BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Cost Recovery Clause

DOCKET NO. 110009-EI
Submitted for filing: May 2, 2011

REDACTED

DIRECT TESTIMONY OF JOHN ELNITSKY

**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 JOHN ELNITSKY

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is John Elnitsky. My business address is 299 1st Avenue North, St. Petersburg, Florida.

Q. Did you file direct testimony in this proceeding in March 2011?

A. Yes.

Q. Did you testify to your employment in your March 2011 testimony?

A. Yes, I did. As I testified in my March 2011 direct testimony, I am currently employed by Progress Energy, Inc. as the Vice President of New Generation Programs and Projects ("NGPP"). As the Vice President of NGPP, I am responsible for the licensing and construction of the Levy Nuclear power plant project ("LNP"), including the direct management of the Engineering, Procurement, and Construction ("EPC") Agreement with Westinghouse and Shaw, Stone & Webster (the "Consortium") as well as NGPP base load transmission, and the program coordination and support teams for the LNP.

Representatives from these program coordination and support teams include project controls, business and financial management services, contract management and administration, and other support functions that formed a Program Management Team ("PMT") within NGPP that I head up to manage the EPC Agreement and the related projects under the LNP.

Q. In your role as Vice President of NGPP, are you involved in the senior management review of the LNP?

A. Yes, as the Vice President of NGPP, I report on the LNP directly to the Senior Management Committee ("SMC"). The SMC has corporate responsibility for the LNP and includes Progress Energy's Chief Executive Officer ("CEO"), Chief Financial Officer, the CEOs of PEF and Progress Energy Carolinas, and the Executive Vice President – Energy Supply. I update the SMC with respect to the LNP, the EPC Agreement, and the Consortium discussions and negotiations.

II. PURPOSE AND SUMMARY OF DIRECT TESTIMONY.

Q. What is the purpose of your direct testimony?

A. I will explain the Company's implementation of the decision made last year to proceed with the LNP on a slower pace. This decision focused LNP work on obtaining the Combined Operating License ("COL") for the LNP from the Nuclear Regulatory Commission ("NRC") while minimizing near term costs until after the LNP COL is obtained. This decision was explained in detail in the Company's April 2010 testimony and exhibits in this proceeding in Docket No.

100009-EI. The Commission determined that PEF's decision to continue pursuing a COL for the LNP was reasonable in its Order No. PSC-11-0095-FOF-EI in Docket No. 100009-EI.

I will further provide and explain the Company's long-term feasibility analysis consistent with Commission Order No. PSC-09-0783-FOF-EI in Docket No. 090009-EI. This will include a discussion of the Company's quantitative and qualitative feasibility analyses for the LNP. Based on the quantitative and qualitative feasibility analyses, the LNP continues to be feasible at this time.

Q. Do you have any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit No. ___ (JE-1), NRC revised review schedule for the LNP Combined Operating License Application ("COLA");
- Exhibit No. ___ (JE-2), a graphic illustration of the steps and timing of the PEF LNP COLA review process;
- Exhibit No. ___ (JE-3), a chart of the current long lead equipment ("LLE") purchase order disposition status;
- Exhibit No. ___ (JE-4), PEF's updated cumulative life-cycle net present value revenue requirements ("CPVRR") calculation for the LNP compared to the cost-effectiveness analysis presented in the Need Determination proceedings for Levy Units 1 and 2;
- Exhibit No. ____ (JE-5), a composite exhibit of PEF's rating agency reports;

- Exhibit No. ___ (JE-6), illustrative example of estimated typical customer bill impact of the near-term LNP costs in 2010-2012;
- Exhibit No. ___ (JE-7), compound annual growth rates for PEF retail customers; and
- Exhibit No. ___ (JE-8), estimate updates of LNP costs post-COL receipt.

These exhibits were prepared by the Company, or they are market reports generally used and relied on by the public and regularly used by the Company in the regular course of its business, and they are true and correct.

Q. Please summarize your direct testimony.

A. The Company is implementing its decision made last year to proceed with the LNP on a slower pace. The Company has focused its efforts on obtaining the LNP COL from the NRC and obtaining or fulfilling other regulatory permit requirements for the project. PEF expects to obtain the LNP COL in the second quarter of 2013 at the earliest. PEF is further performing other work consistent with its decision to proceed with the LNP on a slower pace. This includes the disposition of LLE purchase orders and preparations for an updated transmission study. In summary, PEF is reasonably performing the work necessary to move the LNP forward on a schedule with the expected in-service dates for Levy Units 1 and 2 in 2021 and 2022, respectively.

PEF has performed an updated feasibility analysis for the LNP consistent with the Commission's rule, Orders, and prior PEF analyses that have been approved by the Commission. This analysis demonstrates that the LNP continues to be feasible from both a regulatory and technical perspective. The updated feasibility analysis further demonstrates that the LNP continues to be economically feasible at this time. The Company's qualitative feasibility analysis of the enterprise risks facing the LNP reveals some change in the enterprise risks since last year. There have been no dramatic increases or decreases in the uncertainty associated with the risks facing the project, and there have been no fundamental changes in these risks that indicate a need to either accelerate or cancel the LNP at this time. Essentially, the Company's updated feasibility analysis confirms the Company's decision last year to proceed with the LNP on a slower pace.

III. IMPLEMENTATION OF LNP MARCH 2010 DECISION.

Q. What is the current status of the LNP?

A. The Company continues work on the LNP consistent with the Company's March 2010 decision to proceed with the LNP on a slower pace by extending the partial suspension and focusing near-term work on obtaining the COL. The Company implemented this decision with the execution of Amendment 3 to the EPC Agreement. As we explained in our testimony last year in Docket No. 100009-EI, Amendment 3 allowed PEF to implement the COL- focused option while minimizing near term costs and maintaining the favorable terms and levels of risk of the EPC Agreement during the licensing period. The Commission determined that the Company's decision was reasonable in Order No. PSC-11-0095-FOF-EI in Docket No. 100009-EI.

As a result, the Company is proceeding with the work necessary to obtain the LNP COL from the NRC, and engineering support work associated with the NRC approval of the AP1000 Standard Plant Design and Reference COLA ("R-COLA"). The Company is also proceeding with work in 2011 and 2012 necessary to meet the current anticipated in-service dates for Levy Units 1 and 2 in 2021 and 2022, which is based on receiving the COL by the second quarter of 2013. This work generally falls within the following broad task descriptions for the LNP: (1) the performance of work activities needed to support environmental permitting and implementation of conditions of certification ("CoC"); (2) the continued disposition of long lead equipment ("LLE") purchase orders; (3) the commencement of work on an updated transmission study given the current, anticipated in-service dates for Levy Units 1 and 2, the commencement of an updated Transmission Study, and any associated, targeted land acquisitions; (4) the preparations for, and the negotiations of, the EPC Agreement Amendment(s) necessary to efficiently end the current partial suspension of the LNP and continue with the LNP work on the current, anticipated LNP schedule; (5) continued participation in industry groups to advance the AP1000 design and operation; (6) active involvement in industry groups such as the Nuclear Energy Institutes ("NEI") New Plant Working Group and Nuclear Plant Oversight Committee in addition to INPO's New Plant Deployment Executive Working Group to engage and support industry peers and constructively influence NRC senior management in the development of regulatory response to emerging issues;

and (7) continued joint owner negotiations. PEF will continue to provide for the project management of these work tasks for the LNP in 2011 and 2012.

Q. What is the status of the LNP COLA?

A. I have attached as Exhibit No. ___ (JE-1) the current NRC review schedule for the LNP COLA. The Company filed its COLA with the NRC in July 2008 and it was docketed with the NRC for acceptance review in October 2008. This acceptance review initiated a period of NRC Requests for Additional Information ("RAIs") to respond to NRC questions about the LNP COLA. This period for NRC RAIs officially ended in May 2010 with the successful completion of the NRC RAIs. This does not mean that the NRC will not have any more questions about the LNP COLA and work on open RAIs is on-going, however, the initial NRC review of the LNP COLA and the RAIs generated by that review have been completed.

As also indicated in Exhibit No. ___ (JE-1), the draft environmental impact statement ("EIS") for the LNP was issued in August 2010. The environmental review is one of the three parts to the NRC COLA review. The environmental review includes the review and issuance of a draft EIS for the LNP, a period of public comment and review, and the review and issuance of a final EIS ("FEIS") for the LNP. The public comment period for the LNP draft EIS ended on October 27, 2010. The NRC staff responses to the public comments on the LNP draft EIS are due November 2011. The current NRC milestone for the FEIS is April 2012.

The second part of the NRC COLA review is the review and issuance of a Final Safety Evaluation Report ("FSER"). This is preceded by NRC review of the LNP COLA and the NRC's issuance of an Advanced Safety Evaluation Report ("SER") with no open items. The current NRC milestone for issuance of the Advanced SER is September 2011. The next step is review of the Advanced SER with no open items by the Advisory Committee on Reactor Safeguards ("ACRS"). The ACRS is independent of the NRC staff and reports directly to the NRC. The ACRS is an advisory body that is structured to provide a forum for experts representing different technical perspectives. The ACRS provides independent advice to the NRC for consideration by the NRC in its licensing decisions. The NRC milestone for the ACRS review and report is January 2012. The ACRS review and report is followed by NRC review and the issuance of a FSER. The NRC milestone target for issuance of the FSER for the LNP COLA is April 2012.

The final part of the NRC COLA review is a formal hearing before the NRC Atomic Safety and Licensing Board ("ASLB") for any contentions to the LNP COLA admitted by the ASLB. In April 2009, the ASLB allowed three private anti-nuclear groups, the Nuclear Information and Resource Service ("NIRS"), the Ecology Party of Florida ("EPF"), and the Green Party of Florida ("GPF"), to intervene in PEF's NRC LNP COLA docket. Later, on July 8, 2009, the ASLB ruled on their contentions and admitted parts of three contentions to the LNP COL. One of those three admitted contentions has since been dismissed by the ASLB. A hearing is required for the remaining admitted contentions. The Company currently anticipates that the ASLB hearings will start in October 2012.

All three parts of the NRC COLA review for the LNP COLA must be complete before the NRC will issue a COL for the LNP. The Company currently expects the NRC to complete this review and issue the LNP COL in the second quarter of 2013. Exhibit No. ___ (JE-2) to my testimony graphically illustrates the steps and timing of the LNP COLA that I have addressed in my testimony.

Q. Has the expected date for NRC issuance of the LNP COL changed?

A. Yes. At this time last year, based on the NRC's actions with respect to the LNP COLA and the NRC's review of the AP1000 Standard Plant Design, we anticipated that the NRC would issue the LNP COL at the end of 2012 or beginning of 2013 at the latest. We expressed, however, our view last year that the regulatory schedule uncertainty at the NRC had increased with respect to the LNP COLA review and the NRC's review of the AP1000 Standard Plant Design under the AP1000 Design Control Document ("DCD") amendment before the NRC. Our view that there was heightened regulatory schedule uncertainty at the NRC proved to be well founded. We expect now that issuance of the LNP COL has slipped from late 2012 or early 2013 to the second quarter of 2013 at the earliest.

Q. Did this change in the expected issuance of the LNP COL adversely impact the scheduled in-service dates for the Levy units?

A. No, we do not think it has at this point. Our decision to proceed with the LNP on a slower pace by focusing work on obtaining the COL resulted in a longer term schedule shift than a schedule shift that only accounted for prior NRC regulatory schedule uncertainty. I testified last year that the NRC regulatory schedule shifts at that time resulted in a minimum LNP schedule shift of 36 months, but that this was aggressive given the continued regulatory uncertainty that existed with the NRC LNP COLA and AP1000 DCD reviews. A 36-month schedule shift would have resulted in in-service dates of 2019 and 2020 for Levy Units 1 and 2. Our decision to proceed on a slower pace with the LNP resulted in a schedule shift beyond 36 months to the currently anticipated in-service dates of 2021 and 2022 for Levy Units 1 and 2. The current change in the expected issuance of the LNP COL from late 2012 or early 2013 to the second quarter of 2013 at the earliest does not appear to adversely impact the expected 2021 and 2022 in-service dates for the Levy Units at this time. If there are further shifts in the NRC regulatory review schedules for the LNP COLA or the AP1000 DCD amendments, however, the currently anticipated in-service dates for the Levy Units may be impacted.

Q. What is the status of the NRC review of the AP1000 Standard Design?

A. The NRC is still proceeding with the AP1000 Standard Design review pursuant to the NRC's revised schedule for the AP1000 DCD review issued June 21, 2010. According to that schedule, the NRC will complete the AP1000 DCD review and issue a final rule approving the AP1000 design by September 2011. The NRC and ACRS have reviewed the AP1000 design and declared that it is safe and meets all regulatory requirements. Further, on February 11, 2011, the NRC published for public comment the proposed rule that would amend the certified

AP1000 reactor design for use in the United States. This action is consistent with the current AP1000 DCD review schedule providing for the issuance of a final rule by September 2011.

Q. Are there other NRC regulatory reviews that have an impact on the LNP COL issuance schedule?

A. Yes. The NRC's issuance of the LNP COL is dependent on the issuance of both the final rule approving the AP1000 design certification amendment and the R-COL. The R-COL is the Georgia Power Vogtle AP1000 plant site. The R-COL for the AP1000 standard plant design is expected in November 2011. This approval will allow the PEF LNP COL to be issued after completion of NRC reviews and required hearings. Neither the AP1000 design certification nor the R-COL is expected to impact the LNP COL schedule.

Q. Are there any other potential impacts to the LNP COL schedule?

A. Yes. Recently, on March 11, 2011, a magnitude 9.0 earthquake occurred near the east coast of Honshu, Japan. This earthquake and the subsequent tsunami caused damage to at least four of six nuclear units located at the Fukushima Daiichi nuclear power station in Japan. These events have led to an increased interest globally in the safe design and operation of existing nuclear units and those that will be developed in the future. While it is still too early to fully assess the impact these recent events may have on the design review for new nuclear generation units, early indications are that these events will result in a review of the regulatory and design requirements for these new units, which may impact the AP1000 Design Certification and COLA review schedules. If the AP1000 Design Certification or COLA review schedules are impacted, then, the current expected schedule and project cost estimate for the LNP may be impacted.

Additionally, these events have raised public concerns regarding nuclear plant safety, which may reduce public support for new nuclear development. Reduced public support may lead to the introduction of new contention challenges to the LNP COLA approval. It may also increase the risk premium for the financing of new nuclear development and/or reduce the current interest in joint ownership in the LNP. These additional risks were included in the Company's qualitative feasibility analysis that is discussed later in my testimony.

As I testified above, however, PEF is actively involved in industry groups, such as the NEI New Plant Working Group, NEI New Plant Oversight Committee, and INPO New Plant Deployment Executive Working Group, which are working with the NRC to respond to emerging issues like the issues that have arisen in Japan. These groups follow and help establish consistent direction around industry and regulatory issues associated with New Nuclear Projects. These groups will be directly involved in addressing the implications from Japan and will help shape potential regulatory outcomes from this event.

Q. What COLA work is being performed in 2011 and 2012?

A. PEF will complete the testing and evaluation program that supports the seismic and structural evaluations for the LNP COLA. This includes completion of the

Roller Compacted Concrete ("RCC") mix design and specialty testing programs and the submission of structural, seismic, and other RAI responses to the NRC for the NRC review of the LNP COLA. PEF will also complete environmental surveys for the transmission routes and the work on, and submittal of, the United States Army Corps of Engineers ("USACE") Section 404 permit for the LNP. PEF will further provide the NRC with its annual LNP COLA update and begin preparations for the ASLB hearings and performance of activities required for conditions of certification and environmental permitting.

Q. What work is being performed in 2011 and 2012 for environmental permitting and the conditions of certification?

A. Work supporting the completion of the Environmental Impact Statement by the NRC and the USACE will continue in 2011 and 2012. The NRC is the lead agency on the preparation of the FEIS, which is needed to receive the COL. The NRC has scheduled April 2012 for publication of the FEIS. The USACE is a cooperating agency for the FEIS and will rely on it as part of their determination to issue the Clean Water Act Section 404 Permit, which will be needed for construction. We anticipate receiving the Section 404 Permit later in 2012. Work supporting the completion of the FEIS and the Section 404 Permit includes responding to requests for additional information from the agencies based on comments they received on the Draft Environmental Impact Statement ("DEIS"), which was published in August 2010, supporting consultations with other federal agencies regarding cultural resources and threatened and endangered species, and finalizing the Wetland Mitigation Plan to support the Section 404 Permit. Additionally, work will be conducted in 2011 and 2012 to ensure compliance with the Site Certification Conditions of Certification with regard to anticipation of site construction mobilization and initial construction land disturbance activities including: (i) County Building Permit determinations; (ii) Federal Aviation Authority ("FAA") lighting compliance; (iii) Avian Protection Plan; (iv) Threatened and endangered species surveys (e.g., Gopher Tortoise, Red-Cockaded Woodpecker, and Scrub Jay); (v) Construction site Storm Water Pollution Prevention Plan; (vi) Surface Water Management System Final Plans; and (vii) County road crossing and driveway permits.

Q. You also mentioned the disposition of LLE items, can you explain what that work involves?

A. Yes. The LLE is a reference to fourteen equipment items most of which were part of the Company's Letter of Intent ("LOI") with the Consortium that were later incorporated into the EPC Agreement when it was executed. As a result, the LLE work progressed in accordance with the schedules for LLE included in the EPC Agreement. The Company's initial decision to partially suspend, and ultimate decision to extend the partial suspension period to proceed with the work on a slower pace until the COL is obtained, necessarily suspended the LLE work in accordance with the EPC Agreement schedules. This decision required the Company to work with the Consortium and its vendors on a process to disposition the LLE purchase orders ("POs") in accordance with the Company's decision.

The LLE PO disposition process in 2009 and 2010 is described in my March 1 pre-filed direct testimony in this proceeding.

As I testified there, PEF employed a LLE PO disposition methodology that combined quantitative and qualitative criteria to meet the Company's objectives to minimize the near term costs and impact to customers while maintaining optimal flexibility for the future LNP construction. This methodology was used for each LLE PO item for the three potential paths, (1) continue and store, (2) suspend and resume, and (3) cancel and re-negotiate. As I also testified in my March testimony, using our LLE PO disposition methodology we recommended to senior management to pursue negotiations with the Consortium and its vendors to continue and store seven (7) LLE items and to suspend and resume seven (7) LLE items. Some of the "continue and store" recommendations were based on options limited to continue and store or cancel and re-negotiate by one vendor. Final LLE PO disposition decisions were made when negotiations were complete with the Consortium and its vendors.

Not all decisions on the disposition of LLE items were made in 2010. The majority of the outstanding LLE information (excluding the final proposals on the [redacted]), that was needed for final disposition was provided from the Consortium to PEF on February 1, 2011. Following the receipt of that information, PEF completed its reviews and made its final determination of disposition of all outstanding equipment but one.

Q. What were the final LLE PO disposition decisions made by the Company?

A. The LLE PO disposition negotiations are now complete for all but one of the LLE POs. PEF continues to negotiate suspend and resume terms with the Consortium and vendor for the [redacted]. Otherwise, as demonstrated in Exhibit No. ___ (JE-3) to my testimony, PEF successfully negotiated the disposition of LLE PO items with the Consortium and its vendors for thirteen (13) of the fourteen (14) LLE POs consistent with PEF's recommended decision to senior management. Change orders have either been executed or soon will be executed to implement PEF's LLE PO disposition decisions.

Q. Has the Company's LLE PO disposition decisions had an impact on the LLE PO disposition costs?

A. Yes. As I testified in March 2011, the Company initially included [redacted] for the estimated LLE PO disposition costs in senior management presentations in early March 2010 that served as part of the basis for the Company's decision to proceed with the LNP on a slower pace. This was a conservative estimate based on the estimated costs to continue or cancel the LLE POs for later re-negotiation. The Company included [redacted] of this estimated cost in its actual/estimated 2010 cost estimates. The Company's ability to identify a third option – suspend and resume – to methodically identify recommended LLE PO dispositions, and to successfully negotiate the disposition of LLE POs consistent with the recommended disposition has reduced the estimated LLE PO disposition cost impact to PEF and its customers.

The Company included approximately [redacted] in the 2011 actual/estimated costs for LLE PO disposition (the actual/estimated 2010 LLE PO disposition costs were not incurred in 2010). This estimate may change with resolution of the final LLE PO disposition; however, the cost for the ultimate disposition of all LLE POs will still be well below the Company's initial estimate for the LLE PO disposition costs. These results depended on the Company implementing its LLE PO disposition methodology in Consortium and vendor LLE PO disposition negotiations. The ability to reasonably support the Company's LLE PO disposition decisions directly contributed to the lower LLE PO disposition cost impact to PEF and its customers.

Q. You testified that PEF would be moving forward with an updated transmission study, can you also explain why that work is necessary?

A. Yes. An updated transmission study is necessary because the state-wide transmission system that the LNP will connect with is not static, but instead changes with PEF and other electric utility resource and transmission system additions. The initial transmission study for the LNP was performed for the Levy units based on 2016 and 2017 in-service dates. Now that the Levy units are expected to come on-line in 2021 and 2022, an updated transmission study must be performed to determine the transmission system impacts of the LNP given the later than originally planned in-service dates for Levy Units 1 and 2 and the changes in the state-wide transmission system. PEF will begin preparations for the updated transmission study in 2011. It is expected that a new transmission study will be completed by late 2012.

Q. Will the updated transmission study have an impact on the LNP project cost?

A. The results of the transmission study are not known at this time. Once the updated LNP transmission study is completed, the results are analyzed, and a project work scope based on the study is defined we will be in a better position to estimate the impact of such changes, if any, on the LNP project cost.

Q. You also testified that you will be preparing for and negotiating an Amendment to the EPC Agreement, can you explain why that work is necessary for the LNP?

A. Yes. The Company's decision to proceed with the LNP on a slower pace was implemented through Amendment 3 to the EPC Agreement. Amendment 3 to the EPC Agreement extended the existing partial suspension while primarily providing for work necessary to support receipt of the LNP COL to continue. Another Amendment to the EPC Agreement is necessary to terminate the partial suspension terms and establish the basis for a full notice to proceed ("FNTP") and a contract schedule for continuation of all work necessary to complete Levy Units 1 and 2. PEF will commence preparations for the negotiation of this Amendment in 2011 and proceed with the contract negotiations in 2012. These negotiations will include reviewing the terms and conditions required to implement the FNTP and a new schedule for the LNP work consistent with our current expected schedule for the in-service dates for Levy Units 1 and 2. These negotiations will also include additional, potential changes that have developed since the partial suspension was implemented.

Q. Are there any potential changes that have developed that will need to be addressed during the Amendment negotiations?

A. Yes. One issue to address is the negotiation of existing EPC Agreement design change proposals. These design change proposals exist because of changes to the AP1000 design identified during Westinghouse Design Finalization activities. When PEF executed the EPC Agreement with the Consortium the Agreement incorporated the known changes specified in the EPC Agreement. Since execution of the EPC Agreement, the Consortium has identified additional design changes due to Design Finalization and in response to the NRC AP1000 DCD review. Currently, the NRC is reviewing AP 1000 DCD Revision 19 for approval. The Design Change Proposals identified since the execution of the EPC Agreement will need to be incorporated into the EPC Agreement. These negotiations will include a determination of financial responsibility for the Design Change Proposals between the Consortium and the Company. The negotiations with respect to amending the EPC Agreement to include these Design Change Proposals, therefore, may impact the LNP schedule and the LNP total project cost. The impact of the negotiations to incorporate these Design Change

Proposals on the LNP schedule and total project cost cannot be determined at this time.

Q. Is all of this work necessary for the LNP?

A. Yes. All of this work is reasonable and necessary in 2011 and 2012 to move the LNP forward on a schedule with the expected in-service dates for Levy Units 1 and 2 in 2021 and 2022, respectively. PEF is moving forward with this work on the LNP in 2011 and 2012 with the intent of meeting the current estimated in-service dates for Levy Units 1 and 2. All of this work in 2011 and 2012 is reasonable and necessary to meet that schedule.

IV. TRUE UP TO ORIGINAL COST FILING FOR 2011.

Q. Has the Company filed schedules to provide information truing up the original estimates to the actual costs incurred?

A. Yes. These true up to original cost ("TOR") schedules are attached as Exhibit No. ___ (TGF-3) to Mr. Foster's testimony. I am co-sponsoring schedule TOR-6 and sponsoring schedule TOR-7 attached as Exhibit No. ___ (TGF-3) to Mr. Foster's testimony. This updated project baseline estimate is consistent with the estimate PEF provided in the TOR schedules last year in Docket No. 100009-EI. The total project cost estimate for the LNP has not changed; however, the estimated annual expenditures have been revised to reflect our latest projections. It is still premised on a conservative Class 4/Class 5 estimate consistent with the best practices of the Association for the Advancement of Cost Engineering ("AACE"), the fundamental terms and conditions of the existing EPC Agreement, as amended, and the current project schedule for the LNP with the in-service dates for Levy Units 1 and 2 in 2021 and 2022. As I previously testified, however, the current total project cost estimate is dependent upon, among other things, Consortium negotiations.

V. FEASIBILITY.

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

A. Yes. The Company prepared a feasibility analysis consistent with the feasibility analysis it performed for the LNP in 2010 that was reviewed and approved by the Commission in Order No. PSC-11-0095-FOF-EI in Docket No. 100009-EI. This feasibility analysis is a two-step process. The Company employs both a qualitative and quantitative feasibility analysis. The qualitative analysis is an analysis of the technical and regulatory capability of completing the plants, the enterprise risks, and the costs and benefits of completing the Levy nuclear power plants. The quantitative analysis is an updated CPVRR economic analysis that includes comparisons to the cost-effectiveness CPVRR analysis in the Company's need determination proceeding for the LNP described in Order No. PSC-08-0518-FOF-EI. The Company's updated CPVRR economic analysis for the LNP is included as Exhibit No. ___ (JE-4) to my testimony. I explain the results of the Company's feasibility analysis for the LNP in my testimony and the exhibits to my testimony.

Q. Beginning with the Company's qualitative analysis, is the LNP feasible from a technical standpoint?

A. Yes, it is. The completion of the LNP is technically feasible if the AP1000 nuclear reactor design can be successfully installed at the Levy site. The AP1000 nuclear reactor design remains a viable nuclear reactor technology. Other utilities, in particular Southern Company and SCANA, are still moving forward with the licensing and construction of their proposed nuclear units using the AP1000 design. Southern Company continues with preconstruction site work at the Vogtle site where it will employ the AP1000 nuclear reactor technology. The Haiyang and Sanmen AP1000 nuclear reactor projects are under construction in China. In fact, in February 2011, the Chinese government made a policy decision to primarily focus on the development of nuclear generation using the AP1000 design due to its passive safety system. The continued development and construction of nuclear reactors using the AP1000 design demonstrates that the AP1000 reactor is a viable nuclear technology.

The review of the Company's LNP COLA using the AP1000 design continues at the NRC. There is no indication in this review that the AP1000 design is not viable or that it cannot be used at the Levy site. In fact, as we indicated last year, the NRC review of the LNP COLA is proceeding with the understanding that the AP1000 nuclear reactor design will be used at the Levy site. The Company is continuing with its work on the necessary tests to complete the NRC's review of the geotechnical aspects of the Levy site in 2011 and expects at this time that the NRC review will be complete in accordance with the current NRC schedule for the LNP COLA.

Q. Is the LNP feasible from a regulatory perspective?

A. Yes. PEF still believes that all legal and regulatory licenses and permits for the LNP can be obtained. The NRC has not suspended or terminated its review of the LNP COLA, the RCOLA, or the AP1000 DCD review and is, in fact, proceeding with these reviews. The NRC has provided PEF no indication that these reviews will not be completed and the applicable licenses issued. The NRC and ACRS have reviewed the AP1000 design and declared that it is safe and meets all regulatory requirements. As a result, there is no reason to believe that the LNP COL will not be issued upon completion of the NRC's review of the LNP COLA.

Q. Does the nuclear incident in Japan following the earthquake and tsunami that you discussed previously change your assessment of the feasibility of the LNP from a regulatory perspective?

A. No, not at this time. As I testified earlier, these events may lead to further delays in the AP1000 DCD review or COLA reviews, including the LNP COLA review, but that is an expected part of the process, not a reason to believe that the AP1000 design will not be ultimately approved or the COLA reviews successfully completed and the COLs issued. The United States nuclear industry has a long history of continuously incorporating lessons learned from the operating experience of nuclear power plants around the world. The nuclear industry will accordingly carefully analyze the Japanese accident and how reactors, systems, structures, components, fuel, and operators performed and incorporate lessons learned into United States reactor designs and operating practices. We fully expect this process to apply to existing nuclear power plants and those that will be built in the future. This is the way we operate to ensure the safety at existing and planned nuclear power plants. The fact that the nuclear industry will incorporate lessons learned from the recent Japanese experience in the review of new nuclear power plants does not mean, therefore, that there is any reason to believe the regulatory approval will not ultimately be granted following that review.

All existing and planned nuclear power plants in the United States must be designed to deal with a wide range of natural disasters, whether they are earthquakes, tsunamis, tornados, hurricanes, storm surges, floods, or other extreme seismic or weather events. This includes the AP1000 nuclear reactor design. Further, the AP1000 is a passive design that does not rely on emergency diesel generators for safety related power to ensure core cooling. Unlike the damaged Japanese nuclear units, which depended on electrical power from diesel generators that were inoperable as a result of the tsunami for safety related cooling with the loss of power due to the earthquake and tsunami, the AP1000 design will automatically place itself in a safe shutdown state, cooling the reactor passively without reliance on an external power source for some time until power is restored to the active coolant systems. This passive system relies on internal condensation and natural recirculation, natural convection and air discharge, and stored water all contained within the robust structures of the containment and its shield building to cool the reactor even without electrical power.

Additionally, the Japanese reactors at Fukushima were in a high seismic risk area on the coast and located on the same power plant site. The LNP site is located in an area of low seismic risk, it is located away from the Crystal River site therefore avoiding the concentration of generation at one site, and the LNP site is located approximately eight miles inland at an elevation of fifty feet. In any event, the application of the AP1000 design to the LNP site will be designed and built to withstand natural disasters, including earthquakes, tsunamis, and the more likely hurricanes and storm surges. For example, the tsunami that struck the Japanese reactors at Fukushima was reported at 14 meters (or 47 feet). Although a tsunami of this magnitude is considered to be unrealistic in the Gulf of Mexico, evaluation has determined that a tsunami of this magnitude would not result in flooding of the LNP. The application of the AP1000 design at the LNP will meet all requirements to operate safely under extreme seismic and weather conditions.

Further, the AP1000 shield building design was revised to increase structural design to address concerns regarding possible aircraft impact. The Levy COLA also incorporates actions to address beyond design basis events in response to security considerations following 9/11. Although these strategies are developed in response to projected security threats, the strategies also provide additional protection against any beyond design basis event regardless of the initiating event. Specifically, the LNP COLA contains Mitigative Strategies Description and Plans that the Levy plant will implement in the event that a large area of the facility is lost due to beyond design basis events, such as explosions or fire, unlike the specific Japanese nuclear units located at Fukushima.

As a result, we expect the AP1000 design will receive all required regulatory approvals. These regulatory approvals may take longer as a result of the assessment of the Japanese nuclear reactor operating experience and incorporation of lessons learned. A reduction in public support for new nuclear development as a result of the public reaction to the nuclear operating experience in Japan following the extreme earthquake and tsunami may also slow the regulatory approval process for the AP1000 and COLAs, for example, as a result of potential new contention challenges. These potential risks were taken into account in our qualitative feasibility analysis for the LNP. However, there is no reason to believe now that the regulatory approvals for the AP1000 and the COLAs will not be obtained as a result of recent events in Japan. We are, of course, closely monitoring international and national responses to the Fukushima event.

Q. How did the Company evaluate the enterprise risks associated with the LNP?

A. As we explained last year, the qualitative analysis of the enterprise risks facing the LNP is more of a holistic analysis rather than a measurable or computable analysis. The effects of most enterprise risks cannot be quantified or measured in mathematical terms, they cannot realistically be weighed against other enterprise risks, and, therefore, they cannot be compared based on a quantifiable or measureable standard. The Company must instead evaluate the enterprise risks by identifying events or circumstances that have changed and then use its judgment to determine if those events or circumstances represent fundamental changes in the project's enterprise risks. The Company continued to employ this process for evaluating the LNP enterprise risks as part of its qualitative feasibility analysis this year.

Q. What conclusions did the Company form from its evaluation of the LNP enterprise risks?

A. As a result of our qualitative analysis of the LNP enterprise risks last year we concluded that there was a noticeable increase in the amount of uncertainty associated with the enterprise risks impacting the LNP. Last year, this analysis confirmed the Company's decision to move forward with the LNP on a slower pace with a narrowed scope of work that was focused on obtaining the LNP COL. Our qualitative analysis of the LNP enterprise risks this year confirms that this decision was the correct one to make last year. While we have noticed a few favorable or slightly favorable trends in the LNP enterprise risks, most enterprise risks remain neutral compared to our evaluation last year, and there are a couple of unfavorable trends that we are watching closely to determine if they represent fundamental changes in the project enterprise risks. Our updated qualitative analysis of the LNP enterprise risks, therefore, confirms our decision to take a more cautious approach to proceeding with the LNP.

Q. What were the favorable trends in the enterprise risks facing the project?

A. One favorable trend is in the Company's access to capital. The reason for this favorable trend is the announcement this year of the proposed merger between Progress Energy, Inc. and Duke Energy, Inc. The rating agencies and equity analysts have generally responded favorably to the announced merger proposal. Upon announcement of the proposed merger, Fitch Ratings ("Fitch") affirmed the ratings of Progress Energy and the Company and indicated the rating outlook was stable. Moody's Investors Service ("Moody's") also affirmed the Company's credit ratings and placed them on stable outlook. Standard & Poor's ("S&P") placed Progress Energy and the Company on CreditWatch with positive implications in response to the announcement of the proposed merger. Moody's further commented that the proposed merger better positions the combined company to undertake the construction of new nuclear generation. These rating agency reports are included as Exhibit No. ___ (JE-5) to my testimony.

The proposed merger is a positive development for the Company's position with respect to access to capital for necessary capital projects including the LNP. This positive development must be tempered, however, because it depends on the merger of the two companies, which has not yet occurred. The merger is subject to several regulatory approval processes and will take approximately one year to close if those regulatory approvals are obtained. As a result, during 2011 and until the closing, the two companies will continue to operate as separate entities and the merger has no impact on the Company or the LNP.

Q. Are there any other reasons to be cautious about drawing the conclusion that there is an improvement in the risk associated with the Company's ability to raise the necessary capital for the LNP?

A. Yes. There are other cautionary notes to the positive development in the Company's potential access to capital for the LNP. That is, first, that the current positive rating agency and equity analyst comments must be placed in the context of the prior rating agency actions and comments on the Company's credit and capital position. As we explained last year, following the adverse base rate decision by the Commission, Moody's placed PEF's long-term debt ratings and short term commercial paper rating on review for possible downgrade in January 2010, and S&P placed PEF's long-term ratings on CreditWatch with negative implications in January 2010. Moody's later downgraded PEF one notch in April 2010. S&P later reaffirmed the Company's credit rating but with a negative outlook in March 2010. As a result, the recent positive reactions from the rating agencies due to the announcement of the proposed merger between Progress Energy and Duke Energy does not change the fact that PEF's current credit ratings in 2011 are lower than they were prior these adverse rating agency actions in late 2009 and early 2010.

The reason for these adverse rating actions was the perceived decline in the political, regulatory and economic environments in Florida in 2009 and early 2010. The recent rating agency reports indicate there has been some stabilization in the political and regulatory environment in Florida, particularly with the Company's 2010 base rate settlement establishing base rates through 2012.

Improvement in the political, regulatory, and economic environments, however, will be necessary to maintain or improve PEF's current credit ratings. Indeed, Moody's – who downgraded PEF in early 2010 – made clear that any "[r]ating upgrades are unlikely given last year's adverse regulatory development in Florida," among other factors. See Exhibit No. ___ (JE-5) to my testimony. PEF will need to demonstrate to the rating agencies that it can obtain necessary rate relief for its prudent capital project and operational costs through the cost recovery mechanisms and future base rate proceedings to improve its credit ratings and, as a result, regain the ground lost in late 2009 and early 2010 with the credit agencies.

Second, the Company's recent experience with its Crystal River unit 3 ("CR3") nuclear power plant may impact the Company's credit ratings, and thus, its ability to raise capital for capital projects including the LNP. CR3 remains off-line as a result of a further delamination in one section of the exterior concrete to the CR3 containment building. The rating agencies have not taken any adverse credit action as a result of this event to date, but they are closely following it. S&P, for example, publicly announced that its ratings for PEF and Progress Energy are not immediately affected by this event, however, S&P further explained that timely and full recovery of remaining and additional repair and replacement power costs will be very important to S&P in continuing to support PEF's and Progress Energy's credit profiles. The on-going resolution of the recent events at CR3, and the ultimate reaction of the rating agencies and capital markets to that resolution, is another reason to be cautious regarding the

Company's future ability to raise capital at a reasonable cost for the Company's capital projects, including the LNP.

Q. Were there any other favorable trends in the LNP enterprise risks?

A. There was one other enterprise risk that was viewed as slightly favorable this year, largely as a result of the Company's decision to proceed with the LNP on a slower pace. This decision reduced the near-term capital costs for the LNP and, therefore, reduced the near term impact of these costs on customer bills as the Florida economy slowly rebounds. As we explained last year, the economic recession affected customer ability to pay for nuclear generation development and led to an increase in customer complaints in 2009 about any increase in their bills, including increases for new nuclear generation. The Company took steps in 2008 and again in 2009, in the respective nuclear cost recovery dockets, to mitigate the impact of nuclear cost recovery on customer bills as a result of the on-going recession. The Commission approved both of the Company's proposals and, as a result, the recovery of approved nuclear costs was deferred from 2009 to 2010 and then amortized over a five year period commencing in 2010. This action lowered customer bills in 2009 and 2010 due to the LNP costs.

The Company's decision last year to extend the partial suspension of the LNP under the EPC Agreement and proceed with the project work on a slower pace, focusing on obtaining the LNP COL, also reduced the near term costs of the project to PEF's customers. As a result of the Company's decision, the customer bills will be lower in 2011 and 2012. Exhibit No. ___ (JE-6) to my testimony includes a representative chart of the actual and estimated Levy residential bill in dollars per 1000 kilowatthours ("kWh") for 2010, 2011, and 2012. As the exhibit shows, PEF was able to reduce the LNP costs to customers on their bills as the economy slowly recovers from the recession in 2011 and 2012. As a result, PEF believes the customer ability to pay for and support new nuclear development has a slightly favorable impact. The customer ability to pay for and support new nuclear development will, of course, be tested again in future years, however, beyond the LNP COL when work on the project will increase to meet the current, estimated in-service dates for Levy Units 1 and 2 in 2021 and 2022.

Q. What risks did the Company determine to be neutral in the Company's analysis of enterprise risks?

A. The enterprise risk associated with the economic conditions generally and in particular in Florida is, at best, neutral at this time. As we explained last year, the country and, in particular, Florida suffered the worst economic recession in late 2008 and 2009 since the Great Depression. The effects of this recession continued in this country throughout 2010, especially in Florida, which was particularly hard hit in the construction and housing industries. Throughout 2010, Florida continued to be among the leading states in the number of foreclosures, business failures, and unemployment, even though economic conditions slowly began to improve in the country in mid- to late 2010. There are signs that economic conditions are starting to improve in Florida in 2011, but this improvement is slow, and proceeding at a slower pace than the Company predicted last year.

The Florida unemployment rate is higher than the national average and the Florida housing market continues to decline on nearly every measure. Florida's year-over-year employment growth did not turn positive until the summer of 2010, but even then the increase remained anemic as employment levels in construction, manufacturing, and government sectors continued to decline. A robust construction industry has normally pulled Florida out of prior recessions, but this cannot be expected given the high vacancies in existing housing and commercial buildings. The expectations for improvements in the Florida economy are low. At best, a slow recovery is expected in 2011, but even this recovery may be potentially hampered by Florida's government budget shortfalls. If the economic recovery does not stall in 2011, it is expected to continue to grow slowly in Florida in 2012.

Q. How have these economic conditions affected the Company?

A. As we explained last year, PEF was not immune to the recession. Between 2008 and 2009 PEF lost customers in its service area. This loss of customers continued into 2010. PEF experienced twenty-one straight months of negative year-over-year retail customer growth that did not end until April 2010. PEF also experienced dramatic declines in customer energy sales in 2009 and a dramatic increase in low use accounts due to more vacant but active accounts as a result of the recession. These effects continued in 2010. On a weather normalized basis, PEF's retail megawatt-hour ("MWh") energy sales and KWH use per customer both declined in 2010. PEF's residential KWH use per customer in fact reached levels that were last experienced in 1993. The chart attached as Exhibit No. ___ (JE-7) to my testimony demonstrates the effects of the economic recession on PEF's residential and retail sales. Between 2000 and 2005, PEF's residential MWh sales grew at a rate of 2.9 percent and residential KWH use per customer grew at a rate of .4 percent. Total retail MWh sales grew at a rate of 2.2 percent. However, between 2005 and 2010, PEF's residential MWh sales declined by 1.6 percent and residential KWh use per customer declined at an even more dramatic rate of 2.3 percent. Total retail MWh sales declined 1.2 percent. As this exhibit makes clear, PEF's retail customer energy use and sales declined significantly during the recession and remains at levels well below energy use and sales levels prior to the recession.

As a result, PEF is digging out of a significant hole. Retail MWh sales are expected to remain flat and slightly increase over the course of 2011 with slow growth in 2012. Residential KWh use per customer is expected to remain flat through 2011 and 2012. Customer growth is expected to continue a slow rebound that began in mid-2010 with expected growth in both 2011 and 2012. As shown in Exhibit No. ___ (JE-7), between 2010 and 2015 residential MWh sales are expected to grow 1.4 percent while residential KWh use per customer is expected to grow only .2 percent. Retail MWh sales are forecasted to grow 1.9 percent and retail customer growth is forecasted at 1.3 percent over this period. While this forecast demonstrates a return to sales and customer growth following the recession, the growth has not returned to the pre-recession growth rates PEF experienced between 2000 and 2005.

Q. What has been the impact on customer demand for energy on PEF's system?

A. Lower customer growth and lower sales growth during the recession resulted in lower near term loads on PEF's system. Less generation, therefore, was required to meet the total energy demands required by PEF's system load during the recession. The return of slow customer and sales growth means an increase in retail load because increases in customers and sales drive increases in retail load. As I described previously, these increases are expected to continue in 2011 and 2012, but this growth is only replacing growth that was lost during the recession. Retail customer growth and sales growth is not anticipated to reach pre-recession levels until after 2012. This slow load growth reduces PEF's need for new base load generation in the short term. This is consistent with our decision last year to move forward with the LNP on a slower pace.

Q. Did the recessionary impacts you describe affect the Company financially?

A. Yes. Fewer customers, lower customer use, and lower energy sales during the recession translate into lower revenues. This impact continued into 2010 and led the Company to request additional non-cash relief in the form of certain accounting adjustments from the Commission as part of its base rate settlement that was approved by the Commission in 2010. This settlement provided the Company non-cash earnings while maintaining existing base rates through 2012 for PEF's customers. While this settlement stabilized PEF's earnings through 2012 and provides PEF customers stable base rates as the Florida economy slowly emerges from the recession, PEF must face the longer term impact of these lower revenues. Simply put, PEF is not generating sufficient revenues to cover its cost of service and provide it with cash earnings at a level to ensure the future investment of capital in the Company to meet its future capital needs.

The reasons PEF is in this situation are, first, even though PEF's retail MWh sales fell during the recession and are forecast to only slowly improve in 2011 and 2012, PEF cannot proportionally reduce its costs in response to these declining and flat sales revenues. PEF has an obligation to provide electric service on demand to its customers. PEF cannot shut down power plants and other assets when faced with declining or flat sales revenues to improve its financial position as many private companies without an obligation to serve can do. PEF must continually improve and maintain its capital assets to ensure that its customer energy needs are met instantaneously. To illustrate this point, even though retail energy sales declined significantly during 2009 and 2010, demand for energy at peak times on PEF's system did not decrease, it increased. PEF's customers set new winter peaks in 2009 and again in 2010. Peak demand drives capital investment in generation, transmission, and distribution. PEF must invest this capital to ensure that needed assets are in place to meet customer energy demands at the peak times. As a result, PEF's cost to meet customer peak demand for energy increased during the recession. Yet, PEF had less retail sales revenues to cover the costs of meeting the higher peak demands for energy that our customers require.

Second, providing electric service is a capital intensive industry. PEF must incur costs to build, replace, and maintain the generation, transmission, and distribution assets required to generate electrical energy for customers and transmit it from power plants to areas where it can be distributed to customer homes and businesses. These costs are primarily fixed costs because they are for existing assets that must be maintained, repaired, or replaced on a regular basis. PEF generally must finance these capital investments by obtaining funds from the capital markets. Financial market participants, either in the debt (bond) or equity markets, expect to be reimbursed for and earn a return on their investment in the debt and equity of the Company. Their continued willingness to invest the capital PEF needs to meet its service obligations depends on the Company's financial condition. The Company must generate sufficient revenues to cover all its costs, including its capital costs, by generating sufficient revenues to provide the return on the debt and equity invested in the Company that is expected.

Q. Has the Company's views on the Florida economy changed since last year?

A. No. We explained last year that it was unlikely that we would see significant improvement in PEF's sales revenues in 2011. We still believe that is the case. We expect the Florida economy to slowly improve in 2011 and 2012 with retail sales picking up only in 2012. We do not expect, though, a return to the pre-recession customer and sales growth. The recession in Florida was severe and it will take time for the Florida economy to recover. The rebound from this recession is expected to be much slower than the rebound from prior recessions.

It is important to remember too, that PEF is starting from a lower point in customer growth and retail sales, and a much lower point in customer usage than before the recession. Even with slow growth in customers and retail sales in 2011 and 2012, it will take time for PEF to regain the customers and retail sales levels lost in the recession. In other words, PEF has a big sales revenue gap to close in 2011 and 2012. This will take time, especially when residential customer usage is projected to remain flat in 2011 and 2012 and beyond, due to the economy and the Commission's Demand Side Management ("DSM") goals decision. As we explained last year, while PEF expects the economic recovery in Florida to improve in 2011, PEF does not expect this economic recovery will result in a significant improvement in PEF's near term financial position in 2011 and 2012.

Q. You mentioned the impact of the DSM goals decision on PEF, what is that impact?

A. We do not fully know yet. A final decision is expected later this year. What we do know is that the Commission's decision in Order No. PSC-09-0855-FOF-EG adopted goals for the Florida investor owned utilities ("IOUs") based on the enhanced Total Resource Cost ("E-TRC") test and that this test results in higher estimated energy savings than the other tests because it does not consider utility lost revenues or customer incentive payments in evaluating the costs and benefits of a DSM program. The Commission also adopted DSM goals for the IOUs based on historically excluded DSM measures that encouraged free riders because there was a payback of two years or less without incentives. Both of these decisions in the Commission's order increased the DSM goals beyond those proposed by the IOUs and previously approved by prior Commission actions. In fact, the PSC Order called for more than five times the energy reduction due to the adopted DSM goals compared to the energy reduction based on the previously accepted test for determining the DSM goals that PEF proposed. This means more DSM programs and measures at greater cost to customers and, with the higher DSM goals, lower energy usage overall. As a result, this decision will directly increase customer bills and indirectly reduce customer use and sales. PEF has included an estimate of this impact in its updated load forecast, but the exact degree and nature of all possible impacts cannot be determined at this time.

In November 2010, the Commission required PEF to file two plans for consideration. One plan corresponded to the DSM goals set for PEF by the Commission in Order No. PSC-09-0855-FOF-EG. The second plan involved DSM measures and programs that produced one-half the targeted DSM goals in Order No. PSC-09-0855-FOF-EG. The consideration of both plans is presently before the Commission. The ultimate impact of the DSM goals on PEF's load depends on the Commission's final decision implementing the DSM goals programs for PEF and the ultimate customer response to the DSM programs and measures. The estimated impact that PEF included in its updated load forecast, however, does result in lower customer usage and sales and contributes to the flat usage and slow energy sales growth resulting from the economic impact in 2011 and 2012.

Q. Are there other Florida regulatory or legislative actions that were evaluated in your qualitative analysis of the LNP enterprise risks?

A. Yes. We have continued to follow Florida legislation that may potentially impact the LNP. This includes recent legislation by the same state legislator who introduced similar legislation last year to repeal the nuclear cost recovery statute. This repeated legislative attempt to repeal the nuclear cost recovery statute contradicts the express State energy policy to increase fuel diversity and reduce Florida's dependence on fossil fuels subject to supply interruptions and price volatility that led to the enactment of the nuclear cost recovery statute. As we explained last year, such legislative actions concern the Company because the development of new nuclear generation in Florida is a long term project and continued legislative support -- as evidenced by the existing State energy policy and nuclear cost recovery statute and rule -- is necessary to successfully complete the project. The goals of fuel diversity and reduction of Florida's dependence on fossil fuels for energy generation cannot be met without continued legislative support. Because attempts to undermine the nuclear cost recovery statute have been unsuccessful so far we considered the reoccurrence of this proposed legislation this year to have a neutral impact in the qualitative analysis of LNP enterprise risks at this time. As the Company moves forward with the LNP, however, repeated attempts to undermine the current legislative and regulatory support for new nuclear development will raise further concerns with respect to the successful development of the LNP.

Q. What additional state legislative or regulatory policy decisions may impact the LNP that you evaluated in your enterprise risk analysis for the LNP?

A. PEF continues to follow the potential development of a renewable portfolio standard ("RPS") in Florida. As we explained last year, legislation was passed in 2008 instructing the Commission to produce a draft RPS rule for consideration by the state legislature. The Commission Staff developed a proposed RPS rule and the Commission, with some modifications to the proposed rule, voted to approve the proposed RPS rule in early January 2009 for submittal to the Florida Legislature. The gist of the proposed rule is a 20 percent renewable target by 2020 with a cap on incremental costs at two percent of retail revenue annually. Through two legislative sessions the Florida Legislature has failed to consider the Commission's proposed RPS rule. The Commission RPS docket remains open pending further direction from the Florida Legislature regarding a RPS standard for Florida.

There also is no federal RPS standard for utilities. An RPS that included energy efficiency was included in the Waxman-Markey proposal that passed the House. A similar RPS proposal was included in the Bingaman proposal that passed out of committee in the Senate. No RPS standard was adopted by Congress, however, as comprehensive energy legislation stalled in Congress in 2010. Recent movements in Congress have been toward a "Clean Energy" standard, which would include new nuclear, clean coal, and other non-traditional renewable resources. The outcome of energy legislation in Congress, including a federal RPS or "Clean Energy" standard, however, remains in doubt.

As we explained last year, the development of an RPS for Florida utilities will have an impact on the cost of utility resource decisions to meet the RPS. RPS resource options and resource alternatives that must be available when RPS resources are unavailable generally are more costly than conventional generation resource options. As a result, there will be customer bill impacts if an RPS is adopted for Florida utilities. The precise effects of the RPS on resource decisions and costs to customers, however, remain uncertain at this time.

Q. Are there any other federal or state policy issues that you evaluated this year as part of your qualitative feasibility analysis?

A. Yes. State and federal support for new nuclear development is an important qualitative consideration. Federal support for new nuclear generation remains unclear. The President has continued to express support for new nuclear generation similar to his announcement in the 2010 State of the Union address supporting loan guarantees for new nuclear development, however, little progress has been made in a year in turning this vocal support into concrete action. Additionally, the administration still appears to support the abandonment of Yucca Mountain as the federal nuclear waste storage option despite opposition to this decision by representatives, senators, state attorneys general, and the National Association of Regulatory Utility Commissioners ("NARUC"). As a result, while presidential and administrative statements supporting new nuclear development are welcomed, the current administration's concrete support for the development of new nuclear generation remains uncertain and ill defined. At best, federal support for nuclear generation has a neutral impact on our current qualitative feasibility analysis.

Q. You have testified to favorable and neutral trends in the LNP enterprise risks, were there any identified unfavorable trends?

A. Yes. One of the two unfavorable trends we observed was in the federal and state energy and environmental policy with respect to climate control and greenhouse gas ("GHG") legislation and regulation. This fundamental enterprise risk is important to the LNP from both a qualitative and quantitative perspective. Quantitatively, the effect of climate control and GHG legislation and regulation is reflected in an estimated carbon cost impact in the Company's economic, CPVRR feasibility analysis discussed in more detail below. Qualitatively, climate control and GHG legislation or regulation promotes nuclear generation because nuclear energy generation produces no GHG emissions. As we explained last year, additional clarity regarding federal and/or state climate and environmental policy provides the Company valuable information regarding the qualitative and quantitative benefits of nuclear energy generation. Unfortunately, that additional clarity has not yet been provided at either the federal or state government level.

In Washington, Congress did not take action on a climate or energy bill in 2010. With the elections in 2010, action on this legislation either through the form of a cap-and-trade system or carbon tax is not expected in 2011 and remains unclear for 2012. As we observed last year, debate continues over potential climate control legislation, but Congress seems no closer to proposed legislation to regulate GHG emissions now than it did in 2008, and there appears to be no reason to expect Congressional action this year.

There similarly has been no further action on climate control legislation or regulation at the state level. As we explained previously, the Florida Legislature directed the Florida Department of Environmental Protection ("FDEP") to delay the adoption of any carbon emissions rule until after 2009 and to submit any such rule to the Florida Legislature for approval. The FDEP decided not to ask the Florida Legislature to approve the adoption of a carbon emissions rule in the 2010 Florida Legislative session and we are not aware that the FDEP has asked or will ask the Florida Legislature to consider such regulation in 2011. As a result, there is still no movement toward federal or state climate control legislation that provides guidance on what the regulation of GHG emissions will look like, when it will be implemented, and what it will cost.

Because the legislation regulating GHG emissions remains uncertain this year and potentially next year too, we concluded that the lack of clear legislative direction on climate control at the federal and state government levels was an unfavorable trend in our qualitative feasibility analysis. Depending on the structure and levels of GHG emission control standards, such legislation can have a significant impact on PEF's generation fleet and future generation resource planning, in particular, the LNP. The lack of certainty regarding what this legislation will be and when it will impact the Company negatively impacts our evaluation of this risk in our current qualitative feasibility analysis.

Q. Does this assessment mean that the Company does not expect there to be climate control legislation or regulation?

A. No. PEF still expects some form of climate control legislation at the federal and/or state level. Indeed, much of the debate about climate control legislation or regulation has concentrated on what that legislation should entail and when it should be implemented rather than whether it should be implemented at all. No general movement to abandon climate control legislation or regulation appears to be gaining significant support at the federal or state government levels. However, the continued uncertainty about what form this regulation will take and when it will occur while federal and state climate control and environmental policy with respect to GHG emissions is determined, is a concern. The fact that a uniform climate control policy remains unsettled, then, is the reason this enterprise risk is viewed as an unfavorable trend for the LNP.

In fact, although Congress and the Florida Legislature have not acted on some uniform climate control legislation, the federal Environmental Protection Agency ("EPA") has aggressively pursued the regulation of GHG emissions under the Clean Air Act. The EPA moved forward with the Tailoring Rule in 2010, which is the first rule under the stationary provisions of the Clean Air Act controlling GHG emissions. The Tailoring Rule requires air permits issued for new, large industrial sources and other major new and modified sources to include limits on GHG emissions. As of January 2, 2011, these sources have to obtain Prevention of Significant Deterioration ("PSD") permits. These PSD permits will require regulated sources to comply with GHG emission limits using the "best available control technology ("BACT")". The EPA issued a guidance document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" to address the PSD applicability to GHG, BACT, and other requirements.

Additionally, the EPA will propose new source performance standards ("NSPS") for GHG emissions standards for power plants by July 2011. The NSPS standards will set the level of GHG emissions that new power plants may emit and will also address emissions from existing power plant facilities. Finally, the EPA has imposed GHG reporting requirements on certain facilities that emit 25,000 metric tons or more of GHGs per year. These reports were due to the EPA on March 31, 2011 but that deadline has now been extended. While unclear last year, it is now clear that the EPA has no intention of waiting on federal legislation before implementing GHG emissions regulations. Further, congressional legislation and litigation to delay the EPA's efforts to regulate GHG emissions have stalled.

The EPA's regulation of GHG emissions is one indication that GHG regulation is here to stay. It is still likely that future federal and/or state energy and environmental policy will include climate control aspects that cover GHG emissions from sources like power plants. Therefore, there appears to be no fundamental change in climate control policy that would adversely impact the LNP. Unfortunately, this policy remains a more long term one and, in the near term, it is still unclear what form climate control policy will take, what the ultimate regulation of GHG emissions will look like, and when they will be implemented.

Q. What was the other unfavorable trend that you observed in evaluating the LNP enterprise risks?

A. We observed a trend toward lower natural gas fuel prices. This is also both a qualitative and quantitative risk factor in the LNP feasibility analysis because the trend in natural gas prices can be and has been quantified in the Company's economic CPVRR feasibility analysis. Natural gas prices and carbon costs are two key drivers in the economic CPVRR analysis. Generally, lower natural gas price forecasts reduce, and higher natural gas price forecasts increase the cost-effectiveness of new nuclear generation. Qualitatively, then, we evaluate the natural gas price forecasts over a broader time period than the annual quantitative feasibility analysis update to determine if there are any observable trends in the forecasts and what might be causing those trends. What we have observed is a downward trend in natural gas prices and, thus, the forecast prices from 2009 through the current updated fuel forecast used in the Company's quantitative feasibility analysis. This downward trend in fuel forecasts, in particular natural gas price forecasts, is an unfavorable trend for the LNP.

This downward trend in the natural gas price forecasts corresponds with the recession that is still impacting the economy, particularly in Florida. This downward trend also corresponds to the discovery and initial development of additional natural gas supplies from shale gas reserves in the United States. Both of these factors likely are causing or contributing to the downward trend in the natural gas price forecasts. PEF will continue to closely monitor natural gas price forecasts throughout 2011 and 2012 to determine if the lower natural gas price forecasts year-over-year reflect gas prices settling into a long-term low price trend or reflect the continued effects of the recession. There is insufficient information at this point to determine if there has been a fundamental shift in fuel prices reflecting a longer-term trend toward lower natural gas prices.

Q. What conclusions did the Company draw from the qualitative feasibility analysis?

A. As I have explained, some enterprise risk factors exhibit favorable to slightly favorable trends, some appear to be exhibiting unfavorable trends with respect to the LNP, and others have an apparent neutral impact on the LNP. All in all, little has changed in a year. There has been no dramatic increase in or decrease in the uncertainty associated with the multiple factors that impact the LNP. There also have been no evident fundamental changes in the project's enterprise risks that either suggest moving forward more quickly with the LNP or cancelling the project at this time. This confirms the Company's decision last year to proceed with the LNP on a slower pace, focusing the near-term work and capital investment in the project on obtaining the LNP COL. The Company will continue to monitor the enterprise risks for the LNP, including in particular, the unfavorable trends for the LNP associated with the uncertainty surrounding climate control and carbon cost regulation and the lower natural gas price forecasts, as it moves forward with the project in 2011 and 2012.

Q. What was the Company's quantitative feasibility analysis?

A. As I indicated previously, PEF conducted the CPVRR analysis requested in Commission Order No. PSC-09-0783-FOF-EI and approved in this Order and Order No. PSC-11-0095-FOF-EI as its required economic analysis. The CPVRR analysis includes the required updated fuel, environmental, and carbon compliance cost estimates. The CPVRR analysis also includes a project cost estimate based on the current, estimated future in-service dates for the Levy nuclear power plants. This project cost estimate and estimated in-service dates for the Levy units remains unchanged from the project cost estimate and in-service date estimates used in the CPVRR analysis last year. The updated CPVRR economic analysis compares the LNP to an all natural gas-fired base load generation scenario using a range of fuel forecasts and a range of potential carbon compliance cost estimates. This is the same approach that the Company used to prepare the CPVRR cost-effectiveness analysis in the need determination proceeding for the LNP.

Consistent with the CPVRR analysis last year, the Company is providing CPVRRs for PEF ownership levels of the LNP of 100 percent, 80 percent, and 50 percent. PEF is also providing total LNP project cost sensitivities for cases ranging from 15 percent less to 25 percent greater than the currently estimated project cost. <u>See</u> Exhibit No. __ (JE-4) to my testimony.

Q. What were the results of the Company's quantitative feasibility analysis?

A. The updated CPVRR analysis shows that the LNP is more cost effective than the all natural gas generation resource plan in the mid-fuel forecast at all ownership levels, provided that future carbon costs are included, except in the lowest carbon cost scenario at the 50 percent ownership level. Overall, the CPVRR analysis shows that the LNP is more cost effective in 10 out of 15 cases at the 100 and 80 percent ownership levels and 9 out of 15 cases at the 50 percent ownership level. See Exhibit No. __ (JE-4), p. 8. Based on this year's CPVRR snapshot, the LNP does not appear to be cost effective at any ownership level in the low fuel reference case except in the highest carbon cost estimate case. Conversely, the LNP appears to be cost effective in the high fuel reference case in any scenario, including the no carbon cost case. See Exhibit No. ___(JE-4), p. 8. This CPVRR analysis demonstrates as previous CPVRR analyses did that lower forecasted fuel prices tend to decrease and higher forecasted fuel prices tend to favor the LNP resource plan compared to the all natural gas resource plan. Fuel forecasts appear as before to be a significant driver in this CPVRR analysis.

Q. Did you run more cases in the CPVRR analysis last year?

A. Yes. We included low and high bandwidth fuel cases in our CPVRR analysis last year. These additional fuel price forecast cases were added because of the uncertainty in fuel price forecasts, in particular natural gas price forecasts, in the market. This year, our updated fuel forecast has settled in a range around the low bandwidth fuel forecast case last year. As a result, we did not see the need to develop bandwidths around our updated fuel forecast this year. Natural gas prices have fallen and the current mid fuel forecast case recognizes the lower natural gas prices in the forecast. This updated fuel forecast was developed by the Company consistent with its fuel forecast practices that incorporate fuel projections from widely accepted industry sources. See Exhibit No. ___ (JE-4), p. 4. Accordingly, the number of cases included in the current CPVRR analysis reflects the number of cases included in previous CPVRR analyses for the LNP, including the CPVRR analysis in the LNP need case.

Q. How does this updated CPVRR compare to the CPVRR provided in the LNP need case?

A. The results in the updated CPVRR analysis are similar to the results of the CPVRR analysis in the LNP need case. Both CPVRRs show the LNP to be cost effective compared to an all natural gas resource plan in most cases. The LNP is more favorable than the all natural gas resource plan in 10 of 15 potential fuel and carbon cost emission scenarios in the updated CPVRR analysis and in 9 out of 15 potential fuel and carbon cost emission scenarios in the LNP need case. Both CPVRRs indicate the LNP is more cost effective than the all natural gas resource plan in all high fuel reference cases and that the natural gas resource plan is more cost effective in most low fuel reference cases. In both the LNP need case CPVRR and the updated CPVRR analysis the LNP resource plan is more cost effective than the all natural gas resource plan in more potential fuel and carbon cost scenarios at the 100 percent, 80 percent, and 50 percent ownership levels.

See Exhibit No. ___ (JE-4), pp. 7-8. As a result, the updated CPVRR produces results that are slightly more favorable to the LNP than the CPVRR results in the LNP need case even though the updated CPVRR analysis assumes later in-service dates for the Levy units and a corresponding higher total project cost than the need case CPVRR analysis.

The estimated in-service dates for the Levy units and the estimated total project cost in the updated CPVRR remain unchanged from the CPVRR analysis last year. They still represent the Company's current best estimates of the LNP total project cost and Levy unit in-service dates. These estimates, however, will likely change with the finalization of an EPC Agreement amendment that establishes schedules, unit in-service dates, and that further refines the LNP cost estimates through negotiations to implement that amendment to the EPC Agreement. In addition, these estimates will change pending the results of the updated transmission system study expected to be completed in mid-2012.

Q. What conclusions were drawn from the updated CPVRR feasibility analysis?

A. The updated CPVRR analysis continues to indicate that the LNP is economically viable and has the potential to provide PEF and its customers with billions of dollars of savings over the life of the project. The Company must note, however, that the CPVRR analysis should not be considered a litmus test for the LNP. The Company continues to believe that the long term projections upon which the CPVRR analysis are based on are necessarily uncertain and subject to change from year-to-year. Consequently, this type of analysis cannot be considered the sole basis for a decision to proceed or not with the project, especially at the early stages of the LNP. Instead, the Company continues to view the CPVRR as one factor among many factors that must be considered in making a decision about moving forward with the project.

Q. What did the Company conclude with respect to the feasibility of completing the LNP?

A. The Company determined that completion of the LNP remains feasible based upon its qualitative and quantitative feasibility analyses.

VI. LNP EVALUATION.

Q. Did the Company evaluate its approach to the LNP?

A. Yes, the Company evaluates the LNP each year and with any major change in the project enterprise risks or project schedule, scope, or cost as part of its on-going project management. This evaluation includes the analyses used to determine the feasibility of completing the Levy nuclear units, but the Company also takes a broader, more holistic view of the project to determine if completion of the LNP remains in the best interests of the Company and its customers. In this broader view, the Company weighs the costs and benefits of completing the LNP, including the long-term benefits of additional nuclear generation such as fuel diversity, reduced reliance on foreign fossil fuels, base load capacity needs, and the reduction in environmental emissions for the Company and the state. These longer-term, nuclear generation benefits are the same benefits that the Florida

Legislature recognized in the 2006 legislation that included adoption of the nuclear cost recovery statute and that this Commission recognized in the Company's LNP need determination.

Q. Can you explain what the Company considered in its evaluation of the LNP this year?

A. Yes. The Company evaluated the project status, enterprise and project risks, and costs and benefits of the LNP to determine if its decision to proceed with the LNP on a slower pace by focusing near-term capital and work on obtaining the LNP COL should be changed. The Company included the additional delay in the LNP COLA review, the unfavorable trends in the carbon cost certainty, natural gas price forecasts for the LNP, and the relatively unchanged other enterprise risks that I have discussed above, in its evaluation. This evaluation included project cancellation and project continuation with the current estimated in-service dates for the Levy units in 2021 and 2022. To be consistent with our responses to the Office of Public Counsel's ("OPC's") questioning last year, we again considered and provided details for a scenario where EPC cancellation may be required post-COL receipt. These options were considered and evaluated as part of the Company's on-going evaluation of all options for the LNP to determine the best option for the Company and its customers.

Q. What were the results of the Company's evaluation of the LNP this year?

A. The Company determined that its current decision to proceed with the LNP on a slower pace by focusing work on obtaining the LNP COL remains the best decision for the Company and its customers at this time. An updated Integrated Project Plan ("IPP") was presented to and approved by senior management on March 29, 2011. No fundamental change in the project or the LNP enterprise and project risks at this time compels a decision to accelerate or cancel the project. The near-term estimated capital costs to proceed with the LNP exceed the cost to cancel the project after the COL is obtained by approximately [redacted]. See Exhibit No. ___ (JE-8) to my testimony. This additional cost to proceed with the LNP at this point, while significant, is not so substantial that it compels a change in the Company's decision without a fundamental change in the project or project enterprise risks that adversely affects the LNP. As a result, the Company determined that the best course at this time for the Company and its customers with respect to the LNP was to stay the course and proceed consistent with its decision last year to move forward with the project on a slower pace to reduce near-term capital costs and focus work on obtaining the LNP COL.

VII. JOINT OWNERSHIP.

Q. Does PEF continue to believe there are benefits to joint ownership in the LNP?

A. Yes. PEF continues to believe that joint ownership in the LNP provides PEF and its customers the benefits of sharing the costs and risks of the LNP with other parties. Nothing has changed since last year to lead PEF to believe those benefits do not exist. As a result, PEF continues to pursue joint ownership opportunities in the LNP.

Q. What is the current status of joint ownership in the LNP?

A. There is continued interest in joint ownership participation in the LNP. As we explained last year, that interest exists, but it has not led to joint ownership commitments because of the effects of the economic recession and the uncertainty with respect to project cost, timing, and federal and state energy and environmental policy. The Company has continued joint ownership discussions and meetings with potential joint owners.

Q. What about recent reports of joint ownership option agreements in other planned nuclear generation projects, will those agreements affect the interest in joint ownership in the LNP?

A. No, we do not believe they will, in fact, these joint ownership agreements demonstrate that there is continued interest among Florida utilities in joint ownership participation in the development of new nuclear generation. These agreements, apparently involving Jacksonville Electric ("JEA") and the Orlando Utilities Commission ("OUC"), reflect the recognition by these municipal electric utilities in Florida that new nuclear generation is a prudent future generation option for Florida. We believe this view is generally held by other Florida utilities who value fuel diversity in a future that includes carbon and other greenhouse gas emission constraints in addition to other fossil fuel environmental regulations.

Additionally, these agreements appear to be non-binding options that preserve the right of these municipal electric utilities to buy into the new nuclear power plants years from now, if the development of these new nuclear power plants continues. They do not reflect firm commitments today to participate in the equity ownership of these proposed new nuclear power plants. As a result, we do not believe these agreements represent a constraint on joint ownership participation in the LNP. Further, there is no indication that these municipal electric utilities are no longer interested in joint ownership participation in the LNP at this time.

VIII. CONCLUSION.

Q. How would you characterize the LNP at this point?

A. PEF is proceeding with the LNP on an estimated schedule for completion of the Levy units in 2021 and 2022. This is the result of the Company's implementation of its decision last year to proceed with the LNP on a slower pace, focusing near-term capital expenditures and work on obtaining the LNP COL from the NRC. The Commission determined that this decision was reasonable in Order No. PSC-11-0095-FOF-EI. The Company has evaluated that decision this year and determined that there is no reason to change it at this time. The Company's qualitative and quantitative feasibility analyses demonstrate that completion of the LNP is still feasible. There have been no fundamental changes in the project or the LNP enterprise or project risks at this time that require the Company to reconsider its decision. As a result, the Company is staying the course and proceeding with the LNP consistent with its decision last year.

Q. Does this conclude your direct testimony?

A. Yes.

Updated Levy COLA Schedule

	Previous NRC Review Schedule	Anticipated NRC Review Schedule per 2010 IPP	Current NRC Review Schedule (Rev Nov '10)
RAIs Complete	May 2010	May 2010	May 2010
NRC Milestone - Draft EIS issued	August 2010	August 2010	August 2010
NRC Milestone - Final EIS issued	July 2011	July 2011	April 2012
NRC Milestone - AP1000 DCD Rulemaking	August 2011	August 2011	September 2011
NRC Milestone - ACRS Review	April 2011	October 2011	January 2012
NRC Milestone - FSER issued	July 2011	February 2011	April 2012
Start of ASLB Hearings	[redacted]	February 2012	May 2012
COL [Estimated]	4th Qtr 2012	4th Qtr 2012	2nd Qtr 2013

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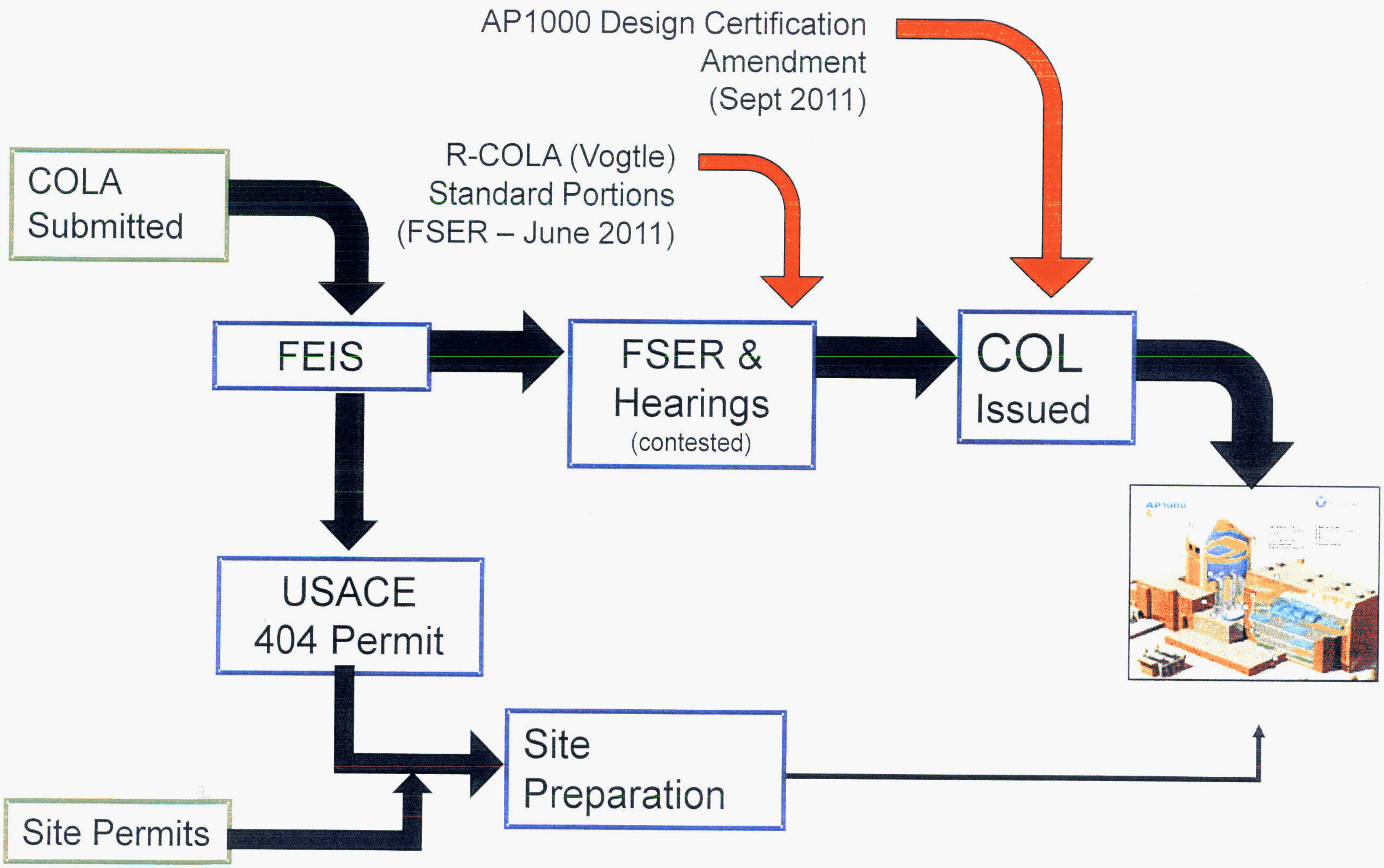
Regulatory Logic Sequence



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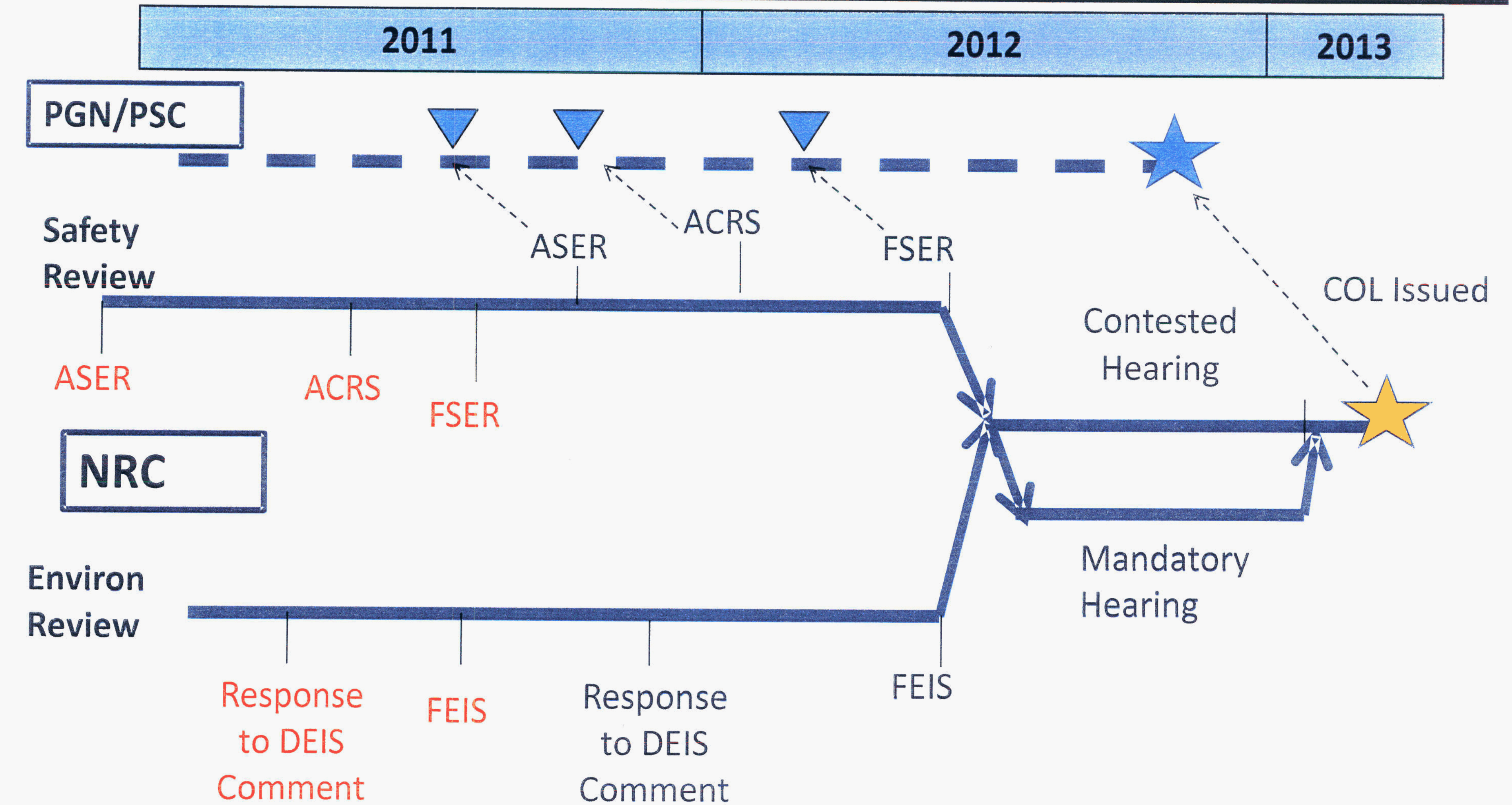
Schedule - LNP COLA



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Summary Brief

Progress Energy Florida

Levy Nuclear Project NCRC 2011 Feasibility Assessment

Updated Life-Cycle Net Present Worth (CPVRR) Assessment

Prepared by:

PEF System Planning & Regulatory Performance

April 29, 2011

Objective:

The Florida Public Service Commission (FPSC) Nuclear Cost Recovery Clause (NCRC) Rule and Order No. PSC-09-0783-FOF-EI require annual feasibility updates for projects under clause recovery. In the 2009 NCRC Proceeding, FPSC Staff required that Progress Energy Florida (PEF) provide an updated life-cycle net present worth (also referred to as cumulative present value of revenue requirements, or CPVRR) assessment of the Levy Nuclear Project as a part of the 2009 feasibility assessment. In anticipation of that requirement in the 2011 NCRC Proceeding, PEF prepared an updated CPVRR assessment of the Levy Nuclear Project based on PEF's current forecasts for submission in the April 29th NCRC filing. PEF's System Planning group, which prepares these evaluations for Need Determination proceedings, updated the life cycle assessment to support this filing.

The results of this updated assessment are presented herein based on the best information available at this time and consistent with the updated projections filed in this proceeding. This assessment has been performed in a manner consistent with the approach presented in the Levy Need Determination Study (FPSC Docket 080148-EI).

Overview of the Updated Assessment:

In the Levy Need Determination Study, PEF initially established the available potential in-service dates for the new nuclear plants and then developed optimized resource portfolios to accompany the new units during the duration of the projected life of the facility (the "Levy Plan"). The remaining resources were selected from natural gas fired simple cycle and combined cycle units to complete each scenario portfolio over the study period. An alternate scenario was also developed based exclusively on natural gas fired generation resources without the nuclear units to develop the "All Gas Reference Plan" resource portfolio. The same approach was followed in developing the results for this updated assessment.

The optimizations were performed using the Strategist™ model in the same manner the scenarios were developed in the Levy Need Study based on PEF's forecasts for Load and Energy requirements, fuel prices, emission allowance costs and the development costs for new unit additions. The study period costs were then compared for these two portfolios (plans) to project the life cycle savings (or costs) between the Levy Plan and the All Gas Reference Plan on a cumulative present value of revenue requirements (CPVRR) basis.

A Summary of Key Assumptions and Key Drivers:

In the Levy Need Determination Study, the key drivers identified in the economic assessment were determined to be the forecasted costs of fuel, the potential impacts of carbon policy and the projected capital costs for new nuclear units and natural gas generation alternatives. PEF's Levy Need filing addressed the relative impacts of each of these drivers in the study results by comparing the cumulative present value of system revenue requirements (CPVRR) for each sensitivity applied to the Levy Nuclear

Plan versus the All Gas Reference Plan. This approach provides a comparable comparison of life cycle cost between alternatives being considered. Forecasts and adjustments included in this updated assessment are summarized below and provided in an appendix for review:

Fuel Forecasts: This assessment was performed with the long term planning fuel forecasts which were updated in 2010 supporting this year's normal planning cycle. PEF included low and high (statistical) forecast sensitivities around the mid reference case in a manner consistent with the approach used in the Levy Need Study.

Emission Forecasts: This assessment was performed with the long term planning emissions forecasts which were updated in late 2009 in support of this year's normal planning cycle. The carbon policy scenarios used in the 2010 study have been retained for this year's study. This reflects the lack of ongoing action on carbon policy at federal and state levels, but recognizes the consensus understanding, supported by PEF, that some carbon policy will be enacted in the timeframe prior to planned in-service dates for the Levy units. In this year's studies, as in last year's, the analysis was run with no CO2 cost and with four CO2 emissions cost projections provided in nominal $/ton of equivalent CO2. The four scenarios were based on studies of the Waxman-Markey draft bill performed by the Environmental Protection Agency (EPA), Charles River Associates (CRA) and the Electric Power Research Institute (EPRI). Two EPRI scenarios were utilized representing the "Full Portfolio" and "Limited Portfolio" perspectives, based on their assessment of the cost and availability of low carbon generating resources in the future. While there are evolving policy developments at the state and national levels, these forecasts are deemed to be a reasonable characterization of potential outcomes and, as such, have been used for this updated assessment.

Commercial In-Service and Cost Projection Update for the Levy Project: To perform this assessment, PEF's Nuclear Project Development (NPD) team was asked to provide an updated project cash flow estimate for construction cost based on the latest projected project schedule. This assessment was performed with the estimates updated in early 2011 which project the first unit entering commercial service in mid-2021 with the second unit entering service approximately 18 months later.

Cost Projections for Gas-Fired New Unit Additions: This assessment was performed with long term planning project cost estimates for new peaking and combined cycle generation resource options which were updated this year to support the regular planning cycle.

Capital Cost Sensitivities: The sensitivities included in this study reflect a range of projected capital costs for all new resources ranging from -15%, -5% to 5%, 15% and 25%.

Load and Energy Forecast: This assessment was performed using the long term planning Load and Energy forecast that was used in preparing PEF's 2011 Ten Year Site Plan (TYSP'11).

Nuclear Joint Ownership: In this updated assessment, PEF is presenting results for ownership sensitivities of 100%, 80% and 50% in a manner consistent with the Levy Need filing.

Discount Rate: This assessment was performed using a discount rate adjusted to reflect the planning basis for weighted average cost of capital based on PEF's current allowed rate of return. The current discount rate being used for long term planning is 6.75%.

Summary Results Overview:

In the Levy Need Determination Study, PEF provided tabular summaries of the economic assessment results (ref Table 1). The results tables represent the benefit (cost) of the life cycle cost comparisons of the Levy Nuclear Plan versus the All Gas Reference Plan based on Cumulative Present Value of Revenue Requirements (CPVRR) for each of the sensitivities addressed. The updated assessment results have been summarized and tabulated in a similar manner in Table 2.

Table 1 provides an overview of the results originally presented in the Levy Need.

Table 2 provides an overview of the updated planning results based on PEF's updated estimates and forecasts based on a 2021 commercial in-service date with an 18 month spread between units.

Observations:

In comparing results for this updated assessment with the Levy Need, these observations are noted:

Mid Reference Fuel Forecasts: The fossil fuel price forecasts (e.g. natural gas, coal and oil) used in the updated assessment are generally lower than the forecasts used in the 2010 analysis. When compared to the Levy Need analysis, forecast prices are now lower in the near term, but are generally similar over the full length of the analysis. The updated nuclear fuel forecast received a slight downward adjustment from 2010, but is similar to the forecasts presented in previous NCRC filings. The updated projections reflect changes in fuel market conditions over time and are based on the most current long term fuel forecasts available to PEF. Lower forecasted fuel prices tend to decrease the life cycle costs projected for the All Gas resource portfolio more than those projected for the Levy Need portfolio which results in a less favorable projection for the Levy Nuclear plan. The fuel forecast updates appear to be a significant driver in the changes in results between these assessments.

Fuel Forecast Sensitivities: The low and high fuel sensitivities presented in the Levy Need and the updated assessment are based on PEF's standard methodology for confidence intervals. The fuel prices in the updated *low* sensitivity forecast are generally lower than the comparable values in the Levy Need. As a result, the projected CPVRR differentials are lower for the *low* fuel forecast sensitivity in the updated assessment. The fuel prices in the updated *high* sensitivity forecast are generally higher than the comparable values in the Levy Need. As a result, the projected CPVRR differentials are higher for the *high* fuel sensitivity in the updated assessment.

Emission Forecasts: The emission forecasts for SO_2, NO_X and Hg were updated in this assessment, but the differentials resulting from the changes appear to be negligible. The projections for the impacts of carbon policy were retained from the 2010 study. Thus, the range of potential carbon cost impacts being studied is still similar to the Levy Need, but narrower to a limited extent. As a result, the impacts in CPVRR differentials due to carbon policy, while still significant, have narrowed to a limited extent.

Commercial In-Service and Cost Projection Updates for the Levy Project: As discussed previously, the updated assessment was performed with information for projected project cost changes based on the updated in-service date. The 2011 estimate differs only marginally from the 2010 estimate for the schedule shift to 2021 and 2022 and results in very little change to the life cycle costs of the Levy Plan as compared to the 2010 analysis. These costs are greater than those in the Levy Need.

Cost Projections for New Natural Gas Fired Unit Additions: As discussed, the updated assessment was performed with adjusted long term planning project cost estimates for new peaking and combined cycle generation resource options. The updated cost projections for natural gas fired generation are generally lower than the projections in the Levy Need which provides downward pressure on the life cycle costs for both the Levy Nuclear and All Gas resource portfolios being compared (since most of the new generation resources in both portfolios are natural gas additions). The cost decreases projected for the natural gas fired units appears to result in a small offset in the life cycle cost results when the CPVRR differentials between resource portfolios are compared.

Load and Energy Forecast: The updated assessment was performed using the long term planning Load and Energy forecast that was developed for PEF's 2011Ten Year Site Plan (TYSP'11). The updated forecast incorporates lower projected load and energy requirements reflecting reduced growth being experienced during the ongoing recession in Florida and more ambitious conservation program goals for the next ten years. The resource plans were adjusted accordingly to reflect appropriately fewer resource additions. *Nuclear Joint Ownership:* The results provided for Ownership sensitivities of 100%, 80% and 50% are directionally similar to the results submitted in the Levy Need. The impacts of many of the key drivers previously discussed affect the results in a manner proportional to ownership percentage.

Discount Rate: The results provided in Table 2 reflect the use of a 6.75% discount rate which reflects the Company's average weighted cost of capital (WACC) for planning purposes. This is the same discount rate utilized in the 2010 analysis. New nuclear project economics are heavily influenced by the initial capital investment in the early years of the assessment weighed against the substantial long term fuel savings and emission cost offsets projected over the life of the project.

Summary:

PEF completed the updated CPVRR assessment and comparison of life cycle costs for the Levy Nuclear Project as part of the required feasibility assessment for the 2011 Nuclear Cost Recovery Clause (NCRC) filing. The results of the updated assessment have been presented in this Summary Report. The benefits projected for development of the Levy Nuclear Project in this updated assessment are similar to those presented in the Need filing.

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TABLE 1

Summary of CPVRR Results from the Levy Need Determination (Docket 080148-EI)

Levy Need Study CPVRR Economic Results Summary Table [$2007]

Fuel Sensitivities				*CapEx Sensitivities*					
Base Capital Reference Case	Low Fuel Reference	**Mid Fuel Reference**	High Fuel Reference	*Mid Fuel Reference Case*	LNP CapEx (5%)	**Mid Fuel Reference**	LNP CapEx +5%	LNP CapEx +15%	LNP CapEx +25%
Levy Need - 100% Ownership, 2016 COD Levy Case Versus All Gas CPVRR $Million ($2007)									
No CO2	($6,416)	($2,888)	$2,635	*No CO2*	($2,365)	($2,888)	($3,400)	($4,434)	($5,469)
Bingaman Specter CO2	($3,834)	($343)	$5,212	*Bingaman Specter CO2*	$109	($343)	($926)	($1,960)	($2,995)
EPA No CCS	($2,684)	$793	$6,318	*EPA No CCS*	$1,207	$793	$172	($862)	($1,897)
MIT Mid CO2	$85	$3,614	$9,077	*MIT Mid CO2*	$3,975	$3,614	$2,940	$1,906	$871
Lieberman Warner CO2	$2,930	$6,380	$11,892	*Lieberman Warner CO2*	$6,674	$6,380	$5,640	$4,605	$3,571
Levy Need - 80% Ownership, 2016 COD Levy Case Versus All Gas CPVRR $Million ($2007)									
No CO2	($5,566)	($2,725)	$1,732	*No CO2*	($2,284)	($2,725)	($3,154)	($4,023)	($4,892)
Bingaman Specter CO2	($3,530)	($733)	$3,756	*Bingaman Specter CO2*	($364)	($733)	($1,234)	($2,103)	($2,972)
EPA No CCS	($2,619)	$171	$4,631	*EPA No CCS*	$502	$171	($367)	($1,236)	($2,106)
MIT Mid CO2	($448)	$2,403	$6,790	*MIT Mid CO2*	$2,681	$2,403	$1,812	$942	$73
Lieberman Warner CO2	$1,799	$4,594	$9,018	*Lieberman Warner CO2*	$4,805	$4,594	$3,936	$3,067	$2,197
Levy Need - 50% Ownership, 2016 COD Levy Case Versus All Gas CPVRR $Million ($2007)									
No CO2	($4,017)	($2,246)	$523						
Bingaman Specter CO2	($2,766)	($963)	$1,783						
EPA No CCS	($2,250)	($409)	$2,317						
MIT Mid CO2	($1,018)	$908	$3,685						
Lieberman Warner CO2	$339	$2,220	$5,139						

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TABLE 2

Summary of March '11 Updated CPVRR Results for the Levy Project

PEF Summary CPVRR Review for 2011 NCRC Filing

Economic Results Summary Table (NCRC'11 Study)

Fuel Sensitivities

Base Capital Reference Case	Low Fuel Reference	**Mid Fuel Reference**	High Fuel Reference
NCRC MAR'11: 100% Ownership, 2021 COD Levy Case Versus All Gas CPVRR $Million, 6.75% Discount Rate			
No CO_2	($12,366)	($3,714)	$8,269
EPA WM CO_2	($8,172)	$936	$12,549
CRA WM CO_2	($5,579)	$3,715	$15,306
EPRI Full CO_2	($2,962)	$6,446	$18,219
EPRI Ltd CO_2	$2,527	$12,062	$24,401
NCRC MAR'11: 80% Ownership, 2021 COD Levy Case Versus All Gas CPVRR $Million, 6.75% Discount Rate			
No CO_2	($10,039)	($3,100)	$6,567
EPA WM CO_2	($6,755)	$399	$9,897
CRA WM CO_2	($4,715)	$2,567	$11,994
EPRI Full CO_2	($2,651)	$4,700	$14,208
EPRI Ltd CO_2	$1,663	$9,099	$18,929
NCRC MAR'11: 50% Ownership, 2021 COD Levy Case Versus All Gas CPVRR $Million, 6.75% Discount Rate			
No CO_2	($7,056)	($2,592)	$3,624
EPA WM	($4,947)	($366)	$5,687
CRA WM	($3,640)	$1,053	$7,030
EPRI Full	($2,343)	$2,425	$8,412
EPRI Ltd	$420	$5,262	$11,499

CapEx Sensitivities

Mid Fuel Reference Case	LNP CapEx (15%)	LNP CapEx (5%)	**Mid Fuel Reference**	LNP CapEx +5%	LNP CapEx +15%	LNP CapEx +25%
NCRC MAR'11: 100% Ownership, 2021 COD Levy Case Versus All Gas CPVRR $Million, 6.75% Discount Rate						
No CO_2	($2,042)	($3,182)	($3,714)	($4,322)	($5,461)	($6,601)
EPA WM CO_2	$2,534	$1,394	$936	$254	($886)	($2,026)
CRA WM CO_2	$5,380	$4,240	$3,715	$3,100	$1,960	$821
EPRI Full CO_2	$8,125	$6,985	$6,446	$5,846	$4,706	$3,566
EPRI Ltd CO_2	$13,748	$12,608	$12,062	$11,468	$10,328	$9,188
NCRC MAR'11: 80% Ownership, 2021 COD Levy Case Versus All Gas CPVRR $Million, 6.75% Discount Rate						
No CO_2	($1,762)	($2,654)	($3,100)	($3,547)	($4,439)	($5,331)
EPA WM CO_2	$1,737	$845	$399	($47)	($939)	($1,831)
CRA WM CO_2	$3,906	$3,013	$2,567	$2,121	$1,229	$337
EPRI Full CO_2	$6,038	$5,146	$4,700	$4,254	$3,362	$2,470
EPRI Ltd CO_2	$10,437	$9,545	$9,099	$8,653	$7,761	$6,869
NCRC MAR'11: 50% Ownership, 2021 COD Levy Case Versus All Gas CPVRR $Million, 6.75% Discount Rate						
No CO_2	($1,746)	($2,310)	($2,592)	($2,874)	($3,438)	($4,002)
EPA WM CO_2	$480	($84)	($366)	($648)	($1,212)	($1,776)
CRA WM CO_2	$1,899	$1,335	$1,053	$771	$207	($358)
EPRI Full CO_2	$3,272	$2,707	$2,425	$2,143	$1,579	$1,015
EPRI Ltd CO_2	$6,108	$5,544	$5,262	$4,980	$4,415	$3,851

APPENDIX

Levy Nuclear March'11 Review
Planning and Modeling Assumptions Summary

Prepared 3/22/11 by PEF System Planning

Levy Nuclear March 2011 Review

Financial and Economic Assumptions

1 PEF Capitalization Ratios and Projected Cost of Capital

Component	*Ratio*	*Cost*
Debt	50%	4.78%
Preferred	0%	na
Equity	50%	10.50%

2 Projected Discount Rate: 6.747%

3 Projected AFUDC Rate: 6.747%

4 Tax Assumptions

a)	Composite Effective Income Tax Rate	37.350%
b)	Combined Cycle Book Life	25 Years
	Combined Cycle Tax Depreciation Life	20 Years
c)	Simple Cycle CT Book Life	25 Years
	Simple Cycle CT Tax Depreciation Life	15 Years
d)	Nuclear Generation Book Life	40 Years
	Nuclear Generation Tax Depreciation Life	15 Years
e)	Transmission Book Life	40 Years
	Transmission Tax Depreciation Life	15 Years

5 General Inflation Rate 2.00%

6 General Escalation Rate 2.00%

Levy Nuclear March 2011 Review

Strategist Input Assumptions - Emission Cost Estimates

	SO2 $/ton	NOX $/ton	EPA CO2 $/ton	CRA CO2 $/ton	EPRI FP CO2 $/ton	EPRI LP CO2 $/ton
2011	12	353				
2012	136	656	11	22		
2013	198	630	12	22		
2014	221	428	13	23		
2015	464	894	14	23		
2016	456	870	15	25		
2017	391	861	16	27		
2018	253	859	18	28		
2019	125	835	19	30		
2020	50	822	20	32	70	82
2021	-	828	22	35	73	89
2022	-	826	24	38	76	96
2023	-	824	26	40	78	103
2024	-	823	28	43	81	111
2025	-	823	30	46	83	118
2026	-	822	32	50	86	125
2027	-	830	34	54	88	132
2028	-	839	36	57	91	139
2029	-	846	38	61	93	146
2030	-	854	40	65	96	153
2031	-	860	44	70	104	166
2032	-	867	48	75	112	180
2033	-	873	52	80	119	193
2034	-	880	55	85	127	206
2035	-	886	59	90	135	220
2036	-	893	63	97	143	233
2037	-	900	67	104	151	246
2038	-	906	70	112	159	259
2039	-	913	74	119	167	273
2040	-	920	78	126	174	286

Levy Nuclear March 2011 Review

New Plant Modeling Information Summary

Capital Cost Estimates for Strategist Modeling

Nuclear Plant Summary Information

	Levy County 2021/22	
	Levy Nuclear Project	Levy Nuclear Project
	1st Unit	2nd Unit
Reference In-Service Year	2021	2022
Projected Nominal Plant Cost ($000 Before AFUDC)	9,356,479	5,178,016
Projected Nominal Trans Cost ($000 Before AFUDC)	1,846,224	126,167
Winter Capacity Rating (MW)	1,120	1,120
Summer Capacity Rating (MW)	1,092	1,092
Fixed O&M ($000/yr)- $2011, Esc Annually at 2%	69,437	48,606
Variable O&M ($/MWh) - $2011, Esc Annually at 2%	2.15	2.15
Decom and Dism Funding ($000/yr) - $2011 Constant	15,039	15,039
Annualized Capital Replacement ($000/yr)	10,000	10,000
Back End (mill/kWh) for Fed Spent Fuel Disposal	1.00	1.00
Planned Outage Rate	3.0%	3.0%
Average Heat Rate at Maximum (Btu/kWh)	9,715	9,715

Gas Fired Generation Summary Information

	Generic 2x1G Combined Cycle	Generic 2x1G Combined Cycle
	1st Unit	2nd Unit
Reference In-Service Year	2014	2014
Projected Nominal Plant Cost ($000 Before AFUDC)	720,100	634,784
Projected Nominal Trans Cost ($000 Before AFUDC)	102,717	205,434
Winter Capacity Rating (MW)	875	875
Summer Capacity Rating (MW)	767	767
Fixed O&M ($000/yr)- $2011, Esc Annually at 2%	5,187	2,158
Variable O&M ($/MWh) - $2011, Esc Annually at 2%	3.30	3.30
Pipeline Reservation Charges ($000/yr) - $2011, Constant	51,742	51,742
Planned Outage Rate	6.7%	6.7%
Average Heat Rate at Maximum (Btu/kWh)	6,710	6,710

Gas Fired Generation Summary Information

	Generic F Frame Simple Cycle
	2nd Unit
Reference In-Service Year	2013
Projected Nominal Plant Cost ($000 Before AFUDC)	102,497
Projected Nominal Trans Cost ($000 Before AFUDC)	25,533
Winter Capacity Rating (MW)	205
Summer Capacity Rating (MW)	178
Fixed O&M ($000/yr)- $2011, Esc Annually at 2%	694
Variable O&M ($/MWh) - $2011, Esc Annually at 2%	7.83
Pipeline Reservation Charges ($000/yr) - $2011, Constant	12,352
Planned Outage Rate	3.84%
Average Heat Rate at Maximum (Btu/kWh)	10,359

Levy Nuclear March 2011 Review

Strategist Fuel Forecasts - Mid Reference Fuel Table (1 of 2)

	FUEL 1 COAL 1.8	FUEL 5 COAL 5	FUEL 4 CR3	FUEL 35 LNP U1	FUEL 36 LNP U2	FUEL 7 OIL 1.1	FUEL 8 OIL 1.7	FUEL 10 GAS FGTF	FUEL 18 GulfFirm	FUEL 27 Dist 0.3	FUEL 28 Dist 0.5	FUEL 29 Dist ULS
2011	4.35	3.12	0.55			12.80	12.41	4.54	4.54	17.69	18.04	17.83
2012	4.72	3.30	0.55			13.53	13.20	5.42	5.42	18.25	18.74	18.45
2013	4.98	3.46	0.67			13.98	13.57	5.85	5.85	18.36	18.99	18.61
2014	5.04	3.61	0.67			13.84	13.48	6.05	6.05	20.44	20.25	20.73
2015	4.99	3.73	0.70			13.70	13.38	6.48	6.48	21.34	21.14	21.64
2016	4.97	3.84	0.70			13.56	13.29	6.70	6.70	22.22	22.01	22.53
2017	4.95	3.87	0.76			13.42	13.20	6.89	6.89	23.02	22.81	23.35
2018	5.08	3.94	0.76			13.28	13.10	7.12	7.12	23.81	23.58	24.14
2019	5.24	4.04	0.84			13.60	13.42	7.46	7.46	24.39	24.15	24.73
2020	5.41	4.14	0.84			13.92	13.74	7.74	7.74	24.98	24.74	25.33
2021	5.56	4.25	0.91	1.07		14.26	14.07	7.98	7.98	25.58	25.34	25.95
2022	5.70	4.35	0.91	1.07	1.10	14.60	14.40	8.27	8.27	26.21	25.96	26.58
2023	5.86	4.46	0.94	1.01	1.10	14.95	14.75	8.48	8.48	26.84	26.59	27.22
2024	6.01	4.56	0.94	1.01	1.10	15.31	15.10	8.65	8.65	27.50	27.24	27.89
2025	-	4.68	0.97	0.96	1.04	15.68	15.47	8.92	8.92	28.16	27.90	28.56
2026	-	4.81	0.97	0.96	0.99	16.05	15.84	9.19	9.19	28.85	28.58	29.26
2027	-	4.94	1.01	1.00	1.03	16.44	16.22	9.47	9.47	29.55	29.27	29.97
2028	-	5.06	1.01	1.02	1.05	16.83	16.61	9.87	9.87	30.27	29.98	30.70
2029	-	5.12	1.05	1.02	1.05	17.24	17.01	10.33	10.33	31.01	30.71	31.44
2030	-	5.27	1.05	1.07	1.09	17.65	17.41	10.85	10.85	31.76	31.46	32.21
2031	-	5.38	1.09	1.09	1.11	18.04	17.80	11.23	11.23	32.48	32.17	32.94
2032	-	5.50	1.09	1.09	1.11	18.44	18.19	11.62	11.62	33.20	32.89	33.67
2033	-	5.61	1.14	1.13	1.16	18.83	18.58	12.00	12.00	33.92	33.60	34.40
2034	-	5.73	1.14	1.15	1.18	19.23	18.97	12.39	12.39	34.64	34.31	35.12
2035	-	5.85	1.18	1.15	1.18	19.62	19.36	12.77	12.77	35.35	35.02	35.85
2036	-	5.96	1.18	1.20	1.23	20.02	19.75	13.16	13.16	36.07	35.73	36.58
2037	-	6.08	1.23	1.22	1.25	20.41	20.14	13.54	13.54	36.79	36.45	37.31
2038	-	6.20	1.23	1.22	1.25	20.81	20.53	13.93	13.93	37.51	37.16	38.04
2039	-	6.31	1.28	1.27	1.30	21.20	20.92	14.31	14.31	38.23	37.87	38.77
2040	-	6.43	1.28	1.30	1.33	21.60	21.31	14.70	14.70	38.95	38.58	39.50

Levy Nuclear March 2011 Review

Strategist Fuel Forecasts - High Fuel Table (1 of 2)

	FUEL 1 COAL 1.8	FUEL 5 COAL 5	FUEL 4 CR3	FUEL 35 LNP U1	FUEL 36 LNP U2	FUEL 7 OIL 1.1	FUEL 8 OIL 1.7	FUEL 10 GAS FGTF	FUEL 18 GulfFirm	FUEL 27 Dist 0.3	FUEL 28 Dist 0.5	FUEL 29 Dist ULS
2011	4.96	3.57				16.69	16.27	6.27	6.27	23.26	23.74	23.45
2012	5.74	4.04				20.11	19.62	7.72	7.72	27.25	28.01	27.56
2013	6.62	4.70				22.31	21.65	8.60	8.60	29.60	30.64	30.02
2014	6.70	5.23				22.99	22.38	9.31	9.31	34.89	34.56	35.40
2015	6.66	5.15				23.39	22.84	10.22	10.22	38.01	37.65	38.56
2016	6.65	5.36				23.64	23.17	10.80	10.80	40.94	40.55	41.54
2017	6.64	5.38				23.82	23.42	11.33	11.33	43.61	43.19	44.25
2018	6.86	5.53				23.93	23.61	11.93	11.93	46.13	45.69	46.81
2019	7.13	5.72				24.85	24.51	12.71	12.71	48.15	47.69	48.85
2020	7.43	5.93				25.77	25.42	13.40	13.40	50.11	49.63	50.84
2021	7.59	6.15				26.69	26.34	14.02	14.02	52.03	51.52	52.79
2022	7.74	6.34				27.63	27.26	14.73	14.73	53.91	53.39	54.70
2023	7.90	6.56				28.58	28.20	15.32	15.32	55.77	55.23	56.59
2024	8.05	6.76				29.55	29.16	15.81	15.81	57.62	57.06	58.46
2025	-	7.00				30.54	30.13	16.51	16.51	59.46	58.88	60.33
2026	-	7.24				31.54	31.12	17.18	17.18	61.30	60.70	62.19
2027	-	7.51				32.57	32.13	17.90	17.90	63.14	62.52	64.06
2028	-	7.75				33.61	33.16	18.84	18.84	64.99	64.35	65.93
2029	-	7.88				34.67	34.21	19.92	19.92	66.84	66.19	67.82
2030	-	8.16				35.76	35.28	21.10	21.10	67.93	67.87	68.02
2031	-	8.39				36.80	36.31	22.02	22.02	69.62	69.67	69.56
2032	-	8.62				37.85	37.34	22.94	22.94	71.32	71.46	71.10
2033	-	8.85				38.89	38.37	23.86	23.86	73.01	73.26	72.64
2034	-	9.08				39.93	39.40	24.78	24.78	74.70	75.06	74.18
2035	-	9.31				40.98	40.43	25.70	25.70	76.40	76.85	75.72
2036	-	9.54				42.02	41.46	26.62	26.62	78.09	78.65	77.26
2037	-	9.77				43.07	42.49	27.54	27.54	79.78	80.45	78.80
2038	-	10.00				44.11	43.52	28.46	28.46	81.48	82.24	80.33
2039	-	10.23				45.15	44.55	29.38	29.38	83.17	84.04	81.87
2040	-	10.46				46.20	45.58	30.30	30.30	84.87	85.84	83.41

Levy Nuclear March 2011 Review

Strategist Fuel Forecasts - Low Fuel Table (1 of 2)

	FUEL 1 COAL 1.8	FUEL 5 COAL 5	FUEL 4 CR3	FUEL 35 LNP U1	FUEL 36 LNP U2	FUEL 7 OIL 1.1	FUEL 8 OIL 1.7	FUEL 10 GAS FGTF	FUEL 18 GulfFirm	FUEL 27 Dist 0.3	FUEL 28 Dist 0.5	FUEL 29 Dist ULS
2011	3.79	2.71				8.57	8.28	3.04	3.04	12.78	13.03	12.88
2012	3.81	2.64				7.74	7.55	3.45	3.45	10.77	11.05	10.88
2013	3.61	2.43				7.15	6.93	3.52	3.52	9.38	9.69	9.51
2014	3.67	2.69				6.56	6.39	3.35	3.35	9.23	9.14	9.35
2015	3.62	2.56				6.10	5.96	3.43	3.43	8.68	8.60	8.79
2016	3.60	2.60				5.73	5.61	3.39	3.39	8.24	8.17	8.35
2017	3.58	2.64				5.41	5.32	3.35	3.35	7.86	7.80	7.97
2018	3.65	2.66				5.14	5.07	3.32	3.32	7.55	7.49	7.65
2019	3.72	2.69				5.06	4.99	3.34	3.34	7.24	7.18	7.32
2020	3.80	2.72				5.00	4.93	3.34	3.34	6.97	6.91	7.06
2021	3.83	2.76				4.94	4.87	3.31	3.31	6.75	6.70	6.83
2022	3.87	2.79				4.88	4.82	3.31	3.31	6.57	6.51	6.64
2023	3.91	2.82				4.84	4.77	3.28	3.28	6.41	6.36	6.49
2024	3.94	2.85				4.79	4.73	3.22	3.22	6.28	6.23	6.35
2025	-	2.89				4.75	4.69	3.21	3.21	6.17	6.12	6.24
2026	-	2.94				4.71	4.65	3.20	3.20	6.08	6.03	6.15
2027	-	2.98				4.68	4.61	3.19	3.19	6.00	5.96	6.07
2028	-	3.02				4.64	4.58	3.22	3.22	5.94	5.90	6.01
2029	-	3.04				4.61	4.55	3.26	3.26	5.89	5.85	5.96
2030	-	3.09				4.58	4.52	3.31	3.31	5.97	5.95	6.00
2031	-	3.13				4.55	4.49	3.33	3.33	5.93	5.92	5.95
2032	-	3.17				4.51	4.45	3.35	3.35	5.89	5.88	5.90
2033	-	3.21				4.48	4.42	3.37	3.37	5.85	5.85	5.86
2034	-	3.25				4.45	4.39	3.39	3.39	5.81	5.81	5.81
2035	-	3.29				4.41	4.35	3.41	3.41	5.77	5.78	5.76
2036	-	3.33				4.38	4.32	3.43	3.43	5.73	5.74	5.71
2037	-	3.37				4.34	4.29	3.45	3.45	5.69	5.71	5.66
2038	-	3.40				4.31	4.25	3.47	3.47	5.65	5.68	5.62
2039	-	3.44				4.28	4.22	3.49	3.49	5.61	5.64	5.57
2040	-	3.48				4.24	4.19	3.51	3.51	5.57	5.61	5.52

Levy Nuclear March 2011 Review
Energy Requirements Forecasts
Net Energy for Load (GWh)

YEAR	Forecast Base	
2010	46,160	(1)
2011	42,047	
2012	44,253	
2013	45,637	
2014	46,367	
2015	46,794	
2016	46,176	
2017	46,128	
2018	46,683	
2019	47,905	
2020	48,390	
2021	48,675	
2022	48,973	
2023	49,097	
2024	49,657	
2025	50,073	
2026	50,659	
2027	51,252	
2028	51,848	
2029	52,434	
2030	53,030	
2031	53,622	
2032	54,213	
2033	54,805	
2034	55,397	
2035	55,988	
2036	56,580	
2037	57,171	
2038	57,763	
2039	58,354	
2040	58,946	

(1) Year 2010 value is based on actuals
It was an abnormal high weather year

Levy Nuclear March 2011 Review
Energy Demand Forecasts

YEAR	Summer Peak Net Firm Demand (MW) Forecast	Winter Peak Net Firm Demand (MW) Forecast	
2010	9,467	11,644	(1)
2011	8,747	9,577	
2012	8,858	9,640	
2013	8,918	9,716	
2014	8,882	9,730	
2015	8,925	9,815	
2016	8,834	9,924	
2017	8,891	9,889	
2018	8,948	10,003	
2019	9,268	10,369	
2020	9,354	10,506	
2021	9,446	10,651	
2022	9,540	10,794	
2023	9,639	10,941	
2024	9,739	11,092	
2025	9,842	11,247	
2026	9,947	11,395	
2027	10,051	11,549	
2028	10,156	11,706	
2029	10,261	11,860	
2030	10,368	12,017	
2031	10,474	12,171	
2032	10,579	12,325	
2033	10,684	12,479	
2034	10,789	12,633	
2035	10,894	12,787	
2036	11,000	12,941	
2037	11,114	13,107	
2038	11,228	13,272	
2039	11,342	13,438	
2040	11,456	13,603	

(1) Year 2010 value is based on actuals
It was an abnormal high weather year

Levy Nuclear Filing

Strategist Optimization Scenarios - 3/22/11 Data Runs

	2011 NCRC Nuclear Plan Full Ownership Case	**2011 NCRC Nuclear Plan 50% Joint Ownership Case**	**2011 NCRC All Gas Reference Case**	
2009 to 2012	**PEF Baseline Assumptions**	**PEF Baseline Assumptions**	**PEF Baseline Assumptions**	2009 to 2012
2013				2013
2014				2014
2015				2015
2016	131 MW Suwannee Steam Retirement (June '16)	131 MW Suwannee Steam Retirement (June '16)	131 MW Suwannee Steam Retirement (June '16)	2016
2017				2017
2018				2018
2019	196 MW Peaker Retirements (June '19)	196 MW Peaker Retirements (June '19)	196 MW Peaker Retirements (June '19)	2019
2020	Generic Simple Cycle CT	Generic Simple Cycle CT	Generic Simple Cycle CT	2020
2021	**100% Levy Unit 1 - 1,092 MW (June '21)**	**50% Levy Unit 1 - 546 MW (June '21)**	Generic 2x1 G CC	2021
2022	**100% Levy Unit 2 - 1,092 MW (December '22)**	**50% Levy Unit 2 - 546 MW (December '22)**		2022
2023				2023
2024	375 MW Crystal River 1 Retirement (Sep '24) 494 MW Crystal River 2 Retirement (May '24) Generic 2x1 G CC	375 MW Crystal River 1 Retirement (Sep '24) 494 MW Crystal River 2 Retirement (May '24) Generic 2x1 G CC (2)	375 MW Crystal River 1 Retirement (Sep '24) 494 MW Crystal River 2 Retirement (May '24) Generic 2x1 G CC (2)	2024
2025				2025
2026			Generic Simple Cycle CT	2026
2027	Generic 2x1 G CC	Generic 2x1 G CC	Generic 2x1 G CC	2027
2028		Generic Simple Cycle CT	Generic Simple Cycle CT	2028
2029	Generic Simple Cycle CT	Generic Simple Cycle CT	Generic Simple Cycle CT	2029
2030				2030
2031	Generic 2x1 G CC	Generic 2x1 G CC	Generic 2x1 G CC	2031
2032				2032
2033				2033
2034				2034
2035	Generic Simple Cycle CT	Generic 2x1 G CC	Generic 2x1 G CC	2035
2036	Generic 2x1 G CC (2)	Generic 2x1 G CC	Generic 2x1 G CC	2036
2037				2037
2038		Generic Simple Cycle CT		2038
2039			Generic Simple Cycle CT	2039
2040				2040
2041				2041
2042				2042
2043				2043
2044				2044
2045	Generic Simple Cycle CT	Generic Simple Cycle CT	Generic Simple Cycle CT	2045
2046			Generic 2x1 G CC	2046
2047				2047
2048				2048
2049	Generic 2x1 G CC	Generic 2x1 G CC (2)	Generic 2x1 G CC (2)	2049
2050				2050
2051			Generic Simple Cycle CT	2051
2052	Generic 2x1 G CC	Generic 2x1 G CC	Generic 2x1 G CC	2052
2053		Generic Simple Cycle CT	Generic Simple Cycle CT	2053
2054	Generic Simple Cycle CT	Generic Simple Cycle CT	Generic Simple Cycle CT	2054
2055				2055
2056	Generic 2x1 G CC	Generic 2x1 G CC	Generic 2x1 G CC	2056
2057				2057
2058				2058
2059				2059
2060	Generic Simple Cycle CT	Generic 2x1 G CC	Generic 2x1 G CC	2060
2061	**Levy Unit 1 - 20 year Life Extension** Generic 2x1 G CC (2)	**Levy Unit 1 - 20 year Life Extension** Generic 2x1 G CC	Generic 2x1 G CC	2061
2062	**Levy Unit 2 - 20 year Life Extension**	**Levy Unit 2 - 20 year Life Extension**		2062
2063		Generic Simple Cycle CT		2063
2064			Generic Simple Cycle CT	2064
2065				2065
2066				2066
2067				2067
2068				2068
2069				2069
2070				2070

Docket No. 110009
Progress Energy Florida
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FitchRatings

Fitch Affirms Progress Energy's Ratings on Duke Merger Announcement; Outlook Stable

Ratings
10 Jan 2011 11:39 AM (EST)

Fitch Ratings-New York-10 January 2011: Fitch Ratings has affirmed the ratings for Progress Energy, Inc. (Progress) and its subsidiaries following the announcement of an agreement to merge with Duke Energy, Inc. (Duke; not rated by Fitch) in a stock for stock transaction. Today's rating actions include the affirmation of Progress' Issuer Default Rating (IDR) at 'BBB' and affect approximately $12 billion of debt. The Rating Outlook is Stable. A detailed list of rating actions follows at the end of this release.

Key rating drivers include similarities between the two companies' business risk and credit profiles as well as standalone credit metrics at Progress that are consistent with Fitch's 'BBB' IDR guidelines. Also, the merger is expected to produce business advantages, including opportunities for future efficiencies, economies of scale, and greater diversity and there would be no incremental debt associated with the merger.

Duke's consolidated credit ratios post-merger are anticipated to be consistent with Fitch's benchmarks and comparable ratios for highly-regulated utility peers with a 'BBB' IDR. The combined entity is expected to have funds from operations (FFO) interest coverage in excess of 4 times (x). Approximately 85% of consolidated pro forma operating income is from regulated utilities. Pro forma combined liquidity is considered strong, with approximately $1.8 billion of cash on hand and available credit facilities of $5.3 billion as of Sept. 30, 2010. At closing of the merger, all holding company debt of Progress would be assumed by Duke. Progress' utility subsidiaries would continue their current pattern of fixed-income financing on an individual basis.

Credit metrics at Progress for the LTM period ended Sept. 30, 2010 were consistent with 'BBB' IDR guidelines and company has no pending base rate cases. Progress' ratios of FFO/Debt and FFO interest coverage were approximately 19% and 4x, respectively, for the 12 month period ended Sept. 30, 2010. The relatively sizable debt at the parent holding company is a credit concern.

The rating affirmation of Carolina Power and Light Company (PEC) reflects its strong financial position and supportive state regulation. PEC's ratings also consider the upstream dividend payments to Progress needed to help support the substantial holding company debt (about 25% of Progress' consolidated debt). While helped by favorable weather, FFO interest coverage was more than 7x for the 12 months ended Sept. 30, 2010. Fitch anticipates PEC's credit metrics would remain strong relative to rating guidelines following closing of the merger. PEC faces execution risk in its fleet modernization plan.

The rating affirmation of Florida Power Corp. (PEF) reflects moderating regulatory risk following a May 2010 base rate settlement that freezes base rates through 2012, effective clause recovery for environmental and nuclear capital spending, strong liquidity and manageable near term debt maturities. Favorably, the Florida PSC has permitted PEF to recover replacement power costs related to the extended nuclear outage at Crystal River 3 (subject to refund for prudence), and with repairs nearly complete, the unit is currently expected to re-enter service in the first quarter of 2011.

Closing of the merger is subject to various contingencies including regulatory approvals from state utility commissions North Carolina and South Carolina, and approvals from the Federal Energy Regulatory Commission, U.S. Department of Justice, Nuclear Regulatory Commission and shareholders. The merger approval standard of the South Carolina Public Service Commission is a 'net benefit' for customers, which is a higher standard than 'no harm'. The close of the merger is targeted for the fourth quarter of 2011.

Fitch has affirmed the following ratings with a Stable Outlook:

Progress Energy, Inc.
--Long-term IDR at 'BBB';
--Senior unsecured debt at 'BBB';
--Short-term IDR at 'F2'.

Florida Power Corp.

--Long-term IDR at 'BBB+';
--First mortgage bonds at 'A';
--Senior unsecured debt at 'A-';
--Preferred securities at 'BBB';
--Short-term IDR/Commercial Paper (CP) at 'F2'.

FPC Capital One
--Preferred securities at 'BBB'.

Carolina Power & Light Co.
--Long-term IDR at 'A-';
--First mortgage bonds at 'A+';
--Senior unsecured debt at 'A';
--Preferred securities at 'BBB+';
--Short-term IDR/CP at 'F1'.

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Additional information is available at 'www.fitchratings.com'.

Applicable Criteria and Related Research:
--'Corporate Rating Methodology', Aug. 16, 2010
--'Credit Rating Guidelines for Regulated Utility Companies' July 31, 2007
--'U.S. Power and Gas Comparative Operating Risk (COR) Evaluation and Financial Guidelines' Aug. 22, 2007
--'Utilities Sector Notching and Recovery Ratings', March 16, 2010.

Applicable Criteria and Related Research:
Corporate Rating Methodology
Credit Rating Guidelines for Regulated Utility Companies
U.S. Power and Gas Comparative Operating Risk (COR) Evaluation and Financial Guidelines
Utilities Sector Notching and Recovery Ratings

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January 10, 2011

Research Update:
Duke Energy 'A-' Rating Affirmed And Progress Energy 'BBB+' Rating Placed On Watch Positive On Planned Merger

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Research Update:

Duke Energy 'A-' Rating Affirmed And Progress Energy 'BBB+' Rating Placed On Watch Positive On Planned Merger

Overview

- Duke Energy Corp. and Progress Energy Inc. have agreed to merge through a stock-for-stock transaction and assumption of existing debt.
- We are placing the 'BBB+' corporate credit and issue ratings on Progress Energy Inc., Carolina Power & Light Co. (dba Progress Energy Carolinas Inc.), and Florida Power Corp. (dba Progress Energy Florida Inc.) on CreditWatch with positive implications to reflect the likely upgrade following the completion of the transaction.
- We are affirming the 'A-' ratings on Duke Energy Corp. and the outlook remains stable. Duke is expected maintain credit quality through the merger-approval process and could show financial improvement post-merger depending on the terms of the regulatory approvals and the success of integration efforts.
- The combined entity would have an excellent business risk profile, with a primary focus on regulated electric utility operations, and a significant financial risk profile.

Rating Action

On Jan. 10, 2011, Standard & Poor's Ratings Services placed its 'BBB+' corporate credit ratings on Progress Energy and its subsidiaries, Progress Energy Carolinas and Progress Energy Florida, on CreditWatch with positive implications. In addition, we affirmed the 'A-' corporate credit rating on Duke Energy and its subsidiaries, Duke Energy Carolinas LLC, Duke Energy Ohio Inc., Duke Energy Indiana Inc., and Duke Energy Kentucky Inc.. The rating actions follow the announcement that Progress Energy has entered into an agreement to merge with Duke Energy. Duke Energy will be the surviving entity. Completion of the merger is possible by the end of 2011 following approvals from the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, the Department of Justice, and North Carolina and South Carolina regulators.

The positive CreditWatch listing on Progress Energy and its subsidiaries reflects that the company's credit quality will benefit from the merger with the higher-rated Duke Energy. The ratings affirmation on Duke Energy reflects our expectation that the combined entity will have an 'A-' corporate credit rating, based on excellent business risk profile and significant financial risk profile. The premium to be paid to Progress shareholders, which we calculate to be about 33% to book value, has a reasonable chance to be recouped through the retention of merger synergies. No additional debt is contemplated as part of the transaction, and regulatory approvals are expected to be timely and credit-supportive given the limited number of jurisdictions involved and the merger synergies available to show benefits to ratepayers.

Both companies are focused on regulated electric utility operations, and we expect the consolidated business risk to remain excellent. The consolidated business risk profile incorporates the following factors:

- A very large customer base of more than 7 million customers spread over six states, providing superior operating and regulatory diversity.
- The states in which the combined entity will operate are viewed as having regulatory environments in the "more credit supportive" or "credit supportive" categories.
- More than 80% of the combined company's credit profile would be characterized as very low-risk, domestic, regulated electric utility operations. The balance is derived from Duke Energy's international operations in South America and merchant activities that include a small generation fleet in the Midwest, wind power investments, and retail energy marketing.
- Total generation capacity will exceed 57,000 megawatts (MW), with about 85% of that capacity being either scrubbed, non-emitting, or having lower emissions. The remainder will present the combined entity with opportunities to retire older power plants and replace them with newer units, thereby growing rate base.

Standard & Poor's expects the combined entity to have a financial risk profile that will be in the significant category, demonstrating some weakness in the first year after the merger, but rebounding in subsequent years as a result of realizing cost savings and implementing base rate increases to recovery invested capital. Therefore, we would expect that post-merger adjusted funds from operations (FFO) to total debt to average about 15%, adjusted FFO interest coverage to average 3.75x, and adjusted debt leverage to be about 52%. Consolidated liquidity should also remain adequate since both companies will preserve their existing revolving credit facilities that total $5.3 billion.

Rationale

The ratings on Duke Energy reflect the consolidated credit profiles of its operating subsidiaries, Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana, Duke Energy Kentucky, the contribution of the company's Latin American operations, and existing and planned renewable generation investments. Ratings also reflect the projected credit profile of Duke Energy after it merges with Progress Energy. The ratings on Progress Energy reflect the consolidated credit profiles of its wholly owned subsidiaries, Carolina Power & Light Co. (dba Progress Energy Carolinas, Inc, PEC) and Florida Power Corp. (dba Progress Energy Florida, Inc. PEF), and the prospect of merging with the higher-rated Duke. Progress Energy has an excellent business risk profile that reflects stable regulated electric utility operations in North and South Carolina and Florida. Duke Energy's excellent business risk profile is characterized by stable regulated utility operations in the Carolinas, Ohio, Kentucky, and Indiana. The company's operations in Latin America consist of about 4,000 MW of generation capacity. Duke is planning to expand its portfolio of wind and solar generation investments, currently at about 790 MW, which are viewed as having higher business risk compared with the regulated utility operations.

Duke Energy's large and diverse U.S. regulated utility operations serve customers in the Carolinas and the Midwest. The utilities operate under generally credit-supportive regulatory environments that provide for slightly below-average returns and timely recovery of fuel and other variable costs. The utility operations benefit from operating diversity in five different states, and demographic and economic diversity in service territories that range from average to attractive. The utilities have strong generation operations with high availability and capacity utilization factors. Rates are competitive for the regions of operations and provide some cushion for future rate increases and fuel cost recoveries. These strengths are offset by a significant capital spending program that will total up to $15 billion through 2012, with about 80% of that targeted for regulated utility projects. The capital spending program is large, will necessitate additional debt issuance, and will require regular base rate increases to incorporate the new generation assets into rate base. As a result, ongoing effective management of regulatory risk that produces improving regulatory returns will be very important to support credit quality.

Duke Energy Ohio's electric security plan (ESP) went into effect in January 2009 and succeeded the earlier rate stabilization plan. The ESP plan, which expires at the end of 2011, provides for staggered base generation rate increases of $36 million in 2009, $74 million in 2010, and $98 million 2011 to compensate the company for dedicating about 4,000 MW of generation assets to serve native load. The ESP plan also includes trackers for fuel, purchased power and capacity costs, and environmental expenditures, avoiding the need for any deferrals, as well as recovery of non-bypassable charges related to new generation, if such projects are approved by the regulator. Since the ESP was implemented, customer and margin losses due to greater competitive forces and low market prices for generation in Ohio have eroded financial results and indicate that business risk has risen in the state. The company's ability to manage the competitive environment for the next few years and its strategic decisions surrounding the terms of the regulatory compact in Ohio in after 2011 could affect credit quality over the long term.

Cost increases in Indiana related to the construction of the 630 MW Edwardsport coal plant could also have credit quality implications, as Duke attempts to buttress its ability to eventually reflect the higher costs in rates through the regulatory process. The integrated gasification combined cycle (IGCC) generating station offers potential environmental and efficiency advantages over conventional coal-fired plant technology, but it has not been constructed on this scale and has proven to be an engineering and financial challenge. Estimated costs to complete the project have risen significantly (almost 50%), and only a portion of the overruns have been formally reviewed and effectively deemed prudent. If Duke is compelled to accept more risk to complete the project, its proficiency in managing that risk will be an important element in assessing its creditworthiness. A recent decision by the parties to renegotiate a settlement on Edwardsport construction and cost recovery could yet have credit implications. Public perception of the settlement, which requires approval by Indiana regulators, may have been affected by recent revelations of interactions between regulators and the utility that have led to dismissals or resignations of several utility executives and regulators. Credit quality would only be impaired if a new settlement or a regulatory decision shifted significant risks to Duke as a condition to completing the plant, and Duke decides to proceed with construction on that basis.

Standard & Poor's ascribes higher business risk to Duke's international operations due to the uncertainty of the local political and regulatory environments in the countries where it operates, especially Brazil, Peru, and Argentina. The Latin American assets have been self-funding, and no cash flow from overseas is factored into our analysis of Duke's ability to service the U.S. rated debt. Any substantial capital spending at the international operations could have ratings implications, depending on the risk profile of the spending. Duke is also pursuing the expansion of its wind generation business that is expected to be financed in a credit-neutral manner and under a model that minimizes market risk through long-term contracts with suitable counterparties. Any acceleration in the growth of this segment could also affect ratings.

Duke's consolidated financial risk profile is in the significant category and is expected to remain in that category after the merger. While recent historical credit metrics have been strong, in part reflecting low debt leverage, the financial profile is expected to weaken modestly over the intermediate term given the company's large capital spending program and the proposed merger. Because the associated cash flow generation will lag capital spending until several generation projects currently under construction are included in rate base, credit protection measures will weaken from 2010 levels, albeit at levels that should still support the current ratings. Adjusted debt leverage is expected to be at or below 50% and adjusted FFO to total debt to be between 15% and 20% to support current ratings.

Progress has a large and diverse customer base, serving more than 3.1 million customers. While the customer base has historically demonstrated consistent growth of more than 2% annually, the recession has slowed customer growth especially in Florida where the total number of customers declined slightly in 2009. Total generating capacity consists of more than 22,000 MW. On a consolidated basis, residential and commercial customers account for about 60% of sales, industrial customers for 15%, and wholesale customers for 20%. Wholesale sales are generally under long-term contracts with various public power, cooperative, and investor-owned utilities, regulated by the FERC on a cost-of-service basis, and lack fuel cost deferrals.

Progress Energy Carolinas and Progress Energy Florida have managed their regulatory relations effectively, achieving timely recovery of fuel and capital expenditures, and storm and environmental costs. In addition, Florida's 2006 comprehensive energy legislation provides support for new generation, including nuclear plants. North Carolina passed legislation in July 2009 that expedites the certification process for new gas-fired power plants as long as existing coal plants at the current site are retired. Progress Energy Carolinas is in the process of building three new combined cycle gas turbine units: the 600 MW Richmond facility with an in-service date of June 2011, the 950 MW Wayne County facility expected to operate in January 2013, and the 620 MW New Hanover County facility expected to operate in early

2014. Despite political overtones that have somewhat increased regulatory risk in Florida, the regulatory environment continues to be reasonably constructive mainly through the use of various clauses that allow for recovery of approved capital expenditures, including environmental expenditures, and fuel. In June 2010, the Florida regulators approved a settlement for Progress Energy Florida that effectively maintains current base rates through 2012 without affecting the various clauses mentioned earlier, while still providing for an ROE of 9.5%-11.5%. The settlement also provides that if the earned ROE falls below 9.5%, Progress Energy Florida may seek rate relief after it has used at least $150 million of the allowed depreciation reserve in the relevant period.

Progress Energy Florida is completing the work to bring the Crystal River 3 (CR3) nuclear plant back on line. CR3 experienced delamination within the concrete of the outer wall of the containment structure during a normal refueling and maintenance outage in September 2009. As of Sept. 30, 2010, Progress Energy Florida had incurred $237 million in replacement power costs, with $63 million already recovered from insurance proceeds, $49 million still to be received from insurance, and $125 million deferred for recovery through clauses. Repair costs totaled $117 million, with $18 million received from insurance, $75 million still to be received from insurance, and the balance to be deferred for base rate recovery. In October 2010, Progress Energy Florida received approval from the Florida regulators to establish a separate docket related to the outage and replacement fuel and power costs associated with the extended outage.

Consolidated capital spending will continue to be significant over the next few years, necessitating additional borrowings, to address environmental compliance, new generation, uprates at existing plants, and system growth and maintenance needs. Total capital spending is expected to be about $2.2 billion in 2011 and $1.9 billion in 2012. Given the completion of environmental projects in Florida and the new generation projects in North Carolina, the capital spending program will be geared in favor of the Carolina operations on a 65%-35% basis. Progress has an aggressive financial risk profile. For the 12 months ended Sept. 30, 2010, financial performance benefited from some stabilization and/or improvement in the local economies as well as favorable weather. The financial performance has slightly exceeded our base case expectations with adjusted FFO of $2.5 billion and adjusted total debt of $14.8 billion, leading to adjusted FFO interest coverage of 3.5x, adjusted FFO to total debt of 16.8%, and adjusted debt leverage of 59.3%.

Short-term credit factors

The short-term rating on Duke Energy is 'A-2' and largely reflects the company's long-term corporate credit rating and the stable regulated utility operations that generate the bulk of cash flows. Liquidity is adequate under Standard & Poor's corporate liquidity methodology, which categorizes liquidity in five standard descriptors. Adequate liquidity supports Duke's 'A-' credit rating. Projected sources of liquidity, mainly operating cash flow and available bank lines, exceed projected uses, mainly necessary capital expenditures, debt maturities, and common dividends, by more than 1.2x. Duke's ability to absorb high-impact, low-probability events with limited need for refinancing, its flexibility to lower capital spending or sell assets, its sound bank relationships, its solid standing in credit markets, and generally prudent risk management further support our description of liquidity as adequate.

Duke Energy's debt maturities total about $600 million in 2011. The company has a $3.14 billion master revolving credit facility maturing in 2012 with approximately $2.5 billion currently available. The master credit facility contains a sub-limit of $1.1 billion for Duke Energy, $840 million for Duke Energy Carolinas, $650 million for Duke Energy Ohio, $450 million for Duke Energy Indiana, and $100 million for Duke Energy Kentucky.

Progress Energy's liquidity is adequate under Standard & Poor's corporate liquidity methodology, which describes a company's liquidity in five standard categories. Progress Energy's liquidity supports its 'BBB+' corporate credit rating. Projected sources of liquidity--mainly operating cash flow and available bank lines--cover projected uses, mainly necessary capital expenditures, debt maturities, and projected common dividends, by about 1.2x over the next 12 months. The short-term rating on Progress is 'A-2' reflecting the company's corporate credit rating and its stable cash-generating capability.

As of Oct. 15, 2010, the consolidated lines of credit totaled $2 billion, with $750 million available at each of the utility operating subsidiaries (fully available at PEC and PEF) and expiring in October 2013, and $500 million available at the holding company with $468 million still undrawn and expiring in May 2012. None of the bank facilities have rating triggers. Progress Energy also had $691 million in cash and short-term investments. There is $1 billion in debt maturities in 2011, and $950 million in 2012.

CreditWatch

The positive CreditWatch on Progress Energy is based on the anticipated consummation of the merger with the higher-rated Duke.

Outlook

The outlook on Duke Energy is stable and reflects Standard & Poor's projection of steady financial performance while the company successfully completes the merger with Progress Energy and its considerable construction projects without further delays or cost increases. We could lower ratings or institute a negative outlook if credit protection measures unduly weaken or if adverse developments in Indiana or Ohio lead to a conclusion that business risk has worsened. A decision to proceed with the merger even if conditions enacted by regulators in the approval process undermine the financial basis for the transaction would also lead to lower ratings. The outlook could be revised to positive if the merger is completed with financial parameters intact, and if the large capital program is successfully completed and is not extended by new spending, especially on nuclear generation.

Docket No. 110009
Progress Energy Florida
Exhibit No. ________ (JE-5)
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Related Criteria And Research

- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, published May 27, 2009.
- 2008 Corporate Criteria: Analytical Methodology, published April 15, 2008.

Ratings List

Ratings List

	To	From
Progress Energy Corp.		
Corporate Credit Rating	BBB+/CW-Pos/A-2	BBB+/Stable/A-2
Carolina Power & Light Co. dba Progress Energy Carolinas Inc.		
Corporate Credit Rating	BBB+/CW-Pos/A-2	BBB+/Stable/A-2
Florida Power Corp. dba Progress Energy Florida Inc.		
Corporate Credit Rating	BBB+/CW-Pos/A-2	BBB+/Stable/A-2
Duke Energy Corp.		
Corporate Credit Rating	A-/Stable/A-2	A-/Stable/A-2
Duke Energy Carolinas LLC		
Corporate Credit Rating	A-/Stable/A-2	A-/Stable/A-2
Duke Energy Ohio, Inc.		
Corporate Credit Rating	A-/Stable/A-2	A-/Stable/A-2
Duke Energy Indiana, Inc.		
Corporate Credit Rating	A-/Stable/A-2	A-/Stable/A-2
Duke Energy Kentucky, Inc.		
Corporate Credit Rating	A-/Stable/--	A-/Stable/--

Complete ratings information is available to RatingsDirect subscribers on the Global Credit Portal at www.globalcreditportal.com and RatingsDirect subscribers at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

Moody's
INVESTORS SERVICE

Rating Action: Moody's affirms Duke Energy and Progress Energy's Baa2 senior unsecured ratings following merger announcement; rating outlooks stable

Global Credit Research - 10 Jan 2011

Approximately $30 billion of debt securities affected

New York, January 10, 2011 -- Moody's Investors Service affirmed the ratings and stable outlooks of Duke Energy Corporation (Duke: Baa2 senior unsecured) and its subsidiaries (listed below) as well as the ratings and stable outlooks of Progress Energy Corporation (Progress: Baa2 senior unsecured) and its subsidiaries (listed below) following today's announcement that the boards of Duke and Progress have agreed to combine in a stock-for-stock transaction. Duke will be the surviving parent company upon consummation of the transaction. In addition, Moody's changed the rating outlook for Duke Energy Ohio to stable from positive.

Ratings affirmed include:

Duke Energy's Baa2 senior unsecured and Issuer Rating and Prime-2 short-term rating for commercial paper;

Progress Energy's Baa2 senior unsecured and Issuer Rating and Prime-2 short-term rating for commercial paper;

Duke Energy Carolinas A1 senior secured, A3 senior unsecured;

Carolina Power & Light Company d/b/a Progress Energy Carolinas A1 senior secured, A3 senior unsecured and Issuer Rating, and Prime-2 short-term rating for commercial paper;

Florida Power Corporation d/b/a Progress Energy Florida's A2 senior secured, Baa1 senior unsecured and Issuer Rating; Baa3 preferred stock, and Prime-2 short-term rating for commercial paper;

Cinergy Corporation's Baa2 Long Term Issuer Rating;

Duke Energy Ohio's A2 senior secured and Baa1 senior unsecured,

Duke Energy Indiana's A2 senior secured, Baa1 senior unsecured and Baa3 preferred stock;

Duke Energy Kentucky's (p)A3 senior secured and Baa1 senior unsecured;

Florida Progress Funding Corporation's Baa2 junior subordinated debt;

FPC Capital 1's Baa2 preferred stock.

RATINGS RATIONALE

"The rating affirmations of Duke and Progress reflect their strong financial positions, sizeable regulated utility business operations and diversity among regulatory jurisdictions. The merger announcement is viewed as a credit neutral event for both companies, although our qualitative view regarding their relative positions within the Baa2 rating category has changed" said Mike Haggarty, Senior Vice President.

Pro-forma consolidated credit metrics for the combined Duke-Progress entity are expected to result in cash flow (CFO-pre WC) to debt of around 15% - 16%. These pro-forma credit metrics and business risk factors position the merged Duke more appropriately within its Baa2 rating category. Previously, we viewed Duke to be strongly positioned, and Progress to be weakly positioned within the Baa2 ratings category.

"We believe the merger transaction has several positive attributes" said Jim Hempstead, Senior Vice President. "The inherent logic behind the merger is the consolidation of two homogenous, capital intensive companies, to spread fixed costs across a larger asset platform. We also see good incremental diversification benefits with the proposed merger, including the addition of a Florida service territory, generation dispatch efficiencies in the Carolinas, and the ability to wring out other operating cost efficiencies across both organizations" Hempstead added. The merger creates one of the largest utility systems in the country, including the largest regulated nuclear generating fleet, operating in generally supportive regulatory environments. A larger Duke/Progress organization will also be better positioned to undertake the construction of new nuclear generation in either the Carolinas or Florida in the event the new company decides to move forward in this direction.

In addition to shareholder approval, we believe the merger will likely require the approval of two state regulatory commissions (North Carolina and South Carolina), the Federal Energy Regulatory Commission (FERC) and the Nuclear Regulatory Commission (NRC). While it is premature to predict the outcome of any of these proceedings, it remains possible that additional merger conditions could be imposed by one or more of the state regulators in order for merger approval to occur. It is also possible that today's merger announcement could have implications for other regulatory proceedings currently underway or planned over the near-term by both companies in various states, particularly given the current economic challenges that exist in their respective service territories.

Notwithstanding the clear fit that exists by merging the two companies, these regulatory issues make the consummation of the merger under the current terms less certain at this juncture. As there is greater clarity concerning the regulatory and shareholder approvals, including the impact, if any, on pending regulatory filings, Moody's will comment accordingly. Also, as the companies provide more transparency around legal structure, integration plans and synergy benefits, rating refinements, if needed, may follow. Today, we incorporate a view that the merger will close by year-end 2011.

Moody's affirmed the ratings for several Duke subsidiaries, including: Duke Energy Carolinas (Duke Carolinas: A3 senior unsecured); Duke Energy Ohio (Duke Ohio: Baa1 senior unsecured); Duke Energy Indiana (Duke Indiana: Baa1 senior unsecured) and Duke Energy Kentucky (Duke Kentucky: Baa1 senior unsecured).

Moody's also affirmed the ratings for all of Progress' subsidiaries, including: Progress Energy Carolinas, Inc. (A3 senior unsecured, Prime-2 commercial paper rating) and Progress Energy Florida, Inc. (Baa1 senior unsecured, Prime-2 commercial paper rating).

The prime-2 commercial paper ratings for both Duke and Progress are also affirmed.

For Duke Ohio, the change in the rating outlook to stable from positive reflects our modest concerns regarding the regulatory restructuring process in Ohio, lingering uncertainties associated with potential generation divestiture plans and the longer-term implications associated with the utility's ultimate capital structure and cash flow generation possibilities. Although we continue to view Ohio as a supportive regulatory and political jurisdiction, the chronic overhang of intermediate-term regulatory restructuring plans present increased uncertainties for Duke Ohio over the near-term. In addition, while we continue to view the Duke Ohio utility as strongly positioned within its Baa1 senior unsecured rating category, a rating upgrade is no longer likely over the near to intermediate term horizon. We are only modestly concerned with the implications associated with customer choice, and prefer to focus on the longer-term fundamentals of the Duke Ohio transmission and distribution utility activities.

The rating affirmations of Duke Indiana and Duke Kentucky reflect the good regulatory and political relationships that those entities have in their respective jurisdictions; the supportive suite of cost and investment recovery mechanisms, including numerous trackers; the diversity of load, customers and generation fuel supplies; and adequate sources of liquidity through the Duke Master Credit Facility. We continue to monitor the regulatory situation at Duke Indiana related to its Edwardsport Coal Gasification project, but incorporate a view that the matter will be resolved without adversely impacting credit quality.

The ratings affirmation of Duke Carolinas and Progress Energy Carolinas reflects the above average regulatory environments in both North and South Carolina, the credit supportive cost recovery provisions in place, strong financial metrics, and service territories that should experience limited growth over the near term. The merger is not expected to immediately alter the utilities' respective capital expenditure programs or planned generation retirements.

However, joint dispatch arrangements should benefit both utilities over the longer-term and could eventually slow the timing of some new generation. Because of the relatively early enactment of North Carolina's 2002 Clean Smokestacks Act, both Duke Carolinas and Progress Energy Carolinas are fairly well positioned in meeting currently mandated environmental requirements.

The ratings affirmation of Progress Energy Florida reflects the stabilization of the political and regulatory environment in Florida, including the utility's recent rate settlement with the Florida Public Service Commission that should preclude the need for additional base rate proceedings through 2012. The utility continues to be negatively affected by the long-term outage of its Crystal River 3 nuclear plant, which has been undergoing repairs since September 2009, although the company expects to recover replacement power costs, which have been relatively manageable due to low gas prices, through its fuel cost recovery clause. The plant is currently expected to be back in service in March 2011. Although the merger will result in no direct benefits to Progress Energy Florida, such as the expected joint dispatch benefits in the Carolinas, the utility will be part of a much larger and more diverse organization in the event it decides to accelerate its currently postponed new Levy County nuclear construction project.

The rating outlooks of Duke, Progress and their respective subsidiaries are all stable and, barring unexpected new developments, Moody's does not anticipate any change in ratings or rating outlooks while the merger integration is underway and regulatory approvals are being obtained over the next year.

Rating upgrades are unlikely given last year's adverse regulatory development in Florida, lingering regulatory uncertainties in Indiana and Ohio, our expectations regarding pro-forma combined key financial credit metrics and high levels of debt at the parent holding companies.

Rating downgrades appear equally unlikely at this time, but could occur if there is a sustained decline in parent company cash flow coverage metrics below current levels, including a ratio of CFO before working capital plus interest to interest below 3.5x, a ratio of CFO before working capital to debt below 15%, a sustained decline in the supportiveness of the regulatory environments in North Carolina, South Carolina, Florida, Indiana or Ohio or a substantial increase in leverage at the parent or utilities.

The principal methodology used in this rating was Regulated Electric and Gas Utilities published in August 2009.

Duke Energy Corporation is a holding company for regulated utilities Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky, as well as international business activities in Central and South America. Duke Energy is headquartered in Charlotte, North Carolina.

Progress Energy, Inc. is a holding company for regulated utilities Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. and Florida Power Corporation d/b/a Progress Energy Florida, Inc., and is headquartered in Raleigh, North Carolina.

REGULATORY DISCLOSURES

Information sources used to prepare the credit rating are the following: parties involved in the ratings, parties not involved in the ratings, public information, confidential and proprietary Moody's Investors Service information, and confidential and proprietary Moody's Analytics information.

Moody's Investors Service considers the quality of information available on the issuer or obligation satisfactory for the purposes of maintaining a credit rating.

Moody's adopts all necessary measures so that the information it uses in assigning a credit rating is of sufficient quality and from sources Moody's considers to be reliable including, when appropriate, independent third-party sources. However, Moody's is not an auditor and cannot in every instance independently verify or validate information received in the rating process.

Please see ratings tab on the issuer/entity page on Moodys.com for the last rating action and the rating history.

The date on which some Credit Ratings were first released goes back to a time before Moody's Investors Service's Credit Ratings were fully digitized and accurate data may not be available. Consequently, Moody's Investors Service provides a date that it believes is the most reliable and accurate based on the information that is available to it. Please see the ratings disclosure page on our website www.moodys.com for further information.

Please see the Credit Policy page on Moodys.com for the methodologies used in determining ratings, further information on the meaning of each rating category and the definition of default and recovery.

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Actual and Estimated Levy Residential Bill

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Progress Energy Florida
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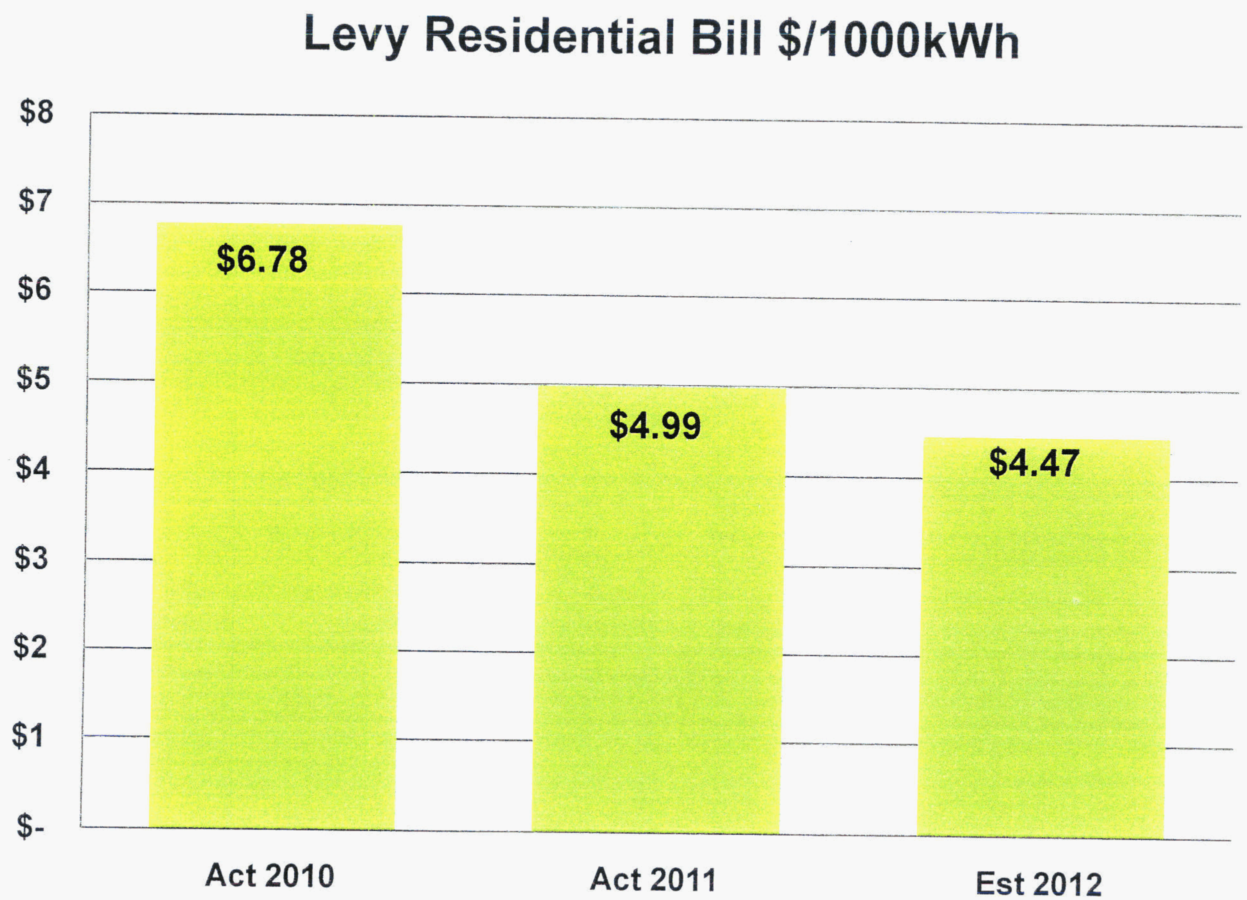

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The table below shows historical and projected growth rates by class for weather-adjusted energy sales and customers.

	Compound Annual Growth Rates			
CLASS	2000-2005	2005-2010	2010-2015	2015-2020
Residential MWh	2.9%	-1.6%	1.4%	1.9%
- Customers	2.3%	0.8%	1.3%	1.4%
- Use/Customer	0.4%	-2.3%	0.2%	0.5%
Commercial MWh	1.9%	-0.1%	2.0%	2.0%
- Customers	2.2%	0.1%	1.7%	1.7%
- Use/Customer	-0.5%	-0.2%	0.4%	0.2%
Industrial MWh	-0.7%	-4.7%	3.5%	-1.9%
Governmental MWh	3.6%	0.6%	2.3%	2.2%
Retail MWh	2.2%	-1.2%	1.9%	1.6%
Retail Customers	2.3%	0.7%	1.3%	1.5%

Estimate Update: Cancellation Costs Post COLA

Estimate Cancellation Post-COLA Receipt	PTD 2010	Forecast 2011	Forecast 2012	Forecast 2013	Estimate 2014-19	Total 2011-19
EPC Payments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LLE Payments & WEC Support	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LLE PO Disposition Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
COLA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wetland mitigation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other Owner's Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cancellation Fees	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cancellation Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LLE Final Payments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other EPC Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Estimated Owner's Unwind Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
(1) Dollars in millions; excluding AFUDC
(2) Estimates based on refined cash flows and assumptions related to final LLE decisions
(3) Cancellation fees includes [redacted] for base EPC and [redacted] for Fuels Contract

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Cost – Summary CapEx 2011-2013

- Continue with EPC Amendment - partial suspension

Estimate of Near-Term Costs	PTD 2010	Forecast 2011	2012	2013	2011-13 3-Yr Total
EPC Payments	[redacted]	[redacted]			
LLE Payments & WEC Support					
LLE PO Disposition Costs					
Transmission					
COLA					
Wetland mitigation					
Other Owner's Cost					
Totals	[redacted]	[redacted]			

Notes:
(1) Dollars in millions; excluding AFUDC
(2) Near-Term Costs reflect best available and/or negotiated LLE information, and reasonable estimates of Consortium costs

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