BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Cost Recovery Clause

DOCKET NO. 110009-EI
Submitted for filing:
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REDACTED

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

**ON BEHALF OF
PROGRESS ENERGY FLORIDA**

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IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA

FPSC DOCKET NO. 110009-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 about 420 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 20 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. Almost two years ago, 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 the Extended Power Uprate ("EPU") project ("CR3 Uprate").

My testimony supports the Company's actual/estimated and projected costs for 2011 and 2012, respectively, and explains why these costs are reasonable. Finally, my testimony explains why the CR3 EPU project is feasible, pursuant to Rule 25-6.0423(5)(c)5, F.A.C.

Q. Have you previously filed testimony in this docket?

A. Yes, I filed testimony on March 1, 2011 in support of the actual costs incurred in 2009 and 2010 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), a detailed description of the engineering scope changes for the EPU phase work required to successfully implement the CR3 power uprate;
- Exhibit No. ___ (JF-2), a schedule of the phase 2 and phase 3 work scope for the Uprate project through the Integrated Project Plan ("IPP") revisions and proposed revisions for the Uprate project;
- Exhibit No. ___(JF-3), Integrated Change Form ("ICF") for EPU actuation design specification and implementation modification for Engineering Change ("EC") 76340; and
- Exhibit No. ___ (JF-4), the summary of the Company's updated cumulative present value revenue requirements ("CPVRR") analysis for the CR3 Uprate project.

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 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-6; and sponsoring TOR-6A 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 site selection, 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 monthly 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. The Company remains committed to the CR3 Uprate project and intends to proceed with the project. The Company finished a complete evaluation of the

Uprate project early this year that demonstrated that the Uprate project remains beneficial to PEF and its customers and, therefore, should be completed.

The Company's recent evaluation of the Uprate project included a detailed analysis of the EPU work scope and costs to ensure that the increased work scope and increased costs were necessary to achieve the technical objectives required to implement the full 180 MWe power uprate upon completion of the EPU phase work. The Company then analyzed the increased Uprate project costs necessary to achieve the full power uprate against the benefits of the power uprate to determine if the Company should proceed with the Uprate project given the increased costs, pursue partial completion options, or cancel the Uprate project. The most economically beneficial option to PEF and its customers is completion of the project. The Company's evaluation demonstrated that the Uprate project work scope and costs are required for the power uprate and that the completion of the Uprate project is economically beneficial to PEF and its customers even with increases in our Uprate project cost estimates.

This determination was not affected by the recent, second delamination event at CR3. This event occurred in mid-March during the last phase of the Company's steps to return the containment building to a condition to support commercial operation following the successful completion of the repairs to the first delamination in the CR3 containment building wall. The Company is currently engaged in engineering analyses to determine the extent of and response to this second delamination event. The Company, however, can proceed with the CR3 Uprate project and may still complete it on the current project schedule based on the facts known at this time. The Company determined that the reasonable course of action at this time is for the Company to take steps to preserve this option without unnecessarily incurring costs for the Uprate project pending the Company's evaluation of the second delamination event. PEF has taken the necessary steps to implement this course of action as part of its management of the CR3 Uprate project.

The Company is providing the Commission with its 2011 actual-estimated and 2012 projected Uprate project costs with this filing in accordance with the Commission's nuclear cost recovery rule. The 2011 actual/estimated and 2012 projected Uprate project costs reflect the best available information the Company currently has with respect to the Uprate project costs. These costs are reasonable, subject to true-up under the Commission's rule next year. The Company also completed its feasibility analysis and determined that the Uprate project is feasible from a technical and regulatory perspective and that it is economically beneficial to PEF and its customers. The Uprate project remains in the best interests of PEF and its customers and the Company. Accordingly, for this reason, the Company requests that the Commission determine that PEF is entitled to recover its prudent and reasonable Uprate project costs.

III. 2011 ACTUAL/ESTIMATED AND 2012 PROJECTED PERIOD COSTS.

A. <u>EPU Phase Status Given Current CR3 Circumstances.</u>

Q. Does the Company plan to incur costs for the CR3 Uprate project during 2011 and 2012?

A. Yes. At this time, PEF is maintaining its capability to complete its current plan to perform the EPU phase of the CR3 Uprate project scheduled during the next CR3 refueling outage. Prior to March 14, 2011, PEF was proceeding with its project plan for this work on this schedule. PEF's actual/estimated and projected 2011 and 2012 costs and its total project costs included in PEF's NFR schedules, and PEF's feasibility analysis for the CR3 Uprate project, were prepared prior to March 14 and reflect this plan.

Q. What happened on March 14, 2011?

A. On March 14, 2011, PEF was in the process of completing the final stages of retensioning the CR3 containment building when an additional delamination occurred. This retensioning was part of the process to return CR3 to commercial service after PEF completed repairs to the outer concrete area of one of the bays to the containment building that had delaminated.

Q. Did the first and second delamination events have anything to do with the EPU phase work on the CR3 Uprate project?

A. No. The current CR3 extended outage occurred because of separate delaminations of concrete in different areas of the CR3 containment building wall during work that was unrelated to the CR3 Uprate project work. The first delamination was discovered while work was being done for the Steam Generator Replacement project during the R16 refueling outage. This containment wall delamination was repaired. The second delamination occurred during the retensioning process that was necessary to return CR3 to commercial service after completion of the SGR project and the repair of the first delamination event. The first and second delamination events had nothing to do with the CR3 Uprate project work.

Q. What is the impact of this second delamination event on the CR3 Uprate project?

A. As I testified above, we currently are maintaining our capability of completing the EPU phase work in accordance with our current project plan. To explain further, our current EPU phase project plan already reflects the re-scheduling of the project work to meet a later scheduled refueling outage for CR3. Last year, I explained that the extended CR3 outage had extended the R17 refueling outage to spring of 2012 and, then, to fall 2012. Earlier this year, based on the continued CR3 extended outage and other factors we consider in planning refueling outages, we determined that the CR3 R17 outage should be delayed further to the spring of 2013. As I further indicated above, our current project plan, and expected costs in 2011 and 2012, reflect the re-scheduling of the work to meet this later R17 refueling outage. Consequently, we have more room in our current schedule to continue the EPU phase work than we did last year. This provides us more time to consider all options.

This is important because we may proceed with the EPU phase work on the current project schedule or re-schedule some or all of the EPU phase work earlier during the extended CR3 outage as a result of the second delamination.

This decision will depend on the results of the analysis of the options for CR3 following the second delamination. There may be a repair option that allows the Company to continue with the EPU phase work on the current project schedule. There also may be a repair option that allows the Company to re-schedule some or all of the EPU phase work earlier than the next planned refueling outage due to the continued extended outage at CR3. There may be other options for the CR3 Uprate project. We will be reviewing all viable options to determine the most cost-effective option for CR3 and the EPU phase work for PEF and its customers.

We will evaluate these options for the EPU phase of the CR3 Uprate project as we evaluate the options for the second delamination at CR3. We expect our evaluations will take place over the course of several months, but we cannot definitively state when these analyses and evaluations will be complete at this time. We believe, however, that the prudent course of action at this time is to maintain all viable options for the EPU phase work, including completing the work on the current or a similar project schedule.

Q. Does this mean you are proceeding ahead with the EPU phase work on the CR3 Uprate project as if the second delamination at CR3 did not occur?

A. No. After our initial investigation determined that there was in fact a second delamination, our EPU project management team evaluated the EPU phase work and schedule under the circumstances we currently face on the project. At this time we are in a relatively early stage of the investigation and evaluation of the second delamination event. There is, as a result, uncertainty surrounding the second delamination and the prudent course of action in response to this event, but, as I explained previously, a repair option that corresponds to the current EPU phase schedule or allows us to re-schedule some or all EPU phase work earlier than planned is just as likely to be the prudent course of action as any other action at this time. We, accordingly, determined that the current EPU phase work plan and schedule should be preserved to the extent possible to provide the Company the opportunity to select these repair options should they be the prudent course of action to resolve the second delamination event.

As I further explained, we do have more time and, thus, room in the current schedule to move work around and still meet the current EPU phase implementation schedule if that is the prudent course of action. We accordingly evaluated the EPU phase work to determine what work is critical to proceed with now to maintain this schedule and what work is not on this critical path. For example, we have proceeded with the execution of the contract for the analog instrumentation system that I discuss later in my testimony, with appropriate contractual protections in the event of suspension or cancellation, because this is the longest lead equipment item needed to meet the current EPU schedule. Further, the assistance of this vendor is needed to respond to any NRC requests for additional information ("RAIs") should we decide to submit the EPU License Amendment Request ("LAR") to the NRC as currently planned. We determined, therefore, that we needed to proceed with this particular contract and work for the EPU phase of the project.

We have slowed down other work on the EPU phase where it is reasonable to do so. No EPU phase work is being accelerated, all overtime work has been postponed, and only regular work hours are permitted at this time on work that we have determined needs to be done to maintain the current schedule. Some work is being postponed. The selection process following the request for proposal ("RFP") responses for the construction contract to install the EPU phase modifications has been delayed. We initially planned to narrow the selection of contractors and commence contract negotiations in March 2011. This has been delayed because our current schedule does not require a decision to be made to issue this contract until June 2011. Additionally, we planned to file our EPU LAR with the NRC in June 2011, so we have time now to decide whether or not to proceed with that filing in accordance with our current schedule. This type of evaluation is being conducted for each item of work for the EPU phase of the CR3 Uprate project.

We are also individually evaluating each contract and change order for the EPU phase work before execution. For contracts or change orders below $100,000, the EPU phase project manager is performing this evaluation. For contracts or change orders at or above $100,000, the project manager conducts this evaluation and makes a recommendation with respect to execution of the contract or change order that is reviewed by the manager of nuclear projects and senior management. No contract or change order at or above $100,000 for the EPU phase work will be executed without senior management approval. That approval will not be granted unless there is a demonstration that the work under the contract or change order is reasonable and necessary at this time to preserve the Company's options for the EPU phase work based on the viable options for resolution of the second delamination event at CR3. This process will apply, for example, to the construction contract for installation of the EPU phase modifications before that contract is executed.

We believe this is the reasonable course of action for the EPU phase of the CR3 Uprate project at this time. This course of action puts PEF in the position that it can reasonably select the prudent course of action from the range of potential courses of action that exist for the EPU phase and the resolution of the second delamination event at CR3. We believe this is the reasonable decision to make for the EPU project at this time for PEF and its customers.

Q. Does the second delamination event and the Company's current response to it with respect to the CR3 Uprate project affect the Company's request for cost recovery in this docket?

A. No. To begin with, the second (and first) delamination event has nothing to do with the prudence of PEF's 2009 and 2010 costs incurred for the CR3 Uprate project. Further, the second delamination event was discovered after PEF had incurred costs in the first quarter of 2011 for the EPU phase of the CR3 Uprate project. The Commission, therefore, can certainly determine the prudence of PEF's 2009 and 2010 CR3 Uprate project costs, and the reasonableness of PEF's first quarter 2011 Uprate project costs, in this docket without any consideration of the potential impact of the second delamination event on the CR3 Uprate project.

With respect to the EPU actual/estimated costs for the remainder of 2011 and the projected costs for 2012, PEF has provided the Commission with the best information it has at this time with respect to these costs. These costs reasonably reflect the option of proceeding with the EPU phase work on the current project schedule that may be selected when the Company evaluates the prudent options for CR3 and the EPU phase of the CR3 Uprate project. As I explained, PEF at this time is evaluating the work under this project schedule in order to preserve this option without unnecessarily spending money on the CR3 Uprate project. PEF, therefore, has reasonably provided the Commission with the most up-to-date cost estimates and projections for the EPU phase of the CR3 Uprate project.

Further, even though these cost estimates and projections may change as a result of this on-going evaluation of the EPU phase work, that possibility always exists on the project and is in fact contemplated by the Commission's nuclear cost recovery rule. The rule provides for the true-up of actual/estimated costs the next year and projected costs are similarly updated in the subsequent year. This is the nature of the rule and work on projects like the CR3 Uprate project. PEF reasonably prepares its actual/estimated and projected costs based on the best information available under the current circumstances facing the Company, but those costs will rarely reflect the actual costs incurred on the project. Some change in the project costs from the cost estimates is inevitable. All PEF can do is to continue to prepare the best cost estimates it can taking into account the current circumstances. That is what PEF has done with its current actual/estimated and projected cost filings for the CR3 Uprate project.

B. <u>EPU Phase Work in 2011 and 2012.</u>

Q. What does the Company's EPU phase work plan include during 2011 and 2012?

A. In 2011 and 2012, the EPU phase work plan included: (1) continuation of the engineering design work for the EPU phase work; (2) field implementation planning of the EPU phase engineering design work; (3) completion and submittal of the EPU LAR to the NRC and work associated with the subsequent NRC licensing review process; (4) development of vendor oversight plans and schedules for the EPU phase work; and (5) vendor selection and procurement for any remaining long lead equipment for the EPU phase work. PEF expected to complete the planning, long-lead equipment procurement, and preparation work for the installation of EPU equipment and other EPU work in time for the next CR3 refueling outage. As I explained above, PEF is continuing with this work plan to the extent necessary to preserve it as a viable option for the Company without unnecessarily incurring costs until the Company prudently selects an option for CR3 and the EPU phase work after it completes its evaluation of the second delamination event options.

Q. What work will be performed during the EPU phase of the CR3 Uprate project to accomplish the power uprate?

A. In general, we will complete the supporting engineering and design calculation work, and install or modify and test major components in the CR3 containment building and the turbine building. This work is necessary to increase the CR3 nuclear plant power output 15.5 percent from 2609 Megawatt thermal ("MWth") to 3014 MWth with an expected increase of gross electrical output of 164 Megawatt electric ("MWe") for a total CR3 output of 1080 MWe gross.

Within the CR3 containment and turbine building several new components will need to be installed, some existing components will need to be replaced, and some existing components will need to be modified to accommodate the power uprate. Examples of the new components include a low pressure injection ("LPI") cross tie in the containment building and a pipe vibration monitoring system in the turbine building. Examples of replaced components in the turbine building include two condensate pumps and associated motors and two booster feed pumps and associated motors. Examples of modified components or systems include the plant process computer in the control room and the main steam supports and whip restraints in the turbine building.

Additionally, within the turbine building, during the EPU phase PEF will replace the high pressure turbine ("HPT") and the low pressure turbines ("LPTs"). Also, during this last phase of the Uprate project, new cooling towers may be installed. Engineering design work is necessary to complete the Engineering Change ("EC") packages for the EPU phase construction contractor to install the new equipment, modifications, and material necessary to achieve the power uprate. Project management support by the Company is also necessary for the EPU phase work.

The EPU phase work was planned for an estimated 45-day refueling outage. This estimate is, of course, subject to change or further refinement pending the Company's resolution of the second delamination event and resulting EPU phase work options. One option under consideration for the EPU phase work is accelerating the EPU phase work or re-scheduling the work over a longer period than the current planned 45-day outage work period during the extended CR3 outage to potentially reduce the EPU phase work costs or mitigate any project cost increase. The Company will preserve these options and the original work scope and schedule plan where efficient to do so in order to provide the Company with the options necessary to make a prudent decision to resolve the second delamination and for the EPU phase of the Uprate project.

Q. What types of costs does PEF project to incur for the CR3 Uprate project work during 2011 and 2012 under this EPU phase work plan?

A. As reflected in Schedule AE-6.3 of Mr. Foster's Exhibit No. __ (TGF-4), the total 2011 actual/estimated construction costs are broken down into six categories: License Application cost of $478,195; Permitting costs of $42,006; Project Management costs of $8.5 million; On-Site Construction Facilities costs of $272,571; Power Block Engineering, Procurement, and related construction costs of $72.2 million; and Non-Power Block Engineering, Procurement and related construction costs of $7.7 million.

As reflected in Schedule P-6.3 of Mr. Foster's Exhibit No. __ (TGF-5), the 2012 projected construction costs are broken down into six categories: License Application cost of $391,956; Permitting costs of $35,633; Project Management costs of $8.7 million; On-Site Construction Facilities costs of $1.6 million; Power

Block Engineering, Procurement, and related construction costs of $61.7 million; and Non-Power Block Engineering, Procurement and related construction costs of $16.0 million.

C. **Low Pressure Turbine Installation in R17 Refueling Outage.**

Q. You mentioned the installation of new low pressure turbines during the next refueling outage. Can you explain why you plan to install these low pressure turbines during the next refueling outage?

A. Yes. The issues surrounding the original, planned installation of new LPTs in the R16 refueling outage were explained in detail in my May 2009 direct and my 2010 direct and rebuttal testimony. Briefly, however, our initial plan to install new LPTs during the CR3 R16 refueling outage was first affected by problems with similar LPTs in September 2008 at the DC Cook plant in Michigan. When installed there, the DC Cook LPTs experienced problems resulting in a forced outage and turbine repairs. Subsequently, in April 2009, during the bunker spin performance testing of the CR3 LPTs, the LPT turbine rotor failed to meet the 120 percent design overspeed acceptance criteria when a last blade row disk slipped. As a result of these events, PEF deferred installation of the LPTs to the R17 refueling outage. PEF used this additional time to fully evaluate the technical issues surrounding the DC Cook LPT failure and CR3 LPT performance test problems. Based on that evaluation, PEF determined that its initial plan to install the new LPTs remained technically sound.

As I explained in more detail in previous testimony, the DC Cook LPT issues were sufficiently unique to that facility and its turbine operating characteristics that the Company determined that they were not a deterrent to the installation of the planned LPTs at CR3. Further, the evaluation of the failure of the LPT turbine rotor to meet the 120 percent design overspeed acceptance criteria during the manufacturer's bunker spin test was determined to be a manufacturing problem and not a design issue. Consequently, PEF determined that this spin test failure was not an impediment to the installation of the planned LPTs at CR3. PEF did, however, exercise its rights under the equipment contract to require assurances from Siemens, the LPT manufacturer, regarding the performance and reliability of the LPTs. PEF received sufficient information to confirm PEF's initial assessment that the design of the planned LPTs is sound and, therefore, PEF determined that it can proceed with the installation of the planned LPTs at CR3 for the CR3 Uprate project.

PEF also evaluated the cost-effectiveness of the installation of the planned LPTs against other LPT options. As I explained last year, the Company evaluated alternative LPT options including continuing operation of the existing LPTs, installing the full new LPTs with the last row of blades at the next refueling outage, and installing the new LPTs without the last row of turbine blades during the next refueling outage. The Company also considered installation of an alternative LPT design at a refueling outage following the next planned outage. Based on this evaluation, the Company determined the prudent course of action was to install the new LPTs with the last row of turbine blades as originally planned. This plan will result in the full increase of approximately 180 MWe for the CR3 plant when the EPU phase is completed and the plant is brought back on-line. PEF determined that this plan will provide PEF's customers the most benefits from the additional fuel savings over the remaining operational life of the nuclear unit.

Q. Have these LPT issues now been resolved?

A. Yes. PEF resolved all LPT issues that arose as a result of the DC Cook event and the failed bunker spin test for the last row of turbine blades for the CR3 LPTs. PEF worked with its primary insurance carrier, the Nuclear Electric Insurance Limited ("NEIL"), in the aftermath of the incident at DC Cook to assess the issues with respect to coverage for the LPTs and obtain partial coverage for the new LPTs. PEF further reached a resolution with Siemens to move forward with the installation of the LPTs as originally planned. This resolution resulted in an amended and restated Work Authorization that addressed, with respect to the prior LPT issues, the additional product assurances PEF required, supplemental insurance [redacted], extended warranties, a new outage schedule window, and adjustments to payment milestones in order for PEF to proceed with installation of the planned LPTs during the next CR3 refueling outage [redacted]

[redacted]

PEF will, however, be paying approximately [redacted] more for the installation of the LPTs in the next refueling outage than the original contract value for the LPTs. The reason for this cost increase is that PEF is receiving more benefits under its renegotiated Work Authorization for the LPTs [redacted] PEF determined these additional contractual benefits were necessary to better ensure that the LPTs perform as planned in order to obtain the full fuel savings benefits from the power uprate.

D. <u>CR3 EPU License Amendment Request.</u>

Q. What Licensing Application work is currently planned for 2011 and 2012?

A. For 2011 and 2012, these costs currently include work to prepare and submit the Company's LAR to the NRC in support of the EPU for the CR3 Uprate and the work necessary to support the NRC's review of the EPU LAR. The LAR is necessary to complete the CR3 Uprate because PEF cannot operate CR3 at the increased megawatt level for the EPU without NRC approval. As previously discussed last year and in my March 1, 2011 testimony, PEF contracted with AREVA to assist PEF in preparing the CR3 EPU LAR. Specifically, this work involved conducting engineering analyses and providing engineering support necessary for the preparation of the LAR content along with oversight and assistance in drafting most of the actual LAR document. As I explained last year, PEF substantially completed the LAR document by the end of March 2010, but as a result of the shift in the R17 outage schedule due to the extended CR3 outage, PEF decided to hold off on the submittal of the EPU LAR document to the NRC.

PEF used the additional time to review and monitor the progress of other EPU LAR applications pending before the NRC and questions from the NRC on such submittals. PEF also used the additional time to address emerging issues. As I explained to the Commission last year, an emerging issue did arise during PEF's interaction with the NRC following the substantial completion of the CR3 EPU LAR document. This emerging issue was a potential digital instrumentation modification under evolving NRC guidelines. This issue delayed our submittal of the CR3 EPU LAR document to the NRC for acceptance review and approval. We have, however, resolved this issue and we are prepared to submit the CR3 EPU LAR document to the NRC for acceptance review by June 2011 on our current schedule, unless our evaluation of the second delamination and EPU phase options that I have discussed indicates we should further delay this submittal. Upon acceptance of the CR3 EPU LAR once it is submitted and completion of the

NRC's review, however, the NRC will issue a Safety Evaluation ("SE") detailing the NRC's findings and providing PEF with the necessary approval for the power uprate at CR3.

Q. Can you explain what the emerging digital modification issue is with respect to the CR3 EPU LAR?

A. Yes. The potential for a digital instrumentation modification arose in connection with the Fast Cooldown System ("FCS") that is required for the power uprate at CR3. The FCS will be implemented in the EPU phase to supplement the normal mitigation systems in the event of certain, possible small break loss of coolant accidents ("SBLOCAs"). All nuclear power plants must plan for and implement mitigation systems for SBLOCAs at NRC-approved existing and uprated plant power levels.

The FCS is necessary to mitigate a narrow spectrum of SBLOCAs at EPU conditions. In simple terms, SBLOCAs are small leaks of the reactor coolant system ("RCS") that leave it at relatively high pressures because the breaks are so small the system does not depressurize quickly. When the system stays at these high pressures it maintains break flow and reduces the normal mitigation system flow into the RCS. Briefly described, the FCS supplements the normal mitigation system by rapidly depressurizing the secondary plant, in particular, the main steam lines from the steam generators. The FCS system de-pressurizes the steam generators by opening Atmospheric Dump Valves ("ADVs"). The ADVs release pressurized steam from the steam generators, and, thus, depressurizes the steam generators. Depressurizing the steam generators leads to higher primary to secondary heat removal and RCS depressurization. Lower RCS pressures allow greater mitigation system flow and, as a result, the adverse effects of the SBLOCAs are mitigated.

As the conceptual design of the FCS was progressing, additional engineering and design work determined that both ADVs were needed to open and be controlled at an intermediate pressure as opposed to simply opening one or both ADVs as originally contemplated and designed. At this point, a manual operator action (turning a control switch) was planned to implement the FCS system. Appropriate instrumentation indications were identified allowing the operator to diagnose the need to implement the FCS. The initial instrumentation indication was the existing loss of sub-cooling margin ("LSCM"). Further, PEF planned to use the existing Safety Parameter Display System ("SPDS") to implement the FCS because the SPDS was available for this use and the operators were familiar with the SPDS. The SPDS was not fully compliant with existing regulatory guidance for safety related functions, however, the NRC had approved reliance on the SPDS to support other more prompt and equally challenging manual actions. As a result, PEF was reasonably confident that the NRC would approve this approach to implementing the FCS.

Further engineering and design analyses to implement the FCS, however, revealed limitations with PEF's approach. One limitation was identified when these analyses revealed the need for another criterion for actuation of the FCS. This criterion was an indication that high pressure injection ("HPI") flow was adequate or inadequate. Another limitation was the vulnerability of the SPDS to a complete system shutdown on the loss of related system function or down power. As a result of these limitations, PEF determined that a separate monitoring system from the SPDS was required for indication of the need to actuate the FCS. This separate system is called the Inadequate Core Cooling Mitigation System ("ICCMS"). The ICCMS design moved to an automated system to activate the FCS with an indication of LSCM and inadequate HPI flow and replacing the planned reliance on manual operator action for FCS diagnosis and action. At the time the need for the ICCMS was identified, this automated system was likely but not certain to have digital or computer-based characteristics.

PEF briefed the NRC with respect to this FCS system design as part of PEF's on-going communications with the NRC regarding potential EPU LAR issues. This initial discussion led to a full briefing of the NRC on the design, operator actions, and anticipated LAR submittal schedule. The NRC indicated that the review of use of digital instruments in future LAR review would be performed using newly drafted guidance for digital instruments, whether or not those instruments provided automatic actions. The SPDS instruments planned to be used for the operator manual actions had been built many years prior to this guidance and could not meet the new standards. The NRC, additionally, indicated its preference for automation of the FCS system -- as well as its preference for automation of other, previously approved manual operator actions for systems unrelated to the FCS and the EPU. Automation of the FCS system for the EPU LAR with a digital instrumentation modification, however, presented other issues with respect to the EPU LAR. These are the circumstances that PEF faced when I testified before the Commission last year regarding this emerging issue with the NRC with respect to the EPU LAR.

Q. Why did PEF discuss this issue with the NRC before filing its EPU LAR?

A. As I have explained in prior proceedings before this Commission, PEF regularly interacts with the NRC regarding the preparation of the CR3 EPU LAR. PEF does not choose a course of action in a vacuum, without input from the NRC. Instead, from the start of the CR3 Uprate project, PEF has taken a more proactive approach by identifying and discussing potential issues and solutions with the NRC before the EPU LAR document is submitted to the NRC. As I explained previously in the 2009 and 2010 nuclear cost recovery proceedings, even when PEF is fairly certain about how an issue should be resolved, we discuss it with the NRC in an abundance of caution before submitting our proposed solution to the issue in the EPU LAR document. In this way, PEF works through potential issues with the NRC, learns the NRC's preferences with respect to the potential solutions to the issues, and we gain more confidence that our ultimate EPU LAR document will be acceptable to the NRC when it is submitted for acceptance review and approval.

PEF, therefore, communicates with the NRC at each stage of developing the CR3 EPU LAR. PEF regularly contacts and meets with the NRC to discuss its engineering analyses and solutions for the EPU phase of the Uprate project. PEF had three meetings with the NRC regarding the EPU LAR by mid-2009. PEF had additional meetings with the NRC in 2010. In setting up one of these 2010 meetings and conducting the meeting in June 2010, PEF became aware that the NRC intended to apply the draft guidance document to PEF's LAR specifically as it related to review and approval of the digital instrumentation issue for the ICCMS that I have just described.

Q. What were the issues associated with the CR3 EPU LAR as a result of the potential digital instrumentation modification for the ICCMS?

A. The NRC regulatory guidance was unclear and, as a result, the path to NRC approval of the digital instrumentation modification for the ICCMS for the CR3 EPU LAR was potentially protracted and uncertain. The NRC had only recently completed a draft regulatory guidance document in May 2010 with respect to the licensing of digital features. At that time, the draft regulatory guidance was incomplete, still evolving, and subject to industry comments and the Advisory Committee on Reactor Safeguards ("ACRS") review, which occurred in the summer and fall of 2010. This regulatory guidance document was also developed by the NRC as a result of the approval process for much larger digital instrumentation conversions under a different context and scope than the automation of the FCS system for the CR3 EPU. As a result, the draft regulatory guidance was not considered directly applicable to PEF's EPU LAR.

Additionally, the draft NRC guidance document has not been applied to any utility LAR. The CR3 EPU LAR would be one of the first industry projects potentially implicating the NRC draft regulatory digital modification guidance document. As a result, the exact application of this NRC draft guidance to the FCS system in the EPU LAR was unclear and the timing of its application to the EPU LAR was uncertain.

What was clear is that the draft regulatory guidance on the licensing of digital modifications or features required substantial software design and other supporting engineering products as part of the LAR submittal. This included, among other requirements, factory acceptance testing ("FAT") documentation that the digital modification works as it was manufactured to work. Consequently, the draft regulatory guidance added additional up-front engineering, design, procurement and manufacturing costs to the EPU LAR. It also impacts the LAR submittal schedule if it is applied without exception or modification to the CR3 EPU LAR submittal because the LAR cannot be submitted until the design, engineering, procurement, and testing work is completed for the digital instrumentation modification. Additionally, the NRC review schedule for digital instrumentation modifications is not encompassed within the NRC internal management expectation of 12 to 14 months for EPU LAR acceptance review and approval. As a result of all these factors, NRC review of a digital instrumentation modification can extend the schedule for acceptance review of the EPU LAR.

Q. How was the digital modification issue resolved with respect to the CR3 EPU LAR?

A. There were two options for the automated FCS instrumentation indication and activation, an analog or digital instrumentation system. Digital instrumentation systems are relatively new to the nuclear industry, as the recent draft NRC guidance on licensing actions demonstrates. As a result, operating experience in the industry is limited with digital instrumentation systems, especially in the application for the CR3 EPU LAR. Other disadvantages to the digital instrumentation system are cyber security concerns, and the regulatory review costs and acceptance review and approval timing and risks that I described above. Digital instrumentation systems, however, are slightly more powerful than analog instrumentation systems and they are projected to have lower maintenance costs than analog instrumentation systems. Analog, on the other hand, is the predominant instrumentation circuitry system in the nuclear industry. The analog instrumentation circuitry system has proved reliable over the last 30 years. In fact, the functions required for the ICCMS are simple functions for which such analog circuitry has existed for decades. The NRC also has considerable experience reviewing and approving analog instrumentation circuitry systems.

PEF initially selected a digital instrumentation system for the ICCMS. PEF made this initial selection primarily because of a concern at the time that the analog instrumentation option for the ICCMS was not commercially available or well supported by commercially available equipment. A lack of commercially available technology or support can adversely impact the timing and cost of the initial implementation of the system and the future maintenance or replacement parts for the system. Accordingly, PEF initially decided to use a digital instrumentation system for the ICCMS and prepared a request for proposals ("RFP") for potential vendors.

PEF worked with potential industry vendors in preparing for the RFP and determined that both digital and analog instrumentation systems could in fact be made commercially available for the ICCMS. PEF, therefore, included both digital and analog instrumentation options in its RFP for the ICCMS and, in late January 2011, PEF received response proposals for both systems. PEF evaluated the proposals using a series of weighted technical requirements including, among others, power and space requirements, reliability, maintenance, cyber security, and the risk and timing of the SE from the NRC. The vendor with the analog ICCMS proposal scored the highest on this technical evaluation even though this will be the first analog instrumentation design for the CR3 EPU ICCMS application.

As a result of this evaluation, PEF discussed the analog instrumentation option for the ICCMS with the NRC. The NRC identified no concerns with the analog instrumentation option that would prevent acceptance of the analog solution for the ICCMS. Accordingly, the analog instrumentation proposal was recommended and selected by PEF.

Q. Was the analog instrumentation proposal for the ICCMS included in the CR3 EPU LAR?

A. Yes. PEF included the analog instrumentation for the ICCMS to activate the FCS in its EPU LAR document that will be submitted to the NRC. An advantage of the analog instrumentation system is that it can be submitted as part of the EPU LAR once the conceptual design of the system is complete. As a result, the analog instrumentation system saves PEF time and cost in preparation of the EPU LAR document for submittal to the NRC compared to the time and cost to include a digital instrumentation system for the ICCMS in the EPU LAR document. The decision to include an analog instrumentation solution for the ICCMS also saves time for the NRC review and allows PEF to remain on schedule for receipt of the SE for the CR3 power uprate at the conclusion of the EPU phase work in the current planned refueling outage if this option is ultimately selected.

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

A. Yes. PEF has no indication from the NRC that its EPU LAR will not be accepted for review and ultimately approved. However, PEF will continue to work closely with the NRC throughout the review process after the EPU LAR is submitted, providing additional information and assistance as required by the NRC for the CR3 EPU LAR review. This includes the typical set of requests for additional information ("RAIs"). As a result of the evolving NRC standards for EPU LAR requirements and the incorporation of "lessons learned" from other utility EPU LARs, however, PEF's CR3 EPU LAR contains more engineering detail and additional engineering and design analysis than EPU LARs previously submitted by other companies to the NRC. This should mean fewer RAIs and a more streamlined review process and timeline. As a result, PEF currently expects to obtain the CR3 EPU SE before the planned EPU work is complete if the current schedule for submittal of the LAR and completion of the EPU work is ultimately maintained. This will allow PEF to implement the power uprate upon completion of the EPU work. The License Application costs for 2011 and 2012 includes the work necessary to obtain NRC approval of the CR3 EPU LAR consistent with this plan.

Q. How did PEF estimate the 2011 and 2012 License Application costs for the CR3 Uprate project?

A. PEF developed the License Application cost estimates using a reasonable licensing and engineering basis, with the best available information at this time, consistent with utility industry standard cost estimation practices. PEF incorporated "lessons learned" on its LAR and other utility LARs in its estimates of the cost to prepare the LAR document and obtain NRC acceptance review and approval. PEF also used its engineering judgment and experience to determine the costs needed to work with the NRC during the EPU LAR review process at the NRC. The 2011 and 2012 licensing application cost projections are, therefore, reasonable.

E. 2011 and 2012 Permitting Costs and the Point of Discharge ("POD") Work.

Q. What Permitting work was and will be done in 2011 and 2012 under the current EPU phase work plan and why does the Company need to incur the cost of that work?

A. PEF's permitting costs in 2011 and 2012 are for work on post-certification activities associated with CR3's Site Certification. The Site Certification represents an integrated environmental approval by state, regional and local agencies. As I explained last year, these activities are needed to implement the South Cooling Tower ("SCT") including the recirculation to intake option, if this option is pursued by the Company.

This point of discharge ("POD") work involves the construction of an additional cooling tower to mitigate the additional heat generated at the CR3 uprate conditions in the site cooling water discharge canal. The purpose of the additional cooling tower is to maintain the cooling water temperature below the permitted maximum temperature at the point of return to the Gulf of Mexico. One feature of the new cooling tower is the return of a portion of the cooled water back to the plant intake canal to be reused in the plant's cooling systems. This feature will reduce the volume of water drawn from the Gulf of Mexico each day needed to support plant operation but must be certified via the revision to the Initial Site Certification. Additional permits or permit changes are also necessary to support operation of the new cooling tower at the Crystal River Energy Complex ("CREC").

As I also explained last year, the Florida Department of Environmental Protection ("FDEP") approved the Company's application to construct this cooling tower. The additional permit work that is necessary in 2011 and 2012 to support the operation of the new cooling tower includes the canal interfaces reviewed by the United States Army Corps of Engineers ("USACE"), Environmental Resource Permits for percolation pond over-flow by FDEP, and any National Pollutant Discharge Elimination System ("NPDES") changes that are addressed with FDEP and the United States Environmental Protection Agency ("EPA").

Q. What is the current status of the POD work for the EPU phase of the project?

A. The POD 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 extended CR3 outage has pushed back the EPU phase work until the spring of 2013 under the current EPU phase work plan and schedule. As a result, the POD work does not need to be complete until the summer of 2013, after completion of the EPU phase work at the CR3 plant, because of the increase in summer time water temperatures. This delay in the need for the additional cooling tower gives the Company additional time to evaluate the POD work in connection with evolving environmental regulatory requirements and their impact on the Company's generation operations.

For this reason, the POD work was placed on hold and the POD costs were deferred last year to late 2011 and 2012, followed by the actual construction of the additional cooling tower in 2013, if it is in fact needed for the EPU phase of the project. The current CR3 Uprate project plan still includes the POD work, with the permitting activities and other design, engineering, procurement and manufacture work commencing again in late 2011 and continuing into 2012 under the current EPU phase work plan and schedule in order to complete the cooling tower by the summer of 2013.

PEF's estimates for the permitting work necessary for the CR3 Uprate project in 2011 and 2012 are based on PEF's experience with similar permitting work on this and other projects. PEF also reasonably incorporated industry knowledge and experience in its estimates. As a result, PEF's cost estimates reasonably reflect the cost of performing the permitting work necessary for the CR3 Uprate project.

F. <u>Other Actual/Estimated and Projected CR3 Uprate Costs.</u>

Q. What Project Management work was and will be done in 2011 and 2012 under the Company's current EPU phase work plan and why does the Company need to incur the cost of that work?

A. PEF will continue to incur costs to manage the CR3 Uprate project through the successful completion of the EPU phase of the project. PEF successfully managed the completion of the CR3 Uprate project work in the first two phases during the 2007 and 2009 CR3 refueling outages, and PEF expects to manage the

EPU phase work to completion of the Uprate project and the successful full power uprate of the plant by 180 MWe.

Project management costs, accordingly, are on-going as we continue to prepare for the Uprate 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, 2011 testimony and in prior testimony in prior nuclear cost recovery clause proceedings.

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, the CR3 Uprate project management cost estimates for 2011 and 2012 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 2011 and 2012 are reasonable.

Q. What On-Site Construction Facilities work was and will be done in 2011 and 2012 under the Company's current EPU phase work plan and schedule and why does the Company need to incur the cost of that work?

A. The 2011 and 2012 costs are related to installing temporary equipment storage and personnel staging facilities in preparation for the EPU phase work during the next refueling outage if that option is ultimately pursued by the Company. PEF developed these on-site construction facilities cost estimates on a reasonable engineering basis, using the best available information, consistent with utility industry and PEF practice. Based on PEF's experience with other construction projects and the successful completion of phases one and two of the Uprate project -- which involve similar types of activities that are necessary before construction can commence -- PEF developed reasonable estimates for the on-site construction facilities costs for the CR3 Uprate project. These costs are therefore reasonable.

Q. Please describe the total costs PEF will incur for the Power Block Engineering, Procurement and related construction cost items.

A. These costs include engineering change ("EC") packages for the EPU phase. The EC packages contain the detailed engineering design instructions for the EPU modifications for implementation or installation by the construction contractor. As I explain in more detail below, the EPU EC packages are approximately 60 percent complete. The remaining work to complete the EC packages for the EPU modifications will be completed in 2011 if the Company continues with its plan to perform the EPU phase work on the current schedule. PEF also expects to award the R17 EPU phase construction contract later in 2011 if the current EPU phase work plan and schedule is selected as the EPU option following a decision regarding the second delamination event this year. If that is the prudent course of action PEF will begin to mobilize construction resources, perform constructability reviews, receive equipment and materials, begin pre-fabrication activities, and perform vendor oversight for the EPU phase work in 2012.

The majority of the long lead items for the EPU phase work were procured during 2010. These contracts included major components such as the main feedwater pump, feedwater booster pumps, condensate pump and motors, atmospheric dump valves, and the feedwater heat exchangers. There are some additional material and equipment needed for the EPU phase that will be procured in 2011 if the Company determines that these procurements are reasonable and necessary for the EPU phase project given the current circumstances facing the project that I previously discussed. One example that I have already described is the contract for the analog instrumentation system for the ICCMS. Other examples of contracts and change orders that are currently being evaluated by project management and senior management under the current requirements for execution of EPU phase contracts or change orders that I previously described include the contracts or change orders for the monitoring equipment for the LPTs, new main feedwater pumps, safety-related motor operated valves, and a pipe vibration monitoring system. All of this material and equipment is necessary to achieve the full power uprate and must be installed during the EPU phase. The timing of the contracts and change orders for these EPU phase material and equipment will depend on the results of the evaluations by project management and senior management.

Q. Why does the Company needs to incur the Power Block Engineering, Procurement and related construction cost items in 2011 and 2012?

A. This work scope is necessary to achieve the power uprate objectives of the CR3 Uprate project and, therefore, the costs of this work scope are reasonable and prudent. PEF estimated its 2011 and projected its 2012 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. The procurement of material and equipment for the EPU phase is scheduled to support pre-outage milestones established by outage and project management and payments for the material and equipment are established to support the EPU phase work schedule. These contractual payment amounts and payment schedule terms are used for the cost estimates and projections and, therefore, the 2011 and 2012 power block engineering, procurement, and related construction item cost projections are reasonable.

Q. Are there any other costs included in the Company's actual/estimated 2011 and projected 2012 costs for the CR3 Uprate project under the current EPU phase work plan and schedule?

A. Yes, PEF projects that it will incur approximately $23.6 million in 2011 and $48.1 million in 2012, gross of joint owner billing and exclusive of carrying costs, to address the POD issue. Of these amounts, $8.6 and $17.3 million respectively are attributable to the Uprate project and included within the NFR schedules attached to Witness Foster's testimony. This POD work was suspended until late 2011 and 2012 to provide PEF time to evaluate the need for this POD work under new and evolving environmental requirements affecting the Company's generation resource options and plans. PEF will also take this time to evaluate the options to resolve the second delamination event at CR3 and address options for the EPU phase of the CR3 Uprate project.

Nevertheless, as I explained above, the Uprate project plan currently includes a new cooling tower that will be constructed at the CREC to eliminate the additional heat from the EPU phase of the uprate project in the discharge canal. Under the current EPU phase work plan PEF expects to place the cooling tower in service before the summer higher water temperatures following completion of the EPU Uprate work. If this EPU work scope and schedule is maintained after the Company completes the evaluations that I have just described, PEF will resume the POD work in late 2011 and incur the POD costs for this additional cooling tower as part of the Non-Power Block Engineering, Procurement, and related construction cost categories on Schedules AE-6 and P-6 of Exhibits Nos. ____ (TGF-4) and (TGF-5), respectively. The POD cost estimates are based on the Company's experience with similar projects and similar industry projects. The costs are therefore reasonable.

Q. Can you please describe the reasons for the difference between the system projected amount for 2011 and the system actual/estimated amount for Non-Power Block Engineering, Procurement and related construction costs?

A. Yes. On April 30, 2010 I filed testimony in Docket No. 100009-EI, including a projection of Non-Power Block Engineering, Procurement and related construction costs in 2011 of $16.9 million. The actual/estimated 2011 costs, as described above, are $7.6 million, a decrease of $9.3 million in the Non-Power Block Engineering, Procurement, and related construction costs. This variance is directly attributable to the suspension of the POD work that I have described while the Company evaluates its options to determine the reasonable course of action with respect to the POD work and, currently, the second delamination event and EPU phase of the CR3 Uprate project.

Q. Are the actual/estimated 2011 and projected 2012 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 has only included for recovery in this proceeding those costs that were incurred or that will be incurred solely for the CR3 power uprate. 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 2011.

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. As reflected on Schedule TOR-7, the total current project estimate, exclusive of AFUDC and including fully loaded costs, is $617 million of which $556.1 million are being driven by the Uprate and included within the NFR schedules attached to Witness Foster's testimony. The original estimate provided in the need determination proceeding was $381 million, which as I have explained before, did not reflect the full "Financial View" or fully loaded costs, but instead reflected the estimated direct costs. The original estimate inclusive of the indirect costs is $439.3 million as presented in Schedule TOR-7. The total project cost estimate last year, inclusive of indirect costs, was $479.4 million of which $418.6 million was driven by the Uprate and included within the NFR schedule attached to Witness Foster's testimony. This was the total project cost estimate approved through IPP Revision 3. The current total project cost estimate represents an increase of $137.5 million compared to the total project cost estimate in IPP Revision 3 for the CR3 Uprate project.

Our current total project cost estimate for the CR3 Uprate project is based on updated contract costs from an independent construction contractor, additional ECs for the EPU work necessary to accomplish the full power uprate, and the estimates of our 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 EPU phase of the project is approximately 60 percent design complete, which supports an AACE Class 2 estimate. An AACE Class 2 estimate is accurate between -15 percent and +20 percent. The amount of contingency on average that is included in the current CR3 Uprate total project cost estimate is 12 percent. This contingency represents 18.5 percent of the total project cost increase.

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

A. The current total Uprate project cost information was developed as part of a rigorous analysis of the Uprate project needs and costs as part of a planned revision to the Uprate project IPP in early 2011 consistent with the Company's project management, contracting, and cost control policies and procedures. The final development and senior management approval of this IPP revision (Revision 4) has been postponed pending the Company's analysis and evaluation of the options for resolution of the second delamination at CR3 and evaluation of the options for the CR3 Uprate project. The current total Uprate project cost estimate, however, 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 in the Company's current total project cost estimate?

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 scope of work required for the power uprate at CR3 is described in eighteen EC packages for material or 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 detailed description of these EC packages is included as Exhibit No. ___ (JF-1) to my testimony. The increased scope of EPU phase work represented by some of these eighteen 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. One of the reasons 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 refueling outages when Uprate project work was performed. Thus, while design, engineering, and procurement work commenced for all three phases after the need for the project was approved by the Commission in early 2007, 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 would be performed.

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

A. This is the CR3 Uprate project plan. The Uprate project plan has always consisted of three phases of modification and efficiency enhancements to the CR3 plant over the course of three separate CR3 refueling outages that ultimately will increase the power output of CR3 from about 900 MWe by 180 MWe to 1,080 MWe. The CR3 Uprate project work cannot be performed during a single refueling outage. The Uprate project was therefore divided into work phases during distinct, successive CR3 refueling outages.

The project was planned over successive, separate refueling outages to take advantage of the period of time that CR3 was off-line for refueling and maintenance. As a result, PEF did not have to take CR3 off-line or extend an existing refueling outage to perform the CR3 Uprate work. By sequencing the Uprate project work this way PEF ensured that the Uprate project work did not interfere with the continuous operation of CR3 after normal refueling and maintenance outages. The three-phased Uprate project work plan in successive CR3 refueling outages, therefore, benefitted customers by maximizing the fuel savings benefits to customers from the increased nuclear energy production from each phase of the Uprate project.

Q. Has this three-phased work plan for the CR3 Uprate project worked?

A. Yes. PEF has successfully implemented the Uprate project plan. The first phase was completed during the R15 CR3 refueling outage in 2007 and led to a 12 MWe increase in the CR3 power output commencing in 2008, thereafter providing customers the fuel savings benefits of this additional nuclear energy production. The second phase was completed during the R16 CR3 refueling outage in 2009 and will lead to an approximate 4 MWe increase in the CR3 power output. Customers will see fuel savings benefits from this additional nuclear energy production after CR3 returns to commercial service. The current EPU phase work plan and schedule calls for completion of the final phase during the R17 refueling outage. When the EPU phase work is complete, this work will lead to an increase of 164 MWe in CR3's power output. Consequently, the project plan has ensured that the fuel savings from the achieved power uprates have been and can be efficiently achieved without any reductions in the expected fuel savings because the Uprate project work has been performed when CR3 was otherwise off-line.

Q. How did the costs for the EPU phase work increase as PEF focused on this phase of the Uprate project work?

A. Work toward the completion of the engineering for the EPU modifications led to increased EPU costs for additional and initial EPU work scope in the following ways. First, as PEF worked on the detailed engineering for these modifications PEF solicited vendor input on available technology to meet the EPU phase technical objectives. Working with vendors of the technology required for the EPU phase to ensure the best application of that technology given the EPU technical objectives is an industry best practice that PEF employs on all of its projects, including the CR3 Uprate project. This vendor input increased the costs of the initial EPU work scope and added work scope to the project to achieve the necessary technical objectives of the vendor equipment and material to obtain the power uprate.

Examples of EC modifications adding work scope to the project include the analog instrumentation system for the ICCMS that I discussed above. This is described in EC 76340 in Exhibit No. ___ (JF-1) to my testimony. Another example is EC76341, which is also described in Exhibit No. ___(JF-1). As a result of the issues with the LPTs for the EPU phase that I have explained above and in previous testimony, PEF worked with the vendor to design for installation during the EPU phase an early warning system for any excessive last stage turbine blade stresses that may cause blade failure. This system will provide PEF additional assurance that PEF can identify and correct any turbine blade stress issues before a failure that can potentially cause damage to the blades and the turbine, resulting in an extended outage for turbine repairs.

Second, the development of more detailed engineering design information for the EPU modifications led to increased costs and the identification of necessary enhancements to EPU modifications. An example is EC74527 described in Exhibit No. __ (JF-1). This EC replaces 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 has always been a part of the EPU scope for the Uprate project, as demonstrated in Exhibit No. ___ (JF-2) to my testimony, which includes a list of the phase 2 and phase 3 work scope from the initial Uprate project IPP back in January 2008 through the current EPU work scope this year (planned for IPP Revision 4 which was postponed due to the second delamination event as I previously explained). However, as a result of the detailed engineering design work in preparation for the final EPU phase work, PEF determined that the complete replacement of the pump assembly, including a new oil skid that the pump and motor will sit on, was a necessary enhancement as well to meet the technical performance objectives associated with the full power uprate.

Additionally, as PEF progressed with the more detailed engineering design work for the EPU modifications, PEF evaluated the system responses and interactions and, as a result of this evaluation, additional or enhanced EC modifications were required to address the system responses and interactions to the proposed modifications. This work increased the EPU cost and scope. An example of the EPU changed scope is EC74526 described in Exhibit No. __ (JF-1) to my testimony. Again, the modification identified in EC74526, the Condensate System Modifications, was always part of the EPU work scope. <u>See</u> Exhibit No. ___ (JF-2) to my testimony. Originally, however, the work scope included variable speed digital control for the condensate pumps. As a direct result of the identification and analysis of the modeled system response and interaction to this modification at the full power uprate, PEF determined that a revision in the work scope for this modification was necessary to support an adequate flow and discharge pressure at full power uprate conditions. This required a modification to change from variable speed digital controls to constant speed direct drive pumps with flow control, recirculation valves, and piping to ensure that there was adequate water flow and discharge pressure at the full power uprate conditions.

Q. Were there any other reasons for increased costs from increased work assessment and scope for the EPU phase of the Uprate project?

A. Yes. Another reason for the cost increases for the EPU phase was changing regulatory requirements at the NRC. Compliance with the NRC's evolving requirements for the EPU LAR document have certainly increased the engineering and licensing costs that PEF has incurred beyond what PEF expected to incur to prepare and submit the EPU LAR document for NRC acceptance review and approval. Evolving NRC regulatory requirements have also led to increases in the work scope for the EPU and, thus, increased costs for the EPU phase.

The principal example is the ICCMS that I have discussed in detail above. PEF's current, proposed analog instrumentation system for the ICCMS to implement the FCS was developed in response to the NRC's evolving guidance regarding the licensing of digital instrumentation modifications. As I have described, this evolution increased the complexity and uncertainty with respect to licensing digital instrumentation modifications. The ICCMS analog instrumentation system for the activation of the FCS is a significant increase in the work scope for the EPU project. I explained to the Commission last year that this modification was going to affect the project cost although I did not know at the time what that impact was going to be. After completing the design and engineering specifications for the RFP for this system, and receiving and evaluating the RFP responses, the Company has selected a proposal and proceeded with the EC for this scope change. This scope change is described in EC76340, which is summarized in Exhibit No. ___ (JF-1) to my testimony. This EPU scope change alone has increased the project cost estimate by approximately [redacted]. See Exhibit No. ___ (JF-3) to my testimony. This EPU scope change represents about [redacted] of the total project cost increase.

Q. Have you generally described all the reasons for the increases in the EPU phase costs and work scope?

A. No. Another reason for these 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 R16 outage. During refueling outages when CR3 is completely shut down, the Company conducts extensive inspections of all material and equipment and performs maintenance. Extensive inspections of the material and equipment within the containment building often can be performed only during the refueling outages when CR3 is shut down and off-line. As a result of these more extensive inspections, data is collected and evaluated regarding the material and equipment. This inspection and evaluation process takes a significant amount of time, but it is essential to the Company's efficient and effective operation and maintenance of CR3.

The results of this inspection and evaluation process during and following the R16 outage also proved beneficial to the successful management of the Uprate project. Upon evaluating the information collected and analyzed from the R16 outage in connection with the EPU phase work, additional, necessary EPU modifications were identified. The need for these EPU modifications was assessed, options were considered, and, once an option was selected, the design and engineering work was performed to best implement that option for the modification.

Q. Can you provide examples of additional or modified EPU work scope due to the results of your analyses following inspections conducted during the R16 CR3 refueling outage?

A. Yes. An example of this process is EC73917 described in Exhibit No. __ (JF-1). PEF originally planned to re-rate feed water heat exchangers ("FWHE") 2A and 2B for the EPU phase work. As a result of the internal inspections and dimensional validations of these pieces of equipment following the CR3 R16 outage, however, PEF determined that the FWHE 2A and 2B could not be re-rated and would need to be replaced for the plant to achieve power uprate conditions. This decision led to the increased EPU work scope described in EC73917.

Another example is EC76342 also described in Exhibit No. ___ (JF-1) to my testimony. EC76342 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 any issues with FWHE 3A and 3B could be addressed under a monitoring and inspection plan that PEF was going to implement. During the R16 refueling outage inspections, however, 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 would not meet efficiency and performance requirements necessary for the full uprate conditions although FWHE 3A and 3B would continue to meet efficiency and performance requirements at current power output conditions. As a result, PEF decided to replace FWHE 3A and 3B and this scope increase change is reflected in EC76342.

Q. Was all of the additional work scope identified in the ECs described in Exhibit No. ___ (JF-1) to your testimony necessary for the EPU phase of the Uprate project?

A. Yes. All of the additional work scope identified in the ECs in Exhibit No. ___ (JF-1) 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 at CR3.

Not all the ECs in Exhibit No. ___ (JF-1) to my testimony represent an increase in the scope of work for the EPU phase that was initially contemplated. In late 2007 and early 2008 the initial pinch point feasibility study for the project was completed following the need determination for the Uprate project. At this point, the original scope of the EPU phase work was conceptually identified. As shown in Exhibit No. ___ (JF-2) and described in Exhibit No. ___ (JF-1), the EPU scope has changed from the initial IPP in January 2008 to the current, expected next IPP revision (IPP Revision 4). Work scope has been eliminated from and added to the EPU phase as the Company progresses toward completion of the design, engineering, and procurement for the material and equipment components for the EPU phase work scope.

Q. Can you explain what work scope has been added, modified, and deleted from the EPU phase of the CR3 Uprate project?

A. Yes. With respect to the eighteen ECs that have been added to the EPU work scope described in Exhibit No. ___ (JF-1), three of these ECs have always been considered part of the total EPU work scope. These three ECs are identified as additional work scope for the EPU phase simply because they were separated from other EPU work into distinct EC packages as the Company progresses toward completion of the EC packages for installation and implementation of the EPU phase work. 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).

The remaining fifteen ECs for the EPU additional work scope include three ECs that represent revisions to previous EPU phase 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). As demonstrated in Exhibit No. ___ (JF-2), the work scope covered by these ECs have always been part of the EPU phase from the initial IPP to the current, anticipated IPP revision (Revision 4). The work scope for these ECs has simply changed and increased over time for reasons I have explained that are also summarized in Exhibit No. ___ (JF-1) to my testimony.

That means there are twelve net new ECs for the EPU phase work scope that are described in Exhibit No. ___ (JF-1) and Exhibit No. __ (JF-2). But as EPU phase work scope has been added to the project, EPU work scope has also been eliminated as the detailed engineering analyses for the EPU modifications has progressed and draws closer to completion. PEF determined through these detailed engineering analyses that five modifications that were initially included in the EPU phase work scope are unnecessary to achieve the technical objectives that must be met to implement the power uprate. Another modification that was added in a prior IPP revision has now been eliminated as part of the modifications in the new EPU ECs described in Exhibit No. ___ (JF-1). As a result, PEF's refinement of the EPU phase work has not always increased the scope or cost of the EPU phase work. Some work scope and cost in fact have been eliminated. Nevertheless, the remaining EPU work scope and cost are needed to achieve the technical objectives necessary to obtain the full 180 MWe power uprate.

Q. When did PEF determine what the cost was for the EPU phase work scope?

A. In late November 2010 PEF obtained an independent "Study for Extended Power Uprate at Crystal River 3" that provided a construction estimate for the EPU Phase 3 work scope. This independent estimate was sanctioned as the EPU phase work scope reached approximately 50 percent engineering detail design completion by late 2010. This level of engineering design detail completion provided PEF with the ability to obtain an estimate with an expected accuracy within -15 percent and +50 percent under the AACE estimate guidelines. The contractor's construction estimate for the EPU phase work under this Study totaled $112.3 million. This estimate was not accepted without a detailed review and analysis of the estimate. PEF's EPU project team conducted a detailed analysis of the estimate and reduced it by $34.7 million to $77.6 million by, among other things, eliminating duplicative project management support and indirect costs, reducing the time necessary for mobilization of resources prior to the planned R17 outage for the EPU phase work, reducing estimated man-hours and expenses, and adding an estimated fifteen percent contingency to the construction estimate. This detailed analysis of the construction cost estimate for the EPU phase was completed in January 2011.

This work was the impetus for a revision to the Uprate project IPP under the Company's project management policies and procedures. This work commenced with obtaining the Study and coincided with the detailed analysis of the construction cost estimate obtained from the Study. This work continued from January to March 2011 as the EPU phase work and costs were subjected to a rigorous review and analysis for an anticipated revision to the IPP for the CR3 Uprate project. As a result of this analysis, PEF determined that there were increases in the engineering, procurement, construction, and project management costs for the EPU phase work scope for the reasons that I have just described, resulting in an increase of the total project cost to approximately $617 million of which $556 million is being driven by the Uprate and included within the NFR schedules attached to Witness Foster's testimony.

Q. What did PEF do with the information regarding the estimated costs for the EPU phase work for the Uprate project?

A. As I have explained, the first step was to conduct a rigorous analysis of the work scope and cost increases for the project for senior management review. This included a detailed analysis of the reasons for the work scope and cost increases for the EPU phase work. These reasons are summarized in my testimony and in Exhibit No. ___ (JF-1). The detailed analysis of the work scope and costs included the independent, third party estimate of the construction costs for the EPU phase work. This construction cost estimate was then broken down and each EPU phase work scope item was internally reviewed and tested against internal and industry construction cost estimation and work experience. The associated engineering and project management costs were similarly reviewed and tested against internal and industry experience with similar engineering and project management costs on other projects. These reviews were conducted to confirm that the current total project cost estimate was complete and accurate. This work was completed in March 2011 for a potential IPP revision for SMC review and approval consistent with the Company's project management policies and procedures.

At the same time the Company was completing its detailed reviews of the CR3 Uprate project costs, the Company decided to identify potential options for the Uprate project for evaluation by project management and senior management. This decision resulted from the increase in the EPU work scope and costs. The Uprate project cost increases were significant enough that the Company decided that it should evaluate completion of the Uprate project against other options including partial completion of the project and project cancellation. To perform this evaluation we identified the work scope and cost for the full and partial project completion options, the expected schedule for implementation of each full and partial project completion option, and the expected power uprate and resulting fuel and carbon cost savings achieved under each full and partial project completion option. These options were then evaluated against project cancellation in the Company's updated economic feasibility analysis. The Company planned to present the results of this evaluation to senior management with the planned revision to the IPP for the CR3 Uprate project.

Q. What were the project continuation options that were evaluated for the CR3 Uprate project?

A. The full project continuation option included completing the balance of the project work scope for the EPU phase with an expected commercial in-service date for the full power uprate following the current, planned R17 outage. The full power uprate will produce an expected total 1080 MWe gross production from CR3. This option was evaluated at the existing total project cost estimate, which includes a ten percent contingency. It was also evaluated with the current total project cost estimate and a twenty percent contingency to provide an additional margin for the cost of the EPU phase work.

There were two project continuation options involving partial completion of the EPU phase work. First, the Company evaluated installing only the LPTs during the current, planned R17 outage with no further EPU balance of work completed. This reduced scope of work results in an expected 940 MWe gross production from CR3. Second, the Company evaluated installing the LPTs and the high pressure turbine ("HPT") during the next planned refueling outage with no further EPU phase work. This reduced scope of work was expected to result in 932 MWe gross production from CR3. The project cancellation option involved no further EPU phase work on the project. If the project was cancelled, CR3 was expected to produce the current power output of 916 MWe gross when CR3 returned to commercial service.

Q. What were the results of this evaluation?

A. The EPU project team recommended completion of the project with the full power uprate as originally planned based on the results of its evaluation of the EPU phase work scope and costs and the Uprate project options. These results demonstrated that the EPU work scope and cost increase were necessary to achieve the full power uprate and that the costs were reasonable. These results further demonstrated that the full and partial Uprate project completion options were economically more beneficial to PEF and its customers than the project cancellation option. The full power uprate under the full project completion option further provided more economic benefits to PEF and its customers than any of the partial completion options even with the increase in the total project cost and ten and twenty percent project cost contingencies. Consequently, based on the results of these evaluations, the EPU project management team concluded that the CR3 Uprate project should be completed. This recommendation was going to be presented to senior management with the current total project cost estimate in a revision to the IPP for the CR3 Uprate project.

Prior to the presentation of an IPP revision for the CR3 Uprate project to SMC, the second delamination event occurred during the final stages of the re-tensioning process to return CR3 to service after the Company successfully completed repairs to the first delamination at the CR3 containment building. The Company is currently assessing this condition and evaluating all viable options for CR3 and the EPU phase. Preparation of a CR3 Uprate IPP revision for SMC review was, accordingly, postponed pending completion of the engineering assessment of the second delamination and evaluation of the viable options for CR3 and the Uprate project.

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

Q. Did the Company prepare an updated feasibility analysis for the CR3 Uprate?

A. Yes. As I have briefly explained, the Company evaluated project costs and options in both a qualitative and quantitative analysis to determine if the CR3 Uprate project remains feasible given the increase in EPU work scope and cost for a revision to the IPP for the CR3 Uprate project.

A CPVRR analysis was performed for the quantitative analysis. The updated, quantitative CPVRR economic analysis included an update of the fuel cost savings to customers under full and partial completion options and under the project cancellation option. PEF also considered the economic benefits of climate control regulation in the form of carbon costs as an alternative to the fuel savings evaluations for the full and partial completion options in the quantitative feasibility analysis. This alternative economic analysis is consistent with the Company's feasibility analysis for the Levy Nuclear Project that was reviewed and approved by the Commission in prior nuclear cost recovery clause proceedings, including the proceeding last year in Order No. PSC-11-0095-FOF-EI.

This economic analysis was completed assuming a 2013 outage date for the EPU phase work. This is the current EPU phase plan for the Uprate project. This plan may or may not change as a result of the pending analyses of the second delamination and options for CR3 and the Uprate project. The results of this economic analysis are included in Exhibit No. ___ (JF-4) to my testimony.

The qualitative analysis of the feasibility of the CR3 Uprate project included a qualitative review of the technical and regulatory capability of completing the EPU phase work. This qualitative analysis is consistent with the qualitative analysis in the Company's Uprate project feasibility analysis last year that was approved as reasonable by the Commission in Order No. PSC-11-0095-FOF-EI.

Q. Is completion of the CR3 Uprate technically feasible?

A. Yes. The first two phases of the CR3 Uprate project were successfully completed and all equipment was installed. Even now, before completion of the EPU phase, PEF's customers received the benefit of an additional 12 MWe gross from the commercial operation of CR3 since the completion of phase one of the Uprate project in 2007. PEF's customers will also received the benefit of an additional 4 MWe gross when CR3 returns to commercial service even if the EPU phase is not completed. However, PEF expects to complete the EPU phase too, and to obtain for PEF and its customers the benefits of the full 180 MWe gross increase in power from CR3's commercial operation when CR3 returns to commercial service after completion of the EPU phase.

Phase one, the MUR, was installed during the 2007 refueling outage and went on-line on January 31, 2008. The MUR is a series of engineering analyses to measure the "secondary heat balance" with improved accuracy through modifications to plant instrumentation and associated calculations. The improved accuracy in measuring the secondary heat balance allows the rated thermal power to be increased by 41 thermal megawatts ("MWt") and plant electrical generation to increase by approximately 12 MWe.

Phase two of this project was a series of improvements to the efficiency of the secondary plant also known as the Balance of Plant ("BOP"). The BOP Phase two work was completed during the 2009 CR3 refueling outage and included the installation of thirteen equipment items. This phase of the Uprate project work will provide an additional 4 MWe when CR3 returns to commercial service. PEF successfully completed both phase one and phase two of the Uprate project in a timely manner with no significant issues.

The third and final phase is the EPU. The EPU includes the installation or implementation of 26 ECs, including major components, significant engineering work, and, under the current work plan, the installation of cooling towers. The Company has completed an updated review of the EPU phase for a planned revision to the IPP for the Uprate project and PEF is confident these ECs and the related EPU phase work can be successfully completed to achieve the full uprate. This updated review included a technical analysis of the EPU work scope. This technical analysis confirmed that the EPU phase work can be successfully completed and the full power uprate achieved.

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

A. Yes. All legal and regulatory licenses and permits for the CR3 Uprate project can be obtained. Even with the second delamination event at CR3, and the current, on-going evaluation of that event and the options for CR3 and the CR3 Uprate project, there is no reason to believe that the necessary licenses and permits will not be obtained and that the EPU cannot be achieved.

The EPU 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 towers and an EPU LAR from the NRC. The environmental permitting for the proposed cooling towers was underway at the time PEF suspended the POD work in response to the extended CR3 outage to take the additional time available in the schedule to complete the POD work to evaluate the impact of new and proposed environmental regulations on PEF and this work. The POD work is not needed before the summer of 2013 and the current schedule targets the necessary environmental permit approvals well before this date even with the current suspension of the POD work. There was no indication from the environmental permitting work that has been completed that the necessary permits for the cooling towers cannot be obtained. In fact, the required environmental permits or permit modifications for the cooling towers are similar to previously obtained permits and permit modifications that PEF has successfully obtained. Therefore, 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 and in the best interests of PEF and its customers.

With respect to the EPU LAR, as I explained earlier, PEF resolved the issue that emerged last year with the EPU LAR and is prepared to submit the LAR to the NRC for review and approval by June 2011 under PEF's current Uprate project schedule. No further delays in the submittal of the EPU LAR are expected as a result of any issues associated with the EPU LAR. Any delay that may occur now in the submittal of the EPU LAR to the NRC will be for reasons unrelated to the EPU LAR itself. In particular, as I also explained earlier, PEF may delay submittal of the EPU LAR to the NRC on this schedule based on its evaluation of the second delamination event and the resulting options for CR3 and the Uprate project. At this time, however, PEF's current schedule for submittal of the EPU LAR by June 2011 has not changed.

Upon submittal of the Company's LAR to the NRC, PEF expects the NRC review and approval of the EPU LAR to take approximately twelve to fourteen months. The NRC has an internal management expectation to review and approve EPU LARs in fourteen months (12 months from LAR acceptance). In an April 21, 2011 meeting with the NRC, however, the NRC informed us for the first time that while the NRC was not formally revising the internal management expectation, the NRC, nevertheless, indicated the review may take longer than the NRC's expectations and possibly as long as two years. Because of the current shift in the EPU phase work schedule, with the EPU phase work currently planned for spring of 2013, there is ample time for the CR3 EPU LAR review and approval in time for the power uprate upon completion of the EPU phase work even if the NRC review takes longer than the NRC's internal management expectation. PEF has no reason to believe PEF will not receive NRC approval of the CR3 EPU LAR consistent with a spring 2013 execution of the increase.

PEF has worked closely with the NRC regarding potential issues with its EPU LAR and PEF has worked to resolve any NRC questions or issues in advance of the submittal of the EPU LAR. As a result, PEF expects at this time that the NRC will approve its EPU LAR and issue the SE for the full power uprate in a timely manner.

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

A. The updated economic analysis demonstrates that the CR3 Uprate project is feasible for all completion options evaluated. As I explained above, both full and partial project continuation options were evaluated. These included full completion of the current EPU phase work scope, installation of the LPTs only, and installation of the LPTs and HPT in the next CR3 refueling outage. The full project completion option included the current, estimated total project cost with the current estimated ten percent contingency and a twenty percent contingency. The additional contingency to the full project completion option provided PEF additional confidence margin with the full project completion option. The full and partial project completion options were evaluated against a project cancellation option. Project cancellation was the baseline in the economic feasibility analysis.

As shown in Exhibit No. ___ (JF-4) to my testimony, the CPVRR economic evaluation of all project continuation options yielded net positive fuel savings and economic benefits to PEF and its customers, with and without the benefits of carbon cost savings, when compared to the project cancellation option. All project continuation options -- the full and partial project completion options -- are economically beneficial to PEF and its customers based on fuel savings alone. The nominal fuel savings range from $0.19B to $1.7B and the net project benefits without the carbon cost impact range from $70M to $490M. Consideration of the carbon cost impacts only increases the economic value of the project completion options to PEF and its customers. These nominal fuel savings range from $.23B to $1.69B and the net project benefits range from $106M to $787M. See Exhibit No. ___ (JF-4) to my testimony. These economic benefits would be lost if the Uprate project was cancelled.

The full power uprate project completion option at the current total project cost estimate (with the ten percent contingency) provided PEF and its customers the greatest net project economic benefits with and without the carbon cost savings generated by the Uprate project. The net present value of the economic benefits of this full project completion option is approximately $787 million including the carbon cost compliance savings (over $490 million if the carbon cost compliance savings are not included). Even at the higher twenty percent cost contingency alternative, the full power uprate completion option provided PEF and its customers more net economic benefits than the other, partial project completion options. The net present value of the project benefits and carbon cost compliance benefits still exceed $757 million ($460 million without the carbon cost compliance benefits included) even if the total project costs increase another twenty percent. See Exhibit No. ___ (JF-4).

As a result of this economic analysis, the CR3 power uprate will provide PEF and its customers substantial operational and carbon cost compliance savings for the extended life of the CR3 plant. These results confirm that PEF's customers will benefit from additional fuel savings and potential carbon cost savings if the EPU phase of the Uprate project is completed as planned.

Q. Did the Company use its updated total project cost estimate for the economic analysis?

A. Yes, as I have explained, the Company included its current estimated cost to complete the CR3 Uprate project in its economic analysis. As I also explained, this project cost estimate includes a ten percent contingency. The economic feasibility analysis, however, also included the same total project cost estimate with an additional ten percent (twenty percent total) contingency. When the additional investment necessary to complete the Uprate project based on these total project cost estimates was evaluated in the CPVRR analysis, it clearly makes financial sense to move forward with the project. The results of these analyses are included in Exhibit No. ___ (JF-4) to my testimony.

The CR3 Uprate project will further enhance the fuel diversity on PEF's system and provide PEF's customers additional, reliable base load capacity from the lowest cost fuel generation resource available to PEF. PEF expects all of these benefits when the Uprate project is completed and the full power uprate is achieved.

Q. What fuel and environmental emission forecasts were used in the quantitative analysis of the feasibility of the Uprate project?

A. The Company performed its updated CPVRR analysis in the same manner that it performed the CPVRR analysis for the Levy Nuclear Project ("LNP") with respect to the fuel, environmental emissions, and carbon cost compliance estimates. In other words, PEF used updated fuel, environmental, and carbon dioxide compliance cost estimates consistent with those used in the LNP quantitative economic analysis in its economic feasibility analysis for the Uprate project. The updated CR3 Uprate project economic feasibility analysis similarly compares the Uprate project to an all natural gas-fired base load generation scenario. The fuel forecast and carbon cost compliance estimates that were used represent the most current information available for the CR3 Uprate CPVRR analysis. Additionally, the Company used its current weighted average cost of capital in its Uprate project feasibility analysis.

This economic analysis demonstrates that the Uprate project is economically feasible when the costs of the project are compared only to the fuel savings benefits on a net present value basis. The updated CPVRR analysis demonstrates that the fuel savings benefits still 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 Uprate project is even more beneficial on a net present value basis to PEF and its customers.

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, 2011?

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, 2011 testimony. The Company did develop a new cost report that it implemented in the first quarter of 2011. This new cost report is a revision to the prior cost report that provides more detailed direct cost information for the project team and project manager. As discussed in my March 2011 testimony, the Company continues to utilize several existing Company policies and procedures to ensure that costs for the CR3 Uprate project are reasonably and prudently incurred.

For example, the CR3 Uprate is managed in accordance with the Company's Project Management Manual, which is used to manage all capital projects, together with the Company's policies and procedures for Major Capital Projects – Integrated Project Plan. The IPP was in the process of being updated through Revision 4 to account for changes in the work plan for the EPU phase and the shift in the R17 outage schedule when the second delamination event occurred. As I also explained previously, the CR3 Uprate project is also managed in accordance with the Project Evaluation and Authorization process and subject to PEF's Project Governance Policy.

Q. How does the Company manage and control project costs for the CR3 Uprate project?

A. The Company has many control mechanisms in place to manage Uprate project costs. As I have explained before, PEF's Uprate project management team conducts regular internal meetings to monitor the project schedule and its costs. The collective knowledge and experience of the project management team is used to address work scope, costs, and schedule performance through a continuous review of the project, including team roles and responsibilities, by creating and implementing lessons learned on an on-going basis, and through regular project management training. Project management regularly addresses equipment and material procurements under contracts, purchase orders, and invoices, and constantly monitors contracts with outside vendors. This includes regular meetings with outside vendors to discuss work scope and implementation, schedule, and costs.

Q. Does PEF take any other steps to ensure its vendor costs on the CR3 Uprate project are reasonable and prudent?

A. Yes. For every vendor on the Uprate project a requisition is created for the purchase of services. The requisition is appropriately reviewed to ensure sufficient data has been provided to process the requisition. An appropriate contract document is prepared for the vendor from pre-approved contract templates in accordance with the requirements stated on the contract requisition. The contract requisition then goes through the bidding process.

PEF typically employs a competitive bidding process to choose the Uprate project vendors. This is true for all vendor contracts in 2010, 2011, and 2012 for the EPU. PEF issues RFPs, evaluates the RFP responses based on a variety of factors including price, dependability of the vendor, technical considerations and the like, and then chooses the vendor that will provide the best value for the price. A list of contracts executed for the EPU in excess of $1 million is included in Schedule AE-7 and a detailed description of these contracts is provided on

Schedule AE-7A. PEF does not anticipate entering into any new single or sole source vendor contracts to complete the CR3 Uprate project.

Contracts are approved in accordance with the Approval Level Policy before they are executed. After execution and approval, payment for work under the contracts is made based on contract invoices that must be validated by the CR3 Uprate project managers. Payment authorizations approving payment of the contract invoices are entered and approved only after this validation requirement is met. Procurement and other project work under contracts, purchase orders, and invoices are addressed on a regular basis by project management. The administration of contracts with outside vendors is constantly monitored. Project managers meet regularly with outside vendors to monitor work scope, implementation, schedule, and costs. This is part of the validation process to ensure that project managers are fully informed regarding the vendor costs before payment to the vendor is authorized.

Q. Is there a review process to ensure that these managers have done what they are supposed to do to ensure that the CR3 Uprate project are reasonable and prudent?

A. Yes. There are other regular project cost reviews. Uprate project cost reports for contract labor, equipment, material, and other project cost transactions recorded to the project are regularly produced, updated, and monitored. PEF accounting also prepares Cost Management Reports for the Uprate project. Project management regularly reviews these project cost reports and the Cost Management Reports produced by PEF Accounting. Internal and external audits are also implemented to ensure that project management and cost oversight controls are effectively implemented. There are regular audits on CR3 Uprate costs and activities. For 2011, there is also a tentative Nuclear Upgrades Nuclear Oversight Section ("NOS") assessment planned that will include the EPU. This review is part of several Nuclear Oversight Committees that review the EPU on a continuing basis, including the Plant Nuclear Safety Committee ("PNSC"), the CR3 Nuclear Safety Review Committee ("NSRC"), and the Nuclear Safety Oversight Committee ("NSOC").

Q. Are the project cost controls and management you have generally described consistent with best practices in the industry?

A. Yes. We believe that our project management and cost oversight policies and procedures and 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 refueling 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.

VII. CONCLUSION.

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

A. Yes it is at this time. We will, of course, evaluate all options for CR3 and the Uprate project as a result of the second delamination event at CR3 upon completion of the second delamination engineering analyses. Our updated analyses of the CR3 Uprate project demonstrate that it remains feasible and that it will ultimately be economically beneficial to the Company and its customers even with the increases we have experienced in our total Uprate project cost estimates. The CR3 Uprate project will further provide PEF and its customers additional carbon-free, clean nuclear generation from the lowest cost fuel source available to the Company, the project adds to the Company's fuel diversity, and it reduces the Company's reliance on fossil fuels. Implementation of the CR3 Uprate project, therefore, remains an important element of Progress Energy's Balanced Solution. As a result, the Company remains committed to completion of the CR3 Uprate project at this time.

Q. Does this conclude your testimony?

A. Yes, it does.

Appendix B - Revision 4 Scope Changes

Note **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. 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. There is no change between IPP 3 and IPP 4 for the BFP replacement itself.

3. 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 as part of stake holder review meetings and therefore design details were evaluated and approved per the ICF process.

4. 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. <u>5-EC70732 – Emergency Feedwater System Upgrades</u>
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 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. 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. <u>EC78021 – Main Feedwater Pump Modifications</u>
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 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. <u>EC74873 - Safety Related MOVs</u>

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. In addition, 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. 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, 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 HPI pump suction line to provide a more immediate reactivity response.

9. EC73917 – FWHE-2A/2B Replacement

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. The design change package is currently at the 70% review level and will meet the expected milestone date for completion.

10. EC76095 - Safety Related MS Supports and Whip Restraints

EC76097 - Non Safety Related Main Steam Supports and Whip Restraints

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. EC76342 – FWHE-3A/3B Re-sleeve

The hydraulic analysis for the combined feed water system determined that the Booster Feed Pump could not meet required EPU conditions without over pressurizing the Intermediate Pressure Feed Water Heat Exchangers FWHE-2A/B. It was further determined that in order to retain the existing FWHE-2A/B, the Booster Feed Pump pressure would have to be limited and the FWHE-2A/B rerated based on reduced internal tube sheet dimension that was confirmed during 16R inspections.

Based on those inspections and the increased demand on the FWHE-2A/B at EPU conditions, it is required to replace the Feed Water Heaters rather than rerate the heaters.

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 17R to resleeve and recover as many FWHE-3A/B tubes as possible to improve performance characteristics.

Based on review and comments from EPU and station stakeholders, Engineering is currently evaluating replacement of the High Pressure Feed Water Heat Exchangers FWHE-3A/B with heaters with increased operational margin and efficiency for the following reasons:

- A new heat exchanger can be designed to provide 10% operational and design margin with respect to pressure drop and terminal temperature difference in accordance with Heat Exchanger Institute (HEI) recommendations.
- The replacement of these heaters also facilitates the move in-move out of the FWHE 3A/B in parallel with the FWHE-2A/B and will improve logistics and overall cost reduction.

12. EC76344 - Vibration Monitoring System

This modification was always considered part of the EPU scope, but was not reflected in previous IPP revisions. 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. <u>EC76340 – Inadequate Core Cooling Mitigation (ICCM) Instrumentation</u>
The following provides a detailed explanation of the decision concerning the Fast Cooldown System and digital Inadequate Core Cooling Mitigation (ICCM) System.

The Atmospheric Dump Valve (ADV) Conceptual Design Study identified the need to increase the ADV sizing (for Appendix R purposes) and reclassify them as Safety Related (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 IC 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. Based on these concerns; it was decided to include a set point to limit the depressurization. Also, it was recommended to use the same push buttons the operators currently use to increase SG level in response to a loss of sub cooling margin. This allowed taking credit for a previously identified operator action. No new operator actions were identified. A concern with SG design at the 15th tube support plate was also raised. The 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 BWR 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 325psi. 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 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. A final LAR submittal schedule will be developed.

14. <u>EC75001 – Automatic Unit Load Demand (AULD) System Upgrade</u>
This modification was always considered part of the EPU scope, but was not broken out separately in previous IPP revisions. No additional funding is required as this was factored into the existing budget.

The EC modifies and rescales the AULD. The AULD provides the initial input to the Integrated Control System (ICS). The system monitors field inputs and performs a station secondary side heat balance to determine actual power based on set point. The AULD then adjusts control systems to within .03% of the LEFM and MUR software installed on the plant process computer to monitor Technical Specifications core operating limits and fuel depletion.

The AULD needs to be modified and rescaled for EPU conditions from 2609 MWth to 3014 MWth and for the station heat balance and NI power calibrations. The AULD was considered part of ICS modifications in the original scope, but requires a separate modification for documentation.

15. <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 ROTSGs 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.

16. <u>16-EC76339 – 17R Heavy Haul Path</u>
This modification was always considered part of the EPU scope, but was not broken out separately in previous IPP revisions. No additional funding is required as this was factored into the existing budget.

The EC provides heavy haul path requirements for transporting 17R 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.

17. <u>17-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.

18. <u>18-EC71193 – Overall Design Margin</u>

This modification was always considered part of the EPU scope, but was not broken out separately in previous IPP revisions. No additional funding is required as this 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 exiting 17R 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.

Appendix B - Revision 4 Scope Changes

IPP REVISION NUMBER	IPP R0	IPP R1	IPP R2	IPP R3	IPP R4	Notes
DATE PREPARED	January 2008	March 2009	October 2009	May 2010	March 2011	
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 - COMPLETE	
Replace	Generator Rotor	Generator Rotor	Generator Rotor	Generator Rotor	EC 69197 - Generator Rotor - COMPLETE	
Replace	Generator Exciter	Generator Exciter	Generator Exciter	Generator Exciter	EC 69197 - Generator Exciter - 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 - 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 - 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 - 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 - 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 - 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 - 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 - 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 - IBD - COMPLETE	
Modify	Integrated Control System (ICS)	Integrated Control System (ICS)	Integrated Control System (ICS)	Integrated Control System (ICS)	Integrated Control System (ICS) COMPLETE	
New				Turbine Bldg Fiber Optic Backbone	EC 71057 - Turbine Bldg Fiber Optic Backbone - COMPLETE	
Modify	Plant Process Computer (PPCS)	Plant Process Computer (PPCS)	Plant Process Computer (PPCS)	Plant Process Computer (PPCS)	Plant Process Computer (PPCS) - 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 - COMPLETE	
Add					EC 71191 - Turbine Bldg Temporary Power - COMPLETE	
Evaluate/Modify					EC 70657 - 16R Heavy Haul Path - COMPLETE	
PHASE 3 SCOPE (17R)						
Replace			(2) Low Pressure Turbines (LPT)	(2) Low Pressure Turbines (LPT)	EC 73794 - (2) LPTs	
Modify					EC 76341 - LPT Supervisory Equipment	1
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 - 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	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		
Replace					EC 76342 - FWHE 3A/3B (FW Heat Exchangers)	11
Add					EC 76344 - Vibration (Pipe Vibration Monitoring System)	12
Add					EC 76340 - ICC (Inadequate Core Cooling Instrumentation)	13
Modify					EC 75001 - AULD (Automated Load Demand System)	14
Reconcile/Adjust					EC 75004 - ROTSG (ROTSG Orifice Plate)	15
Evaluate					EC 76339 - 17R Heavy Haul Path	16
Modify					EC 77901 - Turbine Building Mods for FWHE 2A/2B Removal	17
Document					EC 71193 - Overall Design Margin	18
POINT OF DISCHARGE						
Evaluate	CW Intake Screens					
Mitigate	Thermal Load Increase to Discharge Canal w/Helper Cooling Tower	Thermal Load Increase to Discharge Canal w/Helper Cooling Tower	Thermal Load Increase to Discharge Canal w/Helper Cooling Tower	Thermal Load Increase to Discharge Canal w/Helper Cooling Tower	Thermal Load Increase to Discharge Canal w/Helper Cooling Tower or CR1/2 Derate during summer months	
Mitigate	Increased CW Discharge Flow					
Mitigate	CW Impingement and Entrainment					

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EXHIBIT NO. _______ (JF-3) IS REDACTED IN ITS ENTIRETY

1. Economic Evaluation

A total of 10 analyses were conducted using the Strategist® and Prosym™ models, reviewing 5 cases for completion, reduced scope or 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.

The 5 scenarios analyzed were:

OPTIONS	OPTION TITLE	YEAR (OUTAGE)	SER RECEIVED	IN-SERVICE DATE	MW OUTPUT*
1	**Completion**				
1A	Balance of Work Scope with 10% Estimate Contingency	April 2013	Jan 2013	May 2013	1080
1B	Balance of Work Scope with 20% Estimate Contingency	April 2013	Jan 2013	May 2013	1080
2	**Reduced Scope**				
2A	No Further Balance of Work Scope, Install LPT Only	April 2013	N/A	May 2013	940
2B	No Further Balance of Work Scope, Install LPT and HPT Only	April 2013	N/A	May 2013	932
3	**Cancellation**				
3A	No Further Balance of Work Scope, No LPT or HPT Installation	N/A	N/A	April 2011	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 cases under Option 1 (continuation). In the cases in which the project was discontinued (Options 2 and 3), 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 Reduced Scope Install LPT & HPT Only	Project Reduced Scope Install LPT only	Project Completion SER Received Jan 2013 In-service Date May 2013	Project Completion SER Received Jan 2013 In-service Date May 2013
Option	3A	2B	2A	1B	1A
CPVRR w/ CO_2 ($000)	--	$ 105,469	$169,770	$757,044	$786,914
CPVRR w/o CO_2 ($000)	--	$ 70,165	$117.383	$460,280	$490,150
Nominal Fuel Savings w/CO_2	--	$0.23B	$0.27B	$1.69B	$1.69B
Nominal Fuel Savings w/o CO_2	--	$0.19B	$0.26B	$1.70B	$1.70B

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 projected need for an additional combustion turbine in the 2019 – 2030 timeframe. The variation in the proposed resource plan is reflected below.

	Project Cancellation	Project Reduced Scope Install LPT & HPT Only	Project Reduced Scope Install LPT only	Project Completion SER Received Jan 2013 In-service Date May 2013	Project Completion SER Received Jan 2013 In-service Date May 2013
Option	3A	2B	2A	1B	1A
2019 Unit	CT	CT	CT	--	--
2020 Unit	-	--	--	CT	CT
2030 Unit	CT	CT	CT	--	--

- Units shown reflect only those varying from the common unit assumptions for all cases.
- "CT" indicates an F-class combustion turbine sited at an existing PEF site providing adequate gas and transmission infrastructure.
- The 2020 "CT" indicated in the Option 1 cases is included in PEF's 2011 TYSP.

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

The table below shows a breakdown of the savings associated with completing the uprate in May 2013 compared to the cancellation of the project with no additional megawatts realized.

Project Completion with 10% Estimate Contingency Option 1A (Best Case) versus Project Cancellation Option 3A (Worst Case) ($000)	Without CO2 Costs CPVRR (2011$)	With CO2 Costs CPVRR (2011$)
Fuel	732,578	735,145
Capital EPU	(253,147)	(253,147)
Capital Cooling Tower	(86,255)	(86,255)
Avoided Capacity – Capital	39,094	39,094
Avoided Capacity - Gas Reservation Charges and FOM	28,721	28,721

Emissions	7,623	314,250
Production Costs other than Fuel and Emissions	74,537	74,057
Cooling Tower O&M	(11,597)	(11,597)
Cooling Tower Auxiliary Power Usage	(41,404)	(53,356)
Total Savings (Costs)	**490,150**	**786,914**

Completion of the 151 MW uprate will result in fuel savings with a cumulative present value (CPV) of $735 million when CO_2 allowance costs are modeled.

Delaying the 2019 CT by 1 year and avoiding the CT in year 2030 will reduce the capital investment and associated fixed expenses such as gas reservation charges, providing a system savings of $68 million (CPV).

The uprate is also projected to result in a significant reduction in CO_2 emissions providing a savings of $314 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 $65 million and $53 million (CPV) over the analysis period for the CO_2 and No CO_2 scenarios respectively.