BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Cost Recovery Clause	DOCKET NO. 120009-EI Submitted for filing: April 30, 2012

DIRECT TESTIMONY
OF JON FRANKE IN SUPPORT OF
ACTUAL/ESTIMATED AND PROJECTED COSTS

ON BEHALF OF
PROGRESS ENERGY FLORIDA, INC.

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IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA, INC.

FPSC DOCKET NO. 120009-EI

DIRECT TESTIMONY OF JON FRANKE

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Jon Franke. My business address is 15760 W. Powerline St., Crystal River, FL 34442.

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

A. I am employed by Progress Energy Florida, Inc. ("PEF" or the "Company") in the Nuclear Generation Group and serve as Vice President – Crystal River Nuclear Plant.

Q. What are your job responsibilities?

A. As Vice President I am responsible for the safe operation of the nuclear generating station. The Plant General Manager, Site Support Services and Training sections report to me. Additionally, I have responsibilities in oversight of major project activities at the station. Through my management team I have more than 400 employees that perform the daily work required to operate and maintain the station and provide engineering, training, and other support to the station.

Q. Please summarize your educational background and work experience.

A. I have a Bachelor's degree in Mechanical Engineering from the United States Naval Academy at Annapolis. I have a graduate degree in the same field from the University of Maryland and a Masters of Business Administration from the University of North Carolina at Wilmington.

I have over 25 years of experience in nuclear operations. I received training by the U.S. Navy as a nuclear officer and oversaw the operation and maintenance of a nuclear aircraft carrier propulsion plant during my service. Following my service in the Navy I was hired by Carolina Power and Light and have been with the Company through the formation of Progress Energy. My early assignments involved engineering and operations, including oversight of the daily operation of the Brunswick nuclear plant as a U.S. Nuclear Regulatory Commission ("NRC") licensed Senior Reactor Operator. I was the Engineering Manager of that station for three years prior to assignment to Crystal River as the Plant General Manager in 2002. In April 2009, I was promoted to my current position.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support the Company's request for cost recovery pursuant to the Nuclear Cost Recovery Rule for the replacement and modification of equipment at the Crystal River 3 ("CR3") nuclear power plant in connection with Phase 3, the Extended Power Uprate ("EPU") for the CR3 Uprate project ("CR3 Uprate"). My testimony supports the Company's actual/estimated and projected costs for 2012 and 2013, respectively, and explains why these CR3 Uprate costs are reasonable. Finally, my testimony explains why the CR3 Uprate project is feasible, pursuant to Rule 25-6.0423(5)(c)5, Florida Administrative Code ("F.A.C.").

Q. Have you previously filed testimony in this docket?

A. Yes, I filed testimony on March 1, 2012 in support of the actual costs incurred in 2011 for the CR3 Uprate project.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (JF-1), NRC acceptance review letter for the EPU License Amendment Request ("LAR") for the CR 3 Uprate project;
- Exhibit No. ___ (JF-2), Integrated Project Plan ("IPP") Interim Approval 3A (Short Form) for the CR3 Uprate project;

- Exhibit No. ___ (JF-3), a description of the engineering scope changes for the EPU phase work and a schedule identifying the phased work scope to successfully implement the power uprate for the CR3 Uprate project;
- Exhibit No. ___ (JF-4), the Company's updated cumulative present value revenue requirements ("CPVRR") analysis for the CR3 Uprate project; and
- Exhibit No. ___ (JF-5), February 2012 EPU Options Update.

Also, I am co-sponsoring portions of Schedules AE-4, AE-4A, AE-6.3 and sponsoring Schedules AE-6A.3 through AE-7B and Appendix B of the Nuclear Filing Requirements ("NFRs"), included as part of Exhibit No. __ (TGF-4) to Mr. Thomas G. Foster's testimony. I will also be co-sponsoring portions of Schedules P-4 and P-6.3; sponsoring Schedules P-6A.3 through P-7B of Exhibit No. ___ (TGF-5) to Mr. Foster's testimony; co-sponsoring Schedules TOR-4 and TOR-6; and sponsoring TOR-6A and TOR-7 of Exhibit No. _____(TGF-6) to Mr. Foster's testimony. A description of these schedules follows:

- Schedule AE-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the period.
- Schedule AE-4A reflects CCRC recoverable O&M expenditure variance explanations for the period.
- Schedule AE-6 reflects actual/estimated monthly expenditures for preconstruction and construction costs for the period.
- Schedule AE-6A reflects descriptions of the major tasks.

- Schedule AE-6B reflects annual variance explanations.
- Schedule AE-7 reflects contracts executed in excess of $1.0 million.
- Schedule AE-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule AE-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Appendix B reflects the reconciliation of the beginning construction work in progress ("CWIP") balance for those assets placed into rate base that are not yet in service as detailed on AE-2.3.
- Schedule P-4 reflects CCRC recoverable O&M expenditures for the period.
- Schedule P-6 reflects projected monthly expenditures for preconstruction and construction costs for the period.
- Schedule P-6A reflects descriptions of the major tasks.
- Schedule P-7 reflects contracts executed in excess of $1.0 million.
- Schedule P-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule P-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Schedule TOR-6 reflects actual to date and projected annual expenditures for preconstruction and construction costs for the duration of the project.
- Schedule TOR-6A reflects descriptions of the major tasks.
- Schedule TOR-7 reflects initial project milestones in terms of costs, budget levels, initiation dates, and completion dates.

These exhibits, schedules, and appendices are true and accurate.

Q. Please summarize your testimony.

A. PEF is committed to completion of the EPU phase of the CR3 Uprate project for the benefit of the Company and its customers. The current project plan is to complete the EPU phase during the current, extended CR3 16R outage. The Company performed a quantitative and qualitative feasibility analysis of completing the EPU phase of the CR3 Uprate project. Completion of the EPU phase is feasible from a technical and regulatory perspective. Completion of the EPU phase of the CR3 Uprate project is also economically feasible. The EPU phase of the CR3 Uprate project will provide PEF and its customers substantial operational and carbon cost compliance savings. PEF's customers will benefit from additional fuel savings and potential carbon cost savings from completion of the EPU phase of the CR3 Uprate project when CR3 returns to commercial service.

The Company is providing the Florida Public Service Commission ("PSC" or the "Commission") with its 2012 actual/estimated and 2013 projected CR3 Uprate project costs with this filing in accordance with the Commission's nuclear cost recovery rule. The 2012 actual/estimated and 2013 projected CR3 Uprate project costs reflect the current plan to implement the EPU phase of the CR3 Uprate project in the current, extended CR3 re-fueling outage and reflect the best available information the Company currently has with respect to the CR3 Uprate project costs. These costs are reasonable, subject to true-up under the Commission's rule next year.

The CR3 Uprate project is still in the best interests of PEF and its customers. It provides PEF and its customers additional carbon-free, fuel savings from clean nuclear energy generation while improving the Company's fuel diversity and reducing the Company's reliance on fossil fuels to generate electricity for PEF's customers. The current, 2012 and 2013 CR3 Uprate project costs to achieve these benefits are reasonable. For this reason, the Company requests that the Commission determine that PEF is entitled to recover its prudent and reasonable CR3 Uprate project costs.

III. 2012 ACTUAL/ESTIMATED AND 2013 PROJECTED PERIOD COSTS.

A. <u>CR3 Uprate Project Status.</u>

Q. Does the Company plan to complete the CR3 Uprate project?

A. Yes, PEF currently plans to repair the CR3 containment building and complete the EPU phase of the CR3 Uprate project.

Q. What is the current CR3 Uprate project schedule?

A. PEF plans to complete the EPU phase of the CR3 Uprate project during the current, extended CR3 16R re-fueling outage. Under this schedule, PEF plans to start EPU construction in June 2013 and complete implementation of the EPU in June 2014 with an expected return of CR3 to commercial service in November 2014 and the EPU expected in service in December 2014. The Company's actual/estimated 2012 and projected 2013 CR3 Uprate costs are based on the Company's current schedule to complete the EPU phase during the CR3 16R extended re-fueling outage.

Q. Is the Company's current schedule consistent with the Company's plan last year to complete the CR3 Uprate project?

A. Yes. In early 2011, the Company planned to complete the EPU phase in the next CR3 re-fueling outage. That next CR3 re-fueling outage, R17, was planned for Spring 2013 with the expected return of CR3 to commercial service in 2011 upon completion of the repairs to the CR3 containment building. The Company had re-scheduled the CR3 Uprate project work in late 2010 and early 2011 to meet this project plan. Accordingly, the Company already planned to perform EPU phase construction work in 2013 when the second delamination occurred in March 2011. As a result of that event, the EPU project management team evaluated the EPU phase work and schedule to provide the Company the flexibility to continue to meet this EPU implementation schedule if that proved to be the prudent course of action. The extended CR3 R16 re-fueling outage further provided the Company the opportunity to gain schedule and cost efficiencies because the EPU phase work in 2013 no longer had to be completed during the limited timeframe of a typical re-fueling outage, but instead could be implemented over the course of the year. The current EPU phase work schedule and costs reflect these efficiencies.

Q. Is the Company's current EPU phase schedule consistent with the Company's current repair plan for the CR3 containment building?

A. Yes. The Company's current CR3 Uprate project schedule aligns completion of the EPU phase of the CR3 Uprate project with the current plan to repair the CR3 containment building. The Company currently plans to repair the CR3 containment building and return CR3 to commercial service in November 2014.

Q. Has the Company commenced repairs to the CR3 containment building?

A. No, not at this time. Last year, based on an initial review and analysis, the Company determined that the CR3 containment building should be repaired, selected a repair option, and developed a preliminary cost estimate for the repair. The Company moved forward systematically with additional, detailed engineering analyses and designs to develop a final repair plan. The engineering design process of the final CR3 containment building repair plan is still under way. The Company expects to complete that process later this year. A number of factors might affect the current CR3 containment building repair plan, the estimated November 2014 commercial in-service date, or the estimated repair costs, including the ultimate work scope, engineering designs, testing, weather, and regulatory reviews, among other potential developments. Currently, however, the Company intends to repair the CR3 containment building and complete the EPU phase of the CR3 Uprate project.

Q. Why is the Company proceeding with work on the EPU phase of the Uprate project when the Company has not yet commenced repairs of the CR3 containment building?

A. Completion of the CR3 Uprate project during the current extended, CR3 re-fueling outage is in the best interests of PEF and its customers. Completion of the EPU phase of the CR3 Uprate project in the current CR3 re-fueling outage provides fuel savings benefits to PEF's customers. To obtain these benefits the Company must continue with EPU phase work in 2012 and 2013 to complete the CR3 Uprate project when CR3 returns to commercial service under the current plan to repair the CR3 containment building. As I explained above, the Company currently plans to repair CR3, absent some unforeseen risk, design, engineering, or licensing impediment to repairing the CR3 containment building, and return CR3 to commercial service in November 2014.

The Company has, however, developed an alternative plan to complete the EPU phase of the CR3 Uprate project in the next planned CR3 re-fueling outage, in the event that the Company's current plan to repair the CR3 containment building is delayed or unforeseen risks or other impediments require the Company to complete the EPU phase in the CR3 R17 re-fueling outage. As I explain later, the Company evaluated this alternative project plan in its economic feasibility analysis and determined that it is cost-effective for the Company and its customers. Current project costs in 2012 are virtually identical whether the Company performs the EPU phase work in the current outage or in the next planned re-fueling outage. As a result, PEF has maximum flexibility this year to continue with the EPU phase without adding additional work scope or cost prior to the CR3 repair plan being finalized this year as currently expected.

B. <u>EPU Phase Work in 2012 and 2013.</u>

Q. What does the Company's EPU phase work plan include in 2012 and 2013?

A. The EPU phase work plan includes: (1) engineering design work for the EPU phase; (2) engineering and licensing support work for the EPU LAR review by the NRC; and (3) payments for Long Lead time Equipment ("LLE") items for the EPU phase of the CR3 Uprate project. The EPU phase work plan further includes project management of these EPU phase work activities in 2012 and 2013.

Schedule AE-6.3 of Mr. Foster's Exhibit No. __ (TGF-4) contains the total 2012 actual/estimated construction costs for these EPU phase work activities in the following categories: (1) License Application costs estimated at $2.8 million; (2) Power Block Engineering, Procurement, and related construction costs estimated at $45.4 million; (3) Non-Power Block Engineering, Procurement and related construction costs estimated to be $0.2 million; and (4) Project Management costs estimated at $3.2 million.

Schedule P-6.3 of Mr. Foster's Exhibit No. __ (TGF-5) reflects the 2013 projected construction costs for these EPU phase work activities in the following categories: (1) License Application costs estimated at $2.4 million; (2) Power Block Engineering, Procurement, and related construction costs estimated at $101.5 million; (3) Non-Power Block Engineering, Procurement and related construction costs estimated at $0.1 million; (4) On-Site Construction Facilities costs estimated at approximately $0.6 million; and (5) Project Management costs estimated to be $5.7 million.

Q. How did PEF estimate the 2012 and 2013 License Application costs for the CR3 Uprate project?

A. PEF developed the License Application cost estimates using utility industry standard cost estimation practices, with the best available information at this time, including its engineering judgment and experience, and the incorporation of "lessons learned" on its EPU LAR and other utility LARs, in its estimates of the cost to work with the NRC during the EPU LAR review process at the NRC. The License Application costs for 2012 and 2013 reasonably reflect the cost of the work necessary to obtain NRC approval of the EPU LAR.

Q. What is the status of the EPU LAR?

A. PEF submitted the EPU LAR to the NRC on June 15, 2011. The next step in the NRC review process is referred to as Acceptance Review. During the Acceptance Review process, the NRC technical branches reviewed the submittal to confirm that adequate information was available to complete their review of the EPU LAR. The NRC completed its Acceptance Review on November 21, 2011 and determined that the EPU LAR satisfied the Acceptance Review. See the NRC acceptance review letter for the EPU LAR for the CR 3 Uprate project attached as Exhibit No. ___ (JF-1) to my testimony.

The NRC is now reviewing the EPU LAR for LAR approval. For 2012 and 2013, the Company's License Application costs include the work necessary to support the NRC's review of the EPU LAR. The NRC has indicated that up to eighteen (18) technical branches will be actively involved in the review. The NRC approval review process involves Requests for Additional Information ("RAIs") from the NRC technical branches to obtain information necessary for the NRC review and approval of the EPU LAR. PEF is working with the NRC to address RAIs. To date, most of these branches have completed their review sufficiently to request some level of additional information from PEF and PEF has responded to more than half of the branches. Remaining RAIs from the NRC branches cover some of the more technically complex areas of the review. PEF has scheduled a pre-review workshop with the NRC to discuss some of the distinctive features of the CR3 plant, its safety analyses, and EPU impacts. PEF expects to work on the responses to the remaining RAIs from the NRC branches throughout 2012 and into 2013. PEF's Licensing Application costs for 2012 and 2013 reflect the Company's engineering and licensing work to respond to the NRC RAIs for the NRC technical branch review of the EPU LAR.

Q. Does PEF expect the NRC to approve the EPU LAR for the CR3 Uprate?

A. Yes. Feedback from NRC staff and management during the NRC review of the EPU LAR is very positive. PEF is confident that the NRC will approve the EPU LAR in time to support re-start of CR3 from the current extended 16R outage as currently planned. Based on the feedback from NRC with respect to the NRC review schedule, PEF believes the NRC will approve the EPU LAR in 2013.

Q. Please describe the Power Block Engineering, Procurement and related construction cost activities for the CR3 Uprate project in 2012 and 2013.

A. The Power Block Engineering, Procurement, and related construction activities for the CR3 Uprate project include continued engineering design work to reach an optimal design completion percentage in time for implementation of the engineering change ("EC") packages for the EPU phase work and continued progress payments based on pre-existing contractual commitments for the LLE necessary for the EPU phase of the CR3 Uprate project.

The EC packages contain the detailed engineering design instructions for the EPU modifications for implementation or installation by the construction contractor for the EPU phase work. The EPU EC packages are approximately 70 percent complete. The remaining work to complete the EC packages for the EPU modifications will be completed in 2012 and 2013. PEF also expects to award the EPU phase construction contract early in 2013 under the current EPU phase schedule. Under that schedule, in 2013 PEF will begin to mobilize construction resources, perform constructability reviews, receive equipment and materials, begin pre-fabrication activities, and continue to perform vendor oversight for the EPU phase work.

PEF will continue to make necessary progress payments on the LLE necessary for the power uprate in 2012 and 2013. Last year, PEF reviewed each contract and change order for EPU phase work and no contract or change order was executed without senior management or project management approval. Approval for new and continued payments on contracts and change orders was based on the determination that the contract or change order was reasonable and necessary to complete the EPU phase work during the current CR3 outage. PEF accordingly continued payments on the critical path LLE items to implement the EPU phase in the current extended CR3 R16 re-fueling outage. Most of these LLE progress payments for 2012 and 2013 reflect pre-existing contractual commitments. Deferral of these payments cannot be accomplished without cancellation or suspension of contracts, which would result in penalties and an uncertain future regarding LLE contract renewals to meet the current EPU phase work schedule. As a result, PEF must continue with LLE progress payments in 2012 and 2013 to complete the EPU phase work during the current extended CR3 R16 re-fueling outage.

Q. Are the Power Block Engineering, Procurement and related construction costs in 2012 and 2013 reasonable?

A. Yes. As I explained, this work scope is necessary to implement the EPU phase of the CR3 Uprate project and achieve the power uprate when CR3 is returned to service under the current Company plan to repair CR3 and return it to commercial service by November 2014. PEF estimated its 2012 and projected its 2013 power block engineering, procurement, and related construction item costs using actual contract figures and project schedule milestones under its current EPU phase work plan and schedule. Actual contractual payment amounts and payment schedule terms are used for the cost estimates and projections and, therefore, the 2012 and 2013 power block engineering, procurement, and related construction item cost projections are reasonable.

Q. Please describe the Non-Power Block Engineering, Procurement and related construction cost activities for the CR3 Uprate project in 2012 and 2013.

A. These activities are for the Point of Discharge ("POD") cooling tower for the CR3 Uprate project. Construction of an additional cooling tower is necessary to mitigate the additional heat generated at CR3 power uprate conditions in the site cooling water discharge canal. The additional cooling tower maintains the cooling water temperature below the permitted maximum temperature at the point of return to the Gulf of Mexico.

The work necessary to permit, design, engineer, and procure and manufacture equipment and material for the additional cooling tower was placed on hold as a result of the extended CR3 outage. The POD work was suspended to provide PEF time to evaluate the need for this work under new and evolving environmental requirements affecting the Company's generation resource options and plans. These environmental regulations may impact operation of the fossil units at Crystal River, and therefore, impact the need for the additional cooling tower to mitigate the additional heat generated by the CR3 power uprate. The extended CR3 outage provides additional time for the Company to evaluate these environmental regulations, some which have only been issued this year. Under the current schedule for the EPU phase work, PEF does not need to commence the POD construction work until April 2014 in order to complete the POD work by April 2015 prior to the first summer of CR3 operation at power uprate conditions. As a result, PEF has additional time to evaluate the evolving environmental regulatory requirements and their impact on the Company's generation operations before commencing with POD construction work for the EPU phase of the CR3 Uprate project.

The cost estimates for the POD work in 2012 and 2013 are for reasonable storage costs for equipment associated with the POD cooling tower. PEF estimates that it will incur approximately $0.2 million and $0.1 million in 2012 and 2013 respectively, for these non-power block engineering, procurement and related construction activities, as reflected in the NFR schedules attached to Mr. Foster's testimony.

Q. What On-Site Construction Facilities work will be done in 2012 and 2013 for the CR3 Uprate project?

A. These are primarily 2013 costs to install temporary equipment storage and personnel staging facilities for the additional construction personnel in preparation for the EPU phase construction work. PEF developed these on-site construction facilities cost estimates on a reasonable engineering basis, using the best available information and PEF's experience with other construction projects, including completion of phase two of the CR3 Uprate project, consistent with utility industry and PEF practice. These costs are therefore reasonable.

Q. Can you explain the Project Management work in 2012 and 2013 for the CR3 Uprate project?

A. Yes. PEF will continue to incur costs to manage the CR3 Uprate project through the successful completion of the EPU phase of the project. Project management costs, accordingly, are on-going as we continue to prepare for the EPU phase work under the current EPU phase work plan and schedule. PEF's project management costs include the activities conducted pursuant to our project management and cost control oversight policies and procedures necessary to support, supervise, and manage the EPU phase of the CR3 Uprate project. These project management and cost control policies and procedures were generally described in my March 1, 2012 testimony, and in prior testimony in prior nuclear cost recovery clause proceedings.

As I have explained before, consistent with these project management and cost control policies and procedures, the Company's project management work consists of : (1) project administration, including project instructions, staffing, roles, and responsibilities, and interface with accounting, finance, and senior management; (2) contract administration, including status and review of project requisitions, purchase orders, and invoices, contract compliance, and contract expense reviews; (3) project controls, including schedule maintenance and milestones, cost estimation, tracking and reporting, risk management, and work scope control; (4) project management, including project plans, project governance and oversight, task plans, task monitoring plans, lessons learned, and task item completions; (5) project training, including the uprate project training program, training of personnel in accordance with the training program, and maintaining training records; and (6) management of the CR3 Uprate licensing work. These activities are necessary to ensure that the CR3 Uprate project work scope, schedule, and cost to implement the work scope achieve the CR3 Uprate project objectives.

Consistent with our cost estimation methodologies and past practice on the CR3 Uprate project, the CR3 Uprate project management cost estimates for 2012 and 2013 were developed using the best available information to the Company on the scope of the project management activities, our experience and "lessons learned" from managing the Uprate and other projects, knowledge gained from the industry, and PEF best management practices. As a result, PEF project management costs for 2012 and 2013 are reasonable.

Q. Are the actual/estimated 2012 and projected 2013 costs for the CR3 Uprate project separate and apart from costs that the Company would have incurred to operate CR3 during the extended life of the plant?

A. Yes, they are. PEF only includes for recovery in this proceeding those costs that were incurred or that will be incurred solely for the CR3 Uprate project. No costs are included in the CR3 Uprate project that are needed to continue the operation of the plant for an additional twenty (20) years at power levels prior to the power uprate as a result of the CR3 Uprate project.

IV. TRUE UP TO ORIGINAL COST FILING FOR 2012.

Q. Has the Company filed schedules with the information necessary to true up the original estimates to the actual costs incurred for the CR3 Uprate project?

A. Yes, these schedules are provided in Exhibit No. ___ (TGF-6) to Mr. Foster's testimony, Schedules TOR-1 through TOR-7.

Q. What is the current total project cost estimate, compared to the original estimate for the CR3 Uprate project?

A. The total current CR3 Uprate project cost estimate, exclusive of Allowance for Funds Used During Construction ("AFUDC") and including fully loaded costs, is $617 million ($556 million is applicable to the CR3 Uprate and included in the NFR schedules in this nuclear cost recovery clause ("NCRC") proceeding). The current CR3 Uprate project cost estimate remains unchanged from last year and is included on Schedule TOR-7 in Exhibit No. ___ (TGF-6) to Mr. Foster's testimony.

As I have explained before, this estimate cannot be directly compared to the original estimate provided in the need determination proceeding because the estimate in the need proceeding reflected the estimated direct project costs and not the full "Financial View" or fully loaded project costs. The original CR3 Uprate project cost estimate inclusive of the indirect costs is $439.3 million as presented in Schedule TOR-7. The total project cost approved through IPP Revision 3 for the CR3 Uprate project was $479.4 million, of which $418.6 million was driven by the CR3 Uprate project. In August 2011, IPP Revision 3A (Short Form) was executed to reflect the total financial view budget estimate of $617 million, an increase of $138 million for the CR3 Uprate project, based on the current EPU phase work schedule for completion of the CR3 Uprate project during the current extended CR3 R16 re-fueling outage. See IPP Interim Approval 3A (Short Form) for the CR3 Uprate project attached as Exhibit No. ___ (JF-2) to my testimony.

Q. How was the current total project cost estimate for the CR3 Uprate project developed?

A. The current CR3 Uprate project cost estimate was developed as part of a rigorous analysis last year of the Uprate project needs and costs. It includes EPU phase construction costs based on an estimate from an independent construction contractor, additional ECs for the EPU work necessary to accomplish the full power uprate that are now 70 percent design complete, and the estimates of our CR3 Uprate project management team consistent with PEF's project management and cost control policies and procedures and the Association for the Advancement of Cost Engineering ("AACE") cost estimation guidelines. The current status of the CR3 Uprate project supports an AACE Class 2 estimate, which is accurate between -15 percent and +20 percent, as reflected in the contingency in the current CR3 Uprate total project cost estimate. The current total CR3 Uprate project cost estimate represents the results of the rigorous cost analysis and review that is required to prepare an IPP revision for management approval. The current

CR3 Uprate project cost estimate therefore represents the best information regarding the CR3 Uprate project costs that is available to the Company.

Q. Why have the CR3 Uprate project costs increased from IPP Revision 3 to the Company's current total project cost estimate reflected in IPP Revision 3A?

A. The CR3 Uprate project costs have primarily increased as a result of an increase in the scope of and assessment of the work necessary to successfully implement the full 180 MWe power uprate in the EPU phase of the project work as the EPU phase work has naturally progressed. The increased work scope required for the power uprate is described in the EC packages for material and equipment modifications to the plant. Some of these ECs represent new work scope, some represent revised work scope, and some represent the separation of work scope into its own EC package. A description of these EC packages is included in Exhibit No. ___ (JF-3) to my testimony. The increased scope of EPU phase work represented by some of these ECs and the further assessment of the EPU phase work as the EPU phase naturally progressed led to increases in the engineering, procurement, construction, and project management costs for the Uprate project with the largest increases in the engineering and construction costs for the project.

Q. What are the reasons for the increased work scope and assessment for the EPU phase of the Uprate project?

A. The main reason for the increased work scope and assessment of the EPU phase of the Uprate project was the natural progression of design, engineering, and construction work for this three-phased project. The most efficient means of performing this work was to focus design and engineering work on each phase of work in the order that the phased work was planned. As a result, the completion of the design and engineering work for the EPU phase naturally followed the completion and implementation of the work for phases one and two of the Uprate project. Consequently, the full scope and assessment of the EPU phase work was not known and could not be known earlier in the project when the design and engineering work was focused on completing phases one and two to timely construct and install the material and equipment in those phases during the first two CR3 re-fueling outages when Uprate project work was performed. While design, engineering, and procurement work commenced for all three phases after the need for the project was approved by the Commission, the emphasis of the design, engineering, procurement, and construction work was on each phase of the work in the order that each phase of the Uprate project work was performed.

Q. Why did the Uprate project plan divide the work into three phases in separate CR3 re-fueling outages?

A. This was the CR3 Uprate project plan. It consisted of three phases of modification and efficiency enhancements to the CR3 plant over the course of three separate CR3 re-fueling outages to ultimately increase the power output of CR3 by 180 MWe to about 1,080 MWe. Because the entire CR3 Uprate project work could not be performed during a single re-fueling outage the project was divided into work phases during distinct, successive CR3 re-fueling outages. This plan took advantage of the period of time that CR3 was off-line for re-fueling and maintenance so PEF did not have to take CR3 off-line to perform the CR3 Uprate work. The three-phased Uprate project work plan in successive CR3 re-fueling outages, therefore, benefitted customers by maximizing the fuel savings benefits to customers.

PEF has successfully implemented the Uprate project plan. PEF completed the first phase during the R15 CR3 re-fueling outage that led to a 12 MWe increase in the CR3 power output commencing in 2008. The second phase was installed during the R16 CR3 re-fueling outage in 2009. The current EPU phase work plan calls for installation of the final phase during the current, extended R16 re-fueling outage. When the EPU phase work is complete and CR3 returns to commercial service, customers will receive the fuel savings benefits from an additional 164 MWe in CR3's power output. Consequently, PEF can still complete the CR3 Uprate project when CR3 is off-line as originally planned to maximize the fuel savings from the power uprate for PEF's customers.

Q. What EPU phase work increased as PEF focused on the EPU phase?

A. The development of more detailed engineering design information for the EPU modifications led to increased costs and the identification of necessary changes to EPU modifications. An example is the replacement of booster feed pumps 1A and 1B and the motors with larger feed pumps and motors to increase the head and flow to support the full power uprate. This modification was always a part of the EPU scope for the Uprate project, see the schedule in Exhibit No. ___ (JF-3) to my testimony, however, as a result of the detailed engineering design work in preparation for the final EPU phase work, PEF determined that complete replacement of the pump assembly, including a new oil skid that the pump and motor will sit on, was a necessary change to meet the technical performance objectives associated with the full power uprate. See EC74527 described in Exhibit No. __ (JF-3) to my testimony.

Additionally, the evaluation of system responses and interactions as PEF progressed with more detailed engineering design work for the EPU modifications required additional or enhanced EC modifications that increased the EPU work scope and cost. An example is the Condensate System Modifications in EC74526 described in Exhibit No. __ (JF-3) to my testimony. These modifications also were always part of the EPU phase, however, the original work scope included variable speed digital control for the condensate pumps. As detailed engineering work modeled the system response and interaction to these modifications at the full power uprate, PEF determined that a change from variable speed digital controls to constant speed direct drive pumps with flow control, recirculation valves, and piping was necessary to support an adequate flow and discharge pressure at full power uprate conditions. See Exhibit No. ___ (JF-3) to my testimony.

Q. Were there other reasons the EPU phase work scope and cost increases?

A. Yes. Another reason for the EPU phase work scope and cost increases were changing NRC regulatory requirements. Compliance with the NRC's evolving requirements for the EPU LAR increased the engineering and licensing costs that PEF has incurred beyond what PEF expected to incur for NRC acceptance review and approval. Evolving NRC regulatory requirements also increased the EPU work scope and costs. The principal example is EC76340, representing over ten percent of the total project cost increase, which is summarized in Exhibit No. ___ (JF-3) to my testimony.

Another reason for the increases in the EPU phase costs is that necessary modifications were identified after the Company had the opportunity to evaluate field inspection data obtained during the shutdown of CR3 during the current outage. During re-fueling outages, when CR3 is completely shut down, the Company conducts extensive inspections of all material and equipment and performs maintenance. Data is collected and evaluated regarding the material condition of equipment during these inspections.

This inspection and evaluation process during the current extended R16 re-fueling outage resulted in the identification of additional, necessary EPU modifications to achieve the power uprate. These EPU modifications were assessed, implementation options were considered, and, once an option was selected, the design and engineering work was performed for the modification. An example is EC73917 for the feed water heat exchangers ("FWHE") 2A and 2B. PEF originally planned to re-rate FWHE 2A and 2B for the EPU phase work, but as a result of the internal inspections and dimensional validations of these pieces of equipment during the current CR3 outage, PEF determined that FWHE 2A and 2B cannot be re-rated and need to be replaced for the plant to achieve power uprate conditions. See EC73917 described in Exhibit No. __ (JF-3) to my testimony.

Another example is EC80138, which describes the work scope increase to replace FWHE 3A and 3B. PEF originally planned to keep FWHE 3A and 3B even though the scoping study indicated they were outside industry operating recommendations because the FWHE 3A and 3B issues could be addressed under a monitoring and inspection plan. During the current outage inspections, PEF discovered that there were a number of degraded and plugged tubes in FWHE 3A and 3B. PEF performed a detailed engineering evaluation of these FWHE at power uprate conditions and determined that FWHE 3A and 3B cannot meet efficiency and performance requirements necessary for full uprate conditions although FWHE 3A and 3B can meet efficiency and performance requirements at current power output conditions. As a result, PEF decided to replace FWHE 3A and 3B. This scope increase change in EC80138 is also described in Exhibit No. ___ (JF-3) to my testimony.

Q. Was all of this additional work scope necessary for the EPU phase of the Uprate project?

A. Yes. All the additional work scope identified in the ECs described in Exhibit No. ___ (JF-3) is necessary for PEF to complete the EPU phase work and achieve the full 180 MWe power uprate. This additional work scope was not added to the EPU phase until the Company had fully vetted the need for the work for the power uprate and determined that it was essential to achieve the technical objectives that must be satisfied in order to implement the full power uprate. However, the scope of work for the EPU phase has not always increased. Since the original scope of the EPU phase work was conceptually identified in the feasibility study for the CR3 Uprate project, work scope also has been refined, re-defined, and eliminated from the EPU phase of the project.

To illustrate this point, three of the ECs described in Exhibit No. ___ (JF-3) were always considered part of the EPU work and were identified as additional work scope simply because they were separated from other EPU work into distinct EC packages as the Company completes the ECs for implementation of the EPU phase. These ECs are the vibration monitoring system (EC76344), the heavy haul path requirements for transporting EPU phase components to storage locations on site (EC76339), and the overall EPU design margin work for common engineering analyses, safety analyses, and engineering calculations not covered by existing EPU modifications or associated LAR documents (EC71193). Other ECs for additional work scope represent revisions to previous EPU work scope. These ECs include the feed water booster pumps and motors (EC74527), the condensate pump, motor, valves and recirculation pipe work (EC74526), and the low pressure injection cross tie and hot leg injection modification (EC73934) described in Exhibit No. ___ (JF-3). The work scope for these ECs simply changed and increased over time. See Exhibit No. ___ (JF-3) to my testimony.

EPU phase work scope has also been eliminated as the detailed engineering analyses for the EPU modifications progressed. Several modifications that were initially included or included at one point in the EPU phase work scope were determined to be unnecessary to achieve the technical objectives that must be met to implement the power uprate. The remaining EPU work scope and cost are needed to achieve the technical objectives necessary to obtain the full 180 MWe power uprate.

V. RULE 25-6.0423(5)(c)5, F.A.C.: LONG-TERM FEASIBILITY OF COMPLETING THE CR3 UPRATE PROJECT.

Q. Did the Company evaluate the feasibility of completing the CR3 Uprate project?

A. Yes. The Company performed both a qualitative and quantitative analysis to determine if the CR3 Uprate project remains feasible. The qualitative analysis of the CR3 Uprate project feasibility included a qualitative review of the technical and regulatory capability of completing the EPU phase work. This qualitative analysis is consistent with the Company's CR3 Uprate project qualitative feasibility analysis that was approved as reasonable by the Commission in Order No. PSC-11-0095-FOF-EI. A CPVRR analysis was performed for the quantitative feasibility analysis. This analysis included updated fuel, load, and carbon costs, and was performed in a manner consistent with the Company's quantitative feasibility analysis for the Levy Nuclear Project ("LNP") and the Company's prior CPVRR analyses for the CR3 Uprate project that were previously reviewed and approved by the Commission in prior NCRC proceedings.

Q. Is completion of the CR3 Uprate technically feasible?

A. Yes. The first two phases of the CR3 Uprate project were successfully completed when all equipment and other modifications were installed in a timely manner with no significant issues. The testing of Phase 2 equipment will be completed once the plant returns to service. There is no reason the EPU phase cannot be successfully completed too. The EPU phase includes the installation or implementation of more than twenty-five (25) ECs, including major components such as the Low Pressure and High Pressure Turbines, significant engineering work, and, under the current work plan, installation of a POD cooling tower. PEF's ongoing technical analysis and reviews confirm that the EPU phase work can be successfully completed and the full power uprate achieved. There are no technical impediments to implementation of the full power uprate. Consequently, PEF is confident the EPU phase work can be successfully completed to achieve the full power uprate and obtain for PEF and its customers the fuel-savings benefits of the full 180 MWe increase when CR3 returns to commercial service.

Q. Is the CR3 Uprate project feasible from a regulatory perspective?

A. Yes. All licenses and permits for the CR3 Uprate project can be obtained. There is no reason to believe that the necessary licenses and permits for the EPU phase work will not be obtained. The EPU phase requires a number of permits and license changes to support operation at the higher power level. These include environmental permitting for the currently proposed cooling tower and an EPU LAR from the NRC. The environmental permit approvals can be obtained well in advance of the implementation of the proposed POD cooling tower should PEF determine that it is still necessary after PEF completes its evaluation of the impact of new and proposed environmental regulations on this work. There is no indication that the necessary permits for the POD cooling tower cannot be obtained. The required environmental permits or permit modifications for the POD cooling tower are similar to previously obtained permits and permit modifications that PEF has successfully obtained. PEF fully expects to receive the necessary environmental permits or permit modifications for the cooling towers if PEF determines that completion of the POD work is necessary for the EPU project.

As I explained earlier, the EPU LAR for the CR3 Uprate project can be obtained from the NRC. The EPU LAR was submitted and accepted by the NRC for review in 2011. The NRC has indicated a review period of approximately two years for the EPU LAR. This licensing review is currently underway. PEF does not anticipate any significant impediments to receipt of the EPU LAR well in advance of implementation of the power uprate. PEF expects that the NRC will approve its EPU LAR for the full power uprate.

Q. What was the result of the Company's economic feasibility analysis of the CR3 Uprate project?

A. The updated, quantitative CPVRR analysis demonstrates that the CR3 Uprate project is economically feasible. There are substantial fuel savings for PEF's customers if the EPU phase of the CR3 Uprate project is completed. The results of this economic analysis are included in Exhibit No. ___ (JF-4) to my testimony.

The Company's economic analysis is based on the current, expected EPU schedule with the commencement of construction in June 2013, the completion of construction in June 2014, and the placement of the EPU in service in December 2014. Under this current EPU phase work plan, the EPU phase work is performed in parallel with the current, planned repair to the CR3 containment building with the planned return of CR3 to commercial service in November 2014. The current EPU phase plan (including current project costs) was evaluated in the updated CPVRR analysis against a project cancellation option assuming no further work on the CR3 Uprate project beyond the work already completed in the first two phases of the project. In the event of project cancellation, the system planning models replaced the additional MWe generation from the power uprate as a result of the EPU phase work with additional, natural-gas fired generation available to the Company. The economic feasibility evaluation further considered the benefits of the EPU phase of the CR3 Uprate project with and without carbon cost benefits as a result of future, potential climate control or greenhouse gas ("GHG") emission legislation or regulation.

As shown in Exhibit No. ___ (JF-4) to my testimony, the CPVRR economic evaluation, the current EPU phase plan is economically beneficial to PEF and its customers based on fuel savings alone. Nominal fuel savings without carbon cost benefits are $1.21 billion and the net present value of the total savings is $361 million. When carbon cost benefits are included in the analysis, the economic benefits of completion of the EPU phase during the current extended CR3 re-fueling outage naturally improves. Nominal fuel savings with carbon cost benefits are $1.26 billion and the net present value of the total savings including carbon costs is $650 million. See Exhibit No. ___ (JF-4) to my testimony.

This economic analysis demonstrates that the EPU phase of the CR3 Uprate project is economically feasible when the costs of the project are compared to the fuel savings benefits on a net present value basis. The updated CPVRR analysis demonstrates that the fuel savings benefits exceed the costs to complete the project on a net present value basis. When the carbon cost compliance estimates are included in the economic analysis, the EPU phase of the CR3 Uprate project is even more beneficial on a net present value basis to PEF and its customers.

Q. Did the Company evaluate any other options in its economic analysis of the feasibility of completing the EPU phase of the CR3 Uprate project?

A. Yes. As I discussed above, the Company evaluated an alternative schedule for completion of the EPU phase of the CR3 Uprate project. Under this alternative schedule, completion of the EPU phase of the CR3 Uprate project is deferred to the next planned CR3 re-fueling outage after the CR3 containment building is repaired and CR3 returns to commercial service. The next CR3 re-fueling outage, R17, will be approximately two years after plant start-up. Completion of the EPU phase of the CR3 Uprate project in the next planned CR3 re-fueling outage is also economically feasible.

As demonstrated in Exhibit No. ___ (JF-4) to my testimony, completion of the EPU phase in the R17 CR3 re-fueling outage is economically beneficial to PEF and its customers. Nominal fuel savings without carbon cost benefits are $1.09 billion and the net present value of the total savings is $260 million. When carbon cost benefits are included in the analysis, the economic benefits to PEF and its customers improve. Nominal fuel savings with carbon cost benefits are $1.14 billion and the net present value of the total savings including carbon costs is $513 million. See Exhibit No. ___ (JF-4) to my testimony. There are substantial economic benefits to PEF and its customers if the EPU phase of the CR3 Uprate project is completed in the CR3 R17 re-fueling outage.

Q. Why did the Company evaluate an alternative schedule for completion of the EPU phase of the CR3 Uprate project?

A. The Company prepared and evaluated an alternative schedule to place the EPU phase work in service because it provides the Company project management flexibility to implement the EPU phase of the CR3 Uprate project. In the event the Company's current plan to repair the CR3 containment building is delayed or unforeseen risks or other impediments require the Company to repair the CR3 containment building prior to or ahead of the commencement of the EPU phase work, the Company has an alternative schedule to implement the EPU phase work in the next planned CR3 re-fueling outage and the Company has determined that the alternative EPU phase schedule is economically beneficial to PEF and its customers.

Q. If completion of the EPU phase in the next planned CR3 re-fueling outage is economically feasible why is the Company's current plan to implement the EPU phase in the current CR3 extended outage?

A. Completion of the EPU phase of the CR3 Uprate project in the current CR3 extended re-fueling outage is more beneficial to PEF and its customers. The current 2012 actual/estimated costs for the EPU phase work are the same if the EPU phase work is completed in this re-fueling outage or in the next re-fueling outage because of pre-existing LLE contractual payment commitments and the current, on-going NRC review of the EPU LAR. The EPU phase costs necessarily increase if the construction work is deferred to the next CR3 re-fueling outage and some of the fuel savings benefits to customers are also lost if the EPU power uprate is not placed in service until the next refueling outage. As a result, the fuel savings benefits are greater and commence earlier for PEF's customers if the EPU phase work is completed in the current re-fueling outage and the EPU power uprate is placed in service in December 2014 as opposed to in the next re-fueling outage. Overall, completion of the EPU phase of the CR3 Uprate project in the current extended CR3 re-fueling outage is more beneficial to PEF's customers. See Exhibit No. __(JF-5) to my testimony providing the EPU project management's evaluation of the costs and benefits of completing the EPU phase of the CR3 Uprate project in the current, extended CR3 re-fueling outage or the next planned CR3 re-fueling outage.

Q. Did the Company update its fuel, environmental emission, and load forecasts in the quantitative analysis of the feasibility of completing the EPU phase of the CR3 Uprate project?

A. Yes. The Company performed its updated CPVRR analysis in the same manner that it performed the CPVRR analysis for the LNP with respect to the fuel, environmental emissions, carbon cost compliance, and load forecast estimates. PEF used updated fuel, environmental, carbon dioxide compliance cost, and load estimates consistent with the updated forecasts used in the LNP quantitative economic analysis in the economic feasibility analysis for the Uprate project. The Company further updated its financial forecasts for the economic feasibility analysis for the EPU phase of the CR3 Uprate project.

Q. Last year, the Commission granted PEF's Motion that deferred to this year's docket the review of the long-term feasibility of completing the CR3 Uprate project. Does that decision affect the Commission's review of the Company's current feasibility analysis?

A. No. The Commission granted PEF's Motion for Deferral because the Company expected to update the feasibility analysis filed with the Company's May testimony in the 2011 NCRC docket. The Company has now updated that analysis. My testimony provides the Commission the Company's updated analysis of the long-term feasibility of completing the CR3 Uprate project. Additionally, as this Commission has previously recognized, feasibility is a forward-looking determination. See Order PSC-11-0547-FOF-EI, Docket No.

110009-EI, 2011 WL 5904236, *23, 30, 54, 78 (Fla. P.S.C. Nov. 23, 2011). The Company's prior feasibility analysis filed in the 2011 NCRC docket, therefore, has no bearing on the Commission's review of PEF's updated analysis of the feasibility of completing the CR3 Uprate project in this proceeding.

VI. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT.

Q. Has the Company implemented any additional project management and cost control oversight mechanisms for the CR3 Uprate project since the testimony you filed on March 1, 2012?

A. The Company has not implemented any additional project management or cost control oversight policies or procedures for the CR3 Uprate since the discussion of these procedures in my March 1, 2012 testimony. The Company continues to utilize the Company policies and procedures described in my March 1, 2012 testimony to ensure that costs for the CR3 Uprate project are reasonably and prudently incurred.

Q. Are these the same policies and procedures that the Commission has previously reviewed for the CR3 Uprate project?

A. Yes. As I explained in my March 1, 2012 testimony, the Commission has previously determined that the CR3 Uprate project management and cost oversight controls were reasonably and prudent. The Company's current CR3 Uprate project management and cost oversight controls policies and procedures are substantially the same as the policies and procedures reviewed and previously determined to be reasonable and prudent by the Commission.

Q. Are these CR3 Uprate project management and cost controls policies and procedures consistent with best practices in the industry?

A. Yes. We believe that our CR3 Uprate project management and cost oversight policies and procedures are consistent with best practices for capital project management in the industry. PEF has employed these project management policies and procedures to successfully implement two phases of the CR3 Uprate project, during two separate plant re-fueling outages, and completed the work scope necessary for the first two phases of the CR3 Uprate project. We believe the project management, contracting, and cost control policies and procedures that we have implemented for the CR3 Uprate project are reasonable and prudent and consistent with industry best practices.

VII. CONCLUSION.

Q. Is completion of the EPU phase of the CR3 Uprate project in the best interests of the Company and its customers?

A. Yes, we continue to believe that completion of the EPU phase of the CR3 Uprate project is in the Company's and customers' best interests. Our updated analysis of the feasibility of completing the EPU phase demonstrates that the EPU phase of the project remains feasible and that it will be economically beneficial to PEF and its customers whether it is completed as currently planned in the current CR3 re-fueling outage or in the next CR3 planned re-fueling outage. The completion of the EPU phase of the CR3 Uprate project will provide PEF and its customers additional carbon-free, clean nuclear energy generation from the lowest cost fuel source available to the Company, it will add to the Company's fuel diversity, and it reduces the Company's reliance on fossil fuels, especially from foreign sources, for energy generation. Implementation of the EPU phase of the CR3 Uprate project remains an important element of Progress Energy's Balanced Solution. As a result, the Company is committed at this time to completion of the EPU phase of the CR3 Uprate project.

Q. Does this conclude your testimony?

A. Yes, it does.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

November 21, 2011

Mr. Jon A. Franke, Vice President
Crystal River Nuclear Plant (NA2C)
ATTN: Supervisor, Licensing & Regulatory Programs
15760 W. Power Line Street
Crystal River, Florida 34428-6708

SUBJECT: CRYSTAL RIVER UNIT 3 NUCLEAR GENERATING PLANT – ACCEPTANCE REVIEW OF LICENSE AMENDMENT REQUEST FOR EXTENDED POWER UPRATE (TAC NO. ME 6527)

Dear Mr. Franke:

By letter dated June 15, 2011, as supplemented by letters dated July 5, 2011, August 11 (2 letters), August 18 and 25, 2011, and October 11 and 25, 2011, Florida Power Corporation (the licensee or FPC), doing business as Progress Energy Florida, Inc., submitted a license amendment request for an extended power uprate (EPU) to increase thermal power level from 2609 megawatts (MWt) to 3014 MWt for Crystal River Unit 3 Nuclear Generating Plant (Crystal River, Unit 3). The purpose of this letter is to provide the results of the U.S. Nuclear Regulatory Commission (NRC) staff's acceptance review of this amendment request. The acceptance review was performed to determine if there was sufficient technical information in scope and depth to allow the NRC staff to complete its detailed technical review. The acceptance review is also intended to identify whether the application has any readily apparent information insufficiencies in its characterization of the regulatory requirements or the licensing basis of the plant.

Consistent with Section 50.90 of Title 10 of the *Code of Federal Regulations* (10 CFR), an amendment to the license (including the technical specifications) must fully describe the changes requested, and following as far as applicable, the form prescribed for original applications. Section 50.34 of 10 CFR addresses the content of technical information required. This section stipulates that the submittal address the design and operating characteristics, unusual or novel design features, and principal safety considerations.

The NRC staff has reviewed your application dated June 15, 2011, and requested additional information (RAI) required to continue the acceptance review. You provided the responses to these RAIs by supplemental letters dated July 5, 2011, 2 letters dated August 11, 2011, August 18, and 25, 2011, and October 11 and 25, 2011. In your letter dated October 11, 2011, you committed to provide NRC by November 11, 2011, a summary of a feedwater line break overpressure protection analysis including key analysis input assumptions and reactor coolant system pressure results, which the NRC staff had indicated was required for its detailed review. This information was provided in your letter dated October 25, 2011.

The NRC staff has reviewed your application and concluded that it provides sufficient technical information to enable the NRC staff to initiate its detailed technical review and make an independent assessment regarding the acceptability of the proposed amendment in terms of regulatory requirements and the protection of public health and safety and the environment.

Given the lesser scope and depth of the acceptance review as compared to the detailed technical review, there may be instances in which issues that impact the NRC staff's ability to complete the detailed technical review are identified despite completion of an adequate acceptance review. You will be advised of any further information needed to support the NRC staff's detailed technical review by separate correspondence.

The typical EPU review duration goal is 1 year after NRC acceptance of the application. However, review of the Crystal River, Unit 3 EPU will require additional time based on the following:

- This is a first-of-a-kind application for a Babcock and Wilcox nuclear steam supply system plant.
- The application includes crediting a new safety-related fast cooldown system to assist the emergency core cooling system during a small-break loss-of-coolant accident, which requires substantial review by the NRC staff.

Therefore, the NRC staff anticipates it will require more than 1 year, and possibly up to 2 years, from the date of this letter to complete its review.

In addition to the above, you indicated in your October 25, 2011, letter that the EPU implementation will occur following completion of Crystal River, Unit 3 containment repair activities, and you are still developing the repair plan. Given these schedule uncertainties, the NRC staff may defer portions of our review activities until we have a better understanding of your plan to repair the containment. Once you finalize the containment repair plan and provide a more definitive implementation schedule, we will update our overall review schedule accordingly.

If you have any questions regarding this matter, I may be reached at 301-415-1564.

Sincerely,

Siva P. Lingam

Siva P. Lingam, Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-302

cc: Listserv

Given the lesser scope and depth of the acceptance review as compared to the detailed technical review, there may be instances in which issues that impact the NRC staff's ability to complete the detailed technical review are identified despite completion of an adequate acceptance review. You will be advised of any further information needed to support the NRC staff's detailed technical review by separate correspondence.

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Sincerely,

/RA/

Siva P. Lingam, Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-302

cc: Listserv

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DATE	11/9/11	11/16/11	11/15/11	11/18/11	11/21/11

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Crystal River 3 Extended Power Uprate EPU

Integrated Project Plan (IPP)

Financial Analysis Control Number: Interim Approval 3A

Please Note: **This document contains confidential transmission information and is subject to Progress Energy's Standards of Conduct Procedure, #REG-SUBS-00002. Please do not distribute to Fuels & Power Optimization or Efficiency and Innovative Technology groups.**

Sponsoring Business Unit:	Nuclear Upgrades
Funding Legal Entity:	PEF
Date Prepared:	08/09/2011

Key Project Contacts		
Role, Department / Group	**Name**	**Phone No.**
EPU - Project Sponsor CR3 Site Vice President	Jon Franke	240-3605
EPU – Project Manager Manager, Major Projects	Paul Ingersoll	240-4800

Plan Revision Control

Rev No.	Primary Author(s)	Revision Description	Rev Date
0	Ted Williams	Initial Publication	03/18/08
1	Steve Huntington	Update	03/03/09
2	Ed Avella	Scope Change related to 17R	10/12/09
3	Ed Avella	Milestone Change for In-Service Date	05/27/10
3A	Paul Ingersoll	Interim Approval to Continue Until December 2011 Scheduled Revision	08/29/11

Request for Approval

Purpose:
- ○ Gate 0 - Initiate Project
- ○ Gate 1 - Go Commit
- ◉ Gate 2 - Go Build / Baseline
- ○ Revision

Authorization to make new commitments up to $5 million *

Authorization to spend additional funds up to $ 0million * Continue authorization for previously approved spend

Estimated total project cost $617 million to $650 million*.

Next approval gate expected in: November or December 2011 . Expected in-service date: 16 R

Notes or Exceptions:

* Full Financial View, including AFUDC, Net of Joint Owner

Approval Required

This IPP requires approval by the: Senior Management Committee

Approvals

The parties signing below indicate by their signature that they, or the body they represent below, have reviewed the IPP and either recommend approval of or approve the above Request for Approval.

Action	Name [Type / Print]	Reviewing Position	Signature	Date
Recommend Approval	Paul Ingersoll	Project Manager		
Recommend Approval	Jon Franke	Project Sponsor		
Recommend Approval	Jim Holt	Department Head	J Holt	8/29/11
Recommend Approval	Terry Hobbs	Department Head		
Recommend Approval	Peter Toomey	Legal Entity Finance VP		
Senior Management Committee Approval				
Approve	Bill Johnson	Chairman, President & CEO		
Approve	Mark Mulhern	Chief Financial Officer	Mark Mulhern	8/29/11
Approve	Vincent Dolan	President & CEO – PGN Florida		
Approve	John McArthur	Exec VP–Admin & Corp Relations	John McArthur	8/29/11
Approve	Jeff Corbett	Sr. VP Energy Delivery - Carolinas		

Approve	Jim Scarola	Sr. VP & Chief Nuclear Officer	J. Scarola	8/24/11
Approve	Paula Sims	Sr. VP – Corp Dev and Improvement		
Approve	Lloyd Yates	President & CEO – PGN Carolinas		
Approve	Michael Lewis	Sr. VP – Energy Delivery FL		

[IPP SHORT FORM] August 10, 2011

Request for Approval

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Recommend Approval	Jim Holt	Department Head		
Recommend Approval	Terry Hobbs	Department Head		
Recommend Approval	Peter Toomey	Legal Entity Finance VP	Peter C. Toomey	8/27/11
Senior Management Committee Approval				
Approve	Bill Johnson	Chairman, President & CEO		
Approve	Mark Mulhern	Chief Financial Officer		
Approve	Vincent Dolan	President & CEO – PGN Florida	Vincent Dolan	8/29/11
Approve	John McArthur	Exec VP–Admin & Corp Relations		
Approve	Jeff Corbett	Sr. VP Energy Delivery - Carolinas		

12PMA-DR1CR3-7-000005

Approve	Jim Scarola	Sr. VP & Chief Nuclear Officer		
Approve	Paula Sims	Sr. VP – Corp Dev and Improvement		
Approve	Lloyd Yates	President & CEO – PGN Carolinas		
Approve	Michael Lewis	Sr. VP – Energy Delivery FL	Michael Lewis	8/29/11

Brief Summary

Policy

This short form IPP is submitted to SMC for approval under the following policy:

ADM-SUBS-00080 Progress Energy Project Governance Policy
In rare circumstances where a major event has significantly impacted the Project and an expedited SMC approval is required, at a minimum, the IPP "Request for Approval" page from the template and a brief summary may be submitted in lieu of a full IPP.

Introduction

IPP Revision 3 (May 2010) authorizes a total financial view budget of $479M and reflects a completion of the EPU project in CR3 Refuel Outage 17R (Spring 2012).

Currently a total financial view budget requirement of $617M has been estimated. The $138M increase addresses an increase in the number and complexity of final phase modifications required and includes a preliminary construction estimate received in November 2010. The $617M is reflected in the May 2011 FPSC filing and the August 2011 budget upload.

Note: The project actual cost to date and the projected 2011 and 2012 budgets are still within the IPP Revision 3 authorized budget of $479M.

The extended 16R outage required to repair the containment structure has the potential to impact the implementation schedule of this final EPU stage. During the next few months as the containment repair project progresses, the containment repair engineering and schedule will be better understood. As a result the impact on EPU can be better understood and a full IPP revision can be submitted.

Purpose

This IPP Revision 3A (short form) is meant to accomplish two goals.

First is to formally communicate to the entire SMC a total financial view budget estimate of $617M, an increase of $138M, as reflected in PEF's May 2011 FPSC filing.

Second is to authorize work required to maintain the option of executing the remaining EPU work during the extended 16R outage, until more information is available concerning the schedule and engineering associated with containment repair. A milestone will be established for SMC review prior to moving forward with the construction of the final phase of EPU once this information is available. It is expected that the decision whether to proceed with construction will occur early in 2012.

Request

Interim SMC approval is sought for:

- Continuation of Engineering Activities
- Continuation of License Amendment Request (LAR) Activities
- Continuation of Work Order Planning Activities
- Continuation of Procurement Activities for long lead time equipment currently under contract
- Re-negotiation of Siemens Turbine Contract to secure an installation time slot (to include an exit clause)
- Release AREVA Contract Change Order (CO) to update the Technical Basis Document (TBD) for the Emergency Operating Procedures (EOPs)

Next Steps

- Develop IPP Revision 4 with a schedule and budget that reflects completion of the final phase of EPU during the extended 16R.
- Submit IPP Revision 4 to SMC for Approval 4Q2011
- SMC Release to Construct 1Q2012

Engineering Change (EC) Scope Change Description

1. EC76341 - LPT Supervisory Equipment
   The EC adds monitoring equipment to the new Siemens 18m^2 Low Pressure Turbines (LPT) for early warning of excessive last stage blade root stresses that could cause blade failure. This was identified as part of industry Operating Experience (OE) lessons learned from the DC Cook event in September 2008 and was part of contract negotiations with Siemens completed in the 3rd quarter of 2010 for reconciliation of contract delays due to the industry event and rotor disc slippage identified during bunker testing in the 2nd quarter of 2009.

   The new LPTs are necessary to meet EPU conditions. The monitoring is required to promptly identify any blade degradation and thus prevent any catastrophic failure of the last stage blading. Installation of this equipment also provides for continuous monitoring and an alarming function to allow operations to respond promptly to potentially abnormal conditions.

2. EC74527 – MFP-1A/1B Booster Feed Pump/Motor
   The EC replaces Booster Feed Pumps 1A/1B and Motors. The booster feed pumps require increase head and flow to support EPU conditions. The complete replacement of the booster feed pumps has been in scope. The scope was categorized as an impeller and motor change out in the previous IPP but now includes the complete replacement of the pump assembly, motor and a new oil skid.

3. EC 74526 – Condensate System Modifications
   The EC revises the planned change of Condensate Pump control from variable speed digital control to constant speed direct drive pumps with flow control, recirculation valves, and piping to ensure adequate flow and discharge pressure at EPU conditions. The original scope included a variable frequency drive digital control system. The scope was revised to provide a direct drive pump with control valve regulation for flow control. The change was based on Engineering input, industry and internal OE. This was identified in the fall of 2009 as part of stake holder review meetings and therefore design details were evaluated and approved per the ICF process.

4. EC73934 – LPI Cross Tie and Hot Leg Injection
   The EC added a Low Pressure Injection (LPI) Cross-Tie line. The LPI Cross Tie was part of the original scope to mitigate Core Flood Line break peak clad temperatures. The Hot Leg Injection line was added to the scope to provide a safety related means to mitigate post accident boron precipitation fuel channel flow blockage. The original scope for the hot leg injection line included passive open isolation valves. However, based on thermal hydraulic analysis and assuming worst case pump degradation, these lines cannot remain open at the onset of an accident. This requires safety related Motor Operated Valves (MOVs), control circuitry, and Main Control Board (MCB) switches.

This was identified as part of stakeholder review and a thermal hydraulic analysis. Thereafter design details were evaluated and approved per the ICF process.

With installation of the MOVs, control circuitry, and hot leg injection lines, an existing safety related exemption is removed, post boron precipitation fuel flow channel blockage is averted, and any other GSI 191 concerns for flow blockage due to precipitation of other chemical material in flow channels can be mitigated. This design strengthens the regulatory position for EPU acceptance based on post accident decay heat removal, lower fuel clad temperatures, and long term core cooling ability in accordance with 10CFR50.46 criterion.

5. EC70732 – Emergency Feedwater System Upgrades

The EC adds safety related recirculation lines and valves for additional Emergency Feedwater (EFW) at a flow rate of 660 GPM in a maximum of 40 seconds after actuation. Without this additional EFW flow, the EPU accident analysis cannot be met.

The increased flow rate was identified in the original study. The original plan was to remove cavitating venturies which was later changed to replacement of the Emergency Feedwater Pump 2 (EFP-2) due to degraded pump performance, instrument uncertainties, and single failure criteria. Further evaluation determined acceptable performance capabilities from EFP-2 and provided an alternate means for single failure criterion acceptance by installing safety related recirculation lines and valves. The valves were designed to close based on flow requirements, thus providing more flow to the OTSGs. This configuration also eliminated the need to remove the cavitating venturies or replace EFP-2. PEF elected to perform this modification in-house, the scope was modified and AREVA project credit provided for the scope changes.

The installation of recirculation lines eliminated EFP-2 replacement, allowed the cavitating venturies to remain in place to mitigate pump run out and water hammer concerns, and eliminated reliance on downstream flow controllers which, if failed, would impact the PSA analysis and possibly increase the Core Damage Frequency.

6. EC78021 – Main Feedwater Pump Modifications

As part of the original feasibility study for the Feedwater Heaters, it was determined that the Main Feed Pumps did not need to be replaced. However, it was recommended that the feed water pump impellers be replaced in order to provide adequate flow and head and retain the same operating margin with respect to total flow capability. During bid evaluations in 2010 for new feed water impellers, it was determined that the cost of three new impellers plus a pump casing to perform factory testing was comparable to complete pump replacement. The MFW pump turbines will be evaluated by the OEM to accommodate the increased demand under EPU conditions.

As part of the pump specification development, it was discovered that the retained flow margin originally envisioned could not be achieved based on system pressure limitations. A Kepner Tregoe (KT) Analysis (a step-by-step approach for systematically solving problems, making decisions, and analyzing potential risks) was performed to determine the best option to address the issue. The result of the analysis indicated that the best option was to replace the existing pumps, increase their speed to provide adequate flow and head, and to install system over pressure protection for the following reasons:

- Existing MFP-2A/B have unknown discovery issues with respect to alignment, casing degradation, increased degradation at higher flows and speed, and increased preventative maintenance requirements.
- The existing recirculation lines can be retained without requiring additional recirculation lines.
- Using like-for-like original OEM equipment has less configuration, procedures, and training impact.

Therefore, based on a review and recommendation from EPU Projects and station stakeholders, it was recommended that CR3 install new Main Feed Pumps (MFP-2A/B), with new rotating assemblies with the same current recirculation design requirements, increase the pump design and operating speed, and install system over pressure protection.

7. EC74873 – Safety Related MOVs
The EC adds Safety Related MOVs for the LPI Cross Tie and the Feedwater Pump Booster Pump modification. The Chapter 14 FSAR Accident Analysis requires that the reactor remain in a shutdown condition following a reactor trip. The overcooling associated with a MSLB or MFWLB can cause a reactor restart if overcooling is not controlled or boron concentration is not increased.

As part of the EPU fuel design studies, it was determined that the Shutdown Margin should increase and the MFW isolation valves should close quicker to mitigate this accident condition. As discussed for the LPI Cross Tie system, two new Safety Related MOVs for Boron Precipitation Hot Leg Injection were added to isolate the line in order to credit flow to the LPI Cross Tie during accident scenarios.

These (4) MOVs were specified in the same Engineering Change Specification used for bid proposals. These valves will be installed under their respective System Engineering Change package for the Booster Feed Pump and the LPI Cross Tie.

8. EC75659 – Makeup Tank (MU-1) Bypass Line
The EC adds a MU Injection Line Bypass line around the Makeup Tank. The bypass line will allow faster operator response to maintain power distribution within acceptable limits during transients. Based on EPU fuel design analysis performed in the 1st quarter of 2008, it was identified that operational limits for reactor power imbalance control was being constrained from approximately 30% to 12%. A review of operational history

showed that this new operational limit could challenge reactor power transient control and Reactor Protection System trip setpoints. Based on input from NED Fuels Engineering, Station Reactor Engineering, and Operations, it was determined that a more responsive reactivity addition system was required. The existing system adds boric acid and/or water to a holdup tank (MUT-1) which has a residence response time of approximate 45 minutes before a reactivity change is seen. This residence time would be too slow to prevent a reactor trip for some transient imbalance swings. The addition of boric acid or water directly to the suction of the makeup pumps would provide real time immediate reactivity response to an imbalance power transient.

At EPU conditions in order for the operator to control fuel design limits, reactor protection set points, and core axial power shape with rod control, it is required to inject either boron or water directly into the MU pump suction line to provide a more immediate reactivity response.

9. <u>EC73917 – FWHE-2A/2B Replacement</u>
The EC replaces FWHE-2A/2B. The original concept was to rerate FWHE-2A/B. This required internal inspections and dimensional validations of internal components which determined that the heat exchangers could not be rerated and would need to be replaced. The replacement heaters will meet EPU HEI recommended design limits and booster feed pump discharge pressure shut off head requirements.

10. <u>EC76095 – Safety Related MS Supports and Whip Restraints</u>
<u>EC76097 – Non Safety Related Main Steam Supports and Whip Restraints</u>
The ECs add Main Steam Supports and Whip Restraints. The Main Steam line structural analysis for Turbine Stop Valve closure at EPU conditions was required as part of the EPU LAR recovery efforts. Based on the completed analysis, many hangers and supports were required to be modified to meet EPU conditions. Further analysis and review reduced the number of supports required to be modified for both Safety and Non Safety Structural supports. The original intent was to develop one EC for both Safety and Non Safety supports, however since the requirements are different for safety and non safety modifications as well as different associated paperwork, it was determined to have separate ECs.

11. <u>EC80138 – FWHE-3A/3B Feedwater Heater Replacement</u>
FWHE-3A/3B were evaluated in the original scoping study. The results of that study indicated that FWHE-3A/B would be outside industry recommendations for Terminal Temperature Difference (TTD) and pressure drop. However, that was considered acceptable with the establishment of a monitoring plan and a base line inspection. The 16R inspections determined that the 'as found' number of degraded and plugged tubes would not meet efficiency and performance requirements necessary for EPU conditions. Based on these results, it was determined to add scope to replace the High Pressure Feed Water Heat Exchangers FWHE-3A/B heaters with increased operational margin and efficiency.

12. EC76344 – Vibration Monitoring System

This modification was always considered part of the EPU scope, No additional funding is required as this was factored into the existing budget.

The EC adds a Pipe Vibration Monitoring System for flow induced vibration. The NRC has been requiring vibration analysis of affected systems, as part of industry OE, for previous EPU submittals due to some steam dryers eroding and internal components vibrating loose. This program, monitoring system, and before and after data sampling, will provide assurance to the regulators that vibration will not inadvertently damage any components due to increase flow and pressures within the NSSS or BOP systems.

13. EC76340, etc – Inadequate Core Cooling Mitigation (ICCM) Instrumentation

The following provides a detailed explanation of the decision concerning the Fast Cooldown System and Inadequate Core Cooling Mitigation (ICCM) System.

The Atmospheric Dump Valve (ADV) Conceptual Design Study identified the need to increase the ADV sizing (to meet Appendix R requirements) and reclassify them as Safety Related components (to allow credit in the safety analysis). At that time, only one ADV was required (activated from a switch on the MCB) to open to allow complete depressurization of the SG. This was the initial conceptual design. Subsequent reviews identified concerns with a complete blow down. Only one train would cause the Emergency Feedwater Initiation and Control (EFIC) System to actuate and isolate the system terminating its blow down function.

A complete blow down would likely cause unacceptable shell to tube compressive loads on the SGs due to high temperature differences between the SG shell and shroud. Based on these concerns; it was decided to include a set point to limit the depressurization of the SG during a blowdown. Also, it was recommended to use the same push buttons the operators currently use to increase SG level in response to a loss of subcooling margin. This allowed taking credit for a previously identified operator action. No new operator actions were identified. A concern with SG design due to a SG Tube Wetting issue at the 15th tube support plate was also raised. The SG Tube Wetting issue assumed cooling capability, post-SBLOCA, was only approximately 65% of what had been previously available. In addition, a necessary adjustment in the assumed power profile proposed by AREVA for all PWR Power Plants was identified by AREVA while performing engineering analysis for the Fast Cooldown System. The adjustment resulted in another increase in required heat removal capability. Thus, it was determined that both ADVs would be required for mitigation with the set point established at 325 psig. It was also recognized that the MCB control switch would need to be separate and isolated, which introduced a new operator action to diagnose and manually actuate the Fast Cooldown System. The use of the existing Safety Parameter Display System (SPDS), and monitors were determined to be the best use of existing equipment and operator familiarity.

It was confirmed that the existing SPDS system was vulnerable to a complete system shutdown on the loss of related system function/down power. It was determined that a separate monitoring system was required that would meet all requirements for indication and actuation. This design still relied upon operator action for diagnosis and action.

Concurrently, it was determined to add HPI flow as a criterion for actuation of the FCS, i.e., if HPI flow is adequate, the FCS does not need to actuate and it was not always required for other events that were not SBLOCA related. It was not always desirable based on cool down rates, offsite dose release, and unnecessary exacerbation of transient conditions.

The NRC was briefed on the design, operator actions, and desired licensing schedule to accommodate the EPU and a possible digital modification for operator indication. The NRC suggested that the plant consider automating the FCS operator actions and, by inference, other similar operator actions. While the focus of the EPU LAR would be on FCS, the other actions continue to be relied upon and were likely to be difficult to sustain with the NRC. Further, it reduces operator burden and enhances plant safety to eliminate such actions. Following a briefing with the station management sponsor, it was recommended to automate three operator actions - Reactor Coolant Pump (RCP) trip, raise Steam Generator Emergency Feedwater Initiation and Control (EFIC) level set point for Loss of Sub-Cooling Margin (LSCM), and actuate the Fast Cooldown System (FCS) system with concurrent indication of inadequate High Pressure Injection flow. Including the other actions does not make the system design significantly more complicated or costly.

A presentation to NGG Senior Management was conducted and provided current status, decision making history, regulator interface and LAR schedule submittal information. Based on this meeting, a Kemper Tregoe (KT) analysis of all available options to mitigate SBLOCAs at EPU conditions was performed. This KT analysis was presented to the Senior Management Committee (SMC) with the recommendation to continue with the pursuit of the digital modification and automated operator actions. The development for the FCS modification specification in accordance with NRC DI&C-ISG-0006 also provided the technical basis to support a request for proposal. RFPs were requested including the potential for analog (non-digital) options. Bids were received in January 2011 and although Digital and Analog options were evaluated, the Analog option was selected as the platform for the EC.

14. <u>EC75004 – Qualification and Preparation of ROTSG for EPU</u>

The Replacement Once-Through Steam Generators (ROTSGs) were purchased and installed as a separate project to EPU. They were designed and certified at 2568 MWth. As part of the MUR uprate it was verified that the ROTSG s are qualified at 2609 MWth. To meet EPU conditions, the ROTSGs need to be recertified at 3014 MWth plus Reactor Coolant Pump heat for a total of 3030 MWth.

Based on the Fast Cooldown System (FCS) design change and the impact of Cooldown rates on the ROTSG, B&W Canada (BWC) has been contracted to validate design and operational limits. The overall reconciliation and validation of operational and accident analysis and margins will be documented in an Engineering Change package for configuration control.

15. <u>EC76339 – 17R Heavy Haul Path</u>
This modification was always considered part of the EPU scope. No additional funding is required as this was factored into the existing budget.

The EC provides heavy haul path requirements for transporting EPU components across roadways, berms, grating, and to storage locations in the turbine building. The heavy load drop analysis performed for 16R will serve as a starting point for this EC.

16. <u>EC77901 – Feedwater Heater 2A/2B Removal Path</u>
The EC provides a load path for removal and installation of the new FWHE-2A/B and any other reinforcing structural supports to accommodate the increased size and weight of the heaters.

A path for removal of the FWHE-2A/2B and installation of new equipment is required because several internal interferences, e.g., stairwells, auxiliary steam header and piping, structural supports, and flood barrier wall, will need to be removed. Since the new heat exchangers foot print is slightly different and their weight is heavier, a new structural analysis is required to be conducted and a new support installed. This will be performed as a separate EC. One alternative that is being evaluated is to replace the FWHE-3A/B using the same load path with less interference removal for move in move out logistics. The replacement of FWHE 3A/B is being evaluated as part of the overall system requirements for feed water to address system over pressure and overall operational and design margins.

17. <u>EC71193 – Overall Design Margin</u>
This modification was always considered part of the EPU scope. No additional funding is required as this EC was factored into the existing budget.

The Overall Design Margin EC will be performed using in-house resources. The overall EC establishes the acceptability to uprate the facility to the new power level based on margins and analyses that are the foundation and define the required modifications. The EC will be the repository for analytical supporting documentation and calculations that are part of the license bases as well as accident analysis that are not required to mechanically install the components. The overall EC will evaluate aggregate impact of all individual ECs implemented for EPU.

The EC is the repository for all EPU Phase II common analyses, safety analysis calculations not covered by existing modifications or associated License Amendment Report (LAR) documents, and includes acceptability of design and operating margins for power operation at 3014MWth.

18. EC75814 – New Core Load

This EC documents the Crystal River 3 Cycle 18 reload design. These activities include, but are not limited to, verification of nuclear and mechanical characteristics with respect to the plant licensing bases, vendor surveillance activities including owner reviews of vendor documents, and generation of design data required to support Cycle 18 and EPU operations. Emphasis is placed on ensuring that all functional requirements, performance requirements and design inputs described in EC Section B.4, Design Inputs, are met. Information is also provided to support low power startup physics testing and Cycle 18 full power operation.

The safety analysis for Cycle 18 interface with design changes introduced by the replacement of the Once Through Steam Generators (OTSG) in Refueling Outage 16 (RF16) and other equipment upgrades implemented in RF16 for the Extended Power Uprate (EPU) project.

19. EC79352 – High Pressure Injection Modification

The EC modifies the HPI throttle valves position from throttled to full open to allow margin between the HPI(MU) pump operating curve and FCS (Fast Cooldown System) actuation curve at EPU conditions (3014 MWt). Current scope is to increase the Cv of the four (4) HPI valves. These valves are passive components during normal and accident plant operation. The purpose of the modification is to allow more flow to the core at EPU conditions.

20. EC 84511 Reactor Coolant System Blow Down Line Modification

This modification was determined necessary and required as part of boron precipitation mitigation strategy. For certain Small Break Loss Of Coolant accidents, SBLOCA, RCS pressure remains above the Low Pressure Injection pumps, but low enough to reduce saturation temperature and increase clad temperatures due to lack of sufficient flow from the High pressure injection pumps for the EPU Decay Heat level. A Kempner Trego , KT, analysis was performed evaluating several options, including do nothing option which would result in regulatory risk. The final decision and Integrated Change Process was utilized to include the ability to lower RCS pressure through two safety related blow down lines which include an additional four MOVs and controls to be tied into the RCS LPI cross tie and Hot Leg Injection Line.

21. EC 85409 Aux Transformer Electrical Bus Modification

As part of ongoing station review of electrical calculations, it was determined that analysis for EPU relied upon calculations that required modified input assumptions. Although the Electrical Bus is still acceptable for the existing station requirements, it will not EPU support loads due to the increase demand for the BOP pumps and motors being installed as part of the up rate. A modification is being developed to replace approximately 200 feet of electrical bus bars to provide the additional short circuit rating required for the new short circuit analysis.

SCOPE CHANGE SUMMARY

PHASE 2 SCOPE (16R)						
Replace	(2) Low Pressure Turbines (LPT)	(2) Low Pressure Turbines (LPT)				
Replace	Generator Stator Windings/Core Iron	Generator Stator Windings/Core Iron	Generator Stator Windings/Core Iron	Generator Stator Windings/Core Iron	EC 69197 - Generator Stator/Core - Field COMPLETE	
Replace	Generator Rotor	Generator Rotor	Generator Rotor	Generator Rotor	EC 69197 - Generator Rotor - Field COMPLETE	
Replace	Generator Exciter	Generator Exciter	Generator Exciter	Generator Exciter	EC 69197 - Generator Exciter - Field COMPLETE	
Replace	(2) Turbine Lubricating Oil Cooler Tube Bundles	(2) Turbine Lubricating Oil Cooler Tube Bundles	(2) Turbine Lubricating Oil Cooler Tube Bundles	(2) Turbine Lubricating Oil Cooler Tube Bundles	EC 69197 - TBHE 7A/7B - Field COMPLETE	
Replace	(4) Moisture Separator Reheaters (MSR)	(4) Moisture Separator Reheaters (MSR)	(4) Moisture Separator Reheaters (MSR)	(4) Moisture Separator Reheaters (MSR)	EC 69196 - MSR 3A/3B/3C/3D - Field COMPLETE	
Replace	(2) Condensate Heat Exchangers (CDHE)	(2) Condensate Heat Exchangers (CDHE)	(2) Condensate Heat Exchangers (CDHE)	(2) Condensate Heat Exchangers (CDHE)	EC 68964 - CDHE 3A/3B - Field COMPLETE	
Replace	(8) Heater Drain (HD)Valves/Piping	(8) Heater Drain (HD)Valves/Piping	(8) Heater Drain (HD)Valves/Piping	(8) Heater Drain (HD)Valves/Piping	EC 69172/EC69026 - HD Valves/Pipe - Field COMPLETE	
Replace	(2) Secondary Cooling (SC) Heat Exchangers	(2) Secondary Cooling (SC) Heat Exchangers	(2) Secondary Cooling (SC) Heat Exchangers	(2) Secondary Cooling (SC) Heat Exchangers	EC 68925 - SCHE 1A/1B - Field COMPLETE	
Replace	(2) SC Pump Impellers/Motors	(2) SC Pump Impellers/Motors	(2) SC Pump Impellers/Motors	(2) SC Pump Impellers/Motors	EC 69088 - SCP 1A/1B and Bypass Line - Field COMPLETE	
Add	(2) MSR "Shell Drain" Heat Exchangers	(2) MSR "Shell Drain" Heat Exchangers	(2) MSR "Shell Drain" Heat Exchangers	(2) MSR "Shell Drain" Heat Exchangers	EC 68888 - CDHE 7A/7B - Field COMPLETE	
Replace	Isophase Bus Duct (IBD) Cooler/Fan	Isophase Bus Duct (IBD) Cooler/Fan	Isophase Bus Duct (IBD) Cooler/Fan	Isophase Bus Duct (IBD) Cooler/Fan	EC 68890 - TBF 1 - Field COMPLETE	
Modify	Integrated Control System (ICS)	Integrated Control System (ICS)	Integrated Control System (ICS)	Integrated Control System (ICS)	Integrated Control System (ICS) Field COMPLETE	
New				Turbine Bldg Fiber Optic Backbone	EC 71057 - Turbine Bldg Fiber Optic Backbone - Field COMPLETE	
Modify	Plant Process Computer (PPCS)	Plant Process Computer (PPCS)	Plant Process Computer (PPCS)	Plant Process Computer (PPCS)	Plant Process Computer (PPCS) - Field COMPLETE	
Replace		(4) Turbine Bypass Valves and Mufflers	(4) Turbine Bypass Valves and Mufflers	(4) Turbine Bypass Valves and Mufflers	EC 71757 - TBVs/Piping/Mufflers - Field COMPLETE	
Add					EC 71191 - Turbine Bldg Temporary Power - Field COMPLETE	
Evaluate/Modify					EC 70657 - 16R Heavy Haul Path - Field COMPLETE	
PHASE 3 SCOPE (17R)						
Replace			(2) Low Pressure Turbines (LPT)	(2) Low Pressure Turbines (LPT)	EC 73794 - (2) LPTs	1
Modify					EC 76341 - LPT Supervisory Equipment	
Replace	High Pressure Turbine (HPT)	High Pressure Turbine (HPT)	High Pressure Turbine (HPT)	High Pressure Turbine (HPT)	EC 74980 - HPT	
Modify	ICS and Safety System	ICS and Safety System	ICS and Safety System	ICS and Safety System	EC 71369 - ICS 0 - 1200 Mwe	
Add	Condenser Steam Impingement Baffle Plate					
Add/Replace	De-aerator Bypass Line	De-aerator Bypass Line or New De-aerator	De-aerator Bypass Line or New De-aerator	De-aerator Bypass Line	EC 68886 - FWHE 1 (FW De-aerator Bypass Line)	
Replace	(2) Atmospheric Dump Valves	(2) Atmospheric Dump Valves	(2) Atmospheric Dump Valves	(2) Atmospheric Dump Valves	EC 73907 - MSV 25/26 (MS Atmospheric Dump Valves)	
Modify	(2) Main Steam Valves					
Replace	(2) Pressurizer Relief Valves					
Replace	(4) Circulating Water (CW) Pump Impellers/Motors					
Replace	(2) Booster Feedwater (FW) Impellers/Motors	(2) Booster Feedwater (FW) Impellers/Motors	(2) Booster Feedwater (FW) Impellers/Motors	(2) Booster Feedwater (FW) Impellers/Motors	EC 74527 - FWP 1A/1B (FW Booster Pump/Motor)	2
Replace	(2) Condensate (CN) Pump Variable Drives	(2) Condensate (CD) Pump Variable Drives	(2) Condensate Pumps/Discharge Valves/Recirculation Line	(2) Condensate Pumps/Discharge Valves/Recirculation Line	EC 74526 - CDP 1A/1B (CD Pump/Motor/Head/Valves/Recirc)	3
Add	(2) CN Pump 6.9 KV Breakers	(2) CN Pump 6.9 KV Breakers				
Add	Low Pressure Injection (LPI) Cross Tie	Low Pressure Injection (LPI) Cross Tie	LPI Cross Tie with Hot Leg Injection Line	LPI Cross Tie with Hot Leg Injection Line	EC 73934 - LPI (LP Injection Cross Tie)4	
Modify	Plant Process Computer (PPCS)	Plant Process Computer (PPCS)		Plant Process Computer (PPCS)	EC 75574 - Plant Computer/Simulator Upgrades	
Upgrade		(2) Emergency Feed (EF) Pump Steam Admission/Instruments	(2) Emergency Feed (EF) Pump Steam Admission/Instruments			
Replace			Emergency FW Pump		EC 70732 - EFP 2 (EF Pump System)	5
Replace			(2) Main FW Pump Impellers	(2) Main FW Pump Impellers	EC 78021 - FWP 2A/2B (Main FW Pumps)	
Rerate			(2) Main FW Pump Turbines	(2) Main FW Pump Turbines	EC 78021 - FWP 2A/2B (Main FW Turbines)	6
Replace			(3) Safety Related (SR) FW Isolation Motor Operated Valves (MOV)	(3) Safety Related (SR) FW Isolation Motor Operated Valves (MOV)	EC 74873 - SR MOVs	7
Add			Make Up Tank (MUT) Bypass Line	Make Up Tank (MUT) Bypass Line	EC 75659 - MUT 1 (MU Injection Line Bypass around MUT)	8
Replace				FW Heat Exchangers 2A/2B	EC 73917 - FWHE 2A/2B (FW Heat Exchangers)	9
Modify				MS Structural Supports and Hangers	EC 76095 - SR MS Supports/Restraints	10
Modify					EC 76097- Non SR MS Supports/Whip Restraints	10
Modify				High Pressure Injection (HPI) Line Cavitating Venturies/Instruments	EC80138 - FWHE 3A/3B Feedwater Heater Replacement	11
Add					EC 76344 - Vibration (Pipe Vibration Monitoring System)	12
Add					EC 76340 - ICC (Inadequate Core Cooling Instrumentation)	13
Reconcile/Adjust					EC 75004 - ROTSG (ROTSG Orifice Plate)	14
Evaluate					EC 76339 - 17R Heavy Haul Path	15
Modify					EC 77901 - Turbine Building Mods for FWHE 2A/2B Removal	16
Document					EC 71193 - Overall Design Margin	17
Document					EC75814 – New Core Load	18
Modify					EC79352 – High Pressure Injection Modification	19
Install					EC 84511 - Install RCS Blow Down Lines	20
Repaice					EC 84509 - Replace Aux Calvert Bus Duct	21
POINT OF DISCHARGE						
Evaluate	CW Intake Screens					
Mitigate	Thermal Load Increase to Discharge Canal	Thermal Load Increase to Discharge Canal	Thermal Load Increase to Discharge Canal	Thermal Load Increase to Discharge Canal	Install Forced Draft Cooling Tower or Down Power CR1/2	
Mitigate	Increased CW Discharge Flow					
Mitigate	CW Impingement and Entrainment					
Disposition	Temporary Modular Cooling Towers (MCT)	Temporary Modular Cooling Towers		Thermal Load Removed by MCTs		

1. Economic Evaluation

A total of 6 analyses were conducted using the Strategist® and EPM™ models, reviewing 2 cases for completion and one for cancellation of the project and analyzing the total system cost of each scenario with and without the presence of a cost for carbon. In the cases where a cost for carbon was applied, the company standard carbon cost assumptions (beginning in 2015) were applied. In each case, the current boundary case assumption for the repair of CR3 was employed, i.e. that the unit will be in service November 1, 2014. Two months were allowed for ramp up of the EPU MW to full output on the dates shown.

The 3 scenarios analyzed were:

OPTIONS	OPTION TITLE	YEAR (OUTAGE)	SER RECEIVED	IN-SERVICE DATE	MW OUTPUT*
1	Balance of Work Scope Completed During Delamination Outage	Current	Jan 2013	January 2015	1080
2	Balance of Work Scope Completed During R17 Outage	Nov 2016	Jan 2013	January 2017	1080
Cancellation	No Further Balance of Work Scope, No LPT or HPT Installation	N/A	N/A	November 2014	916

* MW Output listed in this table is total gross MW before adjustment for joint ownership.

Costs for the completion of the EPU helper cooling tower were included for each of the projected continuation. In the case in which the project was discontinued, it was presumed that the cooling tower was not completed.

Overall results for each case are shown below. Values shown are net project benefit (operations, fuel and capital savings) compared to the base case of cancelling the project without additional equipment installation and operating the unit at the current MW output value (916 MW). The results reflect total savings adjusted for Progress Energy's ownership share.

	Project Cancellation	Project Completion In-service Date Jan 2015	Project Completion In-service Date Jan 2017
Option		1	2
CPVRR w/ CO_2 ($000)	--	$650,459	$513,422

CPVRR w/o CO_2 ($000)	--	$361,021	$260,528
Nominal Fuel Savings w/CO_2	--	$1.26B	$1.14B
Nominal Fuel Savings w/o CO_2	--	$1.21B	$1.09B

These analyses exclude costs and benefits that have already been spent or achieved ("sunk").

These analyses did incorporate savings due to the avoided cost of additional new units required to compensate for the lower MW outputs available from the Crystal River 3 unit if the uprate project were not completed. The decision not to complete the uprate results in the earlier construction of the combined cycle scheduled for 2019 and an additional CT in year 2036. The variation in the proposed resource plan is reflected below.

	Project Cancellation	Project Completion Options 101 & 102
2018 Unit	CC	--
2019 Unit	-	CC
2036 Unit	CT	

- Units shown reflect only those varying from the common unit assumptions for all cases.
- "CC" indicates the "generic" 2x1 G combined cycle plant sited at an unspecified site. Generic needs for transmission and gas infrastructure are included in this estimate.
- "CT" indicates the "generic" framed Combustion Turbine plant sited at an unspecified site. Generic needs for transmission and gas infrastructure are included in this estimate.
- Deferral of the CC unit due to completion of the project results in a savings

The table below shows a breakdown of the savings associated with putting the uprate into service in January 2015 compared to the cancellation of the project with no additional megawatts realized.

Project Completion Option 1 vs. Project Cancellation ($000)	Without CO2 Costs CPVRR (2012$)	With CO2 Costs CPVRR (2012$)
Fuel	540,754	556,252
Capital EPU	(227,969)	(227,969)
Capital Cooling Tower	(85,506)	(85,506)
Avoided Capacity – Capital	68,089	68,089
Avoided Capacity - Gas Reservation Charges and Fixed Costs	40,552	40,552
Emissions	2,362	281,158
Production Costs other than Fuel and Emissions	63,886	70,362
Cooling Tower O&M	(11,250)	(11,250)
Cooling Tower Auxiliary Power Usage	(29,895)	(41,228)
Total Savings (Costs)	361,021	650,459

Completion of the 151 MW uprate will result in fuel savings with a cumulative present value (CPV) of $556 million when CO_2 allowance costs are modeled and $540 million without.

Delaying the combined cycle to 2019 (as opposed to the 2018 need in the cancellation case) and avoiding the addition of the combustion turbine in 2036 will reduce the capital investment and associated fixed expenses such as gas reservation charges, providing a system savings of $109 million (CPV).

The uprate is also projected to result in a significant reduction in CO_2 emissions providing a savings of $281 million (CPV) in emissions costs when CO_2 allowance costs are modeled.

Annual cooling tower operating costs, which include O&M of $655K (2006$) and auxiliary power usage of 58 Gwhr, contribute an additional cost of $52 million and $41 million (CPV) over the analysis period for the CO_2 and No CO_2 scenarios respectively.

The table below shows a breakdown of the savings associated with putting the uprate into service in January 2017 compared to the cancellation of the project with no additional megawatts realized.

Project Completion Option 2 vs. Project Cancellation ($000)	Without CO2 Costs CPVRR (2012$)	With CO2 Costs CPVRR (2012$)
Fuel	446,590	459,761
Capital EPU	(236,725)	(236,725)
Capital Cooling Tower	(79,732)	(79,732)
Avoided Capacity – Capital	68,089	68,089
Avoided Capacity - Gas Reservation Charges and FOM	40,552	40,552
Emissions	1,587	246,196
Production Costs other than Fuel and Emissions	55,829	60,912
Cooling Tower O&M	(9,857)	(9,857)
Cooling Tower Auxiliary Power Usage	(25,805)	(35,774)
Total Savings (Costs)	260,528	513,422

Delay of the in service date from 2015 to 2017 results in a reduction in the fuel savings of $96 million (NPV). Still, this option provides substantial benefit compared to the project cancellation option. The model indicates fuel savings with CPVRR values of $460 million with CO_2 costs or $447 million without.

CR3 Extended Power Uprate

EPU OPTIONS UPDATE

February 2012

Presenter: Paul Ingersoll

EPU PHASE 3 OPTIONS

- **KEY ASSUMPTION – CR3 Online** Nov 2014

- **OPTION 1 - Complete Phase 3 in CR3 Extended Outage 16R**
  - Start Construction June 2013
  - End Construction June 2014
  - EPU In-Service Dec 2014
  - POD Start Construction April 2014
  - POD End Construction April 2015

- **OPTION 2 - Complete Phase 3 in CR3 Outage 17R**
  - Start Construction Nov 2016
  - End Construction Jan 2017
  - EPU In-Service Jan 2017
  - POD Start Construction June 2016
  - POD End Construction June 2017

- **OPTION 3 - Cancel Phase 3 (Base Case for Comparison)**

OPTION 1 – 16R (Financial View)

2006 – 2011 Actual	\$333.6 M
2012 Estimate	\$ 56.3 M
2013 Estimate	\$100.7 M
2014 Estimate	\$ 93.8 M
2015 Estimate	\$ 32.6 M
Total	\$617.0 M

CPVRR w/CO_2	\$650.5 M
CPVRR wo/CO_2	\$361.0 M
Fuel Savings w/CO_2	\$1.26 B
Fuel Savings wo/CO_2	\$1.21 B

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OPTION 2 – 17R (Financial View)

2006 – 2011 Actuals	$333.6 M
2012 Estimate	$ 56.3 M
2013 Estimate	$ 28.3 M
2014 Estimate	$ 6.1 M
2015 Estimate	$ 6.3 M
2016 Estimate	$140.7 M
2017 Estimate	$ 78.7 M
Total	$650.0 M

CPVRR w/CO_2	$513.4 M
CPVRR wo/CO_2	$260.5 M
Fuel Savings w/CO_2	$1.14 B
Fuel Savings wo/CO_2	$1.09 B

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OPTION 3 – Cancel (Financial View)

Cost through 2011	$333.6 M
2012 Estimate	$ 20.0 M
Total	$353.6 M

- The Option 1 and 2 net project benefits are compared to this base case of cancelling the project without additional equipment installation and operating the plant at 916 MW.

Residential Rate Impacts

Summary of Residential Rate Impacts (Scenario 1A vs. Scenario 2A)

NCRC Residential Rates	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Scenario 1A	$ 0.18	$ 1.68	$ 1.66	$ 1.89	$ -	$ -	$ -
Scenario 2A	0.18	1.58	1.27	1.32	1.08	0.15	-
Difference	**$ -**	**$ 0.10**	**$ 0.39**	**$ 0.57**	**$ (1.08)**	**$ (0.15)**	**$ -**

Base Residential Rate Impact	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Scenario 1A	$ -	$ -	$ -	$ -	$ 2.03	$ 2.03	$ 2.03
Scenario 2A	-	-	-	-	0.38	1.91	2.23
Difference	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.64**	**$ 0.11**	**$ (0.20)**

NCRC & Base Residnetial Rate Impact	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Scenario 1A	$ 0.18	$ 1.68	$ 1.66	$ 1.89	$ 2.03	$ 2.03	$ 2.03
Scenario 2A	$ 0.18	$ 1.58	$ 1.27	$ 1.32	$ 1.46	$ 2.06	$ 2.23
Difference	**$ -**	**$ 0.10**	**$ 0.39**	**$ 0.57**	**$ 0.56**	**$ (0.04)**	**$ (0.20)**
Fuel Differential	**$ -**	**$ -**	**$ -**	**$ (1.29)**	**$ (1.87)**	**$ -**	**$ -**
Total Residential Rate Differential	**$ -**	**$ 0.10**	**$ 0.39**	**$ (0.72)**	**$ (1.30)**	**$ (0.04)**	**$ (0.20)**

Note:

Scenario 1A Assumes ISD Jan 2015 and full Uprate complete

Scenario 2A Assumes ISD Jan 2015 with phase 2 assets in-service. Phase 3 in-service in 2017.

Fuel Differential Assumes no CO2

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