BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080009-EI
FLORIDA POWER & LIGHT COMPANY

MAY 1, 2008

IN RE: NUCLEAR POWER PLANT COST RECOVERY AMOUNT TO BE RECOVERED DURING THE PERIOD JANUARY – DECEMBER 2009, INCLUDING FINAL TRUE-UP FOR THE PERIOD ENDING DECEMBER 2007, ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD ENDING DECEMBER 2008, AND PROJECTIONS FOR THE PERIOD ENDING DECEMBER 2009

JANUARY 2006 – DECEMBER 2009

TESTIMONY & EXHIBITS OF:

K. OUSDAHL
S. HALE
S. SCROGGS
S. SIM
J. REED

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF KIM OUSDAHL

DOCKET NO. 080009-EI

May 1, 2008

Q. Please state your name and business address.

A. My name is Kim Ousdahl. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL or the Company) as Controller.

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of FPL's filing and demonstrate that the filing complies with Florida Administrative Code Rule 25-6.0423, Nuclear Power Plant Cost Recovery (the Rule). Consistent with the Rule, my testimony requests that the Commission approve a Nuclear Power Plant Cost Recovery ("NPPCR") amount of $258,979,772 on a jurisdictional adjusted basis to be recovered through the 2009 Capacity Cost Recovery Clause ("CCRC"). In conjunction with approval of the NPPCR amount, FPL requests that the Commission do the following:

- Review and approve recovery of carrying charges associated with the 2008 Actual/Estimated and 2009 Projected construction costs for the Uprate Project, as presented in the testimony of FPL witness Stephen Hale.
- Review and approve recovery of the 2007 Actual, 2008 Actual/Estimated and 2009 Projected pre-construction costs and associated carrying charges for Turkey Point 6 & 7, as presented in the testimony of FPL witness Steven Scroggs.
- Determine that FPL's 2007 pre-construction costs for Turkey Point 6 & 7 were prudently incurred, for the reasons presented in the testimony of Mr. Scroggs.
- Approve FPL's proposal to recover FPL's 2006-2007 Site Selection costs and associated carrying costs through the CCRC effective January 1, 2009 as part of FPL's NPPCR amount. Consistent with approving FPL's proposal, FPL further requests that the Commission determine FPL's 2006-2007 Site Selection costs for the Turkey Point 6 & 7 project were prudently incurred, for the reasons presented in Mr. Scroggs' testimony.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes. I am sponsoring portions of the following exhibits:

- STH-2, which consists of Appendix I containing the Nuclear Filing Requirements Schedules (NFRs) for the Uprate Project. Page 2 of Appendix I contains a table of contents listing the NFRs that are sponsored by Mr. Hale, Dr. Sim and me, respectively.

- SDS-1, which consists of Appendix II containing the NFRs for Turkey Point 6 & 7 pre-construction costs. Page 2 of Appendix II contains a table of contents listing the NFRs that are sponsored by Mr. Scroggs, Dr. Sim and me, respectively.
- SDS-2, which consists of Appendix III containing the NFRs for Turkey Point 6 & 7 Site Selection costs. Page 2 of Appendix III contains a table of contents listing the NFRS that are sponsored by Mr. Scroggs and me, respectively.

<u>NUCLEAR COST RECOVERY RULE</u>

Q. Please describe the purpose of the Rule.

A. On March 20, 2007, in Order No. PSC-07-0240-FOF-EI, this Commission adopted the Rule to implement Section 366.93, Florida Statutes (the Statute), which was enacted by the Florida Legislature in 2006. The stated purpose of the Statute is to promote utility investment in nuclear power plants, and it directed the Commission to establish alternative mechanisms for cost recovery and step-wise, periodic prudence determinations with respect to costs incurred to build nuclear power plants. The Rule provides the mechanism and the annual recovery of these costs through the CCRC. FPL has been working with Commission Staff, the Office of Public Counsel, Progress Energy Florida and others to develop a comprehensive set of schedules, Nuclear Filing

Requirements, setting forth construction and cost information on a nuclear project.

Q. Have these schedules been formally adopted?

A. Although the schedules have not been formally adopted by the Commission, FPL understands that all parties agree to the use of the latest draft of the NFRs for filing purposes. The Company has been collaborating with Progress Energy in order to provide as much consistency as possible in the current draft. However, the forms are still evolving and deviations from specific details of the forms may be appropriate. The NFRs provide an overview of the financial and construction aspects of nuclear plant projects, outline the categories of costs represented and provide a roadmap to the calculation of detailed project revenue requirements.

Q. Does the Rule describe the annual filing requirements that a utility is to make in support of a final true-up of prior year costs and a prudence determination for those costs?

A. Yes. Subsection (5) (c) of the Rule states:

" 1. Each year, a utility shall submit, for Commission review and approval, as part of its Capacity Cost Recovery Clause filings:

a. True-Up for Previous Years. By March 1, a utility shall submit its final true-up of pre-construction expenditures, based on actual pre-construction expenditures for the prior year and previously filed expenditures for such prior year and a description of the pre-construction work actually performed during such year; or, once construction begins, its final true-up of carrying costs on its construction expenditures, based on actual carrying costs on construction expenditures for the prior year and previously filed carrying costs on construction expenditures for such prior year and a description of the construction work actually performed during such year."

Q. Is FPL complying with these requirements with respect to its 2007 Uprate and Turkey Point 6 & 7 Project Costs?

A. Yes. FPL filed the T (Final True-up) Schedules containing the 2007 cost information for the Uprate Project on March 3, 2008. Because the final order regarding the need for Turkey Point 6 & 7 was not issued until after the March 3, 2008 filing, FPL has included its 2007 Turkey Point 6 & 7 costs on the A/E (Actual/ Estimated True-up) of Appendix II to this filing. As this is the first opportunity to seek recovery under the Rule, FPL believes it is appropriate to use the final true-up process contemplated by the Rule as the basis for determining the prudence of its 2007 expenditures.

Q. Does the Rule describe the annual filing requirements that a utility is to make for the Commission review and approval for the current year expenditures?

A. Yes. The Rule states:

" 1. Each year, a utility shall submit, for Commission review and approval, as part of its Capacity Cost Recovery Clause filings: ...

b. True-Up and Projections for Current Year. By May 1, a utility shall submit for Commission review and approval its actual/estimated true-up of projected pre-construction expenditures based on a comparison of current year actual/estimated expenditures and the previously-filed estimated expenditures for such current year and a description of the pre-construction work projected to be performed during such year; or, once construction begins, its actual/estimated true-up of projected carrying costs on construction expenditures based on a comparison of current year actual/estimated carrying costs on construction expenditures and the previously filed estimated carrying costs on construction expenditures for such current year and a description of the construction work projected to be performed during such year."

Q. Is FPL complying with these requirements with respect to its 2008 Actual/Estimated Uprate Project and Turkey Point 6 & 7 costs?

A. Yes. FPL has included the AE (Actual/ Estimated True-up) Schedules in Appendix I for the Uprate Project and Appendix II for Turkey Point 6 & 7 of this filing. Although there were no previous projections to "true-up" and compare to the 2008 actual/estimated expenditures, FPL believes it is appropriate to use the actual/estimated true-up process contemplated by the Rule as the basis for determining the reasonableness of its 2008 actual expenditures and projections in its initial filing.

Q. Does the Rule describe the annual filing requirements that a utility is to make for the Commission review and approval for the projected year expenditures?

A. Yes. The Rule states:

" 1. Each year, a utility shall submit, for Commission review and approval, as part of its Capacity Cost Recovery Clause filings: ...

c. Projected Costs for Subsequent Years. By May 1, a utility shall submit, for Commission review and approval, its projected pre-construction expenditures for the subsequent year and a description of the pre-construction work projected to be performed during such year; or, once construction begins, its projected construction expenditures for the subsequent year and a description of the construction work projected to be performed during such year."

Q. Is FPL complying with these requirements with respect to its 2009 projected Uprate Project and Turkey Point 6 & 7 Project costs?

A. Yes. FPL has included the P (Projection) Schedules in Appendix I for the Uprate Project and Appendix II for Turkey Point 6 & 7 of this filing. As contemplated by the Rule, these P schedules provide the basis for determining the reasonableness of FPL's 2009 projections.

Q. How is FPL providing an update to the original Uprate Project and Turkey Point Unit 6 & 7 Project costs, respectively?

A. FPL has included the TOR (True up to Original) Schedules in Appendix I for the Uprate Project and Appendix II for Turkey Point 6 & 7 of this filing. As this is the first filing of projections under the Rule, the TOR schedules cannot provide a comparison to originally filed project costs, but are necessary in order to summarize the revenue requirements for the first recovery period beginning 2009.

Q. Please delineate the Nuclear Project Costs for which FPL is requesting a prudence determination under the Rule.

A. FPL is requesting that the Commission determine that FPL's actual 2006 and 2007 expenditures for the Uprate construction costs and Turkey Point 6&7 Site Selection and pre-construction costs were prudently incurred.

COST RECOVERY FOR THE UPRATE PROJECT

Q. What are FPL's actual/estimated Uprate Project costs for the period January 2008 through December 2009 for which FPL is requesting recovery?

A. FPL is requesting recovery of $20,494,432 in carrying charges for construction costs for the Uprate project through the CCRC in 2009. This amount is made up of carrying charges of $3,746,283 for the 2008 actual/estimated period and $16,748,149 projected for 2009.

As presented in Mr. Hale's testimony and provided on Schedule AE-6 of Appendix I, FPL's actual/estimated Uprate Project expenditures for the period January 2008 through December 2008 are $79,030,565. Schedule AE-6 of Appendix I deducts the projected portion of this total for which the St. Lucie Unit 2 participants may be responsible and then applies the retail jurisdictional factor to the remainder. Although the St. Lucie participants are entitled to elect participation in the uprate project as provided in the participation agreement, that election has not yet been formally made. Should the participants decline participation in the Uprate Project benefits, the Company will reflect these changes in a later true-up filing. For actuals, adjustments are made to present the costs on a cash basis (i.e., excluding accruals and pension and welfare benefit credits) for the calculation of carrying costs. This adjustment is necessary in order to comply with the Commission's current practice regarding AFUDC accruals. After making these adjustments, the net 2008 uprate expenditures are $74,566,687. The calculation of the carrying charges for these expenditures is provided on schedules AE-3.

Additionally, as presented in Mr. Hale's testimony and provided on Schedule P-6 of Appendix I, FPL's projected Uprate Project expenditures for the period January 2009 through December 2009 are $240,845,910. Schedule P-6 of Appendix I deducts the portion of this total for which the St. Lucie Unit 2 participants may be responsible and then applies the retail jurisdictional factor to the remainder. FPL did not project future noncash accruals. The amounts of any such accruals are impractical to project accurately and will be trued-up, with interest. After making those two adjustments, the net 2009 uprate expenditures are $233,294,413. The calculation of the carrying charges for these expenditures is provided on schedules P-3.

For the reasons stated in Mr. Hale's testimony, FPL respectfully requests that the Commission approve FPL's projected 2009 Uprate Project expenditures as reasonable for cost recovery consistent with the Rule beginning in January 2009.

COST RECOVERY FOR TURKEY POINT 6 & 7

Q. What are FPL's Turkey Point 6 & 7 expenditures for 2006 and 2007 for which FPL is requesting a determination of prudence?

A. As presented in Mr. Scroggs' testimony and provided on Schedule AE-1 of Appendix II, FPL's actual pre-construction costs and associated carrying charges are $2,543,239 for 2007. FPL is making adjustments to actuals to present the costs on a cash basis (i.e., excluding accruals and pension and welfare benefit credits) for the calculation of carrying costs.

For the reasons stated in Mr. Scroggs' testimony, FPL respectfully requests that the Commission approve these pre-construction costs and associated carrying costs as prudent consistent with the Rule.

Q. What are FPL's actual/estimated Turkey Point 6 & 7 pre-construction costs and associated carrying costs for the period January 2008 through December 2009 for which FPL is requesting recovery?

A. FPL is requesting recovery of $228,137,689 in pre-construction costs and associated carrying charges for Turkey Point 6 & 7 through the CCRC in 2009. This amount is made up of pre-construction costs of $104,561,783 and carrying charges of $3,879,731 for the 2008 actual/estimated period and pre-construction costs of $109,540,915 and carrying charges of $10,155,260 projected for 2009.

As presented in Mr. Scroggs' testimony and provided on Schedule AE-6 of Appendix II, FPL's actual/estimated Turkey Point 6 & 7 pre-construction costs for the period January 2008 through December 2008 are $105,000,000. The calculation of the carrying charges for these expenditures is provided on schedules AE-2.

Additionally, as presented in Mr. Scroggs' testimony and provided on Schedule P-6 of Appendix II, FPL's projected Turkey Point 6 & 7 expenditures for the period January 2009 through December 2009 are $110,000,000. (The expenditures presented in the testimony of Steven Scroggs found on AE-6 and P-6, are total project expenditures, which differ from jurisdictional recoverable amounts described further herein.) The calculation of the carrying charges for these expenditures is provided on schedules P-2.

For the reasons stated in Mr. Scroggs' testimony, FPL respectfully requests that the Commission approve these expenditures as reasonable for cost recovery consistent with the Rule.

PROPOSED COST RECOVERY APPROACH FOR SITE SELECTION COSTS

Q. Does the Rule address recovery of Site Selection Costs?

A. Yes, section (4) states:

"Site Selection Costs. After the Commission has issued a final order granting a determination of need for a power plant pursuant to Section 403.519, F.S., a utility may file a petition for a separate proceeding, to recover prudently incurred site selection costs. This separate proceeding will be limited to only those issues necessary for the determination of prudence and alternative method for recovery of site selection costs of a power plant."

Q. What site selection costs were expended in 2006 and 2007?

A. As described in Mr. Scroggs' testimony, Schedule AE-6 of Appendix III provides the 2006 and 2007 actual site selection costs of $6,424,121 million.

Q. How does FPL propose to recover the site selection costs for the Turkey Point 6 & 7 Project?

A. FPL proposes to recover the Turkey Point 6 & 7 site selection costs through the 2009 CCRC as part of FPL's approved NPPCR amount. FPL believes the Turkey Point 6 & 7 site selection costs should be reviewed in this docket and approved for recovery as part of the NPPCR amount that is to be included in the CCRC for 2009 for the following reasons:

- The early stage of the project has involved both site selection and pre-construction costs which have been managed consistently within the same overall project development process. Therefore, although the Commission rules afford the opportunity for a separate review and alternative methods of recovery for site selection costs as opposed to preconstruction and construction, this separation is arbitrary from the standpoint of project development, project cost planning and controls and ultimately the determination of prudence. Separation of the review of cost flows and activities with two separate proceedings would only serve to impede and obscure comprehensive review of the early stage project activities and costs.

- This docket affords the earliest opportunity for review and approval of the Turkey Point 6 & 7 site selection costs. Prompt review and approval of the site selection costs is in FPL's and its customers' interests. It will reduce the period of regulatory uncertainty as to recovery of those costs, which is important as FPL embarks upon this lengthy, complex and costly project. It will also minimize the period over which carrying charges will accumulate on the site selection costs, resulting in a lower overall amount to be recovered from customers than would be the case if recovery of the costs were deferred to a later proceeding.
- The NPPCR is the most appropriate vehicle for recovery of the Turkey Point 6 & 7 site selection costs. Site selection is an integral part of that project, and the NPPCR is the recognized mechanism for recovery of nuclear project costs. If the site selection costs are included in the amount that the Commission approves for recovery under the NPPCR, there will be a well-defined mechanism for implementing that recovery (*i.e.*, through the CCRC). Otherwise, the Commission will have to address separately the issue of how to implement recovery of the site selection costs, which would result in duplication of effort and a potentially inconsistent recovery approach.

Consistent with accounting practices in the Commission's existing adjustment clause proceedings and with the treatment of pre-construction costs in subsection (5)(a) of the Rule, FPL proposes to accrue and recover carrying charges on the unrecovered balance of site selection costs until they are fully recovered through the CCRC at the end of 2009.

ACCOUNTING CONTROLS

Q. Please describe the accounting controls that FPL has in place to ensure proper cost capture and reporting for the duration of these projects.

A. The Company relies on its comprehensive and overlapping controls for incurring costs and recording transactions associated with any of its capital projects including that of nuclear uprates and Turkey Point 6&7. These comprehensive and overlapping controls include:

- FPL's Accounting Policies and Procedures
- Financial systems and related controls including its general ledger and construction asset tracking system (CATS)
- Sarbanes-Oxley processes and testing
- Annual budgeting and planning process and reporting and monitoring of plan costs to actual costs incurred as discussed in the testimony of Steven Scroggs and Stephen Hale.

Q. Are these controls documented, assessed and audited and/or tested on an ongoing basis?

A. Yes. The FPL accounting policies and procedures are documented and published on the Company's internal web site, INFPL. In addition, accounting management provides formal representation as to the continued compliance with those policies and procedures each year. The Company's external auditors, Deloitte & Touche LLP conduct an annual assessment of the Company's internal controls over financial reporting. Sarbanes-Oxley processes are identified, documented, tested and maintained, including specific processes for planning and executing capital work orders and acquiring and developing fixed assets. Certain of those key financial processes are tested during the Company's annual test cycle. In addition, Deloitte & Touche LLP, as a part of its annual external audit, will assess the Company's internal controls over financial reporting and express an opinion as to the effectiveness of those controls. The audit procedures performed by Deloitte & Touche LLP include tests of general computer controls and of those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company.

Q. Are there any additional controls being implemented and relied on for this particular project and the related reporting?

A. Yes. First, the Company has issued specific guidelines for charging costs to the project work orders. Those guidelines describe the need for particular care in charging only incremental labor to these particular projects due to the CCRC recovery approach and are intended to ensure careful attention to the incremental recovery guidelines during the duration of these projects. The need for this care is most acute in the initial stages of the project as existing resources are typically utilized until such time that the project requires a greater complement of personnel resources specifically devoted to the project. Secondly, the Company has initiated specific project related internal audits. The initial review being performed is related to the Uprate Project. The objective of this audit is to test the process of recording and capturing costs related to the Uprate project in the pre established work orders to ensure compliance with the Commission's Rule. That audit has just begun and a final audit report is expected in June, 2008. The audit of the Turkey Point 6&7 project will commence this summer and a final report is expected in fall 2008.

SUMMARY

Q. What is the total amount of nuclear project costs that FPL is requesting to recover through the 2009 CCRC?

A. FPL is requesting to recover a total of $258,979,772 through the CCRC in 2009 for the Uprate Project and Turkey Point 6&7. This is made up of:

- For Turkey Point 6&7 S9,082,737 for 2006-2007 actual jurisdictional costs ($6,397,310 for site selection, $2,522,692 for pre-construction and $142,188 in carrying costs for site selection and $20,547 in carrying costs for pre-construction for Turkey Point 6&7).

- $112,917,360 for 2008 actual/estimated jurisdictional costs ($104,561,783 for pre-construction costs and $729,563 in carrying costs for site selection and $3,879,731 in carrying costs for Turkey Point 6&7, plus $3,746,283 in carrying costs for the Uprate Project).
- $136,979,675 for 2009 projected jurisdictional costs ($109,540,915 for pre-construction costs and $10,155,260 in carrying costs for pre-construction and $535,351 of site selection carrying costs for Turkey Point 6&7 plus $16,748,149 in carrying costs for the Uprate Project.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEPHEN T. HALE

DOCKET NO. 080009-EI

May 1, 2008

Q. **Please state your name and business address.**

A. My name is Stephen T. Hale, and my business address is 700 Universe Boulevard, Juno Beach, FL 33408.

Q. **By whom are you employed and what position do you hold?**

A. I am employed by Florida Power & Light Company (FPL) as Engineering Director in the Nuclear Division.

Q. **Have you previously filed testimony in this docket?**

A. Yes.

Q. **Have you prepared or caused to be prepared under your direction, supervision or control an exhibit in this preceding?**

A. Yes, I am sponsoring the following exhibits:

- STH-2, which consists of Appendix 1 containing the Nuclear Filing Requirements Schedules (NFRs) for FPL's power uprate project at the St. Lucie and Turkey Point Nuclear Units (the "Uprate Project"). Page 2 of Appendix 1 contains a table of contents listing the NFRs that are sponsored by Ms.Ousdahl, Dr. Sim and me, respectively.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's 2008 actual/estimated and 2009 projected power uprate costs for the Turkey Point and St. Lucie nuclear power plants to be included for recovery in FPL's Capacity Cost Recovery Factors for the period January 2009 through December 2009. My testimony also presents the True-up to Original (TOR) Projections for the uprate project for the years 2007 through 2012.

2008 ACTUAL/ESTIMATED AND 2009 PROJECTED PERIODS

Q. What types of costs does FPL project to incur for the Uprate Project in 2008 and 2009?

A. Schedule AE-6 of Appendix 1 breaks the 2008 actual/estimated costs down into the following categories: License Application $34,012,730; Engineering and Design $7,665,628; Permitting $1,694,907; Project Management $12,966,855; Power Block Engineering, Procurement, etc. $22,534,388; and Non-power Block Engineering, Procurement, etc. $156,057.

Schedule P-6 of Appendix 1 breaks the 2009 projected costs down into the following categories: License Application $37,865,177; Engineering and Design $9,064,184; Permitting $1,690,981; Project Management $13,164,445; and Power Block Engineering, Procurement, etc. $179,061,123.

Q. Please describe the activities in the License Application category and the need for those activities.

A. For the period ending December 31, 2008, License Application costs are projected to be $34,012,730 as shown on Line 3 of Schedule AE-6 of Appendix 1. For the period ending December 31, 2009, License Application costs are projected to be $37,865,177 as shown on Line 3 of Schedule P-6 of Appendix 1. These amounts consist primarily of contracted services used in preparation of the license application. The contractors will be selected based on their proven record of success with projects of this magnitude. The work includes system and component safety analyses and evaluations in support of the preparation of the License Amendments to be submitted to the Nuclear Regulatory Commission (NRC). It is important that this work be completed in 2008 and 2009 because it is required to support the NRC licensing and overall implementation schedule.

Q. Please describe the activities in the Engineering and Design category and the need for those activities.

A. The engineering and design activities continue in 2008 and 2009 in order to support the overall uprate implementation schedule.

For the period ending December 31, 2008, Engineering & Design costs are projected to be $7,665,628 as shown on Line 4 of Schedule AE-6 of Appendix 1.

For the period ending December 31, 2009, Engineering & Design costs are projected to be $9,064,184 as shown on Line 4 of Schedule P-6 of Appendix 1. The amounts consist primarily of employee and contractor services for owner oversight, review and approval of contracted engineering activities.

The personnel will be selected based on their proven record of success with projects of this magnitude. The amount also includes third party reviews of key evaluations and decisions.

Q. Please describe the activities in the Permitting category and the need for those activities.

A. For the period ending December 31, 2008, Permitting costs are projected to be $1,694,907 as shown on Line 5 of Schedule AE-6 of Appendix 1. For the period ending December 31, 2009, Permitting costs are projected to be $1,690,981 as shown on Line 5 of Schedule P-6 of Appendix 1.

These amounts consist primarily of work to be completed on site certification, an essential step in the uprate approval process, and hence must be completed promptly to maintain the overall implementation schedule. The remainder of the amounts in the Permitting category are allocated to the community outreach programs.

Q. Please describe the activities in the Project Management category for the 2008 actual/estimated and 2009 projected periods and the need for those activities to help ensure that the Uprate Project is completed on a reasonable schedule and at a reasonable cost.

A. For the period ending December 31, 2008, Project Management costs are projected to be $12,966,855 as shown on Line 6 of Schedule AE-6 of Appendix 1. For the period ending December 31, 2009, Project Management costs are projected to be $13,164,445 as shown on Line 6 of Schedule P-6 of

Appendix 1. This category includes FPL employee and contractor services including but not limited to, scope definition, cost estimates, contract negotiations and project execution. These activities are needed to ensure effective management of the uprate project consistent with FPL nuclear project management policies and procedures as discussed earlier. Each of the mentioned activities is an essential part of FPL's project management process that, when executed in accordance with FPL's project management manual, provides reasonable assurance on schedule and cost adherence. FPL employee and contracted personnel involved have a proven record of success with projects of this magnitude and their labor rates are competitive. Where FPL has utilized FPL affiliate personnel, it has done so because those personnel were available with immediately transferable expertise, and they provided an appropriate interim solution to meet personnel needs.

Q. Please describe the activities in the Power Block Engineering, Procurement etc. category for the 2008 actual/estimated and 2009 projected periods and the need for those activities.

A. For the period ending December 31, 2008, Power Block Engineering and Procurement costs are projected to be $22,534,388 as shown on Line 9 of Schedule AE-6 of Appendix 1. For the period ending December 31, 2009, Power Block Engineering and Procurement costs are projected to be $179,061,123 as shown on Line 9 of Schedule P-6 of Appendix 1. This amount consists primarily of engineering, material, fabrication, and installation costs associated with uprate plant modifications.

Q. Please describe the activities in the Non-Power Block Engineering, Procurement etc. category for 2008 and the need for those activities.

A. For the period ending December 31, 2008, Non-Power Block Engineering and Procurement costs are projected to be $156,057 as shown on Line 10 of Schedule AE-6 of Appendix 1. This amount consists primarily of facilities for engineering and project staff at site locations. There are no Non-Power Block Engineering and Procurement costs for 2009.

Q. Are the cost projections presented in your testimony reasonable?

A. Yes, they are. All of the 2008 actual/estimated and 2009 projected costs are for activities that are necessary to the Uprate Project and are appropriately undertaken in 2008 and 2009 in order to maintain the Uprate Project's schedule.

Q. Please describe the project management system FPL has used to ensure that the 2008 actual/estimated and 2009 projected costs are reasonable.

A. FPL has continued to utilize the project management system described in my March 3, 2008 testimony to ensure that the costs projected for those activities are reasonable and necessary. In addition, the project begins with a budget development process that collects input from internal and external subject matter experts and benchmarks those costs to FPL's experience in other capital intensive power generation projects. The proposed budget was independently reviewed by a senior management team from Shaw Stone and Webster (SSW). SSW provided a summary report to FPL senior management. In addition, the proposed budget was presented to the FPL corporate executive management for critical review prior to approval. Once constructed, the project budget is continually managed to maintain overall project objectives and milestones. Periodic meetings are held with representatives of contributing business units and principal contractors to identify upcoming expenditures and ensure budgets are maintained or changes are identified and approved in advance. Monthly business reports are generated, reviewed and approved as a part of FPL's overall project management practices. Variances are noted and explained in senior level reporting documents. Finally, Concentric Energy Advisors, Inc. has reviewed and evaluated the project management and budgeting processes for the Uprate Project. FPL witness John Reed of Concentric, testifies as an FPL witness concerning the results of that evaluation.

<u>TRUE-UP TO ORIGINAL PROJECTIONS</u>

Q. Have you prepared an update to the original uprate project costs?

A. Yes. Appendix 1 includes the TOR schedules that compare the current projections to FPL's originally filed St. Lucie and Turkey Point Project costs. The TOR schedules provide information on the project costs through the end of 2009. FPL has revised its non-binding cost estimate for the following: 1) to remove AFUDC that was originally projected beyond 2009 but is unnecessary now that FPL has approval to recover the Uprate Project costs through the NPPCR; and 2) to reflect reductions primarily related to reimbursement of the share of costs for which the St. Lucie 2 participants are responsible. (While the participants have indicated informally that they intend to take their respective shares of the Uprate Project output, they have not yet made a final election. If the participants decide not to take their respective shares, FPL will adjust these amounts to obtain recovery as part of the true-up including interest). The Company continues to evaluate the costs associated with this project. As activities are more clearly defined the Company will make any necessary revisions to the original cost estimate. The TOR schedules provide the best information currently available for the cost recovery period through 2009.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEVEN D. SCROGGS

DOCKET NO. 080009-EI

MAY 1, 2008

Q. **Please state your name and business address.**

A. My name is Steven D. Scroggs. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL or the Company) as Senior Director, Project Development. In this position I have responsibility for the development of power generation projects to meet the needs of FPL's customers.

Q. **Please describe your duties and responsibilities with regard to the development of new nuclear generation to meet FPL customer needs.**

A. Commencing in the summer of 2006, I was assigned the responsibility for leading the investigation into the potential of adding new nuclear generation to FPL's system, and the subsequent development of new nuclear generation additions to FPL's power generation fleet. I lead the development and permitting team for FPL's Turkey Point Nuclear Units 6 and 7 (Turkey Point 6 & 7).

Q. Please describe your education and professional experience.

A. I graduated from the University of Missouri – Columbia in 1984 with a Bachelor of Science Degree in Mechanical Engineering. From 1984 until 1994, I served in the United States Navy as a Nuclear Submarine Officer. From 1994 to 1996, I was a research associate at The Pennsylvania State University, where I earned a Masters Degree in Mechanical Engineering. I provided consulting and management services to the power generation industry through a number of positions until 2003, when I joined FPL as Manager, Resource Assessment and Planning. In July 2006, I was assigned to my current role as a Senior Director, Project Development.

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

A. The purpose of my testimony is to provide an understanding of how the Turkey Point 6 & 7 project is being developed, managed and controlled to meet the objective of delivering reliable, cost-effective and fuel diverse generation to FPL customers under the earliest practical deployment schedule. Several key decisions have been made in recent months, and a number of critical information gathering activities are planned over the next two years that will lead to important decisions materially affecting the nature, cost and pace of the project. My testimony will provide insight into how those activities are managed and the issues affecting those decisions. I will describe the projected expenditures for 2008 and 2009 that will allow FPL to produce applications for the required licenses and permits and otherwise enable steps necessary to maintain the project schedule.

Q. Please summarize your testimony.

A. My testimony begins by describing the progress FPL has made in identifying the preferred technology. I then describe the approach taken by FPL for developing the Turkey Point 6 & 7 project and introduce the project controls and risk management processes for the project. My testimony then describes the Site Selection costs incurred from April 2006 to October 16, 2007 (the date of the Need Determination Filing, or "Need Filing") and Pre-construction costs that have been or are estimated to be incurred in the period from October 16, 2007 through December 31, 2009. Moreover, I will discuss the rationale for these costs or projections and how expenditures will be managed going forward to meet the project objectives.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this preceding?

A. Yes, I am sponsoring the following exhibits:

- SDS-1, which consists of Appendix II containing the Nuclear Filing Requirements Schedules (NFRs) for Turkey Point 6 & 7 Pre-Construction costs. Page 2 of Appendix II contains a table of contents listing the NFRs that are sponsored by me, Ms. Kim Ousdahl, and Dr. Steve Sim, respectively.
- SDS-2, which consists of Appendix III containing the NFRs that provide the Site Selection costs for Turkey Point 6 & 7 Project. Page 2 of Appendix III contains a table of contents listing the NFRs that are sponsored by me and Ms. Kim Ousdahl, respectively.

- SDS-3, which consists of two reports by MPR Associates, Inc. that review and assess the technology selection process employed by FPL.
- SDS-4, which consists of the Engineering Evaluation conducted to evaluate the technical aspects of candidate nuclear design technologies considered for Turkey Point 6 & 7.

TECHNOLOGY

Q. What reactor technology/design decisions has FPL made regarding Turkey Point 6 & 7?

A. FPL has identified the Westinghouse AP1000 design as our preferred technology. The AP1000 technology provides for a nominal net output of 1,100 MW for each of the two units planned, resulting in a total project capacity of 2,200 MW. The AP1000 technology has achieved design certification from the Nuclear Regulatory Commission ("NRC") and employs a proven pressurized water reactor design with an improved passive safety system.

Q. Why is it important FPL identify a preferred technology at this stage of the Turkey Point 6 & 7 project?

A. FPL is currently in the Licensing phase of the project. Applications are being prepared for submission to state and federal authorities to obtain the approvals for the project. Those applications require detailed information related to the specific technology FPL will use for Turkey Point 6 & 7. In order to maintain the earliest practical deployment schedule, while balancing cost and risk, FPL must identify a preferred technology now as a basis for its applications and licenses.

Q. What was the process by which FPL arrived at its decision?

A. The process involved a technical evaluation, followed by a review of commercial and project execution aspects. The Engineering Evaluation, provided as exhibit SDS-4, was conducted by a team of FPL engineers using accepted industry practices for the collection, rating and evaluation of technical design information. The process resulted in a ranking of designs, where the Westinghouse AP1000 and GE ESBWR technologies were the top two of five considered. Additionally, FPL's participation in the NuStart Consortium ("NuStart") was also considered. As a member of NuStart, FPL will have access to information and documentation that will likely reduce the costs and risks associated with licensing and constructing the AP1000 technology.

Three principal commercial issues were considered in the choice of the AP1000. The first two issues are the estimated capital cost of the total construction project and the ability of the vendor to contribute to managing cost and schedule risk throughout the project. Westinghouse has successfully achieved design certification and, in partnership with Shaw Group, has been selected as the technology for many new nuclear projects currently under consideration in the U.S. These two facts provide an advantage to Westinghouse/Shaw as they establish the engineering and supply chain partners necessary to execute future projects. This position also provides significant confidence the AP1000 technology offers FPL the opportunity to leverage information developed by other projects to manage cost and schedule risk as Turkey Point 6 & 7 proceeds.

The last issue is the execution capability of the Technology Vendor, Engineer and Constructor team that would be assembled to implement the Turkey Point 6 & 7 project. FPL, in discussions with Westinghouse/Shaw, has developed a strategy that will result in selection of the most capable provider to conduct specific portions of the project and to be able to make those selections as the project proceeds. For example, instead of entering into an all-encompassing Engineering, Procurement and Construction contract at the beginning of the project, FPL will work with Westinghouse/Shaw to develop a contract limited to Engineering and Procurement or "EP." The EP contract would define the scope of project management, engineering and procurement services that are required from an outside vendor to maintain the project schedule, leaving the contractual arrangements for the construction component to be defined at a later time. This approach is expected to provide several advantages applicable to new nuclear construction. By completing the engineering efforts a better definition of the scope of construction work will be developed, allowing a more informed bid for construction services. Additionally, the project will benefit from information and competition that will emerge in the next several years that can be incorporated into FPL's approach. FPL views this contracting approach as a conservative means to engender competition for project services and has employed this approach successfully in its Engineering and Construction program over the past ten years.

Q. Has FPL made an irreversible commitment to the AP1000 technology?

A. No. However, a change of preferred technologies at this stage would create a cost and schedule impact to the Turkey Point 6 & 7 project. If FPL were to recommend a change, it would be based on an assessment that the benefits of doing so outweigh the incremental costs and schedule delays. Obviously, this situation could be presented regardless of which technology was chosen. For the reasons stated above, FPL is confident that the need to change the preferred technology at some future point is unlikely and is less likely with the choice of the AP1000 than with other technologies.

Q. What processes were employed by FPL to monitor its decision process and evaluate the process?

A. FPL engaged MPR Associates, Inc. (MPR) a well known independent engineering firm with over 40 years of experience in the commercial nuclear power industry. MPR was directed to review FPL's technology selection process and recommend areas where the process could be made more robust. Reviews were conducted at interim points throughout the process, allowing for feedback to be incorporated and the selection process to be improved. MPR provided two reports documenting its conclusions that are included as Exhibit SDS-3 to this direct testimony. MPR concluded "the FPL assessments and considerations are appropriate and support the decisions to date".

PROJECT APPROACH

Q. What is FPL's overall approach to developing Turkey Point 6 & 7?

A. FPL intends to pursue the timely development of Turkey Point 6 & 7 through a deliberate, stepwise decision making process. This involves monitoring the issues affecting the pace and feasibility of the Turkey Point 6 & 7 project. In the event feasibility is in question, or delays present risk to timely execution, FPL would have the option of slowing the project down or taking an "off ramp" where the project expenditures would be halted. In short, FPL will work to achieve the earliest practical deployment schedule, while monitoring the project feasibility and key decision points.

Q. Please expand on the concept of "off-ramps" and how the pace of the Turkey Point 6 & 7 project is determined based on the assessment of risks.

A. The project team is managing a host of issues at local, state and federal levels and across technical, commercial and regulatory areas of concern. As these issues incorporated into the project plan the impact on cost, schedule and resources will be assessed. If that assessment indicates there will be a considerable cost or schedule impact, mitigation actions are identified that may help manage or reduce the impact. If the magnitude of the impact is such that the cost or schedule impact materially changes the feasibility of the project or significantly increases risk, a decision could be made. The options would be to continue with modifying budget and schedule as needed and taking available mitigation actions, or halt the project temporarily while the impact issue is further assessed or resolved. This allows the pace of the project to be controlled based on the best information available. The option of slowing or halting the project in response to significant events, although it would postpone delivery of Turkey Point 6 & 7's benefits, offers a high level of exposure control for FPL and its customers. Such decisions would also need to address how FPL system capacity and reliability needs would be satisfied if delivery were to be delayed.

Q. How is the management of the Turkey Point 6 & 7 project structured and how does this structure assist in maintaining a risk management focus?

A. The management structure relies on a working combination of two key groups: Project Development and New Nuclear Projects. The organization of the project into these two key groups helps maintain a consistent management and reporting structure, while allowing the project the flexibility to grow and adapt over time. Project Development, which I lead, has the overall responsibility for the management and organization of the project, utilizing matrix relationships with key business units in the company to provide essential support. For example, legal services and environmental services are provided by those business units through dedicated personnel. The Project Development team is focused on overall project management, state regulatory and all non-NRC licenses and approvals.

FPL established the New Nuclear Project team within the Engineering, Construction and Corporate Services group to manage the complex and specialized nature of the Combined Operating License Application (COLA) process and the engineering, procurement and construction activities. This team is managed by Martin Gettler, Vice President of New Nuclear Projects. The New Nuclear Project team has direct responsibility for the development of the COLA and manages the engineering, procurement, site preparation and construction aspects of the project.

Q. How does FPL intend to contract for services associated with the Turkey Point 6 & 7 project?

A. FPL utilizes proven corporate processes to solicit, qualify, negotiate, select and manage service providers for capital projects such as Turkey Point 6 & 7. Leveraging our many years of successful power project development and construction, FPL approaches the process with an understanding of the key players in each specialty field. Where it is appropriate to assign a comprehensive scope to a specific contractor, FPL clearly specifies the deliverables, budget and schedule and then monitors the contractors' progress closely to obtain compliance. Often it is more efficient to divide the scope among multiple contractors to obtain an appropriate level of competition and maintain the "best athlete" approach of assigning appropriate scope to the most capable provider. In such cases FPL acts as the overall coordinator of the function to obtain integration of the various sub-portions of the work.

PROCESS AND RISK MANAGEMENT

Q. What process and risk management tools does FPL apply to obtain cost, risk and schedule objectives?

A. FPL uses industry accepted project controls, systems and practices to obtain a high level of fidelity in the expenditures incurred and projected for all projects. The primary means of control are 1) the project budgeting and reporting process, 2) project schedule and activity reporting processes, 3) the contract management process for external service providers, and 4) internal and external oversight processes.

Q. Please describe the budgeting and reporting processes for the Turkey Point 6 & 7 project.

A. The project begins with a budget development process that collects input from internal and external subject matter experts and benchmarks those costs to FPL's experience in other capital intensive power generation projects. Once constructed, the project budget is managed to maintain overall project objectives and milestones. Regular meetings are held with representatives of all contributing business units to identify upcoming expenditures, maintain budgets and identify changes. Monthly business reports are generated, reviewed and approved as a part of FPL's overall project management practices. Variances are noted and explained.

Due to the size, complexity, duration and unique nature of the Turkey Point 6 & 7 project, the budget was developed in stages and is refined as additional information is obtained. The initial project budget, developed in 2006, focused on project licensing and permitting activities to support the local, state and federal permit applications through 2012. Costs associated with engineering, design and long lead procurement were being investigated at that time. In 2007, FPL completed its non-binding cost estimate range provided in the Need filing. This estimate provided a cost estimate range for all phases of the project through completion of construction. In late 2007 and early 2008, FPL conducted an additional review and refinement of near term cost estimates in all areas through 2009 in support of this filing. This routine process of review and refinement will continue throughout the project.

Q. **Please describe the project schedule and activity reporting processes for the Turkey Point 6 & 7 project.**

A. FPL project management teams establish reporting processes, both internal and external to the project team, to track and communicate status. These processes may be periodic reports or scheduled meetings. Internal reporting mechanisms focus on work execution, issue identification and resolution. An example of an internal reporting process is the routine production of a six week look-ahead schedule monitoring the development of the COLA. This schedule is used in periodic meetings by the FPL project team and all contractors to determine work organization and coordination. The process allows for management of the process and allocation of resources to maintain schedule.

Reports external to the project team allow for project activities to be summarized and communicated. For example, periodic reports are provided to Miami-Dade County regarding compliance with conditions of approval associated with site zoning.

Q. Please describe the contract management processes for the Turkey Point 6 & 7 project.

A. FPL's Integrated Supply Chain team provides procurement and contract management support services to the project to apply and monitor corporate policies. Contractual arrangements are supported by detailed scope of work descriptions and specific terms and conditions that define the content and schedule of products and services needed by the project. Daily contract oversight is provided by the initiating business unit, such as Environmental or New Nuclear Projects. These managers are responsible to review the contracted products or services satisfy the agreements and meet FPL's quality and documentation requirements. Supporting and executing these project controls programs are an experienced team of personnel with a record of success with large licensing and construction projects.

Q. Please describe the internal and external oversight processes for Turkey Point 6 & 7.

A. FPL conducts a number of self-auditing functions throughout the course of each business year. Projects are audited for general financial and accounting practices, tax related issues and regulatory obligations such as Sarbanes-Oxley compliance. Additionally, project management may request specific reviews by third party subject matter experts to validate FPL processes and obtain additional perspectives to be applied to critical project decisions. An example of this is the engagement of MPR to review our technology selection process.

Q. How is the effectiveness of these tools reviewed over time?

A. Effectiveness measures are included within some mechanisms and provided by external review processes for all. As an example, the Engineering & Construction Division Project Dashboard presents issues and the current trends for those issues. Over time, if a problematic issue continues to trend down or remains neutral, the effectiveness of the project management controls are investigated to determine if modifications are needed to affect improvement. Effectiveness of project control processes is also reviewed as a part of the higher level organization reviews and audits, described above.

<u>PROJECT SCHEDULE</u>

Q. How does the current project schedule compare to the Milestone Schedule provided as Exhibit SDS-5 to your testimony in FPL's Need Determination Filing?

A. The current project schedule for Turkey Point 6 & 7 is unchanged from the Milestone Schedule.

Q. What planning activities were undertaken related to the licensing and preparation phases of the Turkey Point 6 & 7 project, and what were the results of those activities?

A. One of the first tasks conducted was the development of a comprehensive COLA schedule. This is the primary driver of the 2008 and early 2009 project schedule. With the COLA schedule established and underway, the schedule for development of the other licenses and permits began and are currently being completed. Likewise, other supporting activities such as conceptual engineering were defined and are being pursued. Procurement of these services is currently underway.

SITE SELECTION ACTIVITIES

Q. What costs has FPL incurred for Turkey Point 6 & 7 that would be classified as Site Selection costs in accordance with the Nuclear Power Plant Cost Recovery Rule (NPPCR Rule, FAC 25-6.0423)?

A. Schedule AE-6 of Appendix III provides a summary of Site Selection costs totaling $6,424,121.

Q. What period of time was covered by the Site Selection costs, and what major activities were undertaken during that period?

A. The project accounts were established in April 2006 and the Site Selection period ended with the submittal of the Need Filing on October 16, 2007. During the summer of 2006, a core project team was formed and several key investigations were initiated. Primary among these early studies were the Site Analysis Study and the Engineering Review of candidate technologies. Project planning activities also addressed major issues, such as transmission integration, project organization, project schedule and budget. At the end of

2006, the Site Analysis Study, combined with site specific investigations, identified the Turkey Point site as the location for the project. In 2007 the project team pursued the development and defense of the Public Hearing Application in Miami-Dade County, continued investigations of design alternatives, project issues and the Need Determination filing.

Q. Please describe the major cost categories for the Site Selection costs.

A. The major cost categories of Site Selection costs included project Staffing, Engineering, environmental licensing and legal expenditures. Project Staffing included project management and controls and support from matrix organizations such as Environmental, Power Supply, Marketing and Communications, Nuclear Engineering, and Legal. Engineering was provided to support technical activities associated with the engineering review of candidate technologies, site investigations and the establishment of schedule and processes that would eventually form the current New Nuclear Projects team. Environmental licensing encompassed the studies, investigations and preparation of the Public Hearing Application in Miami-Dade County that resulted in the necessary zoning approvals supporting the project. Legal services were primarily associated with the development and review of the Public Hearing Application. The following summarizes the Site Selection expenditures by major cost category.

Category	Total
Project Staffing	$1,068,856
Engineering	$3,351,744
Environmental	$1,220,290
Legal	$ 783,231
TOTAL	$6,424,121

PRE-CONSTRUCTION ACTIVITIES

Q. What costs has FPL included in this filing for Turkey Point 6&7 Pre-Construction activities?

A. FPL has actual 2007, actual/estimated 2008 and projected 2009 Pre-Construction costs for Turkey Point 6 & 7. Schedule AE-6 of Appendix II presents the 2007 actual and 2008 actual/estimated costs in the following categories: Licensing ($48,039,775); Permitting ($2,833,949); Engineering & Design ($7,910,661); Long Lead Procurement ($45,860,960) and Power Block Engineering and Procurement ($2,887,920).

Schedule P-6 of Appendix II breaks the 2009 projected costs down into the following categories: Licensing ($26,668,968); Permitting ($2,422,095); Engineering & Design ($10,121,791); and Power Block Engineering & Procurement ($70,787,145).

Q. Please describe the activities for the Licensing category, the need for those activities and the process used to develop estimates for 2008 and 2009 expenditures.

A. For the period ended December 31, 2007, Licensing costs are $2,017,181 as shown on Line 4 of Schedule AE-6 of Appendix II. For the period ending December 31, 2008, Licensing costs are projected to be $46,022,594 as shown on Line 3 of Schedule AE-6 of Appendix II. For the period ending December 31, 2009, Licensing costs are projected to be $26,668,968 as shown on Line 3 of Schedule P-6 of Appendix II.

These Licensing costs consist primarily of employee and contractor labor and consulting services necessary to develop the various license and permit applications required by the Turkey Point 6 & 7 project. The federal COLA requires the majority of expenditures, followed by the Site Certification Application, Army Corps of Engineers permits and delegated programs such as Air and Underground Injection Control. These permit and license applications contain project specific information, assessments and studies that are required by various regulatory authorities to support the reviews leading to decisions on the technical, environmental and social acceptability of the project. Some activities are common between applications, and therefore offer opportunities to coordinate efforts and manage costs. However each application analyzes each issue from a unique perspective and may require differing levels of detail.

The COLA development costs were estimated based on the Bechtel proposal, obtained through a Request for Proposals process. The proposal was reviewed to verify the scope adequately described the activities necessary and that reasonable labor rates and resource costs were utilized. Other licensing and permitting costs were developed in accordance with FPL's budget and accounting guidelines and policies. Further, these cost estimates were compared to FPL's recent extensive experience with the development and permitting of new generation projects in Florida and found to be reasonable.

FPL, as a member of the NuStart Consortium, pays annual membership fees of $1 million. These costs are necessary to obtain the benefits of membership that are specifically relevant to the Westinghouse AP1000 design.

Q. Please describe the activities in the Permitting category, the need for those activities and the process used to develop estimates for 2008 and 2009 expenditures.

A. For the period ending December 31, 2007, Permitting costs are $516,084 as shown on Line 4 of Schedule AE-6 of Appendix II. For the period ending December 31, 2008, Permitting costs are projected to be $2,317,865 as shown on Line 4 of Schedule AE-6 of Appendix II. For the period ending December 31, 2009, Permitting costs are projected to be $2,422,095 as shown on Line 4 of Schedule P-6 of Appendix II.

Permitting fees consist of expenditures for Project Development management and public outreach/education. Additionally, there are legal support costs not specifically associated with the federal or state licensing and permit activities included in Permitting costs. These costs are necessary for the effective management and execution of the project. Outreach is a vital process to inform stakeholders of the project and educate the public with regard to the many processes where they can be involved. The outreach activity involves hosting informational events and providing information on the project through a variety of media platforms. FPL has found that a pro-active outreach approach facilitates a sharing of concerns and perspectives improving the overall project. Legal support expenditures are necessary to support the timely preparation, submission, and review of issues associated with the project at the local, state and federal agency levels.

The estimates for Permitting costs were completed in accordance with FPL's budget and accounting guidelines and policies. The costs were compared to other costs being incurred by the company for similar activities and found to be reasonable.

Q. **Please describe the activities in the Engineering & Design category, the need for those activities and the process used to develop estimates for 2008 and 2009 expenditures.**

A. The Engineering & Design activities performed in 2008 and 2009 are required to support the overall Turkey Point 6&7 schedule. For the period ending December 31, 2008, Engineering & Design costs are projected to be \$7,910,661 as shown on Line 5 of Schedule AE-6 of Appendix II. For the period ending December 31, 2009, Engineering & Design costs are projected to be \$10,121,791 as shown on Line 5 of Schedule P-6 of Appendix II. These expenditures consist primarily of anticipated payments to qualified engineering firms supporting preliminary engineering and detailed site specific design of the project. The contract(s) supporting this scope of work are currently being developed through a Request for Proposal process.

Conceptual level engineering and design services are necessary to define the project to the level of detail necessary to support the content requirements of the license and permit applications. The activities will include site layout, balance of plant design, and integration with existing site utilities and new infrastructure services required by the project. These include water supply, wastewater, transmission and support facilities. Additionally, detailed engineering and design services will provide the basis for construction planning and procurement activities that will begin in 2009 and 2010.

The estimates for these costs were completed in accordance with FPL's budget and accounting guidelines and policies. The costs were compared to other costs being incurred by the company in similar activities and found to be reasonable. Where contracted, rate sheets are provided by the contractor and reviewed to verify rates being charged are consistent with FPL experience in the broader industry.

Q. Please describe the activities in the Long Lead Procurement category for the 2008 actual/estimated and 2009 projected periods, the need for those activities and the process used to develop estimates for these expenditures.

A. For the period ending December 31, 2008, Long Lead Procurement costs are projected to be $45,860,960 as shown on Line 6 of Schedule AE-6 of Appendix II. This amount consists of two components: an estimated $10,860,960 payment by June 2008 to Westinghouse for a forging reservation fee and an estimate for three potential long lead procurement payments in October, November and December of 2008 with a cumulative value of $35 million. Costs for long lead procurement items in future years are anticipated to be a part of the Engineering and Procurement contract payments and are included as part of the Power Block Engineering and Procurement cost line item for 2009.

The Reservation Agreement for the $10,860,960 forging reservation fee is currently under negotiation. The specific terms and payments are expected to be finalized by June 2008. The fee provides for reservation of the manufacturing capacity necessary to produce 23 specific forgings for each of two AP1000 units, or 46 forgings in total. The reservation slots are made based on a fabrication schedule that supports Unit 6 commercial operation in mid-2018 and Unit 7 commercial operation in mid-2020. It is necessary to secure the manufacturing space for the forgings at this time based on competition for the limited manufacturing capacity for these forgings and the pending queue of international heavy industrial projects.

The additional $35 million of funds estimated for long lead procurement in 2008 is based on the anticipated need to respond to dynamic market conditions that may require early purchase of components or materials that have supply system constraints or are in high demand. This would include procurement of Reactor Coolant Pump components and specialty metal such as containment vessel steel or stainless steel tubing. If it turns out not to be necessary to procure these materials in 2008, the procurement will be deferred to 2009 or later, and become a part of the larger Engineering and Procurement contract being negotiated with Westinghouse/Shaw.

The estimates for these Long Lead Procurement costs were completed in accordance with FPL's budget and accounting guidelines and policies. The estimates rely on information from Westinghouse/Shaw due to the unique features, limited market and early stage nature of these procurement activities. The costs have been compared to other costs being incurred by the company in similar activities and available comparable market information and found to be reasonable.

Q. Please describe the activities in the Power Block Engineering and Procurement category for the 2008 actual/estimated and 2009 projected periods, the need for those activities and the process used to develop estimates for these expenditures.

A. For the period ending December 31, 2008, Power Block Engineering and Procurement costs are projected to be $2,887,920 as shown on Line 7 of Schedule AE-6 of Appendix II. This amount consists primarily of anticipated payments to Westinghouse/Shaw necessary to support the development of site specific adaptations of the standard AP1000 plant technology needed for the license and permit applications. Additionally, these payments will support specific Westinghouse project management activities and design certification support.

FPL is currently negotiating the scope, terms and conditions associated with an EP contract with Westinghouse/Shaw that will be one of the defining commercial documents for the project. As discussed earlier, the EP contract would describe the scope of equipment, materials and services provided by Westinghouse/Shaw for the project management, engineering and procurement of the nuclear power island. It is anticipated FPL will be in a position to execute the EP contract in March 2009. The scheduled payments estimated to be required to support the EP contract are listed on the Power Block Engineering and Procurement line item of Schedule P-6. Payments may be made monthly or quarterly depending on the final terms of the EP contract.

For the period ending December 31, 2009, Power Block Engineering and Procurement costs are projected to be $70,787,145 as shown on Line 7 of Schedule P-6 of Appendix II. This amount consists primarily of payments to Westinghouse/Shaw under the anticipated EP contract. The initial scheduled payment of $29,347,145 would be due in May 2009 and periodic progress payments thereafter. These expenditures would allow for Westinghouse/Shaw to assemble and mobilize its full project team for Turkey Point 6 & 7. The Westinghouse/Shaw project team will consist of dedicated Project Management, Engineering and Procurement resources. This level of support is necessary at this stage of the project to maintain the earliest practical deployment schedule. Project Management functions provided by the Westinghouse/Shaw project team includes establishing required programs such as Quality Assurance, Environmental Compliance, and Health and Safety. Engineering activities would undertake the site specific design of Nuclear Power Island systems and safety related civil engineering design to support the standard AP1000 technology at the Turkey Point site. An integrated procurement function would be established to begin the commercial and logistical activities necessary to establish a project specific supply chain for equipment and materials. These functions are critical to be in place by

2009 to support the needed Preparation phase activities to prepare for nuclear system construction as early as 2013.

The cost estimates developed for these cost categories are based on continued negotiations and consultation with Westinghouse/Shaw to evaluate the necessary engineering and procurement activities to maintain FPL's project schedule, and eliminate any costs not needed at this time. The activities being considered and the associated costs are consistent in timing and magnitude with FPL's experience for other capital construction projects and Westinghouse/Shaw's experience in similar AP1000 projects currently underway internationally and in the United States. The EP contract will identify rates to be charged and these rate sheets will be reviewed to verify rates being charged are consistent with FPL experience in the broader industry.

COST RECOVERY REQUEST

Q. Are the actual costs incurred for Site Selection and Preconstruction in 2006 and 2007 prudent?

A. Yes, they are. The activities were necessary and the costs were incurred under a full range of project controls and procedures to verify they were appropriate and priced consistent with FPL's extensive experience in power generation development activities in Florida.

Q. What processes were applied to verify the expenditures were prudently incurred?

A. The Site Selection and Pre-Construction activities for the Turkey Point 6 & 7 project were executed in accordance with FPL's budget and accounting guidelines and policies. All procurement decisions were documented through approved procedures and authorized after appropriate management review to determine that (1) the activities were necessary to maintaining the project schedule, and (2) the costs incurred for the activities were consistent with applicable contract terms and were reasonable. The budgeting and oversight of the project have evolved as additional information is obtained.

Q. Are the actual/estimated and projected costs presented in your testimony reasonable?

A. Yes, they are. The costs represent Site Selection costs incurred in 2006 and 2007, actual/estimated Pre-Construction costs incurred in 2007 and 2008 and projected Pre-Construction costs in 2009. All costs are the result of activities necessary to accomplish Turkey Point 6&7 and are appropriately undertaken in order to maintain the Turkey Point 6&7 Project schedule.

Q. What project control and risk management tools will be used by FPL's project management team to verify the 2008 actual/estimated and 2009 projected costs are reasonable and prudent?

A. All the project management tools described earlier in my testimony will be applied, as appropriate to verify the project costs are reasonable and prudent.

Further, risk factors will be identified and actively managed to reduce impact to cost and/or schedule.

Q. What issues might arise in 2008 and 2009 that could affect the timing or magnitude of the costs estimated for that period?

A. As I discussed earlier, there is uncertainty regarding the timing and magnitude of payments associated with long lead procurement activities and the pending EP contract with Westinghouse/Shaw. Most directly, this could result in a reduction in expenditures of up to $35 million in 2008. If such long lead procurement expenditures are not made in 2008, some or all of these expenditures may be required in 2009 in addition to the $70,787,145 of EP payments anticipated in 2009 or in 2010. The timing and magnitude of the long lead procurement and EP contract payments necessary to maintain the project schedule are affected by the number of U.S. and international projects currently being pursued. If a majority of the announced projects are actively pursued, this will increase market demand for these items. Again, as issues are identified, FPL will consider the impact on project cost, risk and schedule.

TRUE-UP TO ORIGINAL PROJECTIONS

Q. Have you prepared a true up of FPL's current cost projections to the original projections of Turkey Point Unit 6 & 7 costs that were presented in the Need Filing?

A. Yes. Appendix II provides the TOR schedules that compare the current projections to FPL's originally filed Turkey Point Unit 6 & 7 project costs.

The TOR schedules provide information on the project costs through the end of 2009. FPL has not revised its non-binding cost estimate provided in the Need Filing as we have no additional information that would warrant such a revision. The TOR schedules provide the information currently available for the cost recovery period through 2009.

Q. Has FPL revised its cost estimate for project expenses beyond 2009?

A. No. The existing non-binding cost estimate range provides the best information available. When analyzed on a comparable basis, the cost range is consistent with those provided by Progress Energy Florida for their Levy project and other projects described in the industry press. Several significant steps will be required before FPL can effectively assess the need for a revision of the cost estimate range. FPL will undertake actions in 2008 and 2009 that will result in a refined project schedule and a defined commercial arrangement that will cover the Power Island engineering design and equipment costs. Further work will allow FPL to revise Owner's scope, material estimates and projected construction costs associated with the project. A review and integration of this information will allow FPL to revise the overall project cost estimate range.

SUMMARY

Q. Please summarize your testimony.

A. FPL has taken significant positive steps in developing Turkey Point 6 & 7 since 2006. These steps have been taken with the guidance of strong, effective project controls and risk management tools. FPL has identified the Westinghouse AP1000 technology as the preferred technology for the Turkey Point 6 & 7 Project. Site Selection costs incurred in 2006 and 2007 and Pre-Construction costs incurred in 2007 are prudent. FPL's actual/estimated costs for 2008 and projected costs for 2009 are reasonable. There has been no additional information developed since the Need Filing to revise the cost estimate range, however significant activities will be undertaken in the next two years that are expected to provide further information.

Q. Does this conclude your direct testimony?

A. Yes.

SDS – 1 is Appendix II
(Bound Separately)

SDS – 2 is Appendix III
(Bound Separately)

MPR
ASSOCIATES INC.
ENGINEERS

April 17, 2008

Mr. Mitchell S. Ross
Vice President & Associate General Counsel
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408

Subject: Task 1 Review - Nuclear Technology Selection Process

Dear Mr. Ross:

Florida Power & Light Company (FPL) has notified the U.S. NRC of its intent to file a Combined Construction and Operating License Application (COLA) for a potential new nuclear power plant by March 2009. As part of that project, FPL has initiated a technology selection process to evaluate the candidate nuclear technologies.

FPL has requested MPR Associates, Inc. (MPR) to perform an independent review of FPL's approach for evaluating and selecting the nuclear technology for a COLA for a new nuclear power plant. The FPL evaluation of new nuclear power generation technologies is provided in Revision 0 of FPL report "Current Technology Options for New Nuclear Power Generation", dated April 15, 2008. The FPL evaluation considered five candidate technologies and is based primarily on the input received from four Nuclear Steam System Suppliers (NSSS), General Electric Company, Westinghouse Electric Company, Mitsubishi Heavy Industries and Areva in response to a June 22, 2006 Request For Information (RFI) from FPL. The FPL evaluation concludes that:

- All five technologies are technically acceptable.
- Two technologies (ABWR, AP1000) have NRC approved Design Certifications and appear to have the least regulatory risk to developing a COLA by 2009. Further, FPL, through NuStart participation, has had access to the model COLA development process.
- Each technology has technical issues and first of a kind concerns which could affect the desirability of each option.

MPR has performed a review of the FPL RFI, the RFI responses from the vendors, the FPL evaluation, and other FPL and vendor documentation developed during the technology evaluation process. MPR considers that the FPL evaluation develops an objective, graded approach to evaluating the available technologies, and identifies and assesses important considerations. The methods and depth of the evaluation are considered to be reasonable for the stated purpose of the evaluation and to support the overall conclusions. Should FPL decide to proceed with construction of a new nuclear power plant, we understand that the final decision on the technology will be based on further FPL evaluation of the economics and overall project risk associated with each design. We concur with that approach.

If MPR can be of any further assistance, please do not hesitate to contact us.

Sincerely,

George W. Geaney

George W. Geaney

MPR
ASSOCIATES INC.
ENGINEERS

April 15, 2008

Mr. Mitchell S. Ross
Vice President & Associate General Counsel
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408

Subject: Task 2 Report – Nuclear Technology Selection Additional Considerations

Dear Mr. Ross:

Enclosed for your review is the Task 2 final report to support Florida Power & Light Company (FPL) selection of a nuclear technology for Turkey Point Units 6 and 7.

FPL has requested MPR to perform an independent review of FPL's approach for evaluating and selecting the nuclear technology for a Combined Construction and Operating License Application (COLA) for a new nuclear power plant. In Task 1, MPR performed an evaluation of new nuclear power generation technologies documented in FPL Engineering Evaluation PTN-NNP-SEMS-07-002, Revision D.

Task 2, which is the subject of this enclosed summary report, provides MPR comments on other important considerations associated with selecting the nuclear technology for the COLA. Overall, we agree that the FPL assessments and considerations are appropriate and support the decisions to date.

If you have any questions or if we can be of further assistance please do not hesitate to call me at (860) 691-8950.

Sincerely,

George W. Geaney

George W. Geaney

Enclosure

MPR
ASSOCIATES INC.
ENGINEERS

Enclosure to
MPR Letter Dated
April 15, 2008

Task #2 Report - Nuclear Technology Selection Additional Considerations

1. Introduction

Florida Power & Light Company (FPL) has notified the U.S. NRC of its intent to file a Combined Construction and Operating License Application (COLA) for a potential new nuclear power plant by March 2009. As part of that project, FPL has initiated a technology selection process to evaluate the candidate nuclear technologies.

FPL has requested MPR Associates, Inc. (MPR) to perform an independent review of FPL's approach for evaluating and selecting the nuclear technology for a COLA for a new nuclear power plant. In Task 1, MPR performed an evaluation of new nuclear power generation technologies provided in FPL Engineering Evaluation PTN-NNP-SEMS-07-002, Revision D.

Task 2, which is the subject of this summary report, provides MPR comments on other important considerations associated with selecting the nuclear technology for the COLA. Specifically this summary report is based on a review of FPL documents and testimony available on the Florida Public Service Commission website and transmission integration information provided by FPL in a November 5, 2007 e-mail from Scroggs to Geaney. This summary report considers the following important items:

- PWR vs. BWR considerations with FPL's existing infrastructure
- Initial capital costs
- O&M estimated costs including staffing
- Vendor readiness
    - Design completion
    - Major open issues
    - Potential start-up/maintenance challenges
    - Modularization considerations

        - Supply chain experience
        - Labor force availability
    - FPL position in vendor queue
    - Schedule
    - Forgings commitments
    - NSSS/AE/Constructor team
    - FPL vs. vendor project risk/liability assumptions

Also, at the request of FPL, transmission integration challenges are also addressed.

Finally, this report considers the AP1000 PWR technology developed by Westinghouse and the ESBWR BWR technology developed by GE-Hitachi. These two technologies are under consideration by FPL based on the results of the Engineering Evaluation prepared by FPL.

2. Summary and Conclusions

This summary report addresses a number of non-technical and some transmission integration considerations related to selection of a nuclear technology. In terms of the areas evaluated, the AP1000 has the advantage when compared to ESBWR. MPR agrees with FPL preference for the AP1000 based on the relative risks between AP1000 and the ESBWR and the transmission integration considerations. However, it is important to recognize that the technology risk considerations are dynamic in nature and will change as Westinghouse and GE continue with the design development, licensing, and initial construction of their technology.

The MPR opinions expressed herein are based on our involvement with the U.S. nuclear industry; multiple discussions with utilities, nuclear steam supply system vendors, and the Nuclear Regulatory Commission; and reviews of publicly available information. A summary of the considerations discussed in Section 3 is provided in Table 2-1 below.

Table 2-1 Summary of Considerations

Report Section	Consideration	Technology Advantage	Comments
3.1	PWR vs. BWR considerations with FPL's existing infrastructure	AP1000	Based on Westinghouse PWR technology at Turkey Point Units 3 and 4, Point Beach 1&2 and Seabrook.
3.2	Initial capital costs	Cannot be determined at this time	No publicly available binding information available
3.3	O&M estimated costs including staffing	Cannot be determined at this time	Detailed estimate has not been developed
3.4	Vendor readiness		
3.4.1	Design completion	AP1000	Based on status of NRC reviews and approvals
3.4.2	Major open issues	AP1000	Revision 16 of AP1000 DCD in intended to close major open issues
3.4.3	Potential start-up/maintenance challenges	AP1000	Both designs have significant potential challenges, but none believed to be fatal
3.4.4	Modularization considerations	Cannot be determined at this time	Both plan to use modular construction techniques
3.4.5	Supply chain experience	ESBWR	GE overseas experience provides the current advantage, although opportunities for Westinghouse experience development may be realized
3.4.6	Labor force availability	Neither	Likely more an industry resource issue that a technology specific issue
3.5	FPL position in vender queue	AP1000	Based on expressed utility interests, but no binding commitments
3.6	Schedule	AP1000	AP1000 will likely have more actual construction experience than ESBWR for Turkey Point 6 and 7
3.7	Forgings commitments	Cannot be determined at this time	Both technologies will rely on the same supplier in Japan
3.8	NSSS/AE/Constructor team	Cannot be determined at this time	Neither team is comprised of the most qualified and experienced industry companies
3.9	FPL vs. vendor project risk/liability assumptions	Cannot be determined at this time	Will depend upon contractual negotiation
3.10	Transmission Integration	AP1000	Smaller size of each AP1000 provides the advantage

3. Non-Technical Considerations Related to Technology Selection

3.1. *PWR vs. BWR Considerations with FPL's Existing Infrastructure*

The principal and defining difference between a BWR and a PWR is the state of the light-water working fluid in the reactor core. In a BWR, the water in the reactor core boils, and the steam generated is passed directly to the turbine generator for use in power generation. In a PWR, the water in the reactor core is a slightly subcooled liquid that is heated and passed to a steam-generating heat exchanger where it generates steam for the turbine-generator set in a separate, lower-pressure water cycle.

Both reactor concepts are widely used in commercial power production. World-wide, most of the operating commercial power reactors are light-water reactors (LWRs), and in the U.S., all are LWRs. PWRs are the more common, making up about two-thirds of the world's LWRs and about 60% of the U. S. LWRs. Most of the BWRs operating in the world are in the U.S. and Japan, with a handful in Europe.

Turkey Point Units 3 and 4 are both Westinghouse (693 MWe) PWRs. Therefore, the AP1000 technology would seem to offer some operating synergies with the two Westinghouse PWRs at Turkey Point (although we note that the existing units are from an earlier generation design and have some key design differences with the AP1000). Further, FPL currently owns and operates Westinghouse PWRs at Point Beach (two units in Wisconsin) and Seabrook (one unit in New Hampshire), as well as two Combustion Engineering PWRs at St. Lucie (in central/south Florida). It is noted that the current FPL fleet of operating units also includes the GE BWR technology at the Duane Arnold plant in Iowa. Therefore, FPL has some fleet experience with operating GE BWRs.

3.2. *Initial Capital Costs*

Neither the AP1000 or ESBWR detail designs are complete, nor are the details of the Turkey Point site specific aspects of the design complete. Since the plant designs are not complete, vendors and other sub-suppliers to Westinghouse and GE have not developed their cost figures for all equipment items. Further, since the costs for labor and materials will be incurred over a relatively long construction period, market risk including labor force availability, commodity pricing, and other factors will have a significant influence on the price of a new plant. Also the project market risk that is contracted onto the vendor will affect the price. Therefore, it is recognized that binding vendor pricing is probably not available at this time.

In order to develop the cost estimate for Turkey Point 6 and 7, FPL used an existing study conducted by an industry consortium, led by the Tennessee Valley Authority (TVA) in coordination with the U.S. Department of Energy, and published in August of 2005 (the TVA Study). This study provided a detailed cost evaluation for the construction of a General Electric ABWR design reactor unit at TVA's Bellefonte Site. The TVA Study provides a relatively current evaluation of new nuclear generation construction in the United States under expected regulatory, design, logistic and labor conditions. The study provides a detailed and wellresearched basis for new nuclear construction costs for the General Electric ESBWR and Westinghouse AP1000 because the construction methods, materials and schedules are similar. Additionally, FPL discussed design specific construction schedules with General Electric and Westinghouse to confirm that the assumptions used in the TVA Study would be generally consistent with construction of a GE ESBWR or Westinghouse AP1000 design unit. The study provided the information that allowed FPL to develop an overnight cost estimate range on a dollars-per-installed-kilowatt ($/kW) basis of $3,108 to $4,540 for two AP1000s in Florida. The same cost on a dollars-per-installed-kilowatt ($/kW) basis for two ESBWRs was assumed. This estimate considers power plant, owner, and transmission integration costs. At the time of this cost estimate development, the FPL estimated costs were admittedly conservatively higher than others in the industry were estimating.

Since the development of the FPL cost estimate, Westinghouse has further advanced the design of the AP1000 and has provided cost estimates to some utilities. Progress Energy recently reported an estimated overnight cost of about $4,229/kW, which is within the range estimated by FPL. MPR is not aware of any GE provided public cost information for the ESBWR which has a basis more rigorous than the FPL estimate.

As both the AP1000 and ESBWR designs mature and utilities commit to these designs, the estimated overnight costs will become better defined. Escalation of commodity prices and cost of labor over the construction period, length of construction, and the cost of money will have a significant impact on the total cost. In the meantime, MPR considers the FPL cost estimates to be reasonable. FPL should continuously update the project economics and the cost model based on developing information on new plant costs.

It has been MPR's experience with the new plant technologies that the quoted vendor costs are heavily influenced by a number of factors, two of which are the amount of risk that the utility desires to place on the vendor, and the vendor's desire to establish itself as an early supplier of this next generation nuclear capacity in the U.S. As any particular technology supplier consummates these contracts and available capacity in his supply chain diminishes, the cost of that technology will increase. However, there is also the potential to benefit from cost advantages due to economies of scale, particularly with AP1000. If, in fact, a number of utilities enter into binding agreements with Westinghouse, economies of scale from multiple unit fabrication/construction with both Westinghouse and their suppliers have the potential to provide reduced costs to the utility. Currently, there is no apparent cost advantage between the AP1000 and the ESBWR.

3.3. O&M Estimated Costs and Staffing

FPL has stated that based on the limited information available at this time, there is no significant difference in the fixed and variable operating costs of the GE or Westinghouse units. In general, it is presumed that the larger units may provide some benefit from scale economics. Similarly, economies may also be available through industry consortiums, such as owners groups, to share common costs for either technology.

The most significant contributors to the O&M costs are those for the fuel and for an existing site, the incremental staff for the new plant. For the nuclear fuel, although the primary driver is the cost of uranium, vendor fabrication costs will also contribute to the utility cost for fuel. At this point in time, the unit price for nuclear fuel is not expected to be significantly different between the AP1000 and ESBWR. As the number of plants that use the same fuel increase, the overhead fabrication costs can be allocated across more projects, thereby reducing fuel costs in the future, providing a potential future advantage for AP1000. It is expected that, the overall plant efficiency may be slightly better for the ESBWR compared to AP1000. Therefore, the ESBWR is judged have a slight advantage in the initial fuel cost component of the total electric production cost. However, any initial ESBWR fuel cost advantage could be minimized or even overcome in the future if more AP1000s are built and larger fuel quantities are needed.

Relative to staffing, a number of factors will influence the number of personnel required for new plants including contractor/employee mix and ability to share resources with other existing site departments such as security and training. Although initial staffing estimates have been provided by GE and Westinghouse, these are vendor estimates without consideration of Turkey Point existing resources and other site specifics. Detailed evaluations to identify the optimum integration of new plant staffing with existing site resources has not been performed. Since Turkey Point 3 and 4 employ the PWR technology, there are likely to be some inherent benefits should the AP1000 be selected as the Turkey Point 6 and 7 technology.

Overall, at this time, MPR agrees that a differentiation in the estimated O&M costs for Turkey Point Units 6 and 7 between the AP1000 and ESBWR technologies cannot be determined with confidence, and this consideration should not be a major differentiator between the two technologies at this time.

3.4. Vendor Readiness

3.4.1. Design Completion

In March 2006, the NRC provided a revised Final Design Approval for the AP1000 based on Revision 15 of the Design Control Document. In order to address COLA open items, design changes and modifications requested by several utilities, and continued detailed design development by Westinghouse, a revision to the AP1000 Design Certification has been submitted by Westinghouse. It is anticipated that the NRC will issue a safety evaluation report for this amendment in March 2010. The COLA for Bellefonte, which is the reference COLA for AP1000, was submitted to the NRC in October 2007. Over 120 technical reports have been submitted for NRC approval as part of the Bellefonte pre-application phase and will be generically applicable to subsequent COLAs. COLAs for AP1000s at Shearon Harris Units 2 and 3, William Lee Units 1 and 2, Virgil C. Summer Units 2 and 3, and Vogtle Units 3 and 4 (i.e. the AP1000 Wave 1 utilities) have also been submitted to the NRC.

In September 2007, GE submitted Revision 4 of the ESBWR Design Control Document for design certification. NRC review of the ESBWR DCD was subsequently put on hold to allow GE to address a significant number of NRC Requests for Additional Information. Revision 5 of the DCD is now being prepared by GE for NRC submittal. This revision is intended to address all NRC questions and allow the NRC to restart the ESBWR reviews. COLAs for North Anna Unit 3 and Grand Gulf Unit 3 have been submitted to the NRC.

At this time, the AP1000 design, as evidenced by the number of NRC reviews and approvals, is more complete than the ESBWR design.

3.4.2. Major Open Issues

Westinghouse has prepared and submitted for NRC approval Revision 16 of the AP1000 DCD. The purpose of the revision is to address COLA open items related to the AP1000 design and to address design changes or modifications resulting from customer interaction or the Westinghouse detail design process. This revision of the certified design also includes I&C systems detail design. Thus, upon NRC approval of Revision 16, major open items should be minimal. Conversely, GE is presently preparing a revision of the ESBWR DCD to address many open items and questions from the NRC initial review of the DCD. Thus, although GE continues to make progress in the regulatory arena, at present the advantage for closure of major open issues resides with the AP1000.

3.4.3. Potential Start-Up/Maintenance Challenges

ESBWR

1. GE has limited experience with high-power natural-circulation BWRs. The natural circulation concept has evolved from the original concept for the 670 MWe Simplified BWR. Using natural circulation rather than forced circulation allows the elimination of several systems, such as the recirculation pump. The natural circulation concept of the ESBWR is roughly a 30-fold extrapolation in core power from GE's two successful prototype natural-circulation reactors, Humboldt Bay and Dodewaard. Start-up and initial operational challenges for the early fleet plants should be expected as well as potential backfits and/or operational limitations. This has the potential to increase the time to commercial operation on the early units if backfits are required, with associated increases in project interest and construction costs. This also has the potential to require regulatory approvals which could lead to further delays in commercial operation.
2. In traditional forced-circulation BWRs, core power is mainly controlled by varying the recirculation flow rate to the reactor. The recirculation pump flow is varied by either pump speed control or discharge throttling of the pumps. This makes control-rod adjustment less frequent, improves control feedback and maneuverability, and it allows for spectral shift fuel management which improves fuel economics and end-of-cycle capacity factors. With a natural circulation design like ESBWR, reactor power control is achieved solely with rods, and the ability to vary core water content for fuel management is very limited. The impact of natural circulation on reactor power maneuverability, fuel management, control-rod and drive wear, and fuel reliability may present challenges that initially result in less reliable operation and availability for power production.

3. Fuel is removed and replaced from the ESBWR reactor by use of a robotic refueling machine. The refueling machine will take advantage of improved control systems and dual robotic arms to move two fuel bundles simultaneously. This new design includes a positioning system that uses object and character recognition techniques (termed "machine vision") to allow for faster automated refueling. Although robotics are used in other industries, the development of the robotic refueling machine includes FOAKE because it is a new application of an existing technology. Any unanticipated challenges with this FOAKE have the potential to impact refueling outage time, and therefore plant availability for power production.
4. The forced circulation design of operating BWRs allows core flow to be established before bringing the reactor critical and beginning power ascension. In a natural circulation design like ESBWR, core residual heat and/or fission heat must be used to establish core flow unless an externally heated flow is injected to facilitate natural circulation flow. The early transition from single-phase to two-phase flow on start-up is likely to be less than smooth and continuous. There is a potential that flashing will start high in the flow path in or near the steam separators. As flashing begins, the core flow will accelerate due to the buoyancy of the low-pressure steam. This increase in flow will reduce core outlet temperature and suppress flashing with some time delay due to the mass of warmer water. This cyclic flow and its attendant flashing and void collapse are likely to continue until core power is raised sufficient to establish continuous boiling. This has the potential to increase the time to commercial operation on the early units if procedural, operational, or other backfits are required, with associated increases in project interest and construction costs.
5. An issue relating to operational reliability and availability for continued power production is the ability of plant operators to recover the plant from the early stages of an event in which passive safety systems are actuated but subsequent operator actions make non-safety active systems available to avoid a long-term passive cooling event. It would be undesirable if a passive actuation once initiated could not be terminated early without a long-term passive cooldown. The conditions under which a passive safety-system actuation cannot be interrupted and the procedures for recovery of the plant and restoration of normal operation after a passive safety actuation should be carefully reviewed to ensure that both safety and operational flexibility are maintained.

AP1000

1. Westinghouse has eliminated the piping between the steam generators and the suctions of the reactor coolant pumps by mounting the reactor coolant pumps (RCPs) on the steam-generator heads. This eliminates the separate structural supports for the RCPs and eliminates the suction cross-over piping that makes reflooding of the core after a postulated design basis accident difficult in current plant designs. These benefits come at the expense of very close coupling of the RCPs, increased potential for RCP/SG interactions, and potential difficulty in doing simultaneous RCP and SG maintenance work due to proximity along with the associated increase the maintenance time and costs.
2. All operating Westinghouse nuclear power plants use shaft-seal reactor coolant pumps. AP1000 will use seal-less, canned-motor reactor coolant pump design. Westinghouse has

Navy experience with similar, but likely smaller, pumps, and an early commercial prototype plant also had canned-motor pumps. The AP1000 reactor coolant pump design represents a significant departure from existing Westinghouse commercial practice. The seal-less design of the pump, which is a desirable feature from the point of view of safety and maintenance, introduces some unique features. The AP1000 pump design has dual internal flywheels to meet RCS flow coastdown requirements. The flywheels are inside the RCS pressure boundary because all of the rotating parts of the pump and motor are inside the RCS pressure boundary. This will make inspection of the flywheels very difficult without removal and disassembly of the pump which could have potential impact on total RCP inspection and repair costs.

3. The AP1000 reactor coolant pumps operate at variable speed. During plant start ups and shutdowns, the pumps will be operated at reduced speed. Once the reactor coolant system is up to temperature, the pumps will be operated at full speed. The variable speed feature is included to avoid sizing the pump motors for the full-speed cold pumping power requirement, as is current commercial practice. (The constant-speed pump power requirement at cold conditions is about 1/3 greater than that at normal RCS operating temperature.) The net result of the AP1000's hot rating approach is that the motors will normally operate at a much higher fraction of their design rating than is now typical in commercial service. This reduced operating margin has the potential to adversely impact the long-term reliability of the motor and their O&M costs should motor replacements be required in the future.

4. An issue relating to operational reliability and availability for continued power production is the ability of plant operators to recover the plant from such events as an improper actuation of the passive core cooling (PXS)/automatic depressurization system (ADS) or the early stages of an event in which passive safety systems are actuated but subsequent operator actions make non-safety active systems available to avoid a long-term passive cooling event. It would be undesirable if a passive actuation once initiated could not be terminated early without a long-term passive cooldown. The conditions under which a passive safety-system actuation cannot be interrupted and the procedures for recovery of the plant and restoration of normal operation after a passive safety actuation should be carefully reviewed to ensure that both safety and operational flexibility are considered.

It is apparent that both AP1000 and ESBWR face potential challenges during start-up and operation. At this point, MPR considers that the ESBWR risks may be more significant than AP1000. However, the utility that uses a technology that has already undergone these start-up and initial operation evolutions by others will benefit from that operating experience. At this time, although there seems to be more utility interest in the AP1000 (COLAs submitted for 10 plants at five sites) than the ESBWR (COLAs submitted for two plants at two sites), it is not apparent which U.S. utility will actually build the first AP1000 or ESBWR.

3.4.4. Modularization Considerations

Modularization promises to reduce construction schedule durations. Of all the improvements that have been made in construction techniques, modularization appears to play the largest role in reducing each of the construction schedules.

The use of modularization is closely related to two other aspects of new plant construction: the use of open-top construction techniques and a requirement for a large crane on-site during construction. The transportation methods available at the construction site can also affect the module design. For maximum benefit, the site should have good access to water, rail, and roads to make the most effective use of modularization.

The use of modularization in the shortening of the construction schedule is accomplished by:

- Creating parallel construction activities
- Increasing worker productivity by increasing the amount of activity in controlled shop environments as opposed to construction sites
- Reducing work-site congestion so that on-site craft are more productive
- Allowing construction of modules at grade and in easy-to-reach positions
- Reducing the effects of weather at the construction site (if module assembly occurs at indoor facilities)
- Reducing commissioning time of some equipment since some testing may be conducted in the shop.

However, modularization does introduce challenges to project schedules, including:

- Detailed engineering design schedules may be accelerated because of additional up-front work
- There is no prior experience in the U.S. with constructing a commercial nuclear power plant using modularization
- The number of domestic shops capable of performing module construction appears to be limited
- The actual benefits of modularization may not apply to first-of-a-kind (FOAK) plants and may not be realized until N^{th}-of-a-kind (NOAK) plants are constructed
- Construction of temporary transportation infrastructure and laydown areas will be required during the site preparation phase to stage and move large modules once delivered onsite
- Late delivery of modules can result in schedule delays and setbacks
- Installation of modules must be highly structured and prioritized so connections can be made expeditiously
- Damage to modules during shipment to the site has the potential to cause delays

Since both Westinghouse and GE are aligned with a shipyard that has modular construction experience in building nuclear ships, neither technology appears to have a distinct advantage.

3.4.5. Supply Chain Experience

Although nuclear power plants have been regularly built overseas for the past twenty years, nuclear power plants have not been constructed in the U.S. for almost a generation. The U.S. vendors, both NSSS vendors and key suppliers of plant equipment, initially played large roles in many of the overseas projects. However, their role has diminished over time as local capability was developed in those countries. The result of this dormancy has been a marked decrease in the readiness of the U.S. nuclear industry to construct nuclear power plants. This readiness problem is seen at all levels, from the NSSS vendors and the primary constructors, through their supply chains and many of the lower tier equipment suppliers.

Each of the NSSS vendors and the major A/E/Constructors is at a different stage in supply chain development. The on-going nuclear projects in Finland and Taiwan, the four nuclear units under construction in China, and the nuclear Waste Processing Facility under construction in Hanford collectively represent the present day experience with equipment supply and capacity constraints. GE has maintained a role in supplying equipment to ABWRs in Japan and Taiwan. Those projects have provided a foundation to build on for new plants in the U.S. Westinghouse does not have similar recent overseas experience, so Westinghouse is trying to catch-up with their competitors. Their effort to develop the proposal for the AP1000 units in China has helped accelerate the development of the Westinghouse supply chain. In addition, the recent acquisition of Westinghouse by Toshiba and their supply chain experience should benefit the Westinghouse supply chain capabilities.

Although both NSSS vendors acknowledge they need to continue to strengthen their supply chain organizations, they are each confidant and do not foresee problems with their supply chains for their first one or two plant orders. However, they both acknowledge that the cumulative impact of multiple projects throughout the U.S. and world could cause significant problems with projects that start after the initial units. Although both vendors are working to strengthen their supply chains so they will be able to support all of their expected new plant projects, neither of their supply chain organizations are at the maturity level needed for actual recent plant construction. At present, GE is believed to be ahead of Westinghouse because of their overseas experience and be in a better position to avoid potential pinch points. However, should multiple AP1000 plants be contracted in the U.S., this will necessitate improvements in this area by Westinghouse.

3.4.6. Labor Force Availability

It has been MPR's experience that the vendor construction schedules assume sufficient labor will be available to complete the required activities without causing delays. The schedules recognize that some personnel will require training and there will be some challenges to availability of qualified personnel. However, the vendors assume the resulting impact on schedule will be minimal.

This is a key assumption regarding the overall construction schedule. The amount of labor available to be dedicated to a site will impact the rate at which a plant will be constructed. This is especially true for skilled and nuclear certified labor. General construction and maintenance workers most likely will be available from other industries for new nuclear construction and will not require extensive training. However, recruiting for some nuclear specialties (e.g., health physicists, radiation protection technicians, nuclear QA engineers/technicians, welders with nuclear certification, etc.) may be more difficult due to the limited number of qualified people within these fields. These difficulties may affect construction schedules depending on how many qualified workers can be recruited and the availability of these workers for scheduled activities.

This shortage of skilled workers in certain nuclear specialties may prove to be burdensome, especially if orders for new nuclear plants increase at the present rapid pace. Due to the lack of new nuclear construction over the last 25 years, the population with nuclear expertise and training is dwindling and not replacing itself with new workers. Both technically skilled and craft organizations may require time to "catch up" with the industry and train an adequate number of personnel. Additionally, in order to have a sufficient number of workers on-site, the construction firm may need to investigate alternative labor options such as relocating skilled workers to a site for short durations to work around skilled labor shortages.

A major uncertainty regarding the availability of labor for the first few new nuclear power plants is the competing demand for qualified, skilled workers. There are likely to be other nuclear plant projects in the U.S. coincident with the FPL project, as well as major infrastructure construction projects. These projects will all be competing for the same resource pool.

Thus, although the vendors make similar assumptions regarding labor availability, there is considerable risk and uncertainty in this assumption and FPL will need to work closely with the selected vendor to monitor that risk. At this point, neither technology has a clear advantage on labor force availability.

3.5. FPL Position in Vendor Queue

The position in the vendor queue offers both advantages and disadvantages. Those in the front of the queue will have more influence with the vendor in negotiating the costs, terms and conditions of the contract, since the vendors are anxious to secure commitments for the first few plants. Being early in the queue will also provide the utility with more influence over the design of the plant. For example, with the AP1000, the five utilities that Westinghouse considers to be the wave one utilities are Duke Energy, South Carolina Electric & Gas, Southern Company, Progress Energy, and Tennessee Valley Authority. These utilities are engaged with Westinghouse in establishing many of the design details that will become the reference COLA for the AP1000. The wave two utilities will need to accept the design details that are established in the design certification in order to preclude a re-submittal of the design certification to the NRC. However, being part of the second wave provides the benefit of the lessons learned during start-up and initial operation of the first wave, and any associated design and licensing changes that may be required for successful continued operation.

At this point, a number of utilities have proceeded with the licensing aspect of a new technology in engaging the particular new technology and in developing a COLA for that technology. However, very few utilities that have made a significant financial contractual commitment to proceed with the construction of a new plant. Therefore, it is difficult to predict where FPL may be in the vendor queue if the FPL schedule is maintained and, appropriately, this has not been a focus of the technology selection process for FPL. However, since the AP1000 has more utility interest than ESBWR at this point, it is likely, but in no case certain, that selecting the AP1000 technology will advantageously place FPL further back in the vendor queue compared to ESBWR. This has the main advantage of providing increased schedule certainty in the licensing, construction and start-up of Turkey Point Units 6 and 7, and in proving the capability of the vendor supply chain. However, no binding utility commitments to either technology have been made by a U.S. utility. In fact, the possibility of FPL becoming one of the first AP1000 projects to be constructed cannot be ruled out. Events that may provide some certainty in the FPL position in the AP1000 queue include announced financial commitments by the AP1000 Wave 1 utilities to proceed, and the approvals by the Wave 1 utility states for nuclear plant construction.

3.6. Schedule

In response to an initial FPL request for information (RFI) on June 22, 2006, Westinghouse identified a 36 month schedule from first concrete pour to fuel load. More recently in an October presentation to ACRS, for AP1000, Westinghouse estimates that the construction period, which is from first concrete pour to fuel load, will be 48 months, and another 6 months for acceptance testing and commissioning. The first unit will likely take longer as there will be some verification testing that will be required. Should Turkey Point Unit 6 be the third or fourth AP1000 constructed, lessons learned from the construction of the first units should benefit FPL. Also, the construction of Turkey Point Unit 7 should be shorter that Turkey Point Unit 6. Although considerable effort has been expended by Westinghouse in the development of the AP600 and AP1000 schedules, at this point, a fully integrated schedule has not been developed by Westinghouse. Therefore, confidence in the construction time, unless backed by meaningful contractual guarantees, should be guarded.

In response to this June 22, 2006 RFI, GE noted the construction schedule as 36 months. Although GE has some recent construction experience with an ABWR at Lungman, Taiwan, MPR considers the GE schedule estimate to have even less of a basis than the AP1000 schedule, primarily due to the completion status of the detail design.

3.7. Forging Commitments

The most significant manufacturing concern and construction schedule risk is the very limited capacity to manufacture nuclear-grade ultra-heavy (> 200 tons) large ring forgings required for the large nuclear safety related vessels. For the AP1000, large ring forgings will be required for the fabrication of the reactor vessels, pressurizer vessels, steam generators, containment vessels, and reactor coolant pump casings. Presently, these forgings are only available from one supplier, Japan Steel Works, Ltd. (JSW). The singular global manufacturing capability for heavy (< 200 tons) large forgings also constrains the manufacture of similar large vessels for other technology suppliers including GE, Areva, and Toshiba. If sufficient plant orders are made, this constraint will likely be removed by the addition of more capacity, but significant investment will be required. For example, Areva is considering developing an ultra-heavy forging capability at a facility in Europe. However, in the meantime, all U.S. new nuclear plants, foreign new nuclear plants, and other worldwide large equipment needs will be competing for a slot in the JSW production line. FPL is wise to contractually commit to an arrangement now, even in advance of technology commitment, which provides for schedule certainty in the delivery of these large forgings.

Since both the GE and Westinghouse technologies require large ring forgings from the same supplier, there is no inherent advantage of one of these technologies over the other relative to this external constraint. Potential "wild cards" are the relationship between GE and Hitachi, and between Westinghouse and Toshiba. Our experience is that occasionally the major Japanese vendors can have influence with JSW. This may be a benefit associated with the recent acquisition of Westinghouse by Toshiba. However, we would not count on that benefit.

3.8. NSSS/AE/Constructor Team

The greatest risk to successful project completion is the readiness of NSSS/AE/Constructor Team to complete the detailed design, procure the required equipment, and construct the plant on the desired schedule (i.e., the maturity and health of the supply chain). No nuclear power plants have been constructed in the U.S. in almost 20 years and this long period of dormancy has led to a deterioration of the industry capabilities. Also, the standard engineering, procurement and construction model that is being proposed as typical is for the NSSS vendor to be the prime contractor, which will be significantly different than that in the past, with the NSSS vendor having significantly greater overall project responsibilities.

A focus of the selected team's efforts will need to be on the development and implementation of the supply chain, and will include international and domestic suppliers. The ability of this international supply chain to support U.S. projects is not proven.

The current nuclear industry infrastructure is believed to be able to support construction of the first few nuclear plants. However, this capacity will likely be quickly saturated and subsequent plant projects will have supply chain challenges as the needed equipment and materials are not available. We expect that the industry will make the investments in capacity and production to support the nuclear power plant demand in the long-term, but that may not help the plants constructed after the first few plants.

These risks with vendor readiness are expected to be reduced over the first few new plants for each technology supplier as they make progress in building the supply chain and developing detailed construction plans. For the current GE (GE/Washington Group/Black & Veatch/Zachary) and Westinghouse (Westinghouse/Shaw) teams it is not apparent that either team is comprised of the most nuclear qualified/construction capable members. Also, the GE team is comprised of several major companies. The division of roles and responsibilities on that team could be a challenge.

The best approach for mitigating these risks will be for FPL to negotiate with the NSSS supplier on the team members and roles that best fit FPL's needs, and then to provide active oversight to ensure the overall equipment/component/material sourcing plan is robust and will be reliable.

3.9. FPL vs. Vendor Project Risk/Liability Assumptions

Assumption of risk will be another critical consideration in the cost of new U.S. nuclear plants. For Turkey Point Units 6 and 7, FPL estimates the costs as high as \$17.8B for the AP1000 and \$24.3B for the ESBWR. These estimates include overnight costs, escalation, and interest on funds used during construction. Although overnight costs are largely under the control of the vendor, material and labor escalation through the planned 2020 Unit 7 date for commercial operation and potential delays in commencement of commercial operation could have a significant impact on project economics. Considering that the total market capitalization of FPL is approximately $25B, these new nuclear units pose substantial financial risk to the entire corporation. Contracting some of the total cost and schedule risk onto the prime contractor would be wise, but this will result in a potential loss of control over critical decisions. Since Westinghouse and GE are also inherently risk adverse, their assumption of any project risk will come at an additional cost. As Westinghouse has come closer to consummating commitments with utilities and utilities have attempted to transfer risk to Westinghouse, these utilities have seen the costs of the AP1000 increase, although recent increases in commodity prices and other factors have likely also been an influence in these cost increases. At this point, neither, Westinghouse or GE appears to offer an advantage in the assumption of project risk. However, as discussed elsewhere in this summary report, the inherent risks associated with AP1000 at present are less than those with the ESBWR because of the advantage associated with the relative completion of the licensing and detail design.

3.10. Transmission Integration

FPL's investigation of the transmission integration of the candidate sites indicates that the Turkey Point site provides the most flexible transmission integration option. The site has access to both 230 kV and 500 kV transmission facilities and requires no new right of way acquisitions. The Turkey Point site in conjunction with the AP1000 provides FPL with an approach that has the least risk and delivers power on an earlier schedule than with other site and technology combinations.

The costs of the transmission integration estimated by FPL seem reasonable and should be only a secondary consideration in choosing the plant location and technology. The major factors that determine the transmission integration cost are power, voltage and distance with right of way acquisition being the spoiler. These appear to have been appropriately considered in the estimates.

The use of the ESBWR technology also adds risk. As discussed earlier, the advantage of the AP1000 over the ESBWR is associated with the AP1000's state of completion of licensing and detail design. FPL has determined that choosing the ESBWR technology for any of the candidate sites would most likely add a minimum of two years to the overall process with the FRCC/SERC inter-regional planning and engineering being the most complicated and time consuming. There are also indications that installing a "larger sized" unit may negatively impact FPL's long term SERC transmission service allocation. Therefore, the AP1000 will be more advantageous for the Turkey Point site.

Further consideration of green field sites and technologies other than the AP1000 should be reserved for the future after the expansion of the Turkey Point site is underway.

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St. Lucie Units 1 and 2

Extended Power Uprate NSSS Phase 1 Report

1. BACKGROUND

Florida Power and Light (FPL) contracted Westinghouse to begin engineering work on an extended power uprating (EPU) of St. Lucie Units 1 and 2. Westinghouse and FPL are working in concert to define the overall NSSS scope required for the associated uprate License Amendment Requests (LAR's).

Recognizing FPL's goal of uprate implementation at the Fall Outage of 2011 for Unit 1 and Spring 2012 outage for Unit 2, long lead NSSS activities have been initiated. Additionally, a review of the existing documents in key areas has been completed to confirm applicable methodologies and sources of margin.

As such, the project can be defined in two phases as follows:

- Phase 1 – Initial Long Lead activities and Methodology/margin Confirmation activities
- Phase 2 – Remainder of the overall uprate project including NRC support

This report documents the status of the Phase 1 activities as defined in Reference 1.

Reference:

1. Westinghouse Letter LTR-NEM-07-721, "Saint Lucie Nuclear Plants Units 1 & 2 – Power Uprate Methodology / Margin Confirmation Study and Initiation of Long-Lead Activities (Phase 1)," August 6, 2007.

2. NSSS DESIGN PERFORMANCE PARAMETERS STATUS

Westinghouse and FPL have agreed on the program design goals for the selected core power and associated thermal hydraulic conditions for the NSSS. FPL transmitted the input assumptions to Westinghouse to perform the NSSS design performance parameter development in Reference 1. Westinghouse is in the process of developing the NSSS design parameters required from the input assumptions for the program analysis work. This work is scheduled to be completed by February 29, 2008. The following deliverables will be provided.

- The NSSS Performance Capability Working Group (PCWG) Parameters approved and issued for use in the NSSS analyses. These parameters include reactor and NSSS power level, reactor coolant system temperatures, thermal design flow, and design steam conditions.
- The RCS best estimate flow value - issued for use in subsequent evaluations.

Reference:

1. "St. Lucie Units 1 & 2 Engineering Evaluation for Development of Extended Power Uprate Performance Capability Working Group (PCWG) Input Assumptions", PSL-ENG-SEMJ-07-058, Tracking Number 07166, Revision 0.

3. BEST ESTIMATE PERFORMANCE PARAMETERS STATUS

Westinghouse is developing best estimate steam generator outlet conditions at the conditions of the uprating for development of turbine heat balances. The SG conditions are being calculated based on plant calorimetric data from St Lucie Unit 1 and Unit 2 that were provided for use by References 1 and 2.

Reference2:

1. "St. Lucie Unit 1 Engineering Evaluation for Extended Power Uprate Plant Calorimetric Inputs to Westinghouse", PSL-ENG-SEMJ-07-059, Tracking Number 07168, Revision 0.
2. "St. Lucie Unit 2 Engineering Evaluation for Extended Power Uprate Plant Calorimetric Inputs to Westinghouse", PSL-ENG-SEMJ-08-004, Tracking Number 08013, Revision 0.

4. METHODOLOGY / MARGIN CONFIRMATION

4.1 Fuel Margin Assessment (Unit 2)

A detailed fuel margin assessment was performed by Westinghouse for the uprated conditions. This information was transmitted to FPL by separate correspondence.

4.2 Non-LOCA Evaluation (Unit 2)

4.2.1 Methodology

Westinghouse has been requested to provide input to support the St. Lucie Unit 2 Methodology Confirmation Activities for Non-LOCA Analyses. The methodology utilized to perform the UFSAR Chapter 15 Non-LOCA Safety Analyses for the St. Lucie Unit 2 EPU Program will be based on the RETRAN code, consistent with the current St. Lucie Unit 2 Licensing basis. These methods were developed during the 30% Steam Generator Tube Plugging (SGTP) and WCAP-9272 Methodology Transition program. Note that, several Non-LOCA analyses were not transitioned to the RETRAN methodology as part of the 30% SGTP program, they include the:

- Steam Generator Tube Rupture analysis
    - Methods and acceptance criteria consistent with the Analysis of Record other than use of the RETRAN code. The analysis will provide integrated steam generator tube rupture related mass releases and associated data for input to the downstream Dose Analysis.
- Loss of Feedwater / Loss of AC Power analysis
    - The Loss of Normal Feedwater (LONF) / Loss of Offsite Power (LOAC) event for St. Lucie Unit 2 is described in Section 15.2-6 of the UFSAR. UFSAR Section 15.2-6 states that the consequences of the LONF/LOAC event are bounded by other Non-LOCA events including evaluation of the Auxiliary Feedwater System as described in UFSAR Section 10.4.9. The methodology and acceptance criteria applied to the LONF/LOAC event will be consistent with Westinghouse methods and will demonstrate that:
        - The RCS coolant pressure remains within limits,

- Complete Loss of Flow
- Locked Rotor

- Control Assembly Element Drop
- Loss of Condenser Vacuum
  - Primary Overpressure
  - Secondary Overpressure
  - Inoperable Main Steam Safety Valves
- Feedwater Line Break
  - Primary Overpressure – Small Break
  - Primary Overpressure – Large Break

Table 4.2-1 provides the margin related input for the requested safety analyses and the corresponding safety analysis criteria necessary to support the margin assessment. The DNB results provided by Fuel Rod Thermal Hydraulic Design (FRTHD) are based on the current F∆H of 1.70 and the use of the ABB-NV Critical Heat Flux Correlation.

The Chapter 15 safety analyses with the smallest margin to criteria are the Loss of Flow (LOF) event, the Pre-Trip (Hot Full Power) Steamline Break (SLB) event, the Loss of Condenser Vacuum (LOCV) event, the Feedwater Line Break (FLB) event, and the CEA Ejection (CEAJ) event. Preliminary scoping studies were performed for the LOF, LOCV, and CEAJ events at the predicted EPU conditions and indicated that margin to the design criteria existed for the LOCV and CEAJ events. The LOCV scoping study indicated that the peak primary and peak secondary pressure results at the projected operating conditions including modeling of the replacement steam generator (RSG) remain below the design limit pressure criteria of 2750 psia (primary) and 1100 psia (secondary). A scoping study was performed by FRTHD for the LOF event using the existing transient statepoints of the event and the projected operating conditions. It determined that insufficient margin exists when the current F∆H Tech. Spec limit of 1.70 was modeled. FRTHD noted in the scoping analysis that in order to achieve an acceptable result with the current fuel design, the F∆H limit of 1.70 required reduction to a value of approximately 1.60. The introduction of the NGF fuel product is believed to support the margin requirements of the LOF event at F∆H values close to the current Tech. Spec limit. However, tradeoffs may be required to support the LOF margin needs during the transition cycle(s) incorporating the NGF fuel product. The SLB event was reviewed and it is thought that with the incorporation of the integral flow restrictor nozzles in the replacement steam generator design the maximum break size will be reduced by ~44%, thereby limiting the event and providing an overall benefit. It is believed that sufficient margin will exist for the SLB event. The FLB event peak pressure response has not been evaluated at the projected EPU plant conditions. (FLB results are presented in Table 4.2-1.)

Several analyses as noted in Table 4.2-1 incorporate an additional 0.25 second delay to the processing signal associated with the Reactor Coolant Flow which is used as input to the Low Reactor Coolant Flow Reactor trip. This additional delay was incorporated to reduce the flow sensor noise anticipated to occur during St. Lucie Unit 2 Cycle 16 operations with a Thermal Design Flow (TDF) of 335,000 gpm. The total delay time including the additional delay associated with the RCS low flow reactor trip is 0.90 second. Current predictions for the TDF value with the RSGs installed are well above the 335,000 gpm level and therefore it may be possible, with FPL's concurrence, to eliminate this additional 0.25 second delay. Removal of the additional 0.25 second sensor delay will reduce the associated low RCS flow trip delay time from 0.90 to 0.65 second, the same as prior to Cycle 16 and could provide for some level of margin recovery on the identified transients. (The primary path should be to maintain the 0.90 seconds delay time.)

4.2.3 References:

1. CN-TA-05-99, Rev. 0, "St. Lucie Unit 2 (SL2) Evaluation of RCS Flow Signal Delay Analysis to Support 30% Tube Plugging."
2. CN-TAS-07-7, Rev. 0, "St. Lucie Unit 2 (SL2) Hot Full Power Steamline Break With FFBT Analysis in Support of the 30% SGTP Program."
3. CN-TA-03-119, Rev. 0, "St. Lucie Unit 2 Uncontrolled CEAWAP RETRAN Analysis to Support 30% SGTP and WCAP 9272 Implementation."
4. CN-TA-03-57, Rev. 0, "St. Lucie Unit 2 (SL2) Uncontrolled CEA Withdrawal from a Subcritical or Low Power Condition Analysis to Support 30% SGTP Program with WCAP-9272 Implementation."
5. CN-TA-03-106, Rev. 0, "St. Lucie Unit 2 Control Assembly Element (CEA) / Rod Cluster Control Assembly (RCCA) Drop Analysis To Support 30% SGTP and WCAP-9272 Implementation."
6. CN-TA-03-77, Rev. 0, "St. Lucie Unit 2 Loss of Condenser Vacuum for 30% SGTP and WCAP 9272 Transition."
7. CN-TA-04-169, Rev. 0, "St. Lucie Unit 2 - Documentation of Responses to NRC RAIs on Steamline Break, Locked Rotor and Feedline Break."
8. CN-TA-03-97, Rev. 0, "St. Lucie Unit 2 (STL2) Loss of Forced RCS Flow Analysis to Support 30% Tube Plugging with WCAP-9272 Implementation."
9. CN-TA-03-128, Rev. 0, "St. Lucie Unit 2 (SL2) Locked Rotor Analysis to Support 30% Tube Plugging With WCAP-9272 Implementation."
10. CN-TA-03-72, Rev. 0, "St. Lucie Unit 2 (SL2) CEA Ejection Analysis to Support 30% SGTP Program with WCAP-9272 Implementation."

Table 4.2-1

Safety Analysis Title	Ref. No.	Analysis Results	Criteria	Comments
Pre-Trip SLB - LOOP	1	< 1.50% Rods-in-DNB (This should be for inside containment break. Outside containment break case is needed to show no fuel failures.)	< 2.50% Rods-in-DNB	Notes 1 & 2
Pre-Trip SLB - FFBT	2	1.423 mDNBR 20.313 Kw/ft Peak LHR	> 1.32 DNB SAFDL < 22.0 Kw/ft Peak LHR	-
CEA Withdrawal - At Power	3	1.4986 mDNBR 117.7% Full Power Heat Flux 2483.3 psia Peak Pri. Press. 1085.4 psia Peak Sec. Press.	> 1.42 DNB SAFDL < 120% Full Power < 2750 psia < 1100 psia	-
CEA Withdrawal - Subcritical	4	1.361 mDNBR 3060 °F Peak Centerline Melt	> 1.29 DNB SAFDL < 4717 °F Fuel Melt	-
Loss of Flow – Complete LOF	1	1.41 mDNBR	> 1.35 DNB SAFDL	Notes 1 & 3
Loss of Flow - Locked Rotor	1	< 0.6% Rods-in-DNB 1703.6 °F Peak Clad Temp 0.3% Max. Zirconium React. 2660 psia Peak Pri. Press.	< 2.50% Rods-in-DNB < 2700 °F Peak Temp < 16% Zirc. React. < 2750 psia	Notes 1 & 4
CEA Drop - Dropped Rod	5	> 1.42 mDNBR	> 1.42 DNB SAFDL	Note 5
CEA Drop – Misaligned Rod	5	> 1.42 mDNBR	> 1.42 DNB SAFDL	Note 5
LOCV - DNB	6	2.191 mDNBR	> 1.42 DNB SAFDL	-
LOCV – Primary	6	2691 psia Peak Pri. Press.	< 2750 psia	-
LOCV – Secondary	6	1088 psia Peak Sec. Press.	< 1100 psia	-
LOCV – 1 InOp MSSV	6	2610 psia @ 92.8% RTP 1083 psia @ 92.8% RTP	< 2750 psia < 1100 psia	Note 6
LOCV – 2 InOp MSSVs	6	2597 psia @ 79.6% RTP 1080 psia @ 79.6% RTP	< 2750 psia < 1100 psia	Note 6
LOCV – 3 InOp MSSVs	6	2577 psia @ 66.3% RTP 1076 psia @ 66.3% RTP	< 2750 psia < 1100 psia	Note 6
FWLB – Small Break	7	2712 psia Peak Pri. Press	< 2750 psia Pri. Press.	-
FWLB – Large Break/LOOP	7	2775 psia Peak Pri. Press.	< 3000 psia Pri. Press.	-
CEA Ejection	10	272.0 Btu/lb Fuel Stored Energy 1946 °F Peak Clad Temp. 0.33% Max. Zirconium React. 0.0% Fuel Melt	< 360 Btu/lb < 3000 °F < 16% Zirc. React. < 0.5% Fuel Melt, 9.5% DNB failures	-

(This is assuming 3% valve setpoint tolerance for PSVs and MSSVs.)

Note 1 – Analysis includes a 0.25 second delay for the low RCS Flow Sensor Delay for a total RCS Low Flow Reactor Trip delay of 0.90 second. This additional delay (0.25 second) may be removed with FPL concurrence as the RCS Thermal Design Flow is expected to be well above 335,000 gpm and additional flow sensor signal filtering may not be required.

Note 2 – Comparing Ref. 1 and Ref. 7 the impact of the additional 0.25 second delay was determined to be worth ~0.5% rods-in-DNB. Reference 1 provides < 1.5% rods-in-DNB whereas Reference 7, without the delay provided a results of <1% rods-in-DNB.
Note 3 – Comparing Ref. 1 and Ref. 8 the impact of the additional 0.25 second delay was determined to be worth ~2% in DNB. Reference 1 provides a 1.41 mDNBR whereas Reference 8, without the delay provided a result of 1.44 mDNBR.
Note 4 – Comparing Ref. 1 and Ref. 9 the impact of the additional 0.25 second delay was determined to be worth ~0.6% in Rods-in-DNB, 0.16% in Zirconium Reaction, 66.5 °F of Peak Clad Temp., and ~64 psia in Pri. Peak Press. Reference 8 without the delay provided the following results: 1.451 mDNBR, 0.14% Max. Zirconium reaction, 1637.1 °F Peak Clad temp., and a Peak Primary Pressure of 2596.1 psia.
Note 5 – The results of Reference 5 states that the DNB design basis is met and that the peak fuel centerline melt temperature is bounded by the limit corresponding to the fuel centerline melt.
Note 6 – The maximum Rated Thermal Power (RTP) values provided in Reference 6 corresponding to the 1, 2, and 3 Inoperable MSSVs per Bank will be evaluated to determine if Table 3.7-1 of the St. Lucie Unit 2 Technical Specifications will require modification to support the EPU.

4.3 Non-LOCA Fuel Failure and Dose evaluation (Units 1 and 2)

The dose evaluation is not in Westinghouse scope. St. Lucie Units 1 and 2 issued Proposed License Amendments to NRC on 7/16/07 to adopt the AST methodology. This same methodology will be used for the EPU and is expected to achieve acceptable results for the EPU.

4.4 Large Break LOCA (Unit 2)

4.4.1 Methodology

The present LBLOCA AOR supports 30% Steam Generator Tube Plugging and is documented in Reference 1. This analysis is performed using the Westinghouse LBLOCA 1999 ECCS Performance Evaluation Model (1999 EM, Reference 2) for Combustion Engineering designed pressurized water reactors (PWRs), as augmented by CENPD-404-P-A for analysis of ZIRLO™ cladding (Reference 3). This methodology is an Appendix K Evaluation Model.

It is recommended that the EPU LBLOCA analysis be performed using the Westinghouse Best Estimate LOCA (BELOCA) methodology. The original BELOCA methodology is referred to as the "1996 Best-Estimate Evaluation Model", which was documented in the Code Qualification Document (CQD, Reference 5). The 1996 BE EM was built upon to form the current uncertainty methodology called "ASTRUM" which is defined in Reference 6. More specifically, this method relies on the WCOBRA/TRAC code description and code assessment results documented in the CQD, and also follows the steps in the Code Scaling, Applicability, and Uncertainty (CSAU) methodology (Reference 7). The uncertainty analysis technique is based on order statistics. The ASTRUM methodology uses a statistical sampling method where the uncertainty parameters are simultaneously sampled for each case. A statistical treatment of the results allows the determination of values of peak cladding temperature, maximum local oxidation, and core-wide oxidation that bound at least 95% of all possible values at 95% confidence, for a defined plant operating space.

This project would be a first time application of the BELOCA methodology to a CE Unit. The pros and cons of the two methodologies are discussed in FPL-07-225 (Reference 4) and subsequent FPL comments and Westinghouse responses.

4.4.2 Margin

The results from the LBLOCA AOR (Reference 1) are summarized as follows:

Limiting Discharge Coefficient, DEG/PD	0.6
Peak cladding temperature, °F	2130.1
Maximum cladding oxidation, %	16.1
Core-wide cladding oxidation, %	0.802

The acceptance criteria are as follows:

Description	Criterion
Peak Cladding Temperature	≤2200°F
Maximum or Peak Local Oxidation	≤17%
Core-Wide Cladding Oxidation	≤1%

It is expected that acceptable results will be attained for EPU conditions using the BELOCA methodology (with standard fuel or NGF).

As documented in discussions subsequent to Reference 4, there is no certainty that acceptable results can be achieved for the EPU conditions with NGF fuel using the 1999 EM (Appendix K methodology). Based on preliminary cases which were run last year, the 1999 EM is expected to provide acceptable ECCS performance results for the EPU with standard fuel assembly designs. This is accomplished by crediting the beneficial aspects of RSGs and reducing the tube plugging margin. However, implementation of the CE 16x16 NGF assembly design for the EPU negatively impacts the results of the 1999 EM due to changes in fuel rod diameter and fuel performance. The reduction of the fuel rod diameter for NGF has a detrimental impact on the core reflood rates calculated by the 1999 EM during a LBLOCA. Since fuel performance characteristics have not yet been generated for St. Lucie 2 NGF, we cannot evaluate this impact effectively. Our past experience with NGF fuel performance for other plants with different core heights is not expected to be the same as St. Lucie 2 fuel performance. Nevertheless, we would expect that (1) the introduction of ZrB2 IFBA and (2) the use of a newly NRC-approved optional steam cooling model would partially compensate for the degradation in reflood performance for NGF. Staying with Gad absorber in the NGF design would possibly improve the rod internal pressure impact on LOCA compared to ZrB2, but not the stored energy impact. We could evaluate the impact of NGF on the EPU using the 1999 EM after fuel performance data becomes available in the coming months. But for now, the best we can say is that the 1999 EM is expected to provide acceptable ECCS performance for standard fuel assembly designs, but may not be acceptable for NGF designs without finding an additional source of margin. The kW/ft limit could be reduced by up to 0.5 kW/ft to gain significant margin.

4.4.3 Potential Issues

Potential issues with the two potential methodologies are discussed in FPL-07-225 (Reference 4) and subsequent FPL comments and Westinghouse responses.

4.4.4 References

1. CN-OA-03-36, Rev. 00, "St. Lucie Unit 2 1999 EM LBLOCA ECCS Performance Analysis for 30% Steam Generator Tube Plugging," E.F. Jageler, M. Volodzko and R.J. Espinosa, September 15, 2003.
2. CENPD-132, Supplement 4-P-A, "Calculative Methods for the C-E Nuclear Power Large Break LOCA Evaluation Model", March 2001.
3. CENDP-404-P-A, "Implementation of ZIRLO TM Cladding Material in CE Nuclear Power Fuel Assembly Designs," November 2001.
4. FPL-07-225, "Extended Power Uprate – Large Break LOCA Evaluation Model," December 12, 2007.
5. WCAP-12945-P-A, "Code Qualification Document for Best Estimate LOCA Analysis," Volume 1, Revision 2, and Volumes 2 through 5, Revision 1, 1998.
6. WCAP-16009-P-A, "Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment Of Uncertainty Method (ASTRUM)," January 2005.
7. NUREG/CR-5249, "Quantifying Reactor Safety Margins: Application of Code Scaling, Applicability, and Uncertainty (CSAU) Evaluation Methodology to a Large-Break, Loss-of-Coolant Accident," December 1989.

4.5 Small Break LOCA (Unit 2)

Review of existing documents performed to identify margins to criteria, confirm the analyses methodologies, and identify technical approach to potential issues prior to phase 2 of the EPU project.

The present SBLOCA AOR supports 30% Steam Generator Tube Plugging and is documented in CN-OA-03-2. The results are summarized as follows:

Break Size, ft^2	0.05
Peak cladding temperature, °F	1943
Maximum cladding oxidation, %	9.80
Core-wide cladding oxidation, %	< 0.64

Acceptance Criteria is as follows:

Description	Criterion
Peak Cladding Temperature	$\leq$2200°F
Maximum or Peak Local Oxidation	$\leq$17%
Core-Wide Cladding Oxidation	$\leq$1%

4.5.1 Methodology

The AOR used the CE SBLOCA Evaluation Model. Specifically, the 'S2M' version, as described in CENPD-137, Supplement 2-P-A which is NRC-accepted and complies with the requirements of Appendix K to 10 CFR 50.46.

The EPU SBLOCA analysis will also use the above methodology, with no deviation.

4.5.2 Margin

It is expected that acceptable results will be attained for EPU (10% uprate with 2% added uncertainty). The implementation of RSGs in the analysis is beneficial to SBLOCA mitigation which has not been explicitly modeled in the AOR and will be for EPU. The AOR has discretionary conservatism modeled in the High Pressure Safety Injection (HPSI) System delivered flowrate which is of key significance in SBLOCA mitigation. This conservatism could be relaxed to help achieve acceptable results. Other conservative modeled input used in the AOR of lower order significance may also be relaxed. Thus, the benefit of modeling RSGs and using the conservatism presently modeled in the AOR is expected to be sufficient to overcome the negative impact due to higher power and acceptable results are expected to be achieved.
An unverified/undocumented simple scoping case has been run modeling the EPU by increasing the decay heat multiplier proportionately with the power increase using the existing AOR input decks. The results of this case are within the acceptance criteria. However, there does still exist some uncertainty due to the consideration of the adequacy of the simple modeling.

4.6 Long Term Cooling

4.6.1 Methodology

The post-Loss-of-Coolant Accident (LOCA) Long-Term Cooling (LTC) analysis consists of two separate analyses, namely, a boric acid precipitation analysis for the limiting large break LOCA and a decay heat removal analysis, which is performed for a spectrum of break sizes. The purpose of the boric acid precipitation analysis is to demonstrate that boric acid precipitation does not occur in the core region. The purpose of the decay heat removal analysis is to demonstrate that decay heat can be removed in the long-term for any size LOCA and that, regardless of break size and without knowledge of the break size or location, the operator can correctly identify and initiate an appropriate means of long-term decay heat removal. There are two such means, namely Shutdown Cooling (SDC) for small breaks and simultaneous hot and cold (H/C) side injection for large breaks.

4.6.1.1 Boric Acid Precipitation Analysis

The proposed methodology for the Extended Power Uprate (EPU) post-LOCA boric acid precipitation analysis is the Westinghouse post-LOCA LTC evaluation model for Combustion Engineering Pressurized Water Reactors, CENPD-254-P-A (Reference 1) as modified to conform to the four items identified in the Nuclear Regulatory Commission (NRC) staff's letter dated November 23, 2005 (Reference 2). The four items are summarized below.

1. The mixing volume[1] must be justified; its calculation must account for void fraction.
2. The calculation of the mixing volume must account for the pressure drop between the core and the break.

[1] The mixing volume is the region in the reactor vessel wherein boric acid accumulates as a result of boiling in the core. The boric acid is credited to uniformly mix with the liquid in the region.

3. The boric acid solubility limit must be justified, especially if crediting pressures greater than 14.7 psia or chemical additives in the sump water.
4. The analysis must use a decay heat multiplier of 1.2 for all times, if it is performed with an Appendix K evaluation model.

The mixing volume used in the EPU boric acid precipitation analysis will be calculated in accordance with NRC Items 1 and 2. In particular, the mixing volume will be calculated using the procedure that is generally referred to as the "Waterford approach". The Waterford approach has been recognized by the NRC (Reference 3) as an acceptable interim methodology for performing boric acid precipitation analyses prior to the establishment of a new methodology that addresses the issues identified in the NRC staff's letter dated August 1, 2005 (Reference 4). The following are major features of the Waterford approach.

- The calculation of the mixing volume credits 50% of the volume of the lower plenum.
- In the calculation of the mixing volume, the CEFLASH-4AS phase separation model is used to calculate the core void fraction.
- In the calculation of the mixing volume, the outlet plenum void fraction is calculated as the core exit void fraction times the ratio of the core and outlet plenum areas.
- Credit is taken for the mixing of charging flow with safety injection flow prior to the flows entering the mixing volume.

The EPU boric acid precipitation analysis will use the top of the Core Support Barrel nozzles (i.e., nominally, the top of the hot legs) as the top elevation of the mixing volume. This is the same elevation used in the Waterford 3 EPU boric acid precipitation analysis (Reference 5). The analysis will confirm that this elevation complies with NRC Item 2 for St. Lucie Unit 2 EPU conditions.

A target value of 29.27 wt% will be used as the solubility limit of boric acid (Reference 6, Table 2). This is the solubility limit of a binary solution of boric acid and water boiling at atmospheric pressure. Note that this value does not credit a pressure greater than atmospheric pressure or the presence of chemical additives in the sump water (see NRC Item 3). If use of a higher value for the solubility limit, which credits either a pressure greater than 14.7 psia or chemical additives, is found to be necessary, the value will be justified.

In compliance with NRC Item 4, the analysis will use a decay heat multiplier of 1.2 for all times. Note that the St. Lucie Unit 2 boric acid precipitation Analysis of Record (AOR) (Reference 7) used a decay heat multiplier of 1.1 after 1000 seconds post-LOCA. Consequently, compliance with NRC Item 4 effectively results in a 20% increase in decay heat for the EPU analysis relative to the AOR analysis (i.e., a 10% increase for the EPU and a 10% increase for NRC Item 4).

The St. Lucie Unit 2 boric acid precipitation AOR is the analysis performed for 30% Steam Generator Tube Plugging (SGTP) (Reference 7). That analysis used the CENPD-254-P-A evaluation model (Reference 1), without the changes described above. Note: The analysis for 42% SGTP, although not implemented, was approved by the NRC for St. Lucie Unit 2 with these changes.

4.6.1.2 Decay Heat Removal Analysis

The proposed methodology for the EPU post-LOCA decay heat removal analysis is the CENPD-254-P-A evaluation model (Reference 1) with two modifications. First, the analysis will use a decay heat multiplier of 1.2 for all times, in accordance with NRC Item 4. Secondly, the LTC plan that will be generated as part of the analysis will not use a "decision pressure". The second modification is a potential issue and is described in more detail below.

4.6.2. Margin

It is judged that acceptable results for the St. Lucie Unit 2 EPU post-LOCA LTC analysis can be achieved using the methods described above. This judgment is based on the results of boric acid precipitation analysis and decay heat removal analysis scoping studies that were performed for EPU conditions.

4.6.2.1 Boric Acid Precipitation Analysis

For a boric acid precipitation analysis, acceptable results are obtained by demonstrating that initiating simultaneous H/C side injection results in a maximum boric acid concentration in the core region that is less than the boric acid solubility limit for the solution present in the core region. The St. Lucie Unit 2 EPU boric acid precipitation analysis scoping study determined that 275 gpm of simultaneous H/C side injection (i.e., 275 gpm of injection to both the hot and cold sides of the Reactor Coolant System (RCS)) started between 4 and 6 hours post-LOCA prevents the precipitation of boric acid in the core region. This is the same value for simultaneous H/C side injection that was found acceptable in the AOR. However, the AOR identified a time window of 2 to 6 hours post-LOCA for starting the simultaneous H/C side injection as compared to 4 to 6 hours post-LOCA for the EPU. The increase in the early start time for initiating simultaneous H/C side injection from 2 hours post-LOCA to 4 hours post-LOCA is necessary to ensure that there is sufficient safety injection to match core boil-off at the early start time.

4.6.2.2 Decay Heat Removal Analysis

For the decay heat removal analysis, acceptable results are obtained by:

1. demonstrating that decay heat can be removed in the long-term for any size LOCA, and
2. creating a LTC plan that shows that, regardless of break size and without knowledge of the break size or location, the operator can correctly identify and initiate an appropriate means of long-term decay heat removal.

The St. Lucie Unit 2 EPU decay heat removal analysis scoping study achieved these two results. However, the LTC plan that was created did not make use of a decision pressure.

In the typical post-LOCA LTC plan, the decision pressure is the pressure used by the operator to determine whether to use SDC or simultaneous H/C side injection as the method to remove core decay heat in the long-term. Based on the results of the decay heat removal analysis, if the RCS pressure is greater than the decision pressure, there is assurance that the break is a small break and SDC may be used in the long-term to remove core decay heat (and maintain the boric acid concentration below the solubility limit). If the RCS pressure is less than the decision pressure, there is assurance that the break is a large break and simultaneous H/C side injection may be used in the long-term to remove core decay heat (and maintain the boric acid concentration below the solubility limit). In the analysis, the operator makes the decision at a specific time, which is aptly named the decision time.

In order to be acceptable, the decision pressure must be greater than the RCS pressure at the decision time for the largest break for which SDC is appropriate (i.e., the largest small break) and less than the RCS pressure for the smallest break for which simultaneous H/C side injection is appropriate (i.e., the smallest large break) by amounts greater than or equal to the pressure uncertainty of the instrument used to determine the RCS pressure.

The scoping study could not identify an acceptable value for the decision pressure for the EPU conditions. The overlap of RCS pressures at the decision time for the largest small break and the smallest large break was significantly less than the amount required by the pressure measurement uncertainty.

The scoping study achieved acceptable results by creating a plan that abandoned the decision pressure as the way to identify the long-term means for decay heat removal in the post-LOCA LTC analysis. In its place the LTC plan simply used the analysis results of a refilled RCS and a hot leg temperature less than the SDC entry temperature as the indication that SDC is the appropriate means to remove decay heat in the long-term. Additionally, it used the analysis result that breaks that were too large to meet these SDC entry requirements were large enough for the break flow and simultaneous H/C side injection to remove decay heat in the long-term.

This deviation from the CENPD-254-P-A evaluation model, for a reason other than compliance with the four NRC items in Reference 2, is a potential issue.

4.6.3 Potential Issues

4.6.3.1 Boric Acid Precipitation Analysis

No specific potential issues were identified for the boric acid precipitation analysis. The scoping study indicated that acceptable results were obtained for EPU conditions using methods that the NRC staff has found acceptable, given their recent concerns with the historic methods that have been used to perform boric acid precipitation analyses. That being said, it is prudent that both Westinghouse and Florida Power and Light (FPL) continue to monitor the NRC staff's position on post-LOCA boric acid precipitation to help ensure that the EPU boric acid precipitation analysis will meet the NRC staff's expectations at the time of the EPU license submittal.

4.6.3.2 Decay Heat Removal Analysis

One potential issue was identified for the decay heat removal analysis, namely, that an acceptable value for the LTC plan decision pressure could not be found in the scoping study performed for EPU conditions. An analytical solution, which is briefly described above, is suggested for addressing this potential issue. Alternatively, a "hardware" solution to the potential issue could be explored with FPL. In particular, the hardware solution would consist of identifying (and implementing as part of the EPU) plant modifications, which, when incorporated into the decay heat removal analysis, would result in an acceptable decision pressure. Potential plant modifications that could result in an acceptable decision pressure include increasing the minimum usable volume of the Condensate Storage Tank and decreasing the measurement uncertainty of the instrument used for determining when the RCS pressure is below the SDC system entry pressure.

The analytical solution to addressing this potential issue has the benefit of abandoning an analytical "success criterion" (i.e., identifying an acceptable decision pressure) that is far removed from the operator actions in the LOCA emergency operating procedure[2] and replacing it with one that is generally consistent with the LOCA emergency operating procedure. Additionally, the analytical solution would most likely be significantly less costly than implementing plant changes associated with a hardware solution.

One risk of the analytical solution is that it entails a change to the CENPD-254-P-A methodology. However, the suggested change is judged to be technically sound and, arguably, more

[2] For example, the LOCA emergency operating procedure does not use a decision pressure or a decision time. Also, it does not instruct the operator to totally refill the RCS (i.e., to go water solid, including the pressurizer).

appropriate than the approved methodology since the change is more consistent with LOCA emergency operating procedures. Furthermore, the change remains consistent with the underlying philosophy of CENPD-254-P-A, namely, that it can be analytically demonstrated that decay heat can be removed in the long-term for any size LOCA and that the operator can correctly identify and initiate an appropriate means of long-term decay heat removal if more than one means is required. Also, regardless of whether the analytical solution is used, the EPU post-LOCA LTC analysis will be implementing changes to the CENPD-254-P-A methodology. This is the case because addressing the four items in the NRC staff's letter of November 23, 2005 (Reference 2) requires changes to the CENPD-254-P-A methodology.

4.6.4 References

1. CENPD-254-P-A, "Post-LOCA Long Term Cooling Evaluation Model," June 1980.

2. D.S. Collins (NRC) to G. Bischoff (Westinghouse), "Suspension of NRC Approval for Use of Westinghouse Topical Report CENPD-254-P, 'Post-LOCA Long-Term Cooling Model,' Due to Discovery of Non-Conservative Modeling Assumptions During Calculations Audit (TAC No. MB1365)," November 23, 2005. (ADAMS Accession Number ML053220569)

3. S. E. Peters (NRC) to S.L. Rosenberg (NRC), "Summary of August 23, 2006 Meeting with the Pressurized Water Reactor Owners Group (PWROG) to Discuss the Status of Program to Establish Consistent Criteria for Post Loss-of-Coolant (LOCA) Calculations," October 3, 2006. (ADAMS Accession Number ML062690017)

4. R.A. Gramm (NRC) to J.A. Gresham (Westinghouse), "Suspension of NRC Approval for Use of Westinghouse Topical Report CENPD-254-P, 'Post-LOCA Long-Term Cooling Model,' Due to Discovery of Non-Conservative Modeling Assumptions During Calculations Audit," August 1, 2005. (ADAMS Accession Number ML051920310)

5. W3F1-2005-0012, T.G. Mitchell (EOI) to Document Control Desk (NRC), "Supplement to Amendment Request NPF-38-249, Extended Power Uprate, Waterford Steam Electric Station, Unit 3, Docket No. 50-382, License No. NPF-38," February 16, 2005. (ADAMS Accession No. ML050490396)

6. WCAP-16590-NP, Rev. 0, "Technical Basis for Response to NRC Request for Justification of Current Operation for Post-LOCA Boric Acid Precipitation Issues," June 2006.

7. CN-OA-03-32, Rev. 0, "St. Lucie Unit 2 Post-LOCA Long Term Cooling ECCS Performance Analysis for 30% SGTP," T.R. Upton and J.M. Cleary, September 15, 2003.

4.7 Containment peak pressure evaluation: SLB, LOCA (Units 1 & 2)

4.7.1 Methodology

The proposed uprate methodologies that will be used to generate mass and energy release following a large break Loss of Coolant Accident (LOCA) and Main Steam Line Break (MSLB) are the same as those utilized in the Analyses of Record (AORs) for those events.

4.7.2 Margin

The same methodologies as those used in the AORs were utilized in performing the feasibility studies for the containment related LOCA and MSLB events. The feasibility studies have shown that acceptable results could be achieved with the uprated power conditions except the MSLB initiated from 112% of the current rated power. However, acceptable results could be achieved for 112% MSLB event if the containment pressure and temperature response is analyzed with the industry standard GOTHIC computer code.

4.7.3 Potential Issues

If the GOTHIC computer code is utilized for the containment pressure and temperature response analysis to provide additional margin to the acceptance criteria or limit, it will replace the current methodology and computer code for analyzing the containment pressure and temperature response. However, there is little licensing risk for proposing to use GOTHIC, as it has become an industry standard and the NRC has reviewed and approved many plant specific analyses including uprate applications. Use of GOTHIC should be acceptable. NRC has generically approved the use of GOTHIC for other vendors.

4.8 Component Cooling Water / Intake Cooling Water (Units 1 & 2)

4.8.1 Methodology

The proposed uprate methodologies for the containment pressure/temperature response and Component Cooling Water / Intake Cooling Water (CCW/ICW) temperature response are the same as those utilized in the AORs.

4.8.2 Margin

A review of the AOR for the CCW/ICW temperature response for St. Lucie Unit 1 indicated that currently sufficient margin exist to the limit. Therefore, at the uprated power conditions, it is expected that acceptable results can be achieved but with less margin to the limit or a lower ICW temperature than that used in the AOR.

For St. Lucie Unit 2 CCW/ICW temperature response, there is insufficient margin with the current plant configuration (without the Replacement Steam Generators). Hence, in order to achieve acceptable results, modification to the CCW/ICW system and fine-tuning of some of the design inputs will be required.

4.9 LTOP (Units 1 & 2)

4.9.1 Methodology

Unit 1

There is no plan to change from the methodology that is used in the current analyses of record (AOR) to support the extended power uprate (EPU).

The approach to be used with Saint Lucie, Unit 1 is to use the current AOR, References 1 and 2, as the starting point for reassessing the limiting LTOP mass addition and LTOP energy addition transients and to establish the LTOP controls and setpoints.

Unit 2

There is no plan to change from the methodology that is used in the current AOR to support the EPU.

The approach to be used with Saint Lucie, Unit 2 is to use the current AOR, References 4 and 5, as the starting point for reassessing the limiting LTOP mass addition and LTOP energy addition transients and to establish the LTOP controls and setpoints.

4.9.2 Margin

Unit 1

The peak pressure consequences of these transients will be adversely affected by the increase in decay heat corresponding to a 12% power uprate.

The current work plan assumes that the Appendix G Pressure Temperature (P-T) limits for each Unit are unaffected by power uprate. Florida Power and Light (FPL) and/or Areva may need to reinterpret the current fluence limits to correspond to a lesser number of full power years of operation, as necessary, based on FPL's fuel management goals.

The more adverse limiting LTOP mass addition and LTOP energy addition transient consequences can be accommodated via changes in the heatup and cooldown rate limits currently applicable to each unit and/or changes in LTOP controls and setpoints. This effort uses the analysis of Reference 3 as a starting point.

This is a standard application of Westinghouse LTOP methodology and there is no licensing risk based on generic Nuclear Regulatory Commission (NRC) issues at this time.

Unit 2

The peak pressure consequences of these transients will be adversely affected by the increase in decay heat corresponding to a 12% power uprate.

The current work plan assumes that the Appendix G P-T limits for each Unit are unaffected by power uprate. FPL and/or Areva may need to reinterpret the current fluence limits to correspond to a lesser number of full power years of operation, as necessary, based on FPL's fuel management goals.

The more adverse limiting LTOP mass addition and LTOP energy addition transient consequences can be accommodated via changes in the heatup and cooldown rate limits currently applicable to each unit and/or changes in LTOP controls and setpoints. This effort uses the analysis of Reference 6 as a starting point.

This is a standard application of Westinghouse LTOP methodology and there is no licensing risk based on generic NRC issues at this time.

References:

1. F-PENG-CALC-016, Revision 0, "St Lucie Unit 1 RCP Start Transient Analysis for LTOP," 3/10/1999.

2. F-PENG-CALC-017, Revision 0, "St Lucie Unit 1 Mass Addition Transient Analysis for LTOP," 3/17/1999.

3. F-PENG-CALC-020, Revision 0, "St. Lucie Unit 1 LTOP Requirements for RCS with Replacement Steam Generators and New Pressurizer Heaters," 3/31/1999.

4. CN-PS-06-6, Revision 0, "LTOP Mass Addition Analysis for St. Lucie Unit 2," 4/25/2007.

5. CN-FSE-06-62, Revision 0, "LTOP Energy Addition Analysis for St. Lucie Unit 2," 5/3/2007.
6. CN-FSE-07-12, Revision 1, "St. Lucie Unit 2 Low Temperature Overpressure Protection (LTOP) Evaluation for the Period Ending at 55 Effective Full Power Years (EFPY)," 9/17/2007.

4.10 Design Transients input to Structural Integrity (Units 1 & 2)

4.10.1 Methodology

There is no plan to change from the methodology that is used in the current AOR to support the EPU.

4.10.2 Margin

Design Transients provide the pressure and temperature limits needed to analyze stress and fatigue loads for components and supports. The design transient assumptions are selected to provide bounding temperature and pressure responses during operating and test conditions that are anticipated to occur during the intended service life of components and supports. The operating conditions are further divided into Normal Conditions, Upset Conditions, Emergency Conditions and Faulted Conditions.

4.10.2.1 Assumed Operating Conditions

This evaluation will apply the following proposed uprate operating conditions and determine if the current design transient criterion remain bounding for post uprate operations.

Core Power = 3020 MWt

Power Measurement Uncertainty (PMU) = 0.3%

Technical Specification minimum RCS flow = 390,000 gpm

Nominal RCS flow = 400,000 gpm

Temperature entering the core (Minimum) = 546°F

Temperature entering the core (Maximum) = 551°F

No-load temperature = 532°F

Pressurizer pressure 2250 psia

The following calculation provides the range of hot leg temperatures.

Uprate power = 3020 MWt *1.003 ≈ 3030 MWt = 10.34139×10^9 btu/hr

Core flow = (core flow) gpm * 60 m/hr * (Cold leg density) lb/ft^3 / 7.4805 g/ft^3

Hot Leg h = (Cold Leg h) btu/lbm+ (Uprate power) btu/hr / (core flow) lbm/hr

Th = Function of (Hot Leg h) and (2250 psia) in steam tables

Tc °F	Core Flow gpm	Tc density lb/ft^3	Core Flow lbm/hr	Cold leg Enthalpy btu/lb	Hot Leg Enthalpy btu/lb	Th °F
546.0	390,000	47.0984	147,330,066	542.246	612.438	599.5
548.5	390,000	46.9402	146,835,196	545.337	615.7656	601.8
551.0	390,000	46.7801	146,334,381	548.442	619.1116	604.2

The following table provides the operating conditions used for the current design transients. The values are from the St. Lucie 1 & 2 component specifications listed in References 2 through 10.

Component	Core outlet °F	Core inlet °F	Pzr Press psia	Total RCS Flow gpm	SG Press psia	Feedwater °F	Steam Flow lbm/hr
Reactor Vessel	604	550	2250	324,700	NA	NA	NA
Pressurizer	604	550	2250	324,700	NA	NA	NA
Steam Generator	606 *	548*	2250 *	371,600 *	885 *	435*	5.9x10^6 *
Reactor Coolant System	604	550	2250	324,700	NA	NA	NA
Reactor Coolant Pump	604	550	2250	324,700	NA	NA	NA

* Replacement Steam Generator Specifications for Unit 2 were not available. Unit 1 values are assumed for Unit 2.

4.10.2.2 Evaluation of Design Transients

The power uprate does not affect the probability of event occurrence. The number of occurrences is a function of operating history not power. The number of occurrences for each event will remain applicable for uprate conditions. The primary system transient evaluations performed by FPL as part of the License Renewal program will be considered as part of the EPU evaluation.

The no-load RCS conditions of 532°F and 2250 psia will not change due to the power uprate. All design transients at no-load conditions and below will remain applicable. This includes Test conditions and the loss of secondary pressure which is done at no-load conditions.

The RCS pressure response to specific transients is closely tied to initial system pressure, full load temperature and control system setpoints. The uprate initial RCS pressure will remain 2250 psia. Other than a revised RCS temperature program with an equivalent pressurizer level program, this evaluation assumes no changes to control system setpoints. If control system setpoints do change it is reasonable to believe the change will improve the plant transient response. This leaves the change in temperature as the prime parameter affecting the pressure response during a transient. The current design transient pressure response assumes a hot leg temperature change of 532°F to 604°F and a cold leg temperature change of 532°F to 550°F as power changes from no-load to full-load. The uprate full-power cold leg temperature will range from 532°F to 546°F or 551°F. Assuming a Technical Specification minimum core coolant flow of 390,000 gpm, the full-power hot leg temperature will range from 599.5°F to 604.2°F. A full-load hot leg temperature of 604°F or less would result in bounded Normal Condition and Upset Condition power transients. A hot leg temperature above 604°F would be greater than the full load temperature assumed in the current design transients. A full-load hot leg temperature exceeding 604°F could require evaluating the 5% per minute load changes, the 10% step changes and the Upset Condition transients. A hot leg temperature of 604.2°F is close enough to 604°F to not require additional analysis. However, if the final hot leg temperature exceeds 604°F by a larger value, margin can be obtained for the following transients:

Normal Conditions:

Plant load changes at 5% per minute exceed operational practice. If necessary, a reduction in the rate of change of power will reduce the pressure fluctuation associated with load changes so the current pressure transient is bounding. A stress analysis evaluation would then be required to verify the temperature difference is acceptable. The number of occurrences is conservatively based on one loading and unloading transient per day. If necessary the number of occurrences could be reduced to improve the stress analysis results.

Plant step changes of 10% exceed operational practice. A reduction in the power change during a step change will reduce the pressure fluctuation and the temperature change associated with a step change transient. A step change value can be revised so the current design transient remains bounding.

The spray nozzle and charging nozzle design transients are based on a cold leg temperature of 550°F. The assumptions used to define the spray nozzle initial temperature (due to continuous spray) or the charging nozzle temperature (due to changes in the charging rate) should be conservative enough to absorb some variation in the cold leg temperature.

Upset Conditions:

The reactor trip, loss of flow and loss of turbine transients would need to be run with the higher hot leg temperature to evaluate the change in temperature and pressure response. The change in response to the events would then be evaluated by stress analysis.

Emergency Conditions:

The current design criterion for a loss of feedwater flow assumes a dry steam generator with the tube sheet at 610°F and feedwater at 32°F. The assumed feedwater temperature is unaffected by power uprate and the assumed tube sheet temperature of 610°F remains conservative.

4.10.2.3 Conclusion

If the finalized full power hot leg temperature is 604°F or less the current design transients will remain applicable for uprate conditions.

If the hot leg temperature exceeds 604°F some of the operational transients may need to be redefined. The upset transients will need to be rerun to define the uprate pressure and temperature response. Stress analysis would then evaluate the revised data. All other plant transients defined in the component specifications remain applicable for power uprate design.

4.10.3 References

1. Nuclear Services Policies & Procedures, Rev. 25, Effective 08/31/07.
2. 19367-31-1 Rev. 7, Engineering Specification for Reactor Vessel Assembly for Florida Power and Light Co. Hutchinson Island Plant Unit 1.
3. F-MECH-SP-002 Rev. 1, Engineering Specification for Replacement Steam Generator Assemblies for Florida Power and Light Co. St Lucie Unit No. 1.
4. 19367-31-3 Rev. 4, Engineering Specification for Reactor Coolant Pumps for Florida Power and Light Company Hutchinson Island Plant Unit #1.
5. 19367-31-4 Rev. 11, Engineering Specification for A Pressurizer Assembly for Florida Power and Light Co. Hutchinson Island Plant Unit No. 1.
6. 19367-31-5 Rev. 11, Project Specification for the Reactor Coolant Pipe & Fittings for Florida Power and Light Co. Hutchinson Island Plant Unit 1.
7. 13172-31-1 Rev. 3, Project Specification for A Reactor Vessel Assembly for Florida Power and Light Company St. Lucie Unit No. 2.
8. 13172-PE-480 Rev. 5, Project Engineering Specification for Reactor Coolant Pumps for Florida Power and Light Company St. Lucie Plant Unit No. 2.
9. 13172-31-4 Rev. 4, Project Specification for A Pressurizer Assembly for Florida Power & Light Co. St. Lucie Unit No. 2.
10. 13172-31-5 Rev. 5, Specification for the Reactor Coolant Pipe & Fittings for Florida Power and Light Co. St. Lucie Unit No. 2.

4.11 LOCA Blowdown Load Evaluation (Units 1 & 2)

4.11.1 Methodology

The subject analysis produces LOCA hydraulic blowdown loads, in the form of transient pressure differential loadings, on the reactor vessel internals and the fuel. The calculations are performed with the NRC-approved computer code CEFLASH-4B (Reference 1). This transient pressure information is utilized by downstream analyses, to perform the calculations of stress loadings and structural integrity for the reactor vessel internals and the fuel.

References 2 and 3 document the most recent analyses of the LOCA hydraulic blowdown loads on the reactor vessel internals and fuel, for St. Lucie Unit 2. References 2 and 3 performed the analyses for Cycles 1 and 2, at core power of 2560 and 2700 MWt, and with T_{COLD} of 548°F and 552°F, respectively. These analyses considered three large breaks of the main coolant loop piping:

- 200 in^2 cold leg break at a reactor vessel inlet nozzle
- 135 in^2 hot leg break at a reactor vessel outlet nozzle
- 1000 in^2 hot leg break at a steam generator inlet nozzle

Since these analyses of record (AOR) were performed, there have been significant changes in the plant configuration, such as the Replacement Steam Generators (RSGs) and fuel design, as well as the Extended Power Uprate (EPU).

For the reasons described below under Margin, calculations of the LOCA hydraulic blowdown loads on the reactor vessel internals and the fuel will be performed using CEFLASH-4B. These evaluations will be performed at the reduced temperature rampdown end-of-cycle conditions (535 F, which would also cover low power operation), as well as at nominal conditions at full-power, and will employ inputs and assumptions that encompass a range of RSG tube plugging up to 10%. The evaluation of LOCA blowdown loads to accommodate coastdown could be divorced from EPU license submittal if the scope of work impacts proposed NRC submittal date. Based on the Leak Before Break (LBB) methodology, the following RCS tributary line break locations will be analyzed:

- Safety Injection Line Inlet Nozzle Break
- Shutdown Cooling Line Outlet Nozzle Break
- Surge Line Double-Ended Guillotine Break

The results will be forwarded to the downstream structures group to support the related structural loads and integrity analysis.

Westinghouse expects that Florida Power Light Company (FPL) will provide all the necessary input data and analysis assumptions to account for the changes to the plant configuration and operation since the Reference 3 analysis was performed. Westinghouse will work with FPL to document and agree upon the inputs and assumptions to be used for these analyses in a suitable format.

4.11.2 Margin

Since the sole purpose of LOCA hydraulic blowdown loads analyses is to produce data for downstream structural evaluations, the blowdown loads analyses do not produce their own margin assessments. The available margin is determined by the downstream structural evaluations.

Nevertheless, it is possible to assess proposed changes for their potential effect on the LOCA blowdown hydraulic loads (e.g., Reference 4). If the proposed post-EPU plant operation of Unit 2 is at or above the analyzed core inlet temperature, then it *may* be possible to determine that the LOCA hydraulic loads will be no worse than in the AOR.

However, if the Unit 2 end-of-cycle procedure employs a T-cold rampdown strategy, then the plant is subjected to reduced core inlet temperatures during the extended duration of the rampdown. That would place the plant in unanalyzed space, and requires a full analysis of the LOCA hydraulic blowdown loads and structural integrity, in order to support this fuel strategy.

4.11.3 Potential Issues

The calculations described above will follow the same methodology as in the AOR, but will consider operational conditions (inlet temperature rampdown) that are potentially adverse relative to those that the AOR had considered. Since the AOR had produced limited margins for certain reactor vessel internal components, there may be margin issues arising from this analysis.

4.11.4 References

1. Report CENPD-252-P-A, "Blowdown Analysis Method - Method for the Analysis of Blowdown Induced Forces in a Reactor Vessel," July 1979.
2. 13172-LOCA-032, "St. Lucie 2 CEFLASH-4B Blowdown Loads Analysis," January 4, 1981.
3. 13172-LOCA-064, "St. Lucie 2 CEFLASH-4B Blowdown Loads Analysis (Cycle 2)," March 28, 1984.
4. LTR-OA-06-92, Rev. 0, "St. Lucie 2 Blowdown Loads at a Maximum Allowable Measured RCS Flow of 405,500 gpm," September 25, 2006.

4.12 Reactor Vessel Internals Stress/fatigue (Units 1 & 2)

4.12.1 Methodology

Previous analyses have utilized classical stress analysis methods and finite element codes developed by Westinghouse. No change in the overall methodology that might require a license amendment is anticipated.

4.12.2 Margin

Reactor Vessel Internal structures are required to demonstrate structural adequacy for normal operating and upset and faulted condition loads as specified in the design basis of the plant. Continued structural adequacy of the reactor vessel internal structures must be demonstrated for the revised operating parameters associated with the EPU to justify it.

The main objective of the Phase 1 study is to identify the existing stress margins for the internal structures under design loading conditions and perform a scoping study to assess the margins for the proposed uprate conditions.

Methodology consisted of reviewing existing analyses of record (AOR) to extract margins of safety for various components. If, the analysis of record did not consider a loading condition or if some components were not analyzed, analyses performed for other plants similar in design were utilized to project margins for St. Lucie 1 and 2.

For St. Lucie 1, the analysis of record evaluated primary stresses in internal components for normal and upset and faulted conditions. The seismic loads addressed an all Siemens core and the LOCA loads were derived from a Branch Line Pipe Break (BLPB). Core support barrel (CSB) was damaged because of the failure of the thermal shield. The thermal shield was removed and CSB was repaired. The CSB repairs included drilling of crack arrestor holes and installation of several mechanical plugs and patches. Structural adequacy of the CSB and the repair hardware was demonstrated for the design life of the plant. Evaluation of the repair hardware included irradiation induced preload relaxation effects. AOR for thermal analysis considered fuel management and operating conditions that existed in the late 1970's to early 1980's. Since the core shroud generally has the highest thermal stresses due to its proximity to the core and the Gamma heating effects, an analysis of the core shroud thermal stresses performed for a plant similar in design to St. Lucie 1 was examined. This analysis considered thermal loads associated with an Appendix K power uprate.

Existing margins were examined for all design loading conditions and, based upon the level of conservatism in these calculations; an assessment was made for margins for proposed uprate conditions. Based upon this assessment, adequate margins exist for reactor vessel internals to accommodate modest temperature increases associated with the proposed power uprate. Acceptability may depend on fuel management. This assessment does not address the effects of subsequent plant design changes, i.e. replacement steam generators, replacement reactor vessel head and fuel on the loads.

Analysis of record for St. Lucie 2 evaluated reactor vessel internal structures for normal and upset and faulted condition loads. This analysis was performed to evaluate the effects of 42% tube plugging in the original steam generators, increased flow due to replacement steam generators and any combination of standard 16X and Inconel Top Grid fuel assemblies. In order to assess the effects of the proposed next generation fuel (NGF) which is included in the proposed St. Lucie 2 uprate, an analysis performed for a plant similar in design to St. Lucie 2 was examined. This analysis was performed for an 8% power uprate with standard or NGF fuel. Existing margins were examined and, based upon the level of conservatism in these calculations; an assessment was made for margins for proposed uprate conditions. Based upon this assessment, adequate margins exist for reactor vessel internals to accommodate modest temperature increases associated with the proposed power uprate. Acceptability may depend on fuel management.

4.13 Structural Analysis of the Reactor Coolant System Components and Supports (Units 1 & 2)

4.13.1 Methodology

Previous analyses have utilized classical stress analysis methods and finite element codes developed by Westinghouse. No change in the overall methodology that might require a license amendment is anticipated.

4.13.2 Margin

The following pertains to existing RCS stress margins in the design basis for St. Lucie Units 1 and 2.

Stress margins for non-faulted and faulted conditions were examined. The proposed increase in T_{hot} will have a small effect on normal operating conditions, so a closer examination of normal condition stress margins is warranted. Since T_{cold} is either remaining the same or increasing, pipe break loads will not become more severe. There would be a small increase in the normal operating load contribution to some of the overall faulted condition stresses. However, considering all load contributions, it is unlikely that critical faulted condition stress margins will be an issue.

<u>Unit 1</u>

For the RCS stress margins, the majority of the margins are associated with design conditions, service conditions and hydro testing. The loads associated with these conditions are primarily due to pressure, and in some cases, pre-tensioning of bolts. Neither of these types of loadings are anticipated to change.

There are a few critical stress margins associated with the primary piping. The lowest margin, 0.4% for the hot leg elbow, is classified as primary membrane, which is due to the design pressure loading, which will not change. The remaining piping margins are low, but not considered critical.

For the Reactor Vessel (RV) margins for non-faulted conditions, of particular note is the 0.8% primary membrane plus primary local stress margin for Cut 1 of the RV outlet nozzle. The associated load combination does include pipe reactions, which be affected to some extent by the increase in T_{hot} (i.e., system thermal expansion loads). The 0.6% margins at the vessel wall transition and the shell/bottom head juncture are classified as primary membrane stress, which is due to pressure loading. Therefore, no reduction in those margins is anticipated. The core stop lug margin of 0.2%, which is classified as primary membrane plus primary bending, could be affected slightly by operating temperature changes.

Overall, the critical stress margins in the St. Lucie 1 RCS do not appear to pose a problem for the anticipated changes in T_{hot} and T_{cold}. However, a few of the existing margins do indicate that some further, and in some cases, more sophisticated, reanalyzes may be required.

The basis for redoing the seismic and pipe break analyses is as follows:

RCS Seismic Analysis

- RCS seismic analysis is offered as an option but Westinghouse recommends that it be repeated with replacement equipment and current methods. This is recommended to prepare for NRC and ACRS review and for the reasons below: There is an original model calculation, and a report with results but no seismic inputs or outputs for upgrades or replacements.
- There is no up to date seismic data for reactor internals and new fuel evaluation. Data used currently is seismic motion of reactor vessel flange for one horizontal direction only, which neglects rocking of the reactor vessel steam generator system.
- Rerunning the analysis provides an opportunity to evaluate the RSG configuration and any other replacements or upgrades to the RCS in an exact manner.

RCS Pipe Break Analysis

- RCS Pipe Break analysis needs to be repeated. This is required to prepare for NRC and ACRS review.
- Coast down needs to be covered.
- Recent analyses have used Millstone 2 blowdown loads and a simplified but Millstone 2 RCS analysis. It was applied to St Lucie 1 and differences were written off but it never was reviewed by NRC.
- For any future fuel changes or replacements or upgrades there is not plant specific pipe break data for detailed analyses. Where replacements such as CEDMs have been made, Pipe break loads based upon other CE plant results have been used.
- Create margin for low margin areas by quantifying branch line pipe break (LBB) benefit.

Unit 2

Westinghouse report ER-SL2-PS-001 documents a recent effort to qualify St. Lucie Unit 2 for a T_{cold}-3 reduction program. Existing stress margins were determined as part of this effort.

As was the case for St. Lucie 1, the smallest margins generally tend to occur for design condition primary membrane stresses, which are controlled by the pressure load. Critical margins are not shown for the piping. However, in the current scenario where T_{hot} and T_{cold} are both increasing, the temperature differential between the hot and cold leg piping will remain close to the same. Therefore, any differential thermal expansion effect will be minimized. Also, if the change in T_{cold} is minimal, thermal anchor motions at RCS nozzles will essentially remain the same. Therefore, it is safe to assume that the projected increases in T_{hot} and T_{cold} will have a minimal effect on the existing stress margins.

In conclusion, the critical stress margins in the St. Lucie 2 RCS do not appear to pose a problem for the anticipated changes in T_{hot} and T_{cold}. However, the analyses need to be performed to quantify these qualitative conclusions.

The basis for redoing the seismic and pipe break analyses is as follows:

<u>RCS Seismic Analysis</u>

- RCS Seismic analysis needs to be repeated with current methods. This is required to prepare for NRC and ACRS review.
- There is no existing seismic analysis calculation or report that can be found. This was confirmed in the effort on the recent effort to evaluate the replacement RCP motor.
- For NGF fuel, RCS analysis would have to be repeated to provide input for the fuel seismic analysis. None is available.
- Rerunning the analysis provides an opportunity to evaluate the RSG configuration and any other replacements or upgrades to the RCS in an exact manner.

<u>RCS Pipe Break Analysis</u>

- RCS Pipe Break analysis needs to be repeated. This is required to prepare for NRC and ACRS review.
- For NGF fuel, RCS analysis would have to be repeated to provide input for the fuel pipe break analyses. None is available.
- Coast down needs to be covered.
- TCOLD reduction of 3 degrees was based upon evaluation from other CE plants, no specific plant specific analyses performed.
- Rerunning analyses provides an opportunity to evaluate the RSG configuration and any other upgrades to the RCS in an exact manner.
- Margin for low margin areas by quantifying branch line pipe break (LBB) benefit.

4.14 Vessel Internals Component heating (Units 1 & 2)

4.14.1 Methodology

Unit 1

The methodology that will be used to support the EPU evaluation of vessel internal component heating is not documented in a Topical Report. No NRC review of methodology or methodology changes will be needed.

The AOR for the reactor internal components for Unit 1 date back to the late 1970's to early 1980's, for the fuel management and operating conditions that existed during that time period. Consequently, to support the EPU, a complete set of new calculations will be performed for Unit 1 using ANSYS models to represent the reactor internal components.

Unit 2

The methodology that will be used to support the EPU evaluation of vessel internal component heating is not documented in a Topical Report. No NRC review of methodology or methodology changes will be needed.

The approach to be used with Unit 2 is to use the current AOR, Reference 1, as the starting point for reassessing reactor internal component metal temperatures for the EPU. Reference 1 (circa 2003) defines the component temperatures for the current core thermal power level of 2700 MWt. These component temperatures are based on a set of core physics constraints given in Reference 2, in order to support the internals heating rates used in Reference 1.

For EPU, with the 12% core power increase, new calculations will be performed for internal components which are located below and above the core region, such as the lower core support structure and the fuel alignment plate. For the components located radially outward from the core, such as the core shroud and core support barrel (CSB), one of the following two approaches will be used. If the expected fuel management for EPU can maintain the current heating rates for the radially located components, then the Reference 1 core shroud and CSB metal temperatures will remain valid, or will require minor adjustments. However, and this path is more likely, if the heating rates for the core shroud and CSB increase by ~ 12%, new temperature analyses will be performed for the core shroud and CSB.

Component temperature analyses will be performed using the ANSYS code to model the individual reactor internal components. The analyses will be performed for steady state full power conditions and for the design basis events. The resulting component temperature distributions will be forwarded to the structural analysts for input to their calculations.

4.14.2 Margin

Unit 1

A review of a sample of AOR results for Unit 1 component temperatures (and also from trends from the Unit 2 AOR calculations) shows that:

1. Most internal component temperatures are below 800°F by a large enough margin to accommodate the 12% increase in power, while still maintaining temperatures below

800°F. Structural calculations will still have to be performed to assess the impact of secondary stresses resulting from higher metal temperatures due to higher heat rates, even at temperatures below the 800°F level.

2. The new metal temperatures in the core shroud are anticipated to be above 800°F for the EPU. Constraints imposed on the power levels for the peripheral fuel assemblies can contain the level of heating rates and metal temperatures in the core shroud components. This approach was used for the most current (2003) core shroud temperature analysis for Unit 2 at 2700 MWt, Reference 2.

Unit 2

A review of the AOR results for Unit 2 component temperatures shows that:

1. Most internal component temperatures are below 800°F by a large enough margin to accommodate the 12% increase in power, while still maintaining temperatures below 800°F. Metal temperatures above 800°F trigger special nonroutine calculations to show adequate structural margin. Structural calculations will still have to be performed to assess the impact of secondary stresses resulting from the higher metal temperatures, even at temperatures below the 800°F level.

2. The AOR calculated metal temperatures in the core shroud are currently above 800°F. If the EPU fuel management can be constrained to maintain the AOR heating of the core shroud (that is, if internal heating in the shroud does not increase), then the current temperatures are covered. If the internal heating increases, the temperatures and stresses will have to be reassessed. This outcome will mean higher than current metal temperatures, and more of a challenge to show acceptable structural margins.

3. Temperature differentials are calculated between various upper guide structure (UGS) components (such as between adjoining control element assembly (CEA) shrouds) to determine differential growths and the associated resulting stresses. One or more of these differential temperatures are currently large enough to produce significant stresses. If the coolant temperature differentials increase, the structural margins for these components may be challenged.

4.14.3 Potential Issues

There are the following potential issues for Unit 1:

1. If core shroud heating increases by a substantial amount for EPU, this situation will mean more risk in showing acceptable structural margins for the core shroud.

2. If the differential peaking factors between certain assembly pairs and associated temperatures between UGS components increase substantially, the structural margin for one or more of these component pairs may be challenged.

3. Since the CSB contains several plugs installed in the crack arrestor holes in the barrel (due to the damage caused by the loosened thermal shield in 1983), these plugs will have to be reanalyzed to demonstrate that they will remain intact and tight within the CSB holes.

There are the following potential issues for Unit 2:

1. If core shroud heating increases by a substantial amount, due to the higher power level and fuel management considerations, this situation will require a reanalysis of the core shroud metal temperatures and secondary stresses, and will result in even higher than the current 800+ °F metal temperatures..

2. If the differential peaking factors between certain assembly pairs and associated temperatures between UGS components increase substantially, the structural margin for one or more of these component pairs may be challenged.

4.14.4 References

1. CN-PS-03-27, Revision 0, "Normal Operating Design Metal Temperatures for Reactor Vessel Internal Components for St. Lucie 2 with SG tube Plugging up to 30%," 10/24/2003.
2. CAC-03-246, Revision 0, "Component Heating Data for St. Lucie 2, 30% SG Tube Plugging," 10/09/2003

4.15 PTS evaluation (Units 1 & 2)

4.15.1 Methodology

The Methodology used is that described in 10CFR50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events". The assumptions used to project values to 55 EFPY for the margin assessment are described below.

4.15.2 Margin

The material property and neutron fluence values used for input to this margin assessment were obtained from the US NRC Reactor Vessel Integrity Database (RVID) Version 2.0.1. It was conservatively assumed for this margin assessment that a 12% uprate was instituted at the beginning of plant operation, and that the increase in power corresponded directly to an increase in neutron fluence to the reactor pressure vessel beltline. Two cases were assessed, 32 and 55 effective full power years (EFPY) of operation. It was also assumed for this margin assessment that the value of Tcold would increase by 2°F as a result of the uprate.

The input values for the reactor vessel beltline materials are given in Table 4.15-1 for St. Lucie Unit 1 and in Table 4.15-2 for St. Lucie Unit 2. Input values include identification of each beltline material, the currently projected fast neutron fluence for approximately 32 EFPY, the initial RT_{NDT}, and the Chemistry Factor. [Note that the Chemistry Factor for several of the Unit 1 beltline materials was derived using surveillance data as indicated in Table 4.15-1. The relevance of this fact is discussed further below.]

The results of the Unit 1 margin assessment are detailed in Table 4.15-3 for the 40 year (32 EFPY) operating period and in Table 4.15-4 for the 55 EFPY operating period. The results of the Unit 2 margin assessment are detailed in Table 4.15-5 for the 40 year (32 EFPY) operating period and in Table 4.15-6 for the 55 EFPY operating period. The fast neutron fluence at the vessel inside surface was conservatively projected using 112% of the fast neutron fluence from Table 4.15-1 or 4.15-2 and adjusting it upward for the 55 EFPY operating period. Each of the assessment tables presents the projected fast neutron fluence, the fluence factor, the calculated shift, the margin term, and the projected value of RT_{PTS} determined for each material. [Note that the "margin term" used to compute RT_{PTS} is an uncertainty term. This needs to be separated from the margin assessment described below in which the computed value of RT_{PTS} is compared to the PTS screening criteria.] The fluence factor, the calculated shift, the margin term, and the projected value of RT_{PTS} were determined in accordance with the requirements of 10CFR50.61.

The margin assessment for Unit 1 entails a comparison of the RT_{PTS} values given in Tables 4.15-3 and 4.15-4 to the PTS screening criteria provided in 10CFR50.61. Those screening criteria are as follows:

a) 270°F for an axially oriented flaw (i.e., for plates and axial welds)
b) 300°F for a circumferentially oriented flaw (i.e., for circumferential welds)

For 32 EFPY, the two highest values of RT_{PTS} are 199°F and 212°F that correspond to lower shell plate C-8-1 and lower shell axial welds 3-203 A, B & C, respectively. For 55 EFPY the same two materials have the highest values of RT_{PTS}, 211°F and 236°F. The screening criterion for plates and for axial welds is 270°F, thus the remaining margin is 34°F to 59°F.

The margin assessment for Unit 2 entails a comparison of the RT_{PTS} values given in Tables 4.15-5 and 4.15-6 to the PTS screening criteria cited above. For 32 EFPY, the two highest values of RT_{PTS} are 160°F and 163°F that correspond to intermediate shell plates M-605-1 and M-605-2, respectively. For 55 EFPY the same two materials have the highest values of RT_{PTS}, 169°F and 173°F. The screening criterion for plates and for axial welds is 270°F, thus the remaining margin is 97°F to 101°F.

For both Units 1 and 2, the projected values of RT_{PTS} are significantly less than the PTS screening criterion after 55 EFPY, even with the ultraconservative assumption of neutron fluence projection. The existence of that margin reduces the chance that the more rigorous determination of reactor vessel integrity that will follow will uncover an issue arising from the proposed uprate. A mitigating factor associated with the uprate is the anticipated T_{cold} increase of 2°F. This small increase in coolant temperature adjacent to the vessel would be beneficial with respect to reactor vessel integrity given that higher temperatures tend to result in lower rates of neutron embrittlement. A potential complicating factor is the anticipated regulatory change to a new embrittlement trend curve (ETC). Based on currently available information, the new ETC is not expected to seriously erode margin. Associated with that is a change in the application of reactor vessel surveillance data to adjust the chemistry factor and reduce the margin that must be added to the embrittlement prediction (e.g., as described in Position 2.1 of Regulatory Guide 1.99, Revision 2). As noted in Table 4.15-1, three St. Lucie Unit 1 plates and welds rely on reactor vessel surveillance data for embrittlement predictions. Loss of the ability to use surveillance data per Position 2.1 could increase the RT_{PTS} prediction by 20°F to 28°F for axial weld 3-203 A, B & C based on the conservative fluence projections to 55 EFPY. That would erode the PTS screening criterion margin to as low as 6°F. However, the margin erosion is expected to be less severe once more precise neutron fluence values are determined. Furthermore, it is also possible that use of surveillance data may be "grandfathered in" for those plants currently licensed in that manner. In any case, those are contingencies that must be considered in the context of the planned uprate.

In conclusion, an assessment was performed concerning the feasibility of performing a ~12% power uprate for the St. Lucie Units 1 and 2 plants with respect to the Pressurized Thermal Shock screening criteria margin. In the case of the Unit 1 reactor pressure vessel, there is sufficient margin to accommodate the 12% uprate and likely future changes to the underlying regulation (10CFR50.61). In the case of the Unit 2 reactor pressure vessel, there is essentially no issue with screening criteria margin.

The methodology used to perform this assessment is as provided in the "PTS Rule" as described in the current version of 10CFR50.61. The methodology and the input data are summarized in this document. The more detailed assessment of PTS margin to be performed subsequently will require a more rigorous determination of vessel fluence including use of the most recent surveillance capsule neutron fluence analysis results and more explicit representation of the timing of the uprate and its effect on neutron fluence. In addition, a more rigorous determination of reactor vessel materials may be necessary to address PTS margin in light of anticipated future changes to the PTS Rule (i.e., to the embrittlement correlation and to the allowed treatment of reactor vessel surveillance data).

Table 4.15-1 – St. Lucie Unit 1 Reactor Vessel Beltline Materials

Material	Identification	Heat	EOL Fluence (n/cm^2, E> 1MeV)	RTndt (initial)	Chemistry Factor
Intermediate Shell Plate	C-7-1	A-4567-1	3.42 E19	0	74.6
Intermediate Shell Plate	C-7-3	A-4567-2	3.42 E19	10	73.8
Intermediate Shell Plate	C-7-2	B-9427-1	3.42 E19	-10	74.6
Lower Shell Plate	C-8-1	C-5935-1	3.42 E19	20	107.8
Lower Shell Plate	C-8-2	C-5935-2	3.42 E19	20	79.53*
Lower Shell Plate	C-8-3	C-5935-3	3.42 E19	0	82.6
Lower Shell Axial Welds	3-203 A,B,C	305424	2.27 E19	-60	195.16*
Inter./Lower Girth Weld	9-203	90136	3.42 E19	-60	84.36*
Inter. Shell Axial Welds	2-203 A,B,C	A8746/34B009	2.27 E19	-56	90.65

*Chemistry Factor derived based on surveillance data.

Table 4.15-2 – St. Lucie Unit 2 Reactor Vessel Beltline Materials

Material	Identification	Heat	EOL Fluence (n/cm^2, E> 1MeV)	RTndt (initial)	Chemistry Factor
Intermediate Shell Plate	M-605-1	A-8490-2	2.76 E19	30	74.15
Intermediate Shell Plate	M-605-2	B-3416-2	2.76 E19	10	91.5
Intermediate Shell Plate	M-605-3	A-8490-1	2.76 E19	0	74.15
Lower Shell Plate	M-4116-1	B-8307-2	2.76 E19	20	37
Lower Shell Plate	M-4116-2	A-3131-1	2.76 E19	20	44
Lower Shell Plate	M-4116-3	A-3131-2	2.76 E19	20	44
Lower Shell Axial Welds	101-142 A,B,C	83637	2.76 E19	-50	34.05
Inter./Lower Girth Weld	101-171	3P7317	2.76 E19	-80	40.05
Inter./Lower Girth Weld	101-171	83637	2.76 E19	-70	34.05
Inter. Shell Axial Welds	101-124 A,B,C	83642	2.76 E19	-56	36.35
Inter. Shell Axial Weld	101-124 C	83637	2.76 E19	-50	34.05

Table 4.15-3 – St. Lucie Unit 1 RT_{PTS} Predictions for 12% EPU after 32 EFPY

Material Identification	EOL Fluence (n/cm², E> 1MeV)	Fluence Factor	Calculated Shift (°F)	Margin (°F)	RT_{PTS} (°F)
C-7-1	3.83 E19	1.3468	100	34	134
C-7-3	3.83 E19	1.3468	99	34	143
C-7-2	3.83 E19	1.3468	100	34	124
C-8-1	3.83 E19	1.3468	145	34	199
C-8-2	3.83 E19	1.3468	107	17	144
C-8-3	3.83 E19	1.3468	111	34	145
3-203 A,B,C	2.54 E19	1.2504	244	28	**212**
9-203	3.83 E19	1.3468	114	28	82
2-203 A,B,C	2.54 E19	1.2504	113	65.5	123

Table 4.15-4 – St. Lucie Unit 1 RT_{PTS} Predictions for 12% EPU after 55 EFPY

Material Identification	EOL Fluence (n/cm², E> 1MeV)	Fluence Factor	Calculated Shift (°F)	Margin (°F)	RT_{PTS} (°F)
C-7-1	6.58 E19	1.4527	108	34	142
C-7-3	6.58 E19	1.4527	107	34	151
C-7-2	6.58 E19	1.4527	108	34	132
C-8-1	6.58 E19	1.4527	157	34	211
C-8-2	6.58 E19	1.4527	116	17	153
C-8-3	6.58 E19	1.4527	120	34	154
3-203 A,B,C	4.37 E19	1.3750	268	28	**236**
9-203	6.58 E19	1.4527	127	28	91
2-203 A,B,C	4.37 E19	1.3750	125	65.5	134

Table 4.15-5 – St. Lucie Unit 2 RT_{PTS} Predictions for 12% EPU after 32 EFPY

Material Identification	EOL Fluence (n/cm^2, E> 1MeV)	Fluence Factor	Calculated Shift (°F)	Margin (°F)	RT_{PTS} (°F)
M-605-1	3.09 E19	1.2978	96	34	160
M-605-2	3.09 E19	1.2978	119	34	163
M-605-3	3.09 E19	1.2978	96	34	130
M-4116-1	3.09 E19	1.2978	48	34	102
M-4116-2	3.09 E19	1.2978	57	34	111
M-4116-3	3.09 E19	1.2978	57	34	111
101-142 A,B,C	3.09 E19	1.2978	44	44	38
101-171	3.09 E19	1.2978	52	52	24
101-171	3.09 E19	1.2978	44	44	18
101-124 A,B,C	3.09 E19	1.2978	47	58	49
101-124 C	3.09 E19	1.2978	44	44	38

Table 4.15-6 – St. Lucie Unit 2 RT_{PTS} Predictions for 12% EPU after 55 EFPY

Material Identification	EOL Fluence (n/cm^2, E> 1MeV)	Fluence Factor	Calculated Shift (°F)	Margin (°F)	RT_{PTS} (°F)
M-605-1	5.31 E19	1.4141	105	34	169
M-605-2	5.31 E19	1.4141	129	34	173
M-605-3	5.31 E19	1.4141	105	34	139
M-4116-1	5.31 E19	1.4141	52	34	106
M-4116-2	5.31 E19	1.4141	62	34	116
M-4116-3	5.31 E19	1.4141	62	34	116
101-142 A,B,C	5.31 E19	1.4141	48	48	46
101-171	5.31 E19	1.4141	57	57	33
101-171	5.31 E19	1.4141	48	48	26
101-124 A,B,C	5.31 E19	1.4141	51	62	57
101-124 C	5.31 E19	1.4141	48	48	46

4.16 NSSS System Reviews (RCS, SIS, CVCS, SDC) (Units 1 & 2)

This evaluation is applicable to St Lucie Units 1 and 2 except when a specific unit is noted.

4.16.1 Methodology

The methodology that will be used to support the Extended Power Uprate (EPU) evaluation of these systems is not documented in a Topical Report. No NRC review of methodology or methodology changes will be needed.

4.16.2 Margin

The Reactor Coolant System:

The EPU normal operating temperature, pressure, and flow conditions in the Reactor Coolant System (RCS) are expected to be within the existing design limits of the system. Therefore, no modifications to the RCS or system components would be required due to normal operating conditions of the power uprate. RCS accident scenarios are to be evaluated separately as requested in Reference 1. Design margins will be maintained.

The Chemical and Volume Control System:

The Chemical and Volume Control System (CVCS) maintains the chemical concentrations and controls the volume of the RCS. The power uprate requirements for normal charging and letdown will not vary from the normal operating limits for the CVCS, The beginning of cycle boration levels may change as the core design is finalized, however, the operating limits would remain within the design limits of the system.

A parameter that may change is the boron concentration within the Boric Acid Makeup Tank (BAMT). The BAMT is a tank within the CVCS that stores high concentration boric acid to support plant shutdown requirements. The high concentration boric acid is injected into the RCS by the CVCS to raise the boric acid concentration in the RCS. The boron concentration of the BAMT is determined by the fuel and core analysis. The increase in power could require an increase in boron concentration. The new boron concentration could require a change in Technical Specification limits. The new limits are expected to be within the design limits of the system and would not require a hardware change within the CVCS.

Shutdown Cooling:

The Shutdown Cooling (SDC) system removes the decay heat of the core during a normal or emergency shutdown. EPU will increase the decay heat during shutdown. Therefore, in a normal or emergency shutdown scenario, the SDC system would be required to remove more decay heat than required under the current operating condition. This could change the cooldown duration for the RCS; however, cooling down the plant at the uprated power is within the capability of the SDC system. No hardware modifications are expected in order for the SDC system to remove the increase decay heat. A complete evaluation of the SDC system including cooldown rates and time will be done as part of the power uprate analysis.

Safety Injection System:

The Safety Injection System (SIS) supports Loss of Coolant Accidents (LOCA) and non-LOCA events. These events are being evaluated according to Reference 1.

For Unit 2, it is understood that additional SIS delivery/performance is not being assumed/required for non-LOCA, small break LOCA (SBLOCA), large break LOCA (LBLOCA), and long-term cooling for Unit 2. Therefore, the SIS is presumed acceptable for the events listed. No change in operating or design margin is anticipated. As part of the full EPU evaluation, a task is suggested in the current effort to assess the possibility of reduced HPSI delivery for LOCA and Non-LOCA support, in order to improve/reduce the current Technical Specification Surveillance Requirements for this system to improve operation/testing of the HPSI system.

For Unit 1, the non-LOCA and the LBLOCA/SBLOCA events are not within Westinghouse scope. As with Unit 2, no request for increased SI delivery has been made by FPL or others. Consequently for this SIS support, the current SIS is presumed acceptable. Reference 2 states that long term cooling (LTC) for Unit 1 may require additional flow for hot leg injection (HLI). Historic documentation regarding HLI suggests that there is potential for an additional delivery flow. Further discussion with the analysts of the LTC evaluation may result in limiting the requested increase in delivered flow. If neither approach can support acceptable LTC results, possible hardware modifications are available, such as pump or system improvements.

4.16.3 Potential Issues

The HLI capability of the SIS is a potential issue for the EPU. Further investigation into the HLI flow that the system can guarantee and HLI flow required for long term cooling is needed. Further investigation of the LTC evaluation and system capability may result in converging on the necessary delivered flow. If neither approach can support acceptable LTC results, possible hardware modifications are available, such as pump or system improvements.

4.16.4 References

1. LTR-NEM-07-721, Revision 0, "Saint Lucie Nuclear Plants Units 1 & 2 – Power Uprate Methodology/Margin Confirmation Study and initiation of Long- Lead and Activities (Phase 1)," 8/6/2007.
2. LTR-OA-07-112, Revision 0, "St. Lucie Unit 2 EPU Methodology/Margin Confirmation and Technical Approach for SBLOCA," 12/21/2007.

5. LONG LEAD ACTIVITY STATUS

5.1 NSSS Design Transients

A study of the current design transients under uprated conditions was performed. The results of the study show that if the finalized full power hot leg temperature is 604°F or less the current design transients will remain applicable for uprate conditions. If the hot leg temperature exceeds 604°F some of the operational transients may need to be redefined. The upset transients will need to be rerun to define the uprate pressure and temperature response. Stress analysis would then evaluate the revised data. All other plant transients defined in the component specifications remain applicable for power uprate design.

5.2 Internals Steady State Thermal-Hydraulic Analysis

Computer models for the various reactor internal components will be developed for the ANSYS code to determine component metal temperatures. Thermal-hydraulic boundary conditions will be developed to represent steady state full power and design basis events.

Required inputs to the ANSYS analyses include:

1. Component geometry
2. Internal heat generation rates (and their distributions within the components).
3. Definition of the thermal-hydraulic parameters during the design basis events.

The ANSYS cases will then be run to determine the component temperature distributions.

5.3 LOCA Blow Down Loads Analysis

The work to-date has focused on review and consultations:

- Reviewed AORs and related subsequent documentation, in order to meaningfully plan the methodology and evaluate the potential margin limitations.
- Searched previous Calculation Notes for related helpful data.

- Consulted with the structural analysis group to identify potential issues.

5.4 Unit 2 Non-LOCA Analysis RETRAN Model Development

Work has been initiated regarding the development of the Unit 2 EPU RETRAN basedeck. The Unit 2 EPU basedeck currently incorporates preliminary data based on the Non-LOCA data request and the Unit 2 Replacement Steam Generator RETRAN basedeck (currently in final preparation). A calculation note has been prepared and an initial RETRAN Basedeck file has been created. Remaining work includes the incorporation of the PCWG information for the EPU program, inclusion of the Core Thermal Limit (CTL) data, incorporation of the verified data requested in the Non-LOCA Data Request, and completion and independent review of the calculation note and RETRAN basedeck.

5.5 LOCA Mass and Energy Model Development

A study of the current LOCA M&E results under uprated conditions was performed. The results indicated that if the GOTHIC computer code is used in analyzing the containment pressure and temperature response following the LOCA and MSLB events, a generic model developed for the CE designed plant needs to be customized with the St. Lucie specific design data and input parameters. Additionally, the Replacement Steam Generator (RSG) related data for St. Lucie Unit 1 is required prior proceeding with LOCA and MSLB mass and energy model development for St. Lucie Unit 1. The required data will be requested in the input data request letter.

5.6 ECCS Performance (LBLOCA, SBLOCA) Model Development

Since the duration of the BELOCA effort is anticipated to be on the order of 24 months for the EPU project, and the current project duration is 24 months, a significant amount of effort has been put forth for the BELOCA effort. A project kickoff and risk review meeting took place on October 23, 2007. A summary of this meeting was given to FPL via a phone call on the same day and documentation was sent via email to Jack Hoffman and Jay Kabadi November 6, 2007.

The technical effort has been focused on upfront modeling decisions and developing a St. Lucie Unit 2 specific WCOBRA/TRAC (WC/T) base deck. In addition, data including drawings have been collected.

The first peer review was held on December 10, 2007 to discuss WC/T nodalization, the loop model changes necessary for a CE Unit, and sample documentation.

6. PROJECT PLAN/SCHEDULE STATUS

Westinghouse has developed a project plan for the overall uprating project for the Westinghouse scope of work. This effort includes working with other parties associated with the uprate to determine scope split among the parties involved in the uprating, generation of a responsibilities assignment matrix and development of input for the overall project integrated schedule. A preliminary project schedule was developed and provided on December 31, 2007. A final schedule to be integrated with the Shaw St. Lucie Engineering schedule will be provided on January 31, 2008.

7. INPUT DATA REQUEST STATUS

Westinghouse has used the available plant information and target operating point to initiate Phase 1 activities. Westinghouse is preparing to provide a request for input data for Phase 2 that will utilize the existing sources of data, such as "Safety Analysis Plant Parameters" and Drawings subject to FPL confirmation.

Engineering Evaluation of Current Technology Options for New Nuclear Power Generation

CONFIDENTIAL DOCUMENT

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEVEN R. SIM

DOCKET NO. 080009 - EI

May 1, 2008

Q. **Please state your name and business address.**

A. My name is Steven R. Sim, and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. **By whom are you employed and what position do you hold?**

A. I am employed by Florida Power & Light Company (FPL) as Senior Manager of Integrated Resource Planning in the Resource Assessment & Planning Business Unit.

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

A. I supervise and coordinate analyses that are designed to determine the magnitude and timing of FPL's resource needs and then develop the integrated resource plan with which FPL will meet those resource needs.

Q. **Please describe your education and professional experience.**

A. I graduated from the University of Miami (Florida) with a Bachelor's degree in Mathematics in 1973. I subsequently earned a Master's degree in Mathematics from the University of Miami (Florida) in 1975 and a Doctorate in Environmental Science and Engineering from the University of California at Los Angeles (UCLA) in 1979.

While completing my degree program at UCLA, I was also employed full-time as a Research Associate at the Florida Solar Energy Center during 1977 - 1979. My responsibilities at the Florida Solar Energy Center included an evaluation of Florida consumers' experiences with solar water heaters and an analysis of potential renewable resources including photovoltaics, biomass, wind power, etc., applicable in the Southeastern United States.

In 1979 I joined FPL. From 1979 until 1991 I worked in various departments including Marketing, Energy Management Research, and Load Management, where my responsibilities concerned the development, monitoring, and cost-effectiveness of demand side management (DSM) programs. In 1991 I joined my current department, then named the System Planning Department, where I held different supervisory positions dealing with integrated resource planning. In late 2007 I assumed my present position.

Q. What is the purpose of your testimony?

A. My testimony provides an update to the long-term economic analyses filed in the Nuclear Uprate Need Docket No. 070062-EI and in the Turkey Point 6 & 7 Need Docket No. 070650-EI. These updates are presented to satisfy the requirement of Subsection 5(c)5 of the Florida Administrative Code Rule 25-6.0423, Nuclear Power Plant Cost Recovery which states "By May 1 of each year, along with the filings required by this paragraph, a utility shall submit for Commission review and approval a detailed analysis of the long-term feasibility of completing the power plant." The updated long-term economic analyses will generally be referred to as the "detailed feasibility analysis" in the remainder of my testimony.

Q. Are you sponsoring or co-sponsoring any exhibits in this case?

A. Yes, I am co-sponsoring portions of the following exhibits:

- STH-2, an exhibit of FPL witness Stephen Hale, which consists of Appendix I containing the Nuclear Filing Requirements Schedules (NFRs) for the nuclear uprates Project. Page 2 of Appendix I contains a table of contents listing the NFRs that are sponsored by Mr. Hale, Ms. Ousdahl, and me, respectively. I am sponsoring all portions of Schedule P9 of Appendix I except for the Section B portion discussing the nuclear uprate capital cost amounts and schedule that is being sponsored by FPL witness Hale.
- SDS-1, an exhibit of FPL witness Steve Scroggs, which consists of Appendix II containing the NFRs for the Turkey Point 6 & 7 project. Page 2 of Appendix II contains a table of contents listing the NFRs that are sponsored by Mr. Scroggs, Ms. Ousdahl, and me, respectively. I am sponsoring Schedule P9 of Appendix II.

Q. What is the scope of your testimony?

A. My testimony addresses three main points:

(1) I briefly discuss changes in the analytical approach and assumptions used in the detailed feasibility analysis provided in this filing compared to the economic analyses that were provided in FPL's

determination of need filings for the nuclear uprates and for Turkey Point 6 & 7.

(2) I provide the results of the detailed feasibility analysis of the nuclear uprates.

(3) I provide the results of the detailed feasibility analysis of Turkey Point 6 & 7.

Detailed Feasibility Analysis - Approach & Assumptions

Q. Were the analytical approaches used in the detailed feasibility analyses of the nuclear uprates and Turkey Point 6 & 7 similar to those used in the determination of need filings for these projects?

A. Yes. The analytical approaches that were used in the detailed feasibility analysis for each project were virtually identical to the approaches used in the determination of need filings.

In regard to the nuclear uprates project, FPL believes that the analytical approach used currently, and that was used in the determination of need filing; i.e., the direct comparison of resource plans with and without the uprates, is the appropriate approach for analyzing this project.

In regard to the Turkey Point 6 & 7 project, FPL believes that the analytical approach used currently, and in the determination of need filing, i.e., the calculation of breakeven 2007$ overnight capital costs for the new nuclear units, remains the appropriate approach to use at this time for the detailed feasibility analysis of this project. (In later years, as more information becomes available regarding the cost and other aspects of the new nuclear units, another analytical approach may emerge as more appropriate.)

Q. What differences exist between these detailed feasibility analyses and the analyses used in the determination of need filings?

A. When comparing the analyses, there are only four meaningful differences. One of these differences is in regard to the scope of the detailed feasibility analysis of Turkey Point 6 & 7. In the economic analyses supporting the determination of need filing analyses, a Resource Plan with Nuclear that included Turkey Point 6 & 7 was compared to two alternative resource plans. One of these resource plans included a comparable amount of combined cycle (CC) capacity added in the same years the two new nuclear units are projected to come in-service. This resource plan was labeled as the Resource Plan without Nuclear – CC. The other resource plan included a comparable amount of integrated gasification combined cycle (IGCC) capacity in the same years the two new nuclear units are projected to come in-service. This resource plan was labeled as the Resource Plan without Nuclear – ICGG.

As shown in the determination of need filing analyses, the Resource Plan without Nuclear – CC was superior economically to the Resource Plan without Nuclear – IGCC and, therefore, the former was the alternative resource plan that was closer economically to the Resource Plan with Nuclear.

Due to this previous result, FPL decided it was unnecessary to perform further analysis of the Resource Plan without Nuclear – IGCC. Therefore, FPL has focused its detailed feasibility analysis on the Resource Plan with Nuclear and the more competitive alternative Resource Plan without Nuclear – CC.

The second meaningful difference was a decision to focus solely on analyzing the economics of the resource plans for both the nuclear uprates and Turkey Point 6 & 7 projects. The determination of need filings for the two projects clearly demonstrated that the new nuclear capacity from the two projects would significantly increase FPL's system fuel diversity and decrease system carbon dioxide (CO_2) emissions. The changes in assumptions used in the analysis, discussed below, will have very little effect on projections of system fuel diversity and emissions. The previous projections of increased FPL system fuel diversity and decreased system CO_2 emission from both nuclear projects is expected to remain essentially unchanged, thus leaving these impacts as very beneficial attributes of the nuclear projects.

In contrast, the assumption changes will have more significant impacts on the projected economics of the projects. Consequently, FPL's analytical focus is the relative economics of the two projects.

The third meaningful difference is in regard to the schedules for capital costs for the two nuclear projects. The detailed feasibility analyses use updated capital cost expenditure schedules for both projects compared to the schedules used in the determination of need filings.

The fourth meaningful difference between the detailed feasibility analysis and the analyses conducted for the determination of need filings was that certain assumptions were revised based on more current information.

Q. What assumptions were revised for the detailed feasibility analyses?

A. Several assumptions were revised for the current analyses based on more current information that was available to FPL in the first quarter of 2008. These updated assumptions include:

- FPL's load forecast that includes the Lee County Electric Cooperative (Lee County) load. The revised load forecast resulted in changes to FPL's projected capacity needs (and, subsequently, resulted in minor changes in the resource plans being analyzed compared to those used in the determination of need filings);
- The forecast for environmental compliance costs. This updated forecast is based on ICF's most recent forecast of environmental compliance costs;
- The forecasts for fuel costs;
- The forecasted capital costs of non-nuclear combined cycle (CC) generation units; and,

- The cost of debt and the discount rate used for both generation and transmission costs.

These updated assumptions are identical to those used in the analyses for, and presented in, FPL's recent determination of need filing for the conversions of FPL's existing Cape Canaveral and Riviera plants.

Detailed Feasibility Analysis Results for the Nuclear Uprates Project

Q. What were the results of the detailed feasibility analysis for the nuclear uprates project?

A. The results of this analysis are presented in section C of Schedule P-9 of Exhibit STH-2. As shown in this Schedule, the Resource Plan with Nuclear Uprates is projected to have a lower cumulative present value of revenue requirements (CPVRR) cost, compared to the Resource Plan without Nuclear Uprates, in 8 of 9 scenarios of fuel cost and environmental compliance cost forecasts utilized in the analyses.

Q. How do the results of the detailed feasibility analyses compare with the results of the economic analyses provided in the determination of need filing for the nuclear uprates?

A. In the determination of need filing, the Resource Plan with Nuclear Uprates was also projected to have a lower CPVRR cost in 8 of the 9 scenarios of fuel cost and environmental compliance cost forecasts. In these 8 scenarios, the economic advantage of the Resource Plan with Nuclear Uprates ranged from $222 million CPVRR to $963 million CPVRR.

In the detailed feasibility analysis for these same 8 scenarios, the economic advantage of the Resource Plan with Nuclear Uprates now ranges from $346 million CPVRR to $1,109 million CPVRR.

Also, for the remaining scenario in the determination of need filing, one that features low natural gas costs and low environmental compliance costs, the Resource Plan with Nuclear Uprates was projected to have a higher cost of $214 million CPVRR. The detailed feasibility analysis for this same scenario shows that the Resource Plan with Nuclear Uprates is now projected to result in a higher cost of $127 million CPVRR.

Consequently, the already significant economic advantage of the nuclear uprates previously presented in the determination of need filing has further increased. These results fully support the feasibility of continuing the nuclear uprates project.

Detailed Feasibilty Analysis Results for the Turkey Point 6 & 7 Project

Q. What were the results of the detailed feasibility analysis for the Turkey Point 6 & 7 project?

A. The results of this analysis are presented in section C of Schedule P-9 of Exhibit SDS-1. As shown in this Schedule, the Resource Plan with Nuclear is projected to have a higher breakeven cost (in terms of $/kw in 2007$) for Turkey Point 6 & 7 than the range of non-binding capital costs for new nuclear units of $3,108/kw to $4,540/kw in 8 of 9 scenarios of fuel cost and environmental compliance cost forecasts. In these 8 scenarios, the updated breakeven costs range from $5,994/kw to $8,835/kw. For the remaining scenario, one that features low natural gas costs and low environmental compliance costs, the projected breakeven cost of $4,408/kw is in the upper range of the non-binding capital cost estimate for new nuclear units.

Q. How do the results of the detailed feasibility analyses compare with the results of the economic analyses provided in the determination of need filing?

A. In the determination of need filing, the Resource Plan with Nuclear was also projected to have a higher breakeven cost ($/kw in 2007$) for Turkey Point 6 & 7 than the range of non-binding capital costs for new nuclear units of $3,108/kw to $4,540/kw in the same 8 of 9 scenarios of fuel cost and environmental compliance cost forecasts. In these 8 scenarios, the range of breakeven costs was $4,543/kw to $7,281/kw. For the remaining scenario, the projected breakeven cost of $3,206/kw was in the lower range of the non-binding capital cost estimate for new nuclear units.

Consequently, the already promising breakeven capital costs for Turkey Point 6 & 7 previously presented in the determination of need filing have become even more promising in the detailed feasibility analysis. These results fully support the feasibility of continuing the Turkey Point 6 & 7 project.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF JOHN J. REED

DOCKET NO. 080009-EI

MAY 1, 2008

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 relating 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 30 years of experience in the energy industry, having served as an executive in energy consulting firms, including the position of Co-Chief Executive Officer of the largest publicly-traded management consulting firm in the United States and as Chief Economist for the largest gas utility in the

United States. I have provided expert testimony on a wide variety of economic and financial issues related to the energy and utility industry on numerous occasions before administrative agencies, utility commissions, courts, arbitration panels, and elected bodies across North America.

Q. **Have you previously provided expert testimony?**

A. Yes. I have been accepted as an expert in dozens of jurisdictions located in the United States and Canada.

Q. **Are you sponsoring any exhibits in this case?**

A. Yes. I am sponsoring Exhibits JJR-1and JJR-2, which are attached to my direct testimony.

Exhibit JJR- 1	Curriculum Vitae
Exhibit JJR- 2	Testimony of John J. Reed 1997 – 2008

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

A. The purpose of my testimony is to review the processes and procedures used by Florida Power and Light ("FPL" or the "Company") to manage the development and implementation of the Extended Power Uprate ("EPU") Projects at FPL's St. Lucie Units 1 & 2 and Turkey Point Units 3 & 4 ("PSL 1 & 2" and "PTN 3 & 4" respectively) in the 2011 to 2012 timeframe, and the development and construction of two new nuclear generating units at FPL's Turkey Point site (PTN 6 & 7, collectively the "Projects"). Specifically, I have reviewed FPL's policies and procedures governing their development of the Projects and will offer an opinion as to the reasonableness of these policies and procedures relative to other nuclear generating facilities currently being developed in the United States. I have not reviewed and do not offer an opinion as to the reasonableness of the specific costs of which FPL requests recovery in this proceeding. My review is solely related to the processes used to develop such costs and the risk management and project development practices utilized by FPL to administer the Projects.

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 25 years. My clients have retained me for assignments relating to the construction of nuclear plants, the purchase and sale of nuclear plants, power uprates and major capital improvement projects at nuclear plants, and the decommissioning of nuclear plants. I have had significant experience with these activities at the following plants:

Pilgrim	Ginna
Oyster Creek	Duane Arnold
Seabrook	Palisades
Hope Creek	Point Beach 1 and 2
Peach Bottom	Big Rock Point
Salem	Wolf Creek
Nine Mile Pt. 1 and 2	Callaway

I was also extensively involved in nuclear construction audits and prudence reviews for nuclear plants built in the 1980s, including Vogtle, Limerick, Susquehanna, Wolf Creek and Callaway.

I am currently active on behalf of a number of clients in pre-construction activities for new nuclear plants across the U.S., including state and federal regulatory processes, raising debt and equity financing for new projects, and evaluating the costs schedules and economics of new nuclear facilities. These activities have included detailed reviews of cost estimation and construction project management activities of other nuclear project developers.

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

A. The remainder of my testimony is organized into the following three (3) sections listed below.

Section 1: The framework of my review

Section 2: A description of each of the FPL processes I reviewed

Section 3: My conclusions and opinions of FPL's project development, risk management and cost estimation practices.

Q. Please generally describe how, in your experience, the FPL project management processes compare with other EPU projects and new nuclear development projects around the country.

A. Based on my review of FPL's practices used to manage the Projects, I find that the FPL EPU and new nuclear development projects compare favorably with other similar nuclear projects in the United States. The project management, cost estimation and risk management attributes of FPL are highly developed, well documented, and conscientiously adhered to, and are well positioned to meet FPL's needs as these projects continue to develop.

Section 1 Framework of Review

Q. Please describe the process by which you reviewed FPL's project development capabilities.

A. In order to assess FPL's project development, risk management and cost estimation capabilities, my staff and I reviewed numerous documents provided to us by FPL. These documents included FPL's general corporate procedures, the Company's nuclear procedures and instructions, various status reports prepared by the Company to monitor the progress of the Projects, contracts executed by the Company for materials and services related to the Projects, and the Company's cost estimates for the Projects for the calendar years 2008 and 2009. In addition, our team interviewed several members of FPL's project teams at FPL's corporate offices in Juno Beach, Florida.

Q. Prior to commencing your review of FPL's capabilities was there a framework you used to organize your review?

A. Yes. My review was developed based on a framework that Concentric developed in a recent evaluation of another new nuclear power development project. This framework was established to specifically address an investor's evaluation of a multi-billion dollar investment in that facility.

Q. Please describe that framework.

A. My review was focused on six (6) primary elements. Each of these elements is necessary to promote proper communication among the project team, interested stakeholders and the Company's vendors. In addition, these elements represent best practices that I have observed throughout my career. These six elements are listed below.

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

I have attempted to review each of these elements for the five processes described below and later in my testimony. In addition, I have attempted to provide examples from both projects in each case. The five processes are:

- Project Estimating and Budgeting Process
- Project Schedule and Management
- Contract Management and Administration
- Internal Oversight Mechanisms
- External Oversight Mechanisms

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

A. Defined corporate procedures are critical to any project development process as they explicitly define the steps required to successfully complete the project in the most prudent and cost effective manner. These procedures detail the methodology in which certain aspects of the project, such as the cost estimation and execution of key contracts, will be completed and to make certain that processes are consistently applied to the projects. To be effective, these procedures should be documented with sufficient detail to allow the project teams to implement the procedures, and they should be clear enough to allow the project teams to easily comprehend the procedures. Similarly, the most recent version of the procedures should be readily accessible by members of the project teams.

It is also important to assess whether the procedures are known by the project teams and adopted into the company's culture. This includes a process that allows staff to openly challenge and seek to improve the existing procedures and to incorporate lessons learned from other projects into the company's procedures. Within FPL, the Project Controls staff is responsible for ensuring FPL's corporate procedures are applied correctly.

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

A. Written project execution plans are necessary to establish a framework for executing the project development plans. 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 makes certain at an early stage of the project that the vendor's approach to achieving key project milestones is consistent with the project sponsor's needs.

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

A. One of the most difficult aspects of developing a large project is the ability to balance the needs of all stakeholders. This balance is necessary to make certain that the maximum value of the project is realized. For example, it is important that an extended power uprate project can be successfully implemented in a timely manner to avoid interfering with the project sponsor's ability to provide safe and reliable electric service to its customers. By including these customers as stakeholders in a transparent project development process, the project sponsor will be better able to deliver on these high-value projects.

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

A. 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. The purpose of a well informed senior management team is two-fold. First, reporting requirements give senior management the information they need in order to leverage their background and previous experience on an as-needed basis. Second, established reporting requirements are critical to make certain that senior management is fully aware of the activities of the respective project teams so management can effectively control the overall project risks. This level of project administration by senior management is appropriate considering the large expenditures that will be required to complete the Projects.

In order to be considered robust, these reporting requirements should be frequent and periodic (i.e., established daily, weekly and/or monthly reporting requirements) and should include varying levels of detail based on the frequency of the report. For instance, a daily status report may not need as much detail as it will soon be reviewed by a project manager who is able to quickly address issues and concerns. In contrast, a monthly status report will require significantly more detail to discuss the status of the Projects, as well as plans for near-term activities. The need for timely and effective project reporting is well recognized in the industry:

> "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[1]."

Lastly, these reports should include a mechanism to identify problem areas and document lessons learned for future project enhancements.

Q. What is the purpose of corrective action mechanisms and why is it important for robust project management processes?

A. Corrective action mechanisms are a defined process by which a learning culture is implemented across an organization to eliminate reoccurring concerns that can interfere with the successful completion of the project. Specifically, corrective action mechanisms help to identify the root cause of issues such as an activity that is trending behind schedule, and provides the opportunity to adopt mechanisms to mitigate the negative impact from these issues. A robust corrective action mechanism should assign responsibility for implementing the corrective actions and a means by which these activities are managed.

Q. Please explain why you believe it is important for a project sponsor to rely on viable technologies.

A. Nuclear projects are inherently subjected to several significant risks. One of the largest of these risks, particularly when developing a new nuclear power generating facility, is selecting the type of technology to be used at the

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

facility. Similar to the corrective action mechanisms described above, relying upon a viable technology allows the project sponsor to implement lessons learned from other projects and avoid the costly mistakes or delays that they may have experienced.

Q. Are there any other categories that were included in your review?

A. No, there were no other categories included in this general framework of my review. While I have attempted to review the categories for each process, some processes require greater emphasis in certain categories than the others included in my review.

Project Estimating and Budgeting Process

Q. Please explain why the project estimating and budgeting process are important to FPL's project development capabilities.

A. The project estimating and budgeting process is one of the most important processes for assessing FPL's project development capabilities for a number of reasons. Foremost is that the project budgets are used to determine the feasibility of the Projects (i.e., is the project cost-effective and worth pursuing from an economic point of view). If the project budgets are estimated unrealistically low FPL might pursue a project that, in the end, will not benefit FPL's customers and other stakeholders. In the alternative, FPL might not pursue a project that would benefit FPL's customers and other stakeholders in the long-term due to an unrealistically high budget. Additionally, the project budget is a useful tool for continuous monitoring of the project's performance.

In the context of the Public Service Commission's Nuclear Power Plant Cost Recovery Rule, the budgets will also be used as initial levels of costs to be recovered by FPL.

Q. Does FPL have corporate guidelines that dictate how a cost estimate should be prepared?

A. Yes, FPL has a set of corporate procedures that are broken down further into a set of department procedures and instructions that explicitly document the process for developing a cost estimate. The PTN 6 & 7 is not covered by a specific set of department procedures and instructions at this time, but appears to follow a process similar to that put in place by the Nuclear Project Department and is consistent with corporate procedures. Nuclear Project Department Instruction 304 Revision 0 covers the preparation of cost estimates.

Q. In general terms, please describe FPL's corporate procedures and their purpose.

A. FPL Group maintains a set of corporate procedures known as General Operating Procedures ("GOs") that dictate how the Company's policies and objectives are implemented across FPL Group's various business lines. The procedures are relatively detailed and help to make certain that the same high standards of excellence are demonstrated within each department. In addition to the corporate GOs, each department can develop and maintain its own set of procedures and instructions. The additional procedures are developed to cover aspects of the division's business lines that may not be applicable to the entire Company. For example, the Nuclear Division relies on several additional procedures known as Nuclear Administrative Procedures ("NAP") that incorporate NRC regulatory requirements and nuclear industry best practices in the Nuclear Division's practices. Further, various departments then establish more detailed instructions for implementing the GOs and NAPs in their groups' daily activities.

The department-specific procedures and instructions are maintained on an FPL internal database that is accessible by each employee for whom they are applicable. These procedures and instructions include highly detailed descriptions that guide the employee through a step-wise process for completing these activities. The activities covered by the GOs, NAPs or department instructions include, but are not limited to:

- Cost estimation or budgeting
- Contract negotiations
- Contract administration
- Project governance

Q. What is the process utilized by FPL to develop their budgets for each project?

A. FPL utilizes a robust, bottoms-up approach to develop their cost estimates and budgets. In general, there are two accepted methods for developing a project cost estimate. A top-down estimate is a process where the Project Estimator develops a budget for the entire project based on their experience building similar plants, and then allocates portions of this budget total to each task or activity. While this typically results in a cost estimate that compares similarly to other projects, it does not necessarily result in the most accurate estimate for individual activities or site-specific changes to the project's design. FPL has chosen the alternative of a bottoms-up cost estimating procedure.

FPL begins this process by defining the project using scoping documents, system walk-downs, as-built drawings, project plans and plant modification packages. The project is then broken into the various discrete activities required to complete each stage of the project. A Project Estimator then quantifies the material required to complete each activity. For instance, the Project Estimator determines the number of cubic yards of concrete that must be poured, or the length of 3-inch pipe that must be fitted. Project Estimators then estimate the labor requirements using the crew method to identify the number of craft personnel that are required to process the material quantities determined for each activity. The Project Estimator identifies the applicable wage rates by researching contracts and seeking quotes if available and applies the applicable wage rates to the man-hour estimates along with uncertainty or contingency factors. These labor cost adjustments account for productivity losses for activities that involve more complex work including above-grade work or work conducted in a radiological environment. For equipment and materials pricing, the Nuclear Materials Management and Integrated Supply Chain Organizations obtain equipment costs including the cost of mobilization, fuel and demobilization. Materials prices are determined using the FPL materials management system and by obtaining vendor budgetary quotes for engineered materials or materials for which an existing purchase order does not exist. The instructions then direct the Project Estimator to determine and apply a contingency factor based on the level of risk in the project at that time. In general, FPL guidelines for this contingency factor are as follows:

- 25-30 percent for conceptual estimates
- 15-20 percent for Level 1 or preliminary estimates
- 5-10 percent for Level 2 or definitive estimates

These contingencies are applied on a case-by-case basis, and are generally consistent with my prior experience, as well as with direction from the United States Department of Energy[2]. The final steps in the cost estimation instruction are to review the estimate for accuracy and to assemble the documentation for each assumption. These final two steps are necessary to promote accuracy and credibility of the estimates[3].

Q. Is FPL's cost estimation procedure consistent with general industry practices?

A. Yes. FPL's cost estimation procedure is known as a partial takeoff estimate. While several authors note that this method is difficult to undertake at an early

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[2] United States Department of Energy, Cost Estimating Guide DOE G 430.1-1, March 28, 1997, Chapter 11.
Oberlender, Garold D., Project Mangement for Engineering and Construction, Mcgraw-Hill, 2000, Pg. 49.

[3] Oberlender, Garold D., Project Mangement for Engineering and Construction, Mcgraw-Hill, 2000, Pg. 64-65.

stage in a project's development, it is recognized that this type of estimate provides the most accurate preliminary cost estimate[4].

Q. Does FPL appear to have followed this procedure in developing the cost estimates for the EPU and PTN 6 & 7 projects?

A. Yes. FPL has implemented the procedure as described. It is important to note that while the Nuclear Projects Department Instruction currently applies only to the Nuclear Projects Department, which is responsible for the Extended Power Uprate, the methodology for developing the cost estimate for both projects appears to be similar.

Further, estimating the cost of the Projects produced a substantial volume of supporting documentation that serves as evidence of this process being thoroughly implemented. Both Projects maintain multiple large volumes that document each of the activities' cost estimate assumptions and their source.

Q. What processes are in place to track actual expenditures relative the budget?

A. Actual expenditures relative to the budget are tracked on a weekly, monthly, and annual basis to determine if the project is meeting its goals. On a weekly basis the EPU project produce status reports that includes budget performance. These reports are distributed to the Company's Chief Nuclear Officer, who is responsible for overseeing the EPU project.

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[4] Sears, Keoki S., Glenn A. Sears, and Richard H. Clough, Construction Project Management: A Practical Guide to Field Construction Management. 5^{th} Edition, John Wiley & Sons, Hoboken, NJ,

Monthly reports also monitor budget performance. For the EPU project, these take the form of a Key Project Indicator report that tracks overall project performance over time. The PTN 6 & 7 project produces similar reports, known as Project Dashboard Reports which use a green, yellow and red color code system to visually indicate the status of several performance indicators including the development budget[5]. Within both Projects, the Project Controls Manager is responsible for preparing a monthly variance report that tracks deviations from the project budget as a method to monitor expenditures. This document also includes a section known as a "Risk Tracker" which requires a description of each project risk as it becomes known and a determination of its status. The variances are tracked within this document until such time as money has been allocated in the project budgets to account for the risks or when the risk no longer exists.

On an annual basis, or at major project milestones, the project teams update their respective budgets to reflect a better-defined scope of work, executed contracts, and performance to-date. Through this process they are able to maintain a relatively current estimate of the Projects' ultimate costs.

Additionally, staff from the Project Controls and Integrated Supply Chain Management organizations are assigned to monitor the activities of outside contractors to make certain that they are delivering the agreed upon scope and

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2008, Pg. 33.

[5] "Dashboard tab – Guidelines," Project Dashboard Template 2-14-2008 – Guidelines & Definitions.

terms. At times both projects are periodically asked to report their status to FPL's senior executive team. These reports typically include the Projects' ability to meet their budget projections.

Q. What processes does FPL have in place to manage higher than expected costs?

A. In the event actual expenditures significantly exceed the Projects' budgets, the project teams are responsible for immediately identifying the root cause of these increases and for developing a strategy to mitigate future increases. Once identified, the mitigation strategy or corrective action is maintained on a consolidated list of corrective actions for each project that is maintained by the respective project managers. In each case, the corrective action cannot be removed from this list until the employee responsible for its implementation signs-off on the corrective action. The EPU Key Performance Indicators and PTN 6 & 7 Project Dashboards are also tracked over time to establish trends that monitor performance and make certain the corrective actions are implemented appropriately.

Q. Are there any other tools utilized by FPL to make certain that robust cost estimates are developed or to control the project's projected costs?

A. Yes, FPL has selected a relatively viable technology in the Westinghouse AP 1000 reactor design and developed project execution plans from which to effectively manage the projects. As noted in the testimony of FPL witness Scroggs[6], the AP 1000 has been selected by many of the companies who are currently seeking to develop new nuclear power facilities. Thus, FPL should be able to leverage the experience of those companies in developing its own cost estimates. FPL's project execution plans for the Projects are also important for developing the scope of work and resource needs. With regard to the PTN 6 & 7 project, FPL has required Bechtel to develop a similar plan for their completion of the project's COLA[7]. Ultimately these plans will serve as a benchmark with which to measure performance.

Project Schedule and Management

Q. What mechanism governs the process for establishing project schedules?

A. Similar to the cost estimation procedure, the method for establishing project schedules is governed by corporate procedures that define the process for developing each schedule[8].

Q. Please describe the process for establishing project schedules as defined in the corporate procedures.

A. While each project team or business unit may develop its own specific procedures or instructions, the method for developing the Projects' schedules is similar to that employed when developing the Projects' budget. The process begins by defining the projects' scope as best as possible given the development status of the projects. The scope is then broken into individual activities and productivity and man-hour estimates are used to develop an

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[6] Direct Testimony of Steven D. Scroggs, Docket No. 080009-EI, Pg 6.

[7] Bechtel Project Execution Plan For the Florida Power and Light Turkey Point Combined License Applicatoin Project, Bechtel Job No 25409.

[8] FPL Extended Power Uprate Project Instruction – 310, Rev 0.

estimated schedule for each activity. Each activity schedule is then consolidated into an overall project schedule.

Q. What tools does FPL use to develop and manage the Projects' schedules?

A. FPL relies upon an industry standard software application developed by Primavera Systems Inc. Specifically, Primavera "provides Critical Path Method Scheduling ("CPM"), 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[9]." This software is used throughout the nuclear power industry to schedule refueling outages and major capital projects. In addition, the CPM is a commonly cited scheduling methodology for the civil engineering field as a whole[10].

Q. Is it your opinion that the EPU and PTN 6 & 7 project teams have followed this procedure and utilized the Primavera software to manage their projects' schedules?

A. Yes, my review indicates the project teams have followed this procedure and moreover are appropriately relying on the Primavera software to manage their existing development schedules. Further, as the Projects are still very much in the development stage, it is my understanding that the schedulers assigned to

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[9] www.primavera.com/products/p6/planning_man.asp. April 19 2008.

[10] Oberlender, Garold D., Project Mangement for Engineering and Construction, Mcgraw-Hill, 2000, Pg. 143.
Sears, S Keoki, Glenn A. Sears and Richard H. Clough, Construction Project Management: A Practical Guide to Field Construction Management, 5th Edition, John Wiley & Sons, Inc., Hoboken, NJ, 2008, Pg. 21.

each project team are currently adjusting certain activities within the schedule to maximize the flexibility of the schedules.

Q. How do the EPU and NTP 6 & 7 project teams monitor the performance of each activity that is currently underway?

A. As discussed earlier in my testimony, the EPU project team is required to prepare weekly, monthly and annual reports, while the NTP 6 & 7 project team prepares monthly and annual reports. Included among those reports is a discussion of the project staffs' ability to meet their projected schedules. A six week look forward report is also used to identify key upcoming milestones and make certain the relevant project team members are focused on meeting their respective deadlines.

Additionally, for the PTN 6 & 7 project, the Project Controls Manager prepares an activity-by-activity project performance indicator report that tracks the status of each of the COLA's sections and the vendor's ability to meet the project's schedule. This report uses the following color-coded system to indicate the sections status relative to the original schedule.

- Green if the activity is less than or equal to 5 days behind schedule
- Yellow if the activity is greater than 1 week but less than 2 weeks behind schedule
- Red if the activity is greater than or equal to two weeks behind schedule.

Q. How does FPL respond when an activity is determined to be behind schedule?

A. In the event that an EPU activity falls behind schedule, the EPU project team begins a corrective action program to identify the root cause of the delay and to develop a mitigation strategy to bring the activity back on schedule. This corrective action is added to a consolidated list of corrective actions maintained by each project manager and a project team member is assigned to implement the corrective action to bring the activity back on-schedule. A corrective action cannot be removed from this list until the project team member responsible for its implementation has indicated that the corrective action has been satisfactorily implemented. The Project Manager is responsible for administering the corrective action process.

The PTN 6 & 7 project team includes a dedicated Integrated Supply Chain Manager. This employee is responsible for working with the outside contractors to meet deadlines and ensuring the vendors comply with the terms of their contracts. In the event that an activity falls behind schedule, the Integrated Supply Chain Manager and the Project Manager work with the vendor to bring that activity back on-schedule.

<u>**Contract Management and Administration**</u>

Q. Please explain why it was important to review FPL's contract management and administration procedures.

A. For large projects such as the EPU and PTN 6 & 7 projects, FPL will rely on a large number of outside vendors to complete the work. Thus, a large portion of the cost associated with developing and constructing the facilities will be paid to parties outside of FPL. This represents a significant risk to both Projects' cost estimates and schedules.

Q. Do you believe FPL should avoid using outside vendors for the EPU and PTN 6 & 7 projects to eliminate this risk?

A. No, I do not. It is a standard industry practice to use outside vendors to complete the activities associated with these types of projects. The use of outside vendors allows FPL to retain the services of specialists who are experts in their fields without having to invest the time and resources to recruit these experts and maintain a sizeable workforce on FPL's payroll. Instead, it is important that FPL have robust procedures in place for obtaining services from, and managing relationships with, outside vendors.

Q. Does FPL have specific corporate procedures and instructions in place to adequately manage vendors' contracts?

A. Yes, FPL has specific procedures or instructions that appear to cover every stage of contract development including:

- Selecting and auditing appropriate vendors
- Maintaining and administering an approved vendor list
- The process for issuing a Request for Proposal ("RFP") to prospective vendors

- Contract negotiations, including the process for making certain that the appropriate legal, integrated supply chain management and subject matter personnel are included in the negotiations
- Issuing a purchase order to commence work under a contract
- The means for managing changes in scope and/or budget
- The inspection of certain deliverables under the contract terms to make certain they are adequate.

Q. Please briefly describe the contract management process as implemented by FPL.

A. FPL's contract management process begins by approving or qualifying a vendor onto an approved vendor list. In order to be qualified, the vendor should demonstrate the ability to deliver on the terms of its contracts and to deliver goods and services which are sufficient for their use within FPL's facilities. This approved vendor list is maintained by the integrated supply chain management organization.

Once a need for an outside vendor is determined, FPL considers the various suppliers who are capable of performing the services. If more than one vendor is capable of providing the service, FPL will typically issue an RFP to those vendors. The RFP contains sufficient detail for the bidder to submit its qualifications and proposed pricing and terms and often offers an opportunity to meet with the Company. In the event that the RFP requires further clarification, FPL will amend the original RFP and provide this amendment to all potential vendors. This is done to preserve a level playing field throughout the vendor selection process. Once FPL has received proposals from each of the prospective vendors, FPL uses a scorecard approach to evaluate the proposals. This scorecard is completed by various groups from within FPL depending on the service being sought, but may include departments such as engineering, integrated supply chain management, legal, and/or site operations. Once the Company has completed its evaluation of the proposals, FPL will seek to negotiate a definitive agreement with the winning vendor. The process of negotiating a definitive agreement includes several functions from within FPL, such as the integrated supply chain management, legal and risk management functions, among others. Finally, in order for the vendor to proceed with the scope of work defined by the contract, FPL will issue a purchase order ("PO") allowing the contractor to proceed with either the entire scope of work or on a more limited basis as project needs dictate.

In the event that FPL is unable to locate more than one vendor that is qualified to perform the work sought by the project team, the Company will seek a sole or single source contract with this vendor. A sole source contract refers to instances where only one provider is able to perform the work. A single source contract refers to instances where a provider is selected by FPL without issuing a competitive solicitation. Prior to entering into a single source agreement however, the project team should first complete a Single or Sole Source Justification Memorandum that explains in sufficient detail why a single source contract is being pursued. Acceptable reasons for a single source contract may include the original equipment manufacturer is the only qualified vendor, or prior high quality service and competitive pricing from a specific vendor. In the event that a sole or single source contract is sought, additional approvals should be obtained before executing in the agreement.

Q. What is your opinion regarding the use of sole or single source contracts in the nuclear industry?

A. In my experience, the use of sole or single source contracts is frequently unavoidable, but any risk from using such contracts can be effectively controlled. In general, the United States faces a shortage of qualified vendors for many nuclear-related or safety-related activities. This lack of vendors stems from the nearly 30 years that have passed since a new nuclear power facility has been ordered, and the aging, consolidation and contraction of industry participants. As a result, graduation rates in nuclear engineering programs have steadily declined since the 1970s. This has led to increased competition for qualified nuclear engineers and increased labor costs, which has led some vendors to give up their nuclear-related certifications. Further, the NRC requires vendors performing safety-related work to maintain or adopt quality assurance programs which must be maintained at a high cost. While these programs certainly are necessary to promote safe and reliable operation of nuclear power facilities, their costs, along with an increasing number of reactors that have ceased commercial operations in the last 20 years, have caused some vendors to exit the nuclear service industry. As a point of comparison, in 1980 there were more than 500 companies certified to perform nuclear-related work; today there are approximately 100 companies with such certifications[11].

Q. Please provide an example of how contract review processes have been implemented for the PTN 6 & 7 project.

A. The contract with Bechtel Corporation for the preparation of the PTN 6 & 7 COLA is currently the highest-value contract associated with the project. Work on this contract began in June, 2007 when FPL began evaluating potential vendors capable of completing this work. At that time, it was determined that Black & Veatch and Bechtel were the most qualified vendors based on their experience completing COLAs for other nuclear power project developers. FPL then began a process to develop an RFP based on feedback from other project developers that completed similar processes and from the NuStart Consortium. Specifically, the Company sought feedback from other utilities as to what should be included in the RFP to obtain timely and adequate vendor responses. Based upon this information, FPL issued a RFP to Black & Veatch and Bechtel on July 13, 2007. Two amendments were subsequently issued to the prospective vendors on July 13, 2007 and July 25, 2007. These amendments narrowed FPL's likely choice of reactor technologies to the ESBWR and the AP 1000, provided additional

[11] Hansen, Teresa. "The Nuclear Renaissance's Future," Power Engineering. September 2007.

documentation and extended the original bid submission deadline from August 3, 2007 to August 17, 2007. On August 17, 2007 FPL received detailed proposals from both Black & Veatch and Bechtel. FPL then evaluated the proposal using evaluation "scorecards" that listed certain criteria and were distributed to internal subject matter experts responsible for reviewing the proposals. The criteria included in the evaluation scorecards included:

- Quality and detail of the response
- Experience, including the specific experience of the proposed project team
- Proposed sub-contractors
- Pricing

Upon completion of this evaluation, FPL established a negotiation team that negotiated with Bechtel, the winning vendor, to finalize a definitive agreement. This agreement was executed on November 16, 2007 and a purchase order to commence work was issued on that same day.

Since issuing the purchase order, FPL has issued three modifications for changes to the project's scope and budget. These changes have generally been associated with a delayed start to the project (the original proposal had anticipated work commencing in October 2007), site conditions that necessitated the use of additional equipment and an FPL decision to have Bechtel investigate multiple cooling water options. In each case, however, FPL has used a process to review Bechtel's proposed budgets for these changes. This process includes the Project Controls Manager who reviews the proposed budget with the various subject matter experts to determine the reasonableness of the budget. Once a final budget has been agreed upon, the change of scope is submitted for approval and responsibility transfers to the Integrated Supply Chain Manager who makes certain that proper authorization for the changes are obtained and issues the appropriate purchase order.

Q. Please provide an example of how contract review processes have been implemented within the EPU project team.

A. In contrast to the PTN 6 & 7 project, whose largest contract was the result of a competitive bidding process, the EPU project has been forced to rely heavily upon sole or single source contracts. This is a common issue with power uprate projects because the work is being implemented at an existing facility. In this case, the Original Equipment Manufacturer ("OEM") is often best positioned or the only vendor capable of completing the work necessary to execute the project, alternate vendors prior experience with the existing nuclear facility.

Consistent with FPL's GOs and the nuclear divisions NAPs, FPL provided me with sole source or single source justifications for the following vendors:

- Shaw Stone & Webster
- Westinghouse
- Siemens

- Golder Associates
- Areva

In each case, these sole or single source justifications followed a review of the prospective vendors, if any others were available, and were completed prior to entering into any definitive agreements. In addition, each sole or single source justification completed by the EPU project team required approval by the Vice President of Technical Services prior to executing a definitive agreement.

Q. Are there other tools which FPL uses to manage and administer contracts and relationships with outside vendors?

A. Yes, first, FPL has employees assigned to each project team that previously worked for the major vendors involved with each project. These employees have unique insight into the vendors' processes and practices that will help FPL better manage these vendor relationships. These employees are also able to assist FPL in their negotiations with these vendors.

Second, for safety-related work completed by either project team, the NRC requires that the vendors implement a Quality Assurance Program ("QAP") or adopt FPL's QAP[12]. Compliance with the QAP will make certain that the materials and services provided by the vendor for use in FPL's nuclear power facilities meet the standards required by the contracts and applicable regulations. The programs also provide for an employee concerns program

[12] *10 CFR 50*
10 CFR 52

that encourages Company and vendor employees to report concerns on a strictly confidential basis to the NRC. These programs also provide FPL an opportunity to inspect the vendor's record keeping procedures and work prior to delivery of the final product.

Q. What corrective action mechanisms does FPL have in place to correct concerns that may arise with outside vendors?

A. FPL has included Project Controls and Integrated Supply Chain Management staff on both project teams. These employees are responsible for monitoring vendor performance to identify concerns before they affect the Projects' critical path schedules and budgets. Once issues are identified, these employees are tasked with working with the vendor to develop a corrective action plan that will help to mitigate any future impact on the project. In addition, when negotiating vendor agreements, FPL seeks a set of terms and conditions that will give the Company flexibility to terminate the contract should the vendor fail to perform as required.

Internal Oversight Mechanisms

Q. Please explain how the Projects are currently managed.

A. The EPU and PTN 6 & 7 projects are currently managed by different divisions of the Company. The EPU project is being developed by FPL's Nuclear Division, whereas the PTN 6 & 7 project is being developed by a combined team of FPL's Project Development group and it's Engineering Construction Services Division. FPL chose to separate these projects for two reasons.

First, this separation allows the organization best suited to developing each project to focus on their respective work. For instance, the EPU project involves coordinating work activities with the existing plants' operations and integrating the project schedule into the plants' previously scheduled refueling outages, therefore it is necessary to use project personnel that are well acquainted with site personnel and plant operations. The PTN 6 & 7 project requires a focus on new project development and construction management that is best handled by those who have recently been involved in large energy-related construction projects. Second, by dividing the projects between FPL's Nuclear and Construction Divisions, FPL is responding to NRC recognition of the potential to distract employees at the existing facilities by diverting their attention to the new construction projects[13]. Nonetheless, there is some crossover between the two projects as certain of the employees working on the PTN 6 & 7 project have experience with the Nuclear Division and its procedures.

Q. **Please describe the reporting relationships of each of the EPU and PTN 6 & 7 project teams.**

A. Ultimately both project teams report to James Robo, Chief Operating Officer of FPL Group. The reporting relationship below that level is quite different for the Projects. In the case of the EPU project, the project team reports to the Vice President – Technical Services and to FPL Group's Chief Nuclear Officer. The PTN 6 & 7 project team reports to the President of Florida

[13] Remarks of NRC Commissioner Jeffrey S. Merrifield at the 2001 ANS Annual Meeting.

Power & Light and the Senior Vice President of Engineering Construction Services, who both report directly to James Robo.

Q. What processes are in place to keep each level of the FPL organization up-to-date regarding the Projects' status?

A. Both the EPU and NTP 6 & 7 project teams are responsible for preparing periodic management updates. As discussed earlier in my testimony, the project teams are responsible for preparing periodic status reports that convey the Projects' progress to-date and their performance relative to their original schedule and budget. These reports are presented to senior management for their review. In addition, the project teams routinely provide senior management with presentations that cover the Projects' progress and performance as well as identifying crucial issues or decisions which require the attention of the senior management team.

Q. Has either of the Projects completed an internal audit?

A. Since the Projects are at such an early stage in their development, neither project has completed an internal audit. The EPU project recently began an internal audit and a final audit report is expected in June 2008. The PTN 6 & 7 project is expected to begin an internal audit this summer and a final report is expected in fall 2008. These audits will help to make certain that the project teams are complying with established accounting practices and Sarbanes-Oxley reporting requirements. In the interim, the Projects will utilize Project Controls Managers to perform similar duties on an on-going basis. In the case of the PTN 6 & 7 project, this position has already been filled. A similar position has been posted within the EPU project team and is expected to be filled imminently.

Q. What other internal oversight mechanisms are employed by FPL to manage the Projects?

A. In addition to the various mechanisms described above, the Projects should be reviewed by FPL's Corporate Risk Committee. These reviews are expected to take place just prior to the achievement of major project milestones. The committee consists of employees who hold the title of director or above are tasked with identifying key project risks while proposing mitigation strategies based on the committee members' experience. At times, however, the committee does not propose risk mitigation strategies, but may request that the project teams perform further analysis to study options that may help to mitigate identified risks.

External Oversight Mechanisms

Q. What is meant by external oversight mechanisms?

A. An external oversight mechanism is a process by which the project teams avail themselves of outside subject matters experts in order to introduce lessons learned from other projects at the Company and to improve FPL's project development program procedures.

Q. Why are strong external oversight mechanisms important for successful project development programs?

A. While not critical to the success of a project development program, the application of select external oversight mechanisms shows that the Company has a strong commitment to becoming a learning organization. In other words, the organization is committed to implementing industry best practices to help prevent issues from reoccurring to mitigate the resultant cost increases and schedule delays. Project development of nuclear power facilities is a dynamic process that can change on a frequent basis, thus, it is important to seek constant improvement of the Company's procedures and to learn from the practical experience of others involved in the industry.

Q. Has FPL shown a commitment to external oversight?

A. Yes. FPL has retained the services of outside expert advisors, where appropriate, to review their processes and provide recommendations for continuous improvement. FPL's commitment is also demonstrated by the Company's membership in industry groups such as the Nuclear Energy Institute and in the NuStart project development consortium. While these groups do not provide oversight of the Projects, they give FPL access to the experience of other nuclear power project developers.

Q. What outside experts has FPL retained to review its processes for the Projects?

A. FPL has retained the engineering firm MPR Associates and Concentric to review their processes. Concentric's work is detailed in this testimony. MPR was retained to review FPL's reactor technology selection process and also provided input on how the Company could improve the process over a period of several months beginning in the fall of 2007.

Conclusions

Q. What have you concluded from your review of FPL's project management processes?

A. I have found that the processes used by FPL to study the feasibility, estimate costs, and manage both the EPU and PTN 6 & 7 projects are reasonable, and meet or exceed the norms for these practices as used by other nuclear power industry participants. This opinion is based on my more than 30 years of experience in the utility industry and my recent experience assessing the project management capabilities of another major nuclear project developer in the United States.

Q. What conclusions specific to the EPU project have you developed as result of your review?

A. I have found that the EPU practices are specifically focused on managing risk and cost, and include appropriate levels of senior management oversight. In addition, the practices have been applied in a manner that is generally consistent with FPL's policies and procedures. These practices are designed to benefit from lessons learned and to use actual experience to help prevent reoccurring issues from adversely affected the project through a corrective action program. More specifically, this corrective action program appropriately assigns responsibility for ensuring that the corrective actions are implemented and it is applicable to contractors and FPL employees alike. Further, the EPU projects use a cost estimating procedure that is robust and based upon obtaining budgetary quotes from vendors while leveraging FPL's own very recent power plant construction experience.

Q. **Have you developed any specific recommendations for the EPU project team?**

A. No, I have not at this time.

Q. **What conclusions specific to the PTN 6 & 7 project have you developed as a result of your review?**

A. Similar to the EPU project, I have found that the PTN 6 & 7 project practices are specifically designed to address project risks and costs. The PTN 6 & 7 project practices are also aimed most directly at utilizing a thoroughly documented process that maintains the option to build new nuclear capacity, but does not commit the Company to constructing a new nuclear power facility if market conditions should change. I have also found that while the current PTN 6 & 7 project cost estimation process is not yet as robust as that developed for the EPU project, it is completely consistent with the extremely long interval between initial project planning and the beginning of construction, and meets or exceeds industry norms for a project at this stage of development. Finally, the PTN 6 & 7 project appears to have appropriate levels of senior management oversight.

Q. **Do you have any specific recommendations for the PTN 6 & 7 project team?**

A. No, I do not at this time.

Q. Does this conclude your direct testimony?

A. Yes, it does.

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 25 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 125 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 CEA 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 20 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 125 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Have been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

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

Resource Procurement, Contracting and Analysis

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

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

Strategic Planning and Utility Restructuring

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

PROFESSIONAL HISTORY

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

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

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

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

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

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

EDUCATION AND CERTIFICATION

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

BOARDS OF DIRECTORS (PAST AND PRESENT)

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

AFFILIATIONS

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Colorado Public Utilities Commission				
Xcel Energy	8/04	Xcel Energy	Docket No. 031-134E	Cost of Debt
CT Dept. of Public Utilities Control				
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
District Of Columbia PSC				
Potomac Electric Power Company	3/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Direct)
Potomac Electric Power Company	5/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Supplemental Direct)
Potomac Electric Power Company	7/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Rebuttal)
Fed'l Energy Regulatory Commission				
BEC Energy - Commonwealth Energy System	2/99	Boston Edison Company/ Commonwealth Energy System	EC99-___-000	Market Power Analysis – Merger
Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	10/00	Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	Docket No. EC00-___	Market Power 203/205 Filing
Wyckoff Gas Storage	12/02	Wyckoff Gas Storage	CP03-33-000	Need for Storage Project
Indicated Shippers/Producers	10/03	Northern Natural Gas	Docket No. RP98-39-029	Ad Valorem Tax Treatment
Maritimes & Northeast Pipeline	6/04	Maritimes & Northeast Pipeline	Docket No. RP04-360-000	Rolled-In Rates
ISO New England	8/04	ISO New England	Docket No. ER03-563-030	Cost of New Entry
Transwestern Pipeline Company, LLC	9/06	Transwestern Pipeline Company, LLC	Docket No. RP06-614-000	

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Florida Public Service Commission				
Florida Power and Light Co.	10/07	Florida Power & Light Co.	Docket No. 07____-EI	Need for new nuclear plant
Hawaii Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/00	Hawaiian Electric Light Company, Inc.	Cause No. 41746	Standby Charge
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/01	Northern Indiana Public Service Company	Docket No. 99-0207	Direct Testimony, Valuation of Electric Generating Facilities
Northern Indiana Public Service Company	01/08	Northern Indiana Public Service Company	Cause No. 43396	Asset Valuation
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	Public Benefits
Interstate Power and Light	5/07	City of Kalona, Iowa	Docket No. SPU-06-6	Public Benefits
Interstate Power and Light	5/07	City of Wellman, Iowa	Docket No. SPU-06-10	Public Benefits
Interstate Power and Light	5/07	City of Terril, Iowa	Docket No. SPU-06-8	Public Benefits
Interstate Power and Light	5/07	City of Rolfe, Iowa	Docket No. SPU-06-7	Public Benefits
Maryland Public Service Commission				
Potomac Electric Power Company	8/99	Potomac Electric Power Company	Docket No. 8796	Stranded Cost & Price Protection (Direct)

Mass. Department of Public Utilities				
NStar	9/07, 12/07	NStar, Bay State Gas, Fitchburg G&E, NE Gas, W. MA Electric	DPU 07-50	Decoupling
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	Consumers Energy Company	Case No. U-14992	Sale of Nuclear Plant
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
Northern States Power Company d/b/a Xcel Energy	09/06	NSP v. Excelsior	Docket No. E6472/M-05-1993	Industry Norms and 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
Missouri Public Service Commission				
Missouri Gas Energy	1/03	Missouri Gas Energy	Case No. GR-2001-382	Gas Purchasing Practices; Prudence
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case Nos. ER-2004-0034 HR-2004-0024	Cost of Capital, Capital Structure
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case No. GR-2004-0072	Cost of Capital, Capital Structure
Missouri Gas Energy	11/05	Missouri Gas Energy	Case Nos. GR-2002-348 GR-2003-0330	Capacity Planning

Nat. Energy Board of Canada				
Maritimes & Northeast Pipeline	2/02	Maritimes & Northeast Pipeline	GH-3-2002	Natural Gas Demand Analysis
TransCanada Pipelines	8/04	TransCanada Pipelines	RH-3-2004	Segmented Service
Brunswick Pipeline	9/06	Brunswick Pipeline	GH-1-2006	Market Study
TransCanada Pipelines Ltd.	3/07	TransCanada Pipelines Ltd.: Gros Cacouna Receipt Point Application	RH-1-2007	
New Brunswick Energy and Utilities Board				
Atlantic Wallboard/JD Irving Co	1/08	Atlantic Wallboard/JD Irving Co.	MCTN #298600	Rate Setting for EGNB
New York Public Service Commission				
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
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
Oklahoma Corporation Commission				
Oklahoma Gas & Electric Company	9/05	Oklahoma Gas & Electric Company	Cause No. PUD 200500151	Prudence of McLain Acquisition
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
Rhode Island Public Utilities Commission				
Providence Gas Company and The Valley Gas Company	1/01	Providence Gas Company and The Valley Gas Company	Docket No. 1673 and 1736	Gas Cost Mitigation Strategy

The New England Gas Company	3/03	New England Gas Company	Docket No. 3459	Cost of Capital
Texas Public Utility Commission				
Oncor Electric Delivery Company	8/07	Oncor Electric Delivery Company	Docket No. 34040	Rate Filing Package; Regulatory Policy, Rate of Return, Return of Capital and Consolidated Tax Adjustment
Utah Public Service Commission				
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	benchmarking
Vermont Public Service Board				
Green Mountain Power	7/98	Green Mountain Power	Docket No. 6107	Direct Testimony
Green Mountain Power	9/00	Green Mountain Power	Docket No. 6107	Rebuttal Testimony
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
American Arbitration Association				
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
State of Colorado District Court, County of Garfield				
Questar Corporation, et al	11/00	Questar Corporation, et al.	Case No. 00CV129-A	Partnership Fiduciary Duties
State of Delaware, Court of Chancery, New Castle County				
Wilmington Trust Company	11/05	Calpine Corporation vs. Bank Of New York and Wilmington Trust Company	C.A. No. 1669-N	Bond Indenture Covenants
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				
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
State of New Jersey, Mercer County Superior Court				
Transamerica Corp., et. al.	7/07	IMO Industries Inc. vs. Transamerica Corp., et. al.	Docket No. L-2140-03	Breach-Related Damages, Enterprise Value

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 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 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, 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	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 Litigation
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, 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	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Expert Report, Shortnose Sturgeon Case
Central Hudson Gas & Electric	8/00	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Revised Expert Report, Shortnose Sturgeon Case
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	VPEM v. Aquila, Inc.	Civil Action 304 CV 411	Breach of Contract, Damages
District of Columbia Court City Council				
Potomac Electric Power Co.	7/99	Potomac Electric Power Co.	Bill 13-284	Utility restructuring