used to manage the EPU Project's procurement functions in 2012?

A. Yes. Overall, Concentric noted that the EPU Project's procurement functions performed quite well in 2012. FPL appropriately reassessed its contracting structure and assignment of EPU scope, and continued to apply robust procedures to its purchasing activities.

Internal Oversight Mechanisms

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

A. There are several mechanisms used to make certain the EPU Project received adequate oversight in 2012. 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.

The EPU Project was also subject to an annual review by the FPL Internal Audit Department, and the FPL QA/QC department was responsible for making certain that the FPL QA program was being implemented by the

EPU Project team. Lastly, the FPL Employee Concerns Program ("ECP") provided FPL employees and contract workers with the ability to confidentially express concerns related to the EPU Project.

In addition, FPL transferred operational experience from NextEra's nuclear fleet to the EPU Project. That internal transfer of knowledge allowed FPL to benefit from lessons learned within NextEra that resulted 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 2012?

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 Department 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 Department did not report to any of the EPU Project team members to protect the Internal Audit Department's employees' independence. Rather, Internal Audit reported to the Senior Vice President of Internal Audit and Compliance, who reported directly to the Chairman and CEO of NextEra Energy.

Q. Did the Internal Audit Department complete any audits in 2012?

A. Yes. FPL's Internal Audit Department completed several audits in 2012. Although I have reviewed these, I will not be discussing them in my testimony because the Company maintains confidentiality with respect to these audits.

Q. Did those audits result in findings that were adverse to FPL's application of its procedures and management of the EPU Project?

A. No. While Internal Audit typically issues findings and recommendations as part of its audits, the 2012 findings and recommendations did not indicate imprudent management by FPL, and FPL has taken steps to address those findings to improve its oversight of the project. As I described above, Internal Audit acts as a backstop to the EPU's project controls functions, and its investigations and findings allow the project to address issues of human performance and, in some instances, further improve upon its procedures.

Q. Were any EPPIs issued in 2012 as a result of findings by the Internal Audit Department?

A. Yes. As a result of Internal Audit's PTN and PSL contract worker overtime audit, EPPI-235: Work Hours Validation Sampling Program was issued on August 20, 2012 and provides a mechanism for performing random validations of contractor invoiced hours versus those actually worked on a project to ensure labor billing accuracy. The EPPI mandates a quarterly comparison of vendors' invoices and security gate logs to ensure appropriate charges for all individuals in the random sample.

Q. Is Internal Audit conducting a review of the EPU Project costs charged in 2012?

A. Yes. Costs incurred by the EPU Project in 2012 are being reviewed by the Company's Internal Audit Department, with a final report expected to be issued by Internal Audit in the second quarter of 2013. Internal Audit performed a similar review in 2012 with no significant findings.

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

A. In 2012, the FPL QA/QC employees were 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 an NRC licensee's QA program. It was the responsibility of the QA/QC employees to ensure that FPL's QA program met those criteria.

Q. What QA activities related to the EPU Project took place in 2012?

A. Throughout 2012, the QA/QC function oversaw the implementation phase of the EPU Project. As the EPU Project commenced its outages, QA/QC evaluators were assigned to both PTN and PSL. The QA/QC evaluators were 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. Those activities included multiple in-person reviews of the project vendors' methodologies, qualifications and QA programs. Finally, the QA/QC evaluators monitored NRC QA activities and suggested changes to the EPU Project to respond to the NRC's findings at other power uprate projects.

Q. Please describe the FPL ECP and its purpose.

A. The FPL ECP is a confidential process through which EPU employees and contractors can raise concerns regarding nuclear safety and hostile work environments. ECP had a physical presence at both PSL and PTN, and ECP coordinators conducted outreach in order to educate employees and contractors about the existence of the program. When a concern was brought to the attention of ECP personnel, initial feedback was provided to the concerned individual and, if necessary, a formal investigation was launched. Many of the concerns raised were not substantiated; however, some contract worker supervisors were disciplined. In order to determine whether concerns were resolved, ECP personnel followed-up with concerned individuals three months after their initial meeting to ensure that the employee's concerns were addressed.

Q. What internal operational experience did FPL incorporate into the EPU Project in 2012?

A. In 2012, 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 2012.

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 2012 to ensure the EPU Project had adequate internal controls and were prudently incurring costs?

A. As in prior years, there were several external oversight and review mechanisms in place for the EPU Project. Those oversight and review mechanisms included the retention of my firm, Concentric, to perform the review described in this testimony, 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. In 2012 did industry contacts provide a form of external oversight and review?

A. Yes. FPL is a member of several industry groups, including the Institute of Nuclear Power Operations, the World Association of Nuclear Operators, the Electric Power Research Institute and NEI, among others, which provided further guidance about uprate projects. Each of those groups provided the EPU Project team with access to a wide breadth and depth of information that was used to enhance the project team's effectiveness. Additionally, relationships that the EPU Project team members have with their counterparts at other nuclear power plants around the country allow the EPU Project team to benefit from operating and construction experience at other plants and incorporate that experience into the planning and implementation at PSL and PTN.

Q. Did Concentric have any observations related to external oversight and review of the project in 2012?

A. During its review, Concentric noted that FPL appeared to have taken reasonable steps to obtain and implement lessons learned from outside sources in 2012. These lessons learned are vital to the successful execution of the projects.

<u>**Section VI: PTN 6 & 7 Project Activities in 2012**</u>

Q. How is this section of your testimony organized?

A. This section describes Concentric's 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 2012.

Q. As a preliminary matter, what did your review lead you to conclude with regard to the prudence of FPL's actions in 2012 on the PTN 6 & 7 Project?

A. FPL's decision to continue pursuing PTN 6 & 7 in 2012 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 2012 has resulted in prudently incurred costs. During 2012, 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 2012?

A. Since 2008, few changes have occurred in the PTN 6 & 7 Project organization, which is depicted in Exhibit JJR-5. In 2012, 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 through the same executive management chain, 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 2012. In contrast, the New Nuclear Projects organization remains responsible for submitting and defending the PTN 6 & 7 Construction and Operating License Application ("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 2012, who was responsible for the New Nuclear Projects organization?

A. In 2012, the New Nuclear Projects organization fell 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 2012?

A. Throughout 2012, the Project Development organization also fell 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 Director of Development who was supported via matrix relationships by a variety of FPL functional departments.

Q. What internal FPL departments supported the New Nuclear Projects and Project Development organizations in 2012?

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 2012?

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 2012?

A. The main focus of the New Nuclear Project in 2012 was to maintain progress in the facilitation of the federal and state licensing reviews. To that end, PTN 6 & 7 achieved several important milestones.

Since its completion in September 2011, the project's state Site Certification Application ("SCA") has continued to move forward in the review process. Reports from both county and state level agencies provided analysis of the transmission and plant portions of the project, including the ongoing review of two alternative transmission corridors that were formally proposed in December 2012. New Nuclear Project staff has maintained an ongoing dialogue with these agencies in support of the Environmental Impact Statement ("EIS") for the federally authorized land exchange with the Everglades National Park. On November 16, 2012, FPL submitted a draft SCA amendment to reflect updated information. In addition, work was focused on an Underground Injection Control ("UIC") well construction permit application.

On the federal licensing front, throughout 2012 the project continued to respond to Requests for Additional Information ("RAIs") from the NRC as the agency's staff reviews the PTN 6 & 7 COLA. On May 4, 2012, the NRC identified two issues with FPL's RAI responses and placed the review of certain portions of the FPL COLA under review, awaiting revisions to a restricted set of RAI responses and reviews of the QA programs in place within the project and within one of the project's contractors. I discuss this issue in greater detail below. QA audits of the internal and external review processes for RAI responses were completed in July 2012 and communicated to the NRC. Finally, in December 2012, FPL submitted the fourth revision of its COLA, which incorporates data addressed in the responses to RAIs throughout 2012.

In addition, FPL applied for zoning approval of its Radial Collector Wells and Reclaimed Water Treatment Facility with Miami-Dade County ("MDC") in July 2012. An initial hearing to determine whether ancillary services associated with water treatment comply with MDC's land-use regulations was held in December 2012.

Q. Were there changes in 2012 that affect expectations for the timing of future regulatory approvals?

A. As I mentioned above, on May 4, 2012, the NRC sent a letter to FPL in which it identified concerns with responses to a subset of the agency's RAIs that were submitted in the Fall of 2011. The NRC stated that those issues affect the NRC Staff's ability to complete its safety and environmental reviews of certain sections of the PTN 6 & 7 COLA. The concerns raised by the NRC fall into two specific categories: 1) geology, seismology and geotechnical engineering as discussed in Section 2.5 of the Final Safety Analysis Report ("FSAR"); and 2) alternative sites (Section 9.3 of the Environmental Report). With respect to Section 2.5 of the FSAR, the NRC directed FPL to conduct internal and external audits of its QA practices associated with specific RAIs. In terms of the Environmental Report, the NRC requested that FPL revise its site selection process to generate at least three inland alternative sites.

Two nuclear oversight evaluators performed audits of internal FPL management oversight and QA, and the results were conveyed to the NRC in a July 2012 public meeting. Those audits will be addressed later in my testimony. Work continues on the development of supplemental responses to the previously submitted FSAR 2.5 RAIs.

The effect these scheduling changes will have on the PTN 6 & 7 Project (if any) is currently unknown. If review of the remaining portions of the COLA continues, it is possible that there will be no delay in the review schedule. As of year-end 2012, FPL expected those responses to be complete in February 2013 and a new schedule to be released in early 2013.

In addition to schedule uncertainty on the timing of the federal licensing process, there have been changes to the timing of the SCA process. FPL has been in discussions with MDC over key terms in land-use and zoning policy that affect the siting of the reclaimed water facility required for PTN 6 & 7. A hearing before the MDC County Commissioners was held on this issue in December 2012, and the matter was expected to be resolved in early 2013.

Schedule delays associated with resolution of the land-use issues have caused the public hearings on the project's SCA to be delayed. As of December 31, 2012, that hearing was expected in July 2013. Because the SCA is not a critical path schedule element, those changes are expected to have no effect on the current commercial operation dates for the new units.

Q. Do challenges facing the NRC affect the PTN 6 & 7 Project?

A. Yes. The NRC was presented with two significant challenges in 2011 that continued to affect the nuclear industry in 2012. In March of that year, the earthquake near Japan's Fukushima Daiichi Nuclear Generating Station prompted the NRC to shift considerable personnel resources to an emergency task force assigned with ensuring that both existing and proposed U.S. nuclear facilities are adequately protected from similar seismic events. An earthquake that struck Virginia only months later caused additional reassignment of NRC engineering staff members to an assessment of that incident. As a result of those emergent priorities, some members of the teams assigned to review licensing applications for new nuclear projects were tasked with other assignments, delaying technical reviews of new nuclear licensing applications. The PTN 6 & 7 Project is not alone in having been affected by those staffing challenges. Exelon, Tennessee Valley Authority, PSEG, and other projects have also received revised review schedules. In addition, ongoing budget discussions within the federal government have created uncertainty with respect to the NRC's budget. FPL has been made aware that constraints have limited the extent to which the NRC can use outside expert technical contractors (a resource that is typically heavily relied upon by the NRC) to assist in its review of licensing applications.

Q. Please describe what decisions related to PTN 6 & 7 were made in 2012.

A. FPL determined that continuing to extend PTN 6 & 7's reservation agreement with Westinghouse for reactor vessel head 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, and, as of year-end 2012, had been extended to March 31, 2013. The constraints on that market have loosened considerably, and 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 maintaining the reservation.

In addition, during the process of completing its EIS for the Everglades Land Swap, the National Park Service has indicated that it would prefer to consider additional transmission corridors that were not originally suggested. Despite the fact that the submission deadline had passed for the submission of alternative routes, FPL agreed to re-open the review process to allow interveners to suggest additional alternatives for analysis, increasing the robustness of the review process. As a result, two new proposed pathways were introduced in December 2012 and are currently under review by FPL and state and federal agencies.

Lastly, due to remaining uncertainty with the timing of the NRC's license review process for PTN 6 & 7, FPL has made plans to reevaluate its execution schedule for the units after the NRC publishes a new review schedule.

No other major decisions affecting the direction of the project were made in 2012.

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

A. Yes. In the second fiscal quarter of 2012, the Company performed a feasibility analysis regarding PTN 6 & 7, concluding that the project continued to be feasible in five of the seven scenarios of fuel and environmental compliance costs considered. FPL revisits its feasibility analysis on an annual basis in accordance with NCRC requirements.

Project Estimating and Budgeting Processes

Q. Please describe how the 2012 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 (*i.e.*, 15%) for undefined scope or project uncertainties.

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 2012 budgets was consistent with FPL's corporate procedures, which outline the process to be used by each business unit when developing annual budgets.

No changes were made to the procedures that govern the development of project budgets during 2012.

Q. What mechanisms did the PTN 6 & 7 Project team use to monitor budget performance in 2012?

A. The PTN 6 & 7 Project team used numerous reports to manage budget performance. Those reports are more fully described by FPL Witness Scroggs on Exhibit SDS-4. Throughout the year, on a monthly basis, the PTN 6 & 7 Project management team 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, project management presented a status update to FPL's senior management on a monthly basis. 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. Reporting mechanisms in place throughout 2012 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 in place for approving invoices and tracking project expenditures are codified in formal procedures used by the PTN 6 & 7 Project team.

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

A. Concentric found that in 2012 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 continue to 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 important tools 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 Risk Assessments 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 a prior review, 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, and I believe that opportunity to strengthen the Quarterly 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 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. 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. The Company plans to obtain a more definitive cost estimate as the project progresses beyond the licensing phase.

Q. Did FPL review its overnight cost estimate for the PTN 6 & 7 Project?

A. Yes. FPL evaluated whether design changes that have been incorporated by Westinghouse in response to the Fukushima events are likely to materially affect FPL's cost estimate for PTN 6 & 7.

After conducting a thorough review of cost trends among other AP1000 projects, FPL determined that no change in its cost estimate is warranted at this time. The Company plans to continue monitoring cost trends among the other utilities pursuing new nuclear units, and will work with them and its contractors to update cost estimates in the future, as appropriate.

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 2012.

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.

As I discussed above, state and federal review schedules continue to evolve. FPL continues to believe that the project can be successfully completed within the current commercial operations schedule. When a revised schedule from the NRC becomes available, FPL will evaluate the effect that any schedule adjustments may have on the project timeline, including the assessment of whether early construction phases can be further condensed to capture lost time from extended regulatory reviews.

Q. What procedures or project instructions existed in 2012 to govern the development and refinement of the PTN 6 & 7 schedule?

A. New Nuclear Project - Project Instruction 100 continues to govern the development, refinement and configuration of the project schedule. No substantive changes were made to this project instruction in 2012.

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. In addition, 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 2012?

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 informed on 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 2012?

A. Yes. In order to avoid the need to recruit, train and retain the significant number of employees required to obtain a COL and State Certification, to complete other project activities, and to respond to interrogatories from federal, state, and local agencies, FPL continued to use a number of outside vendors in 2012. Those vendors were utilized to provide ongoing post-submittal support, among other tasks. As has been the case in years past, FPL's use of outside vendors and contractors is consistent with expectations in the new nuclear industry.

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

A. FPL has a number of corporate 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 corporate procedures, while also containing nuclear-specific procurement procedures. The corporate procedures, along with the Procurement Process Manual, are sufficiently detailed to ensure that ISC prudently manages the 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. Were any procedures used by the ISC team revised in 2012?

A. In 2012, no changes were made to procedures governing contractor oversight and management. However, several changes were made to procedures related to contractor selection. The threshold for procurements that require competitive bidding was changed from $25,000 to $50,000, with a corresponding change to the SSJ threshold. Finally, the instructions outlining the use of pre-determined sources were revised to require approval from an ISC Director level or a higher level in the project organization.

Q. Did Concentric review examples of how these processes were implemented throughout 2012?

A. Yes. Concentric reviewed information related to new contracts, purchase orders and change orders issued for the PTN 6 & 7 Project that involved at least $100,000. Relative to early phases of the project, PTN 6 & 7 entered into comparatively few new contracts in 2012, executing only seven such contracts during the year. Of these, two were competitively bid and five were single-sourced.

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 2012 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 project directors and their staffs 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 2012 in which there was disagreement between the project and its vendors over charges included in invoices?

A. Yes. In 2012 FPL was charged for warranty work that was performed by Bechtel. Upon discovering that warranty work would be required, FPL requested that Bechtel track billings under special billing codes. As a matter of course, the Company then withheld payment of the aggregate overcharge when completing payment of monthly invoices.

The work included in these invoices pertains to work performed in response to the NRC's May 4, 2012 letter in which the agency expressed concerns with RAI responses pertaining to Section 2.5 of the FSAR. The Project Director and Project Controls staff continue to work with Bechtel to resolve these billing issues.

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 2012. In addition, the Company continued to follow recommendations that Concentric has made in prior years with respect to contracts and ISC management.

<u>Internal Oversight Mechanisms</u>

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 continued to use a number of periodic reports in 2012 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 FPL 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 procedures, but has been developed outside of the FPL Nuclear Division. Thus, PTN 6 & 7 has not been 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. QA/QC staff has created a regular update schedule to revise and update this procedure in order to adapt to the dynamic nature of the project.

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 department.

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. Each year, the FPL Internal Audit Department performs an audit of PTN 6 & 7 to test whether charges billed to the project are appropriate and that those charges are 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. Costs incurred by the New Nuclear Project in 2012 are currently being reviewed by the

Company's Internal Audit Department. As of December 31, 2012, a final report was expected to be issued by Internal Audit in May 2013.

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 for the EPU Project, which was discussed earlier in my testimony.

Q. Please describe the QA/QC function's findings from the audit performed in response to the NRC's May 4 Letter regarding questions on Section 2.5 of the FSAR.

A. As I have discussed in testimony filed in prior years, FPL has reasonably and appropriately relied on Bechtel to prepare responses to RAIs in situations in which FPL staff does not have the specific expertise required to address questions. This is the case for questions related to geologic seismology, which is discussed in Section 2.5 of the FSAR, a subsection of the PTN 6 & 7 COLA. In January 2012, the NRC began to express concern with responses that had been submitted to RAIs pertaining to this portion of the COLA. The NRC's subsequent letter to FPL indicated that several responses had failed to address the questions posed, and that there were indications that the QA protocols in place to ensure accurate responses may have been lacking.

In order to determine whether there were any faults in the QA programs as implemented by the PTN 6 & 7 Project, the FPL QA/QC team undertook an extensive audit of FPL management oversight and QA processes in the areas of geology, seismology, and geotechnical engineering. Despite finding that FPL's framework for meeting regulatory requirements is satisfactory, the QA audit confirmed that several responses pertaining to seismology and geology submitted to the NRC were of poor quality and had failed to adequately address the questions that had been asked. In addition, the report indicated that while FPL had initially failed to identify the need for additional expert resources to confirm the accuracy of certain RAI responses, the Company's decision to immediately hire an outside industry expert to support its RAI response program was the appropriate corrective action.

Q. Did the report find any deficiencies with Bechtel's QA processes?

A. Yes. The audit found deficiencies in the implementation of Bechtel's independent QA oversight of RAI responses. Specifically, there was no independent Bechtel QA oversight associated with the responses to RAIs pertaining to FSAR Section 2.5, and responses had been submitted without all relevant questions being addressed.

FPL's QA Manager communicated specific concerns identified in the QA audit to Bechtel, which undertook significant efforts to rectify the issues identified by the NRC and the FPL QA audit. In September 2012, the FPL QA/QC team conducted a comprehensive audit of Bechtel's processes for responding to NRC RAIs. That audit was conducted at Bechtel's offices in Frederick, Maryland, and involved an extensive review of work product samples and in-person interviews. The results of the audit confirmed that the Bechtel QA program, as revised and improved in response to concerns raised by the NRC and FPL, is being implemented properly.

Q. Did the QA/QC function conduct an Extent of Condition review to determine whether similar problems exist in FPL's responses to other parts of the COLA?

A. Yes it did. An Extent of Condition review found similar concerns with review processes for COLA documents beyond those associated with FSAR Section 2.5. Specifically, the audit found that internal and external reviews had not detected errors in a subset of responses that had been submitted to the NRC.

However, in all cases identified, FPL was able to detect and rectify errors and resubmit responses before any issues were raised by the NRC.

Q. How did FPL respond to the NRC's early indications of concern with the responses related to Section 2.5 of the FSAR?

A. Because FPL does not have internal expertise in geologic seismology, FPL contracted with AMEC, a recognized industry leading expert in geology and seismology, in January 2012, immediately after learning of the NRC's concerns. The scope of the contract with AMEC included a review of all responses that had been provided on FSAR Section 2.5, as well several additional components of the COLA. AMEC had performed similar work on behalf of Progress Energy Florida for the proposed Levy nuclear plant.

Q. How else has FPL responded to the QA findings?

A. Lessons learned in the evaluation of responses to questions on Section 2.5 of the FSAR have been used to improve the technical review of all RAI responses provided to the NRC. FPL also has confirmed that Bechtel has responded vigorously to the NRC's concerns and has implemented revisions to its QA processes to ensure that similar errors do not occur in any of its responses.

Q. Has FPL issued warranty claims for work performed by Bechtel in response to the issues raised by FPL and the NRC?

A. Yes. FPL has continued to work with Bechtel to resolve these warranty claims and, as of year-end 2012, expected to resolve all outstanding claims in 2013.

Q. What is your overall assessment of FPL's decisions, policies and procedures as they relate to the issues raised by the NRC?

A. My overall assessment is that the issues raised by the NRC are not the result of imprudent management or decision making by FPL. FPL reasonably relied on an industry expert (*i.e.*, Bechtel) to perform the initial RAI responses, acted quickly and appropriately to the issue by hiring an additional expert (*i.e.*, AMEC), increased its internal and vendor oversight of the RAI response process, and issued warranty claims to Bechtel for the corrected work.

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. Concentric has found that FPL's internal oversight mechanisms were prudently and appropriately applied in 2012.

External Oversight Mechanisms

Q. What external review mechanisms were used by the PTN 6 & 7 Project team in 2012 to ensure 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 2012, FPL maintained membership in several industry groups that relate to the development of new nuclear projects. Those groups include the NuStart Consortium, APOG (the AP1000 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.

Q. Did Concentric have any observations related to the external oversight mechanisms utilized by FPL in 2012?

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 2012. FPL's decision making and management actions as they related to the EPU Project in 2012 included: management and receipt of the necessary NRC license amendment request ("LAR") approvals for both the PTN and PSL sites; management of five implementation outages, including one mid-cycle outage; incorporation of lessons learned from earlier outages into the design, engineering, and implementation of subsequent outages; and the re-assignment of work scope from the EPC vendor to other, qualified specialist firms in order to efficiently manage the multiple outages, along with rigorous oversight and management of those vendors. For PTN 6 & 7, 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. As a consequence, it is my opinion that FPL's 2012 expenditures on the EPU Project and PTN 6 & 7 were prudently incurred.

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:

[1] Environmental Protection Agency, eGRIDweb online application. http://cfpub.epa.gov/egridweb/view.cfm

[2] "Review of the 2012 Ten-Year Site Plans for Florida's Electric Utilities," *Florida Public Service Commission*, December 2012.

[3] Broder, John . "E.P.A. Clears Way for Greenhouse Gas Rules." *New York Times*, April 17, 2009.

[4] Smith, Rebecca, "Rush to Natural Gas Has Coal-Fired Utilities Seeing Red," *The Wall Street Journal*, January 24, 2013.

[5] Production cost is equal to operating and maintenance costs plus fuel costs.

[6] Nuclear Energy Institute Resources & Statistics

[7] 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.

[8] 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 35 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. Has 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 and served on a "Blue Ribbon" panel established by the Province of New Brunswick regarding the future of natural gas distribution service in that province.

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, pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to most 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, 24, 79 and 99 Licenses

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

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

ARTICLES AND PUBLICATIONS

"Maximizing U.S. federal loan guarantees for new nuclear energy," *Bulletin of the Atomic Scientists* (with John C. Slocum), July 29, 2009

"Smart Decoupling – Dealing with unfunded mandates in performance-based ratemaking," *Public Utilities Fortnightly*, May 2012

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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
Alberta Utilities Commission				
Alberta Utilities (AltaLink, EPCOR, ATCO, ENMAX, FortisAlberta, Alta Gas)	1/13	Alberta Utilities	Application 1566373, Proceeding ID 20	Stranded Costs
Arizona Corporation Commission				
Tucson Electric Power	7/12	Tucson Electric Power	Docket No. E-01933A-12-0291	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

Sponsor	Date	Case/Applicant	Docket No.	Subject
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Connecticut Natural Gas	11/87	Penn-York Energy Corporation	Docket No. RP87-78-000	Cost Alloc./Rate Design
AMAX Magnesium	12/88, 1/89	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
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, 11/92	Northern Natural Gas Company	RP92-1-000, et al	Cost of Service

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Canadian Association of Petroleum Producers and Alberta Pet. Marketing Comm.	10/92. 7/97	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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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	
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. RP10-79-000	Affidavit re: Impact of Preferential Rate

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
Florida Power and Light Co.	3/12 7/12	Florida Power & Light Co.	Docket No. 120009-EI	New Nuclear cost recovery , prudence
Florida Power and Light Co.	3/12 8/12	Florida Power & Light Co.	Docket No. 120015-EI	Benchmarking in support of ROE
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.	Docket No. 99-0207	Standby Charge

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/01	Northern Indiana Public Service Company	Cause No. 41746	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
Maine Public Utility Commission				
Northern Utilities	5/96	Granite State and PNGTS	Docket No. 95-480, 95-481	Transportation Service and PBR

Sponsor	Date	Case/Applicant	Docket No.	Subject
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
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

Sponsor	Date	Case/Applicant	Docket No.	Subject
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
Boston Edison Company	2/99	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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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 04/03	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 2/06 7/06	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
Laclede Gas Company	5/11	Laclede Gas Company	Case No. CG-2011-0098	Affiliate Pricing Standards

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Union Electric Company d/b/a Ameren Missouri	2/12, 8/12	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.	12/06, 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
Maritimes & Northeast Pipeline	7/10	Maritimes & Northeast Pipeline	RH-4-2010	Regulatory policy, toll development

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
TransCanada Pipelines Ltd	9/11, 5/12	TransCanada Pipelines Ltd.	RH-3-2011	Business Services and Tolls Application
Trans Mountain Pipeline ULC	6/12, 1/13	Trans Mountain Pipeline ULC	RH-1-2012	Toll Design
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New Jersey Natural Gas	2/89	New Jersey Natural Gas	B.P.U. GR89030335J	Cost Alloc./Rate Design
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
Southwestern Public Service Co., New Mexico	12/12	SPS New Mexico	Case No. 12-00350-UT	Rate Case, Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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
Nova Scotia Utility and Review Board				
Nova Scotia Power	9/12	Nova Scotia Power	Docket No. P-893	Audit Reply
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
ATOC	3/96 4/96	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 3/02	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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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
Cross Texas Transmission	08/12 11/12	Cross Texas Transmission	Docket No. 40604	Return on Equity
Southwestern Public Service	11/12	Southwestern Public Service	Docket No. 40824	Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Utah Industrial Group	7/90 8/90	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	Rate development
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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, Northern District of Illinois, Eastern Division				
U.S. Securities and Exchange Commission	4/12	U.S. Securities and Exchange Commission v. Thomas Fisher, Kathleen Halloran, and George Behrens	Case No. 07 C 4483	Prudence, PBR
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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

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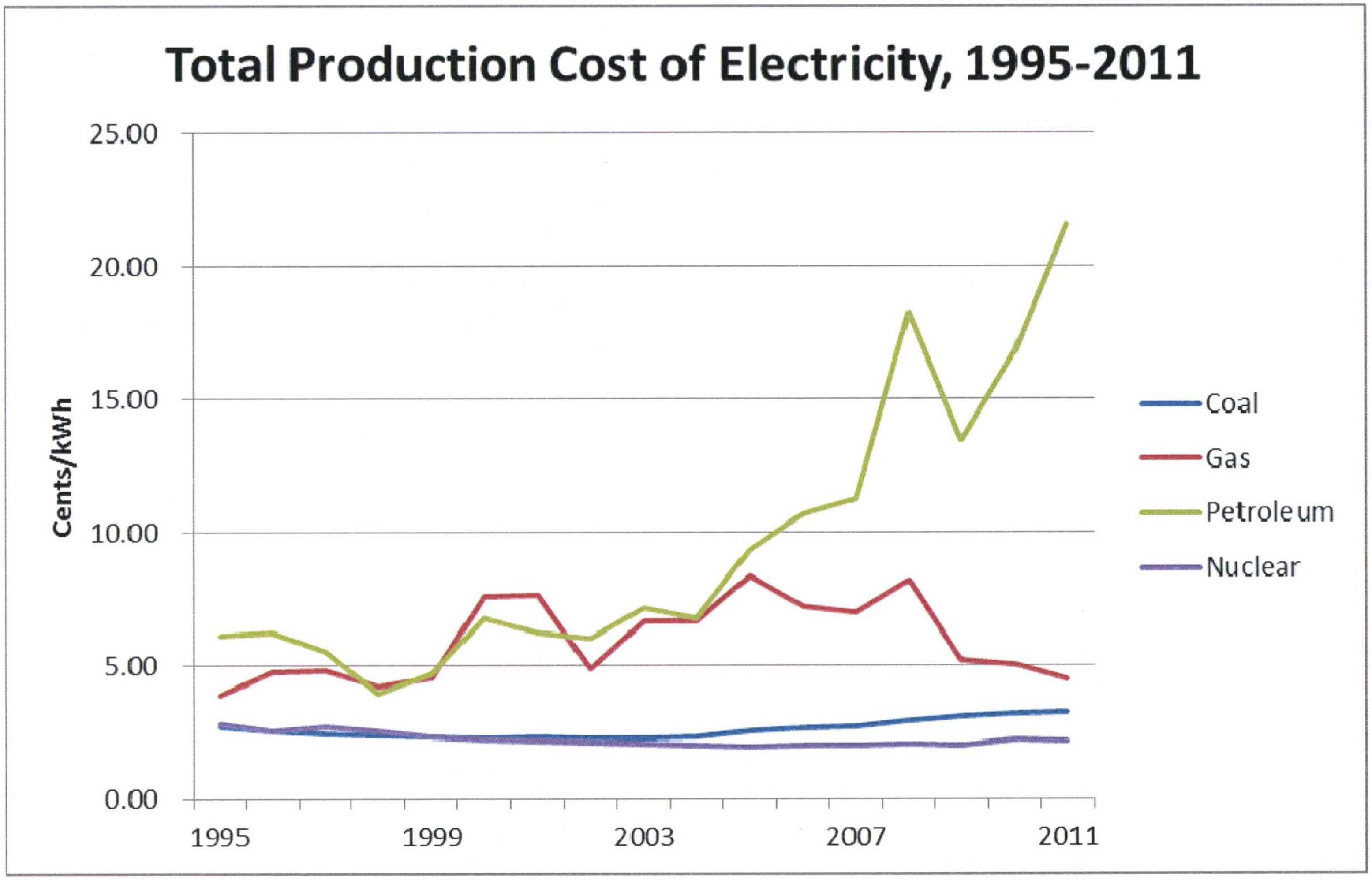

Docket No. 130009-EI
Total Production Cost of
Electricity, 1995 – 2011
Exhibit JJR-NNP-3, Page 1 of 1

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Index of the EPU Projects' Periodic Meetings

Meetings

1. EPU Executive Steering Committee Meeting (meetings held or presentations delivered to the members and "one-off" meetings held with senior executives)
    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 (outside of outages)
    b. Attendees: Site representatives
    c. Purpose: review and report daily work plans
3. Engineering and Construction Trend Review Meeting (PSL & PTN)
    a. Occurs: as needed
    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 (PTN), as needed (PSL)
    b. Attendees: managers
    c. Purpose: review and track identified project risks

6. EPU Leadership Meeting (discontinued at PSL in August 2012 – PSL held separate weekly meetings outside of outages and daily meetings during outages; discontinued at PTN in November 2012)
    a. Occurs: weekly
    b. Attendees: FPL leadership and the major vendors managers
    c. Purpose: discussion of project strategies and progress
7. Plant Change Modifications (discontinued when engineering was essentially complete; discontinued at PTN in July 2012 and at PSL in October 2012)
    a. Occurs: weekly
    b. Attendees: Engineering Supervision
    c. Purpose: 8-week look ahead meeting
8. FPL – Siemens meeting (discontinued following the completion of Siemens work scope; discontinued at PSL in November 2012)
    a. Occurs: weekly
    b. Attendees: EPU Management
    c. Purpose: review status of Siemens EPU scope
9. Bechtel Schedule and Cost Performance meeting (discontinued at PSL, Bechtel demobilized in December 2012)
    a. Occurs: weekly (daily during outages)
    b. Attendees: Bechtel and EPU management
    c. Purpose: review of Bechtel's CPIs and SPIs
10. 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
11. Project and Plant Integration meeting (PTN)
    a. Occurs: weekly
    b. Attendees: EPU project management and plant management
    c. Purpose: project and plant integration

12. Key Supplier Meeting (discontinued in March)
    a. Occurs: Quarterly
    b. Attendees: Senior FPL management and senior management from major vendors
    c. Purpose: first time quality and interfacing between vendors
13. CNO Meeting
    a. Occurs: approximately bi-monthly
    b. Attendees: EPU Senior management
    c. Purpose: report project status
14. Lead Team Meeting (PTN)
    a. Occurs: Daily
    b. Attendees: FPL Site EPU leadership team
    c. Purpose: review progress and project execution
15. 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
16. NRC EPU LAR Status meeting (discontinued when licenses were past the ACRS subcommittee meeting recommendation)
    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
17. Project Manager Review Meeting (PTN; discontinued in June 2012)
    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
18. Outage Turnover Meeting
    a. Occurs twice per day during outage period (merged with Plan of the Day Accountability Meeting in November 2012)
    b. Attendees: Team Room Lead, Night / Day shift PM, Construction Manager
    c. Purpose: Review status from one shift to the next

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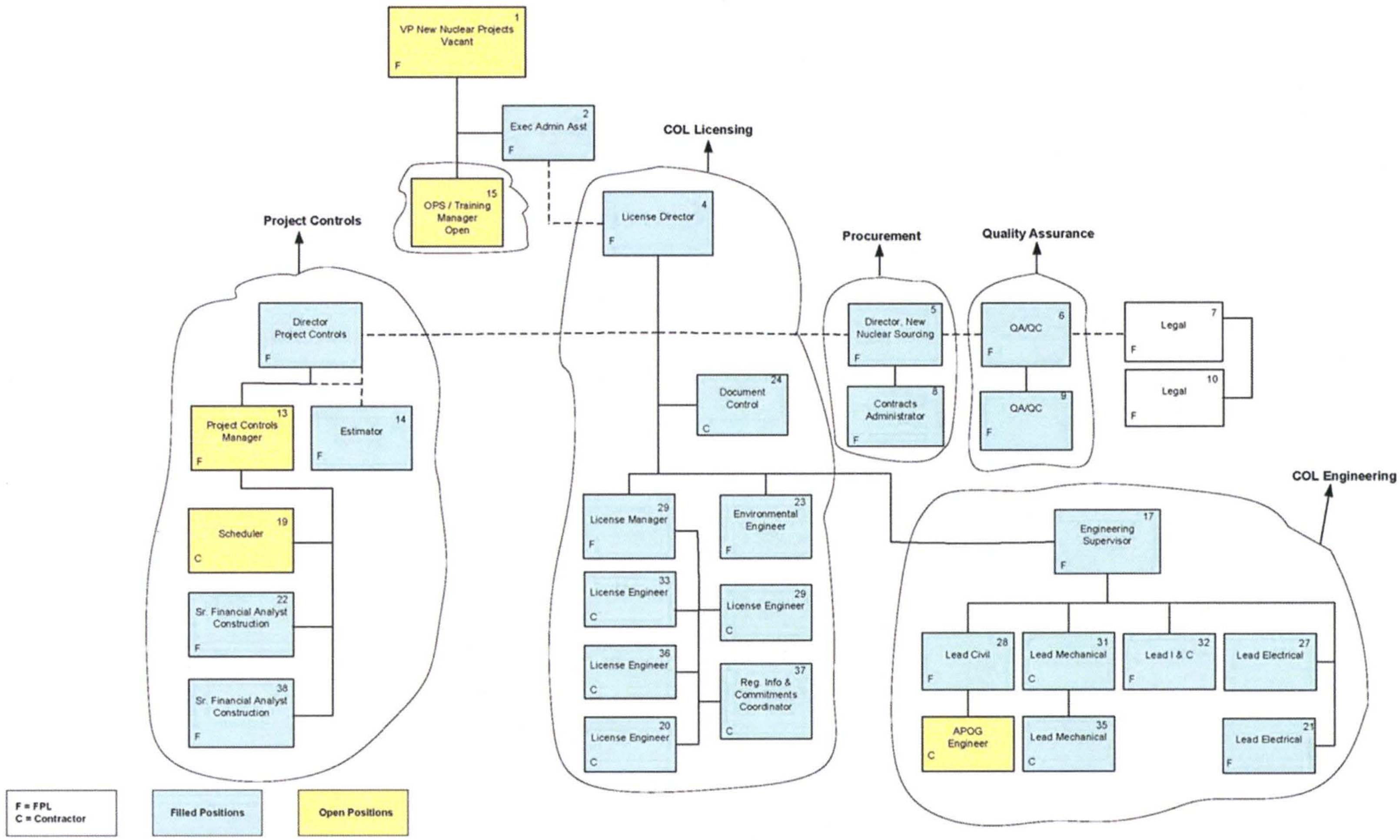
Docket No. 130009-EI
PTN 6 & 7 Organization Charts
Exhibit JJR-5, Page 1 of 2



Docket No. 130009-EI
PTN 6 & 7 Organization Charts
Exhibit JJR-5, Page 2 of 2

Turkey Point 6 & 7
Development Project Organization
Licensing Phase