BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Cost Recovery Clause

DOCKET NO. 100009
Submitted for filing: August 3, 2010

REDACTED

REBUTTAL TESTIMONY OF JEFF LYASH

**ON BEHALF OF
PROGRESS ENERGY FLORIDA**

COM 5
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IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA

FPSC DOCKET NO. 100009

REBUTTAL TESTIMONY OF JEFF LYASH

I. INTRODUCTION, PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY.

Q. Please state your name and business address.

A. My name is Jeff Lyash. My business address is 410 South Wilmington Street, Raleigh, North Carolina.

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

A. I am currently employed by Progress Energy, Inc. ("Progress Energy") as the Executive Vice President-Energy Supply. I assumed my current position on June 1, 2010. Prior to this appointment, I was employed by Progress Energy as the Executive Vice President of Corporate Development. I also held the position of President and Chief Executive Officer ("CEO") of Progress Energy Florida, Inc. ("PEF" or the "Company") from 2006 until July 6, 2009. In this role, I had overall responsibility for the operations of PEF.

Q. What is your role with respect to the development of the nuclear power plants, Levy Units 1 and 2?

A. As the Executive Vice President-Energy Supply for Progress Energy, I still have senior management oversight responsibility for the Levy nuclear power plant project ("LNP"), just as I did as the Executive Vice President of Corporate Development. The Nuclear Plant Development ("NPD") organization has been folded into New Generation Programs and Projects ("NGPP") led by John Elnitsky. NGPP continues under Corporate Development and Improvement, which is now led by Paula Sims, the Senior Vice President-Corporate Development and Improvement. Paula Sims has administrative oversight of the LNP. The program oversight and enterprise governance charter for the LNP, however, remains unchanged. This charter continues to provide program execution oversight including ongoing review of performance and decision making on the LNP under the Levy Program Performance Review. John Elnitsky, as Vice President-NGPP, leads the Levy Program Performance Review. The Levy Program Performance Review includes the following functional areas with respect to the LNP: transmission planning; finance; regulatory; external relations; communications; and nuclear operations, safety, and quality. In terms of this governance and execution oversight role, John Elnitsky continues to report to me as the Executive Sponsor of the Levy Program Performance Review.

Also, I remain a member of the Senior Management Committee ("SMC"), which has senior management responsibility for the LNP. I have briefed the SMC and participated in the SMC's decisions with respect to the LNP, and I have briefed the

Progress Energy Board regarding the LNP in my current position and in my prior position as Executive Vice President of Corporate Development.

As I explained in my direct testimony, in my prior position as PEF's President and CEO I also had broad responsibility for the development of the LNP. As the LNP progressed, and the NPD organization was formed to take responsibility for the LNP in early 2008, the NPD reported to me for direct line accountability for the LNP development. As I have explained above, I still have direct line accountability for the LNP development.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to explain that the Company evaluated all viable options for the LNP under the circumstances facing the Company in reaching its decision. This evaluation necessarily included an assessment of the existing and future uncertainty of all risks associated with the LNP. As a result of this evaluation, PEF determined that proceeding with the LNP by focusing on obtaining the Combined Operating License ("COL") for the LNP is in the best interests of the Company and its customers. This decision, however, depended on negotiating an amendment to the Engineering, Procurement, and Construction ("EPC") agreement with Westinghouse and Shaw, Stone, & Webster (the "Consortium") to suspend all work except work necessary to obtain all LNP permits, including the COL, while preserving the benefits under the existing EPC agreement. PEF was able to negotiate this favorable EPC amendment to implement this option. As a result, this was a reasonable and prudent decision. It is also, in my view, the right decision for PEF, its customers, and the State of Florida.

Another purpose of my rebuttal testimony is to explain that the Company determined that the LNP is feasible under a long-term feasibility analysis consistent with the Company's feasibility analysis in Docket No. 090009-EI that was approved in Florida Public Service Commission ("FPSC" or the "Commission") Order No. PSC-09-0783-FOF-EI. The Company's fuels, environmental, and load forecasts in its current feasibility analysis were performed in the same manner that the same forecasts were prepared in the previously-approved feasibility analysis. These Company forecasts were further prepared in a manner that is consistent with the forecast methodology approved by the Commission in other proceedings and dockets before the Commission.

Q. Have you reviewed the Intervenor and Staff Testimony filed in this Docket?

A. Yes, I have. I have reviewed and I will provide rebuttal testimony to the following intervenor direct testimony: (1) William R. Jacobs, Jr., Ph.D. ("Jacobs") filed on behalf of the Office of Public Counsel ("OPC"); (2) Dr. Mark Cooper ("Cooper") filed on behalf of the Southern Alliance for Clean Energy ("SACE"); and (3) Arnold Gundersen ("Gundersen") filed on behalf of SACE. Mr. John Elnitsky will also provide rebuttal testimony to the Intervenor witness testimony and the Commission Staff witness direct testimony of Mr. William Coston and Mr. Kevin Carpenter filed jointly on behalf of the Commission Staff.

Q. Can you summarize the Intervenor Witnesses' claims and your responses to those claims?

A. Yes. OPC witness Jacobs claims that PEF's decision-making process is incomplete. Based on his independent analysis of the enterprise risks facing the LNP, Jacobs claims that PEF should have considered the option of continuing with the LNP as PEF decided to do and then cancelling the LNP after receipt of the COL in late 2012. (Jacobs Test., p. 7, L. 16-19). Jacobs argues that if the costs to customers of this option are "significantly" higher than immediate cancellation of the project the Company should justify why the option selected is preferred over immediate cancellation. (Id., p. 8, L. 30-33). Finally, Jacobs asserts that the Commission "might" want to consider placing "some" unidentified amount of PEF's "proposed" costs at risk if the Commission believes PEF has not prudently evaluated the LNP options. (Id., p. 13, L. 16-21).

Jacobs, however, does not claim in his testimony that PEF's evaluation of the LNP options was unreasonable or imprudent. He appears to accept that PEF can evaluate the option he identifies and reasonably and prudently reach the same decision it has made, even if the costs of this option to customers are "significantly" higher than immediate cancellation, as long as PEF justifies its decision. If the costs of this option are not "significantly" higher than immediate cancellation he appears to agree that PEF's decision is reasonable and prudent without the need for further justification.

Boiled down to its core, Jacobs is simply asserting that while PEF's choice may be reasonable, he would have reached a different decision. He appears to believe that project cancellation now is a more reasonable option than continuing to pursue the

COL. PEF agrees that project cancellation is a reasonable option for the LNP given the existing schedule shift on the LNP and the risks PEF faced on the project, and that is why PEF evaluated this option before making its decision to continue pursuing the COL. In fact, PEF decided to continue with the LNP only when PEF was able to obtain favorable terms to amend the EPC agreement and implement an extended partial suspension to focus the work on obtaining the LNP COL while maintaining the existing contractual benefits and risks under the EPC agreement during this licensing period.

This favorable amendment allowed the Company to continue with the project [redacted] to PEF and its customers. As a result, the Company was able to extend the near-term LNP costs to customers in excess of one billion dollars to the period after the LNP COL is obtained while preserving the long-term benefits of low-fuel cost, carbon-free nuclear energy generation for PEF and its customers. This is a reasonable and prudent decision under the circumstances and Jacobs does not contend otherwise. Indeed, for all the reasons provided in my direct and rebuttal testimony in this proceeding, this was the right decision for PEF, its customers, and the State of Florida.

Later in his testimony, Jacobs does claim that PEF was unreasonable with respect to PEF's execution of the EPC agreement at the end of 2008 without the Nuclear Regulatory Commission ("NRC") Limited Work Authorization ("LWA") determination in hand. (Jacobs Test., p. 12, L. 20-25, p. 13, L. 1-24, p. 14, L. 1-18). Jacobs admits, however, that he made this exact same argument last year in the 2009 nuclear cost recovery clause ("NCRC") docket. (Id., p. 12, L. 23). In that docket, the

Commission determined that PEF was reasonable in executing the EPC agreement when PEF did and that PEF's actions and planning regarding an LWA leading up to signing of the EPC agreement were reasonable and consistent with good business practices. Thus, while Jacobs may not agree with the decision the Commission made last year in this regard, he must recognize that the Commission has already ruled on these issues and that he cannot ask for a "do-over" this year simply because he did not like the Commission's ruling.

SACE witnesses Cooper and Gundersen claim that the long-term feasibility of the LNP has not been demonstrated, that the LNP is in fact not feasible, and that the LNP should be cancelled and PEF should not recover "additional" costs on the project. (Cooper Test., p. 3, L. 1-6; Gundersen Test., p. 3, L. 12-20). Neither Cooper nor Gundersen, however, dispute the reasonableness and prudence of PEF's qualitative and quantitative feasibility analysis. They nowhere argue that PEF's feasibility methodology is flawed or that PEF failed to implement that methodology. Instead, they simply disagree with PEF's judgment and its feasibility decision.

Both Cooper and Gundersen erroneously claim that PEF is not pursuing the development of the LNP because of their misunderstanding of the nature and status of PEF's LNP project. (Cooper Test., p. 11, L. 21-22, p. 12, L. 1-3; Gundersen Test., p. 10, L. 1-20). The LNP is an active project under an existing NRC COLA and EPC agreement. Cooper and Gundersen also make different, unsupported judgments about the enterprise risks facing the LNP. (Cooper Test., pp. 22-27; Gundersen Test., pp.16-25). Gundersen further challenges the regulatory and technical feasibility of the LNP based on his own prejudiced and unsupported views about the AP1000 design and the

LNP site. (Gundersen Test., pp. 16-25). Simply put, there are no technical design issues with the AP1000 design that have precluded the NRC from continuing with its review towards approval of that design and its review of the LNP COLA towards application of that design to the LNP site. Nuclear reactors can be built and operated in Florida, in fact, PEF has built and is operating a nuclear reactor within ten miles of the LNP site.

Cooper challenges the economic feasibility of the LNP by simply replacing PEF's forecast assumptions with unproven and unsupported assumptions of his own, just as he did in last year's proceeding. (Cooper Test., p. 5, L. 17-22, pp. 6-7). PEF's forecasts, however, are based on proven forecast methods previously approved by the Commission in the 2009 NCRC docket and other dockets. Further, PEF has demonstrated that the LNP is still feasible applying the same methodology this Commission approved last year.

Q. Do you have any exhibits to your testimony?

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

- Exhibit No. ___ (JL-7), Excerpt of Jacobs' testimony in Docket No. 090009-EI;
- Exhibit No. ___ (JL-8), Final Order Approving Nuclear Cost Recovery Amounts for Florida Power & Light Company and Progress Energy Florida, Inc., Order No. PSC-09-0783-FOF-EI in Docket No. 090009-EI, dated November 19, 2009;
- Exhibit No. ____ (JL-9), Excerpt of Jeff Lyash rebuttal testimony in Docket No. 090009-EI, p. 22, and

- Exhibit No. ___ (JL-10), Excerpt of Jeff Lyash rebuttal testimony in Docket No. 090009-EI, pp. 15-17.

These exhibits were prepared by the Company, they are 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.

II. REASONABLENESS AND PRUDENCE OF PEF DECISION.

Q. Was PEF's decision-making process complete in that PEF considered all reasonable options for the LNP?

A. Yes. As I explained in my direct testimony, the Company determined that it had two viable alternatives to proceeding with all LNP work as quickly as possible: (1) amending the EPC agreement to focus LNP work on obtaining the COL and deferring most other LNP work until the LNP COL is obtained; or (2) termination of the EPC agreement and cancellation of the project. The Company identified these options based on its assessment of the enterprise risks facing the LNP.

In sum, the Company realized that regulatory determinations beyond the Company's control precluded PEF from proceeding with confidence with the LNP on a minimum LNP schedule shift as short as 36 months because there was no additional float for additional regulatory or other project delays in that schedule. Based on recent experience, this was an optimistic and aggressive schedule.

The Company also realized that there were increasing uncertainties and therefore increasing enterprise risks associated with the LNP that I identified and discussed in detail in my direct testimony. Realistically, then, a longer schedule shift beyond 36 months was necessary to continue work on the project and ensure that there was sufficient float built back into the LNP schedule for potential future schedule impacts and the effects of enterprise risk events and circumstances.

Proceeding with the LNP work as quickly as possible on a minimum 36 month schedule exposed the Company and customers, therefore, to the near term increased enterprise risks for the LNP. This option did not allow additional time before significant capital investment in the LNP must be made for greater certainty with respect to the regulatory determinations, the economy, and federal and state energy and environmental policy, among other enterprise risks facing the project.

One viable option to mitigate these risks was continuation of the project on a longer term schedule focusing on the regulatory permits for the LNP and deferring substantial capital investment in the LNP until those permits were obtained. Another viable option to eliminate these risks was project cancellation. Both of these options were viable and reasonable and the Company evaluated both of them before making its decision.

Q. But Jacobs claims the Company did not consider all reasonably possible options because he says the Company did not consider at this time cancellation of the project after receipt of the COL in early 2013. Is he correct?

A. No. The Company necessarily considered the option Jacobs suggests when it evaluated the option of terminating the EPC agreement and cancelling the project. To explain, Jacobs claims that cancellation after receipt of the COL is a reasonably likely outcome <u>in the future</u> based on his <u>current</u> assessment of the project risks. Jacobs believes <u>now</u> that there is increased uncertainty and risk, that there likely will not be less uncertainty and reduced risk in the future, and, therefore, PEF will likely terminate the project in 2013 after it obtains the LNP COL. In other words, Jacobs asserts that the Company should consider immediate cancellation because the Company will likely cancel the project in 2013 after receipt of the COL based on his <u>current</u> assessment of the project risks.

The Company did evaluate immediate cancellation of the project based on the Company's assessment of the same project risks, including the Company's ability to mitigate those risks through an amendment to the EPC agreement. PEF, therefore, did evaluate the option Jacobs claims PEF did not evaluate when PEF evaluated and considered cancellation of the project. PEF and Jacobs simply evaluate the project risks <u>differently</u> and reach different conclusions regarding the decision that should be made now with respect to continuation or cancellation of the project namely because Jacobs does not evaluate the mitigation of those risks through the amendment to the EPC agreement.

To illustrate this point, Jacobs claims "it is possible" the Company will gain clarity and certainty on the risks facing the project by 2013, but, in his view, it is "just as likely" that PEF will not have sufficient clarity and certainty by 2013 with respect to the enterprise risks to decide to continue the project. (Jacobs Test., p. 10, L. 16-18). Indeed, he asserts PEF may find in 2013 that "these risks have not diminished and in fact have increased." (Id., p. 10, L. 18-19). He also claims that "PEF has not demonstrated that an additional 2 to 3 years will provide the degree of certainty necessary" for the Company to decide to proceed with the project when the COL is issued. (Id., p. 11, L. 20-22). Jacobs concludes that, given the "tenuous nature of the LNP project and the lack of foreseeable resolution of uncertainties," the Commission "might" consider placing "some" unidentified amount of PEF's "proposed" expenditures at risk if the Commission believes PEF did not prudently evaluate the options that involve "spending customer funds for the next three to four years." Boiled down, Jacobs is simply stating that he believes the project should be immediately cancelled even though he nowhere in his testimony expressly states that PEF should have cancelled the project.

Q. Are there increased uncertainties and risks associated with the LNP?

A. PEF does not dispute that there is greater uncertainty and risk facing the LNP today and that the uncertainty has not diminished over the past year. We addressed these risks and uncertainties in detail in my direct testimony, in our evaluation of the feasibility of the project, and in making the decision whether it was in the best interests of the Company and its customers to continue with the project or to cancel it. We agree cancellation was a reasonable option given these uncertainties and risks and that is, in fact, why PEF evaluated that option and used it as its "default" position when negotiating amendments to the EPC agreement.

PEF believes however, as explained in more detail below, that PEF has sufficiently mitigated the risks and uncertainties associated with the project such that it is in the best interests of the Company and its customers to proceed with the project at this time by focusing on obtaining the COL under the terms of the amended EPC agreement. This is a reasonable and prudent decision. Jacobs, in fact, nowhere testifies that it is not a reasonable or prudent decision. He simply disagrees with PEF's decision because he evaluates the project risks differently. Jacobs further fails to consider and address PEF's mitigation of these risks through Amendment 3 to the EPC agreement, which he nowhere mentions in his testimony. In our view, then, Jacobs' assessment of the risks of proceeding with the project compared to immediate cancellation is incomplete because he does not evaluate the mitigation of risks through the EPC agreement amendment.

Q. Does Jacobs identify any project or enterprise risk that PEF did not consider in its evaluation of the decision to continue or cancel the project?

A. No. Jacobs, in fact, relies on the exact same recitation of risks that I identified in my direct testimony in this proceeding and that the Company evaluated. (Jacobs Test., pp. 9-11). Again, he just evaluates these risks differently and he fails to consider PEF's risk mitigation through Amendment 3 to the EPC agreement.

Jacobs does claim that PEF has not met all of the "conditions to proceed" with the LNP that were identified in an April 2009 company Board presentation and he goes on to say that this is an additional reason PEF should cancel the project. (Jacobs Test., p. 12, L. 1-19). These factors -- sufficient co-ownership, credible financing plan, and continued political, regulatory, and public support -- represent enterprise risks that were specifically evaluated by the Company in reaching its current decision. In other words, these needs and issues were considered in the Company's evaluation of the enterprise risks and they were a factor in the Company's decision along with the

Company's assessment of all other enterprise risks affecting the LNP as I describe in detail in my direct testimony.

Q. If termination of the EPC agreement and cancellation of the LNP was a reasonable option why didn't the Company cancel the project?

A. PEF was able to amend the EPC agreement to continue the project, focusing work on obtaining the COL under an extended partial suspension, while maintaining the favorable terms and conditions of the existing EPC agreement. In Amendment 3 to the EPC agreement, PEF further placed the majority of the milestone dates on hold until the COL is issued [redacted]. This allowed PEF to [redacted] During this licensing period, then, PEF and its customers have the benefit of [redacted]. PEF, therefore, was able to obtain the [redacted] in Amendment 3 while placing the Company and its customers [redacted].

Q. Would PEF have continued with the LNP without Amendment 3 to the EPC agreement?

A. No. In the event PEF was unable to negotiate the favorable terms to amend the EPC agreement that PEF obtained in Amendment 3 to the EPC agreement, PEF would have terminated the EPC agreement and cancelled the project. As I explained in detail in my direct testimony, the enterprise risks associated with the LNP have increased. Over the past year, there has been more uncertainty with respect to the enterprise risks facing the project. On this point, there is no disagreement between PEF and the intervenor witnesses. This increased uncertainty associated with the risks facing the project led PEF away from proceeding as quickly as possible with the LNP construction to consider cancellation of the project if PEF could not continue with the project on a longer term schedule shift. PEF determined that it would proceed with the project only if it was able to [redacted]. PEF was able to achieve these objectives in Amendment 3 to the EPC agreement. PEF, therefore, decided that cancellation of the project at this time was not in the best interests of PEF and its customers.

Q. What contractual and long-term project benefits were preserved by Amendment 3 to the EPC Agreement?

PEF was able to preserve all of the contractual benefits that PEF obtained [redacted]. These beneficial contract terms and provisions were identified in my testimony in Docket No. 090009 and include:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

All of these beneficial contractual terms and provisions were maintained in Amendment 3 to the EPC agreement.

This decision also preserves the long-term benefits of nuclear generation for the Company, its customers, and the State of Florida. These long-term benefits are fuel portfolio diversity, reduced reliance on fossil fuels for energy production, carbon free energy generation, and base load capacity with a relatively low cost fuel source. The LNP will provide PEF with fuel portfolio diversity, reduce PEF's reliance on fossil fuels for energy production, and provide essentially carbon-free energy production, regardless of the impact of global warming concerns and attendant legislation or regulation of carbon emissions in the future. The LNP will further provide PEF with unparalleled base load capacity with the lowest cost fuel source available to the Company. These long-term benefits to the Company and its customers will be preserved if the nuclear generation option is preserved with the Company's decision to amend the EPC agreement, focus on obtaining the COL, and defer all possible LNP costs until the COL is obtained.

These are the same benefits that the Florida Legislature recognized in the 2006 legislation revising the need determination requirements for nuclear power plants and establishing alternative cost recovery mechanisms to encourage utility investment in nuclear generation in Florida. These are also the same benefits the Commission recognized in granting the need determination for the LNP. These benefits, in our judgment after weighing the benefits and costs of this option and the option to terminate the EPC agreement and cancel the project, are worth the costs compared to the costs of terminating the EPC agreement and cancelling the project.

Q. Were there other considerations weighing against termination of the EPC agreement and cancellation of the project?

A. Yes. As I explained in my direct testimony, termination of the EPC agreement and cancellation of the project will end the LNP and likely will end the development of new nuclear generation for the Company for the foreseeable horizon. The Consortium will invest its resources in those utilities actively pursuing development of the AP1000 in the United States and around the world. Right now, there are six AP1000 plants being designed for construction or constructed in China alone. If PEF terminates the

EPC agreement and cancels the project, and later wants to initiate another nuclear project at the Levy site with the Consortium or with another vendor, PEF will fall behind all other utilities with active nuclear projects in obtaining a commitment of resources from vendors and suppliers.

Likewise, the NRC's limited resources will be committed to review of COLAs or the engineering and construction of active nuclear projects. There are currently 13 COLAs for 22 nuclear power units docketed and under NRC review. Priority will be given to the active nuclear projects by the NRC. The NRC's limited resources will not be applied to newly initiated or renewed nuclear projects ahead of the nuclear projects actively under development or construction. As a result, termination of the EPC agreement and cancellation of the LNP will likely end the Company's ability to develop new nuclear generation in Florida for the foreseeable horizon.

Q. Did the Company compare the cost of each of these options to the Company and its customers before making its decision?

A. Yes, it did. As I explained in my direct testimony, the Company compared the cost of each option, considering the costs paid to date, and the costs that will likely be incurred between 2010 and 2012 when the Company expects to receive the LNP COL. The cost difference between each option represents the incremental cost to the Company and its customers of that option. This cost comparison estimate is included in the SMC presentation included in Exhibit No. ___ (JL-6) to my direct testimony.

As demonstrated in Exhibit No. ___ (JL-6) to my direct testimony and explained in that testimony, over this project time frame, the estimated cost to proceed with the LNP as quickly as possible is approximately [redacted], the estimated cost to terminate the EPC agreement and cancel the project is [redacted], and the estimated cost to amend the EPC agreement and defer most capital costs until the COL is obtained is [redacted]. Again, the Company's decision will defer over $1 billion in capital costs for the LNP until after the COL is obtained. Further, for an estimated [redacted] --- the difference over this period between immediate cancellation and proceeding with the project by extending the partial suspension and focusing work on the COL --- the Company preserves the favorable terms and conditions of the EPC agreement and the long-term benefits of nuclear generation. The Company also avoids any lost benefits of sunk costs in the project for the Company and its customers if the project is not terminated.

As I explained in my direct testimony, termination of the EPC agreement and cancellation of the project involves not only [redacted], and administrative costs to conclude the project, it also involves an opportunity cost because the benefit of some of the costs already incurred on the LNP, or the sunk project costs, may be lost upon termination of the EPC agreement and project cancellation. The lost benefit of these sunk costs is likely if there is no renewed effort for nuclear generation in Florida for the foreseeable future. These lost opportunity costs are difficult to identify and therefore estimate, but they certainly exist in the event of project cancellation and should be and were considered in the Company's evaluation of the LNP options.

Q. Jacobs claims that PEF failed to consider all costs because PEF did not consider at this time the costs of cancellation of the project in 2013 after the COL is obtained. Do you agree with his claim?

A. No, I do not. As I explained above, Jacobs' argument boils down to an argument that PEF should have immediately cancelled the project because there are increased uncertainties and risks that are unlikely to diminish by the time PEF obtains the LNP COL. Jacobs believes today that PEF will likely terminate the project after PEF receives the LNP COL in 2013 because of these project uncertainties and risks. This is, in essence, an argument that PEF should immediately cancel the project. PEF did evaluate the immediate cancellation option including the costs of that option.

It makes no sense to compare the estimated costs of cancellation three years from now to the estimated costs of cancellation or continuation today if one now believes as Jacobs apparently does that the project uncertainties and risks are so great that the project will be cancelled in the future. If that is the case, immediate cancellation is the reasonable option and one would simply consider the estimated costs of immediate cancellation in the evaluation, just as PEF did in its evaluation of the LNP options. It also makes no sense to compare the estimated costs of cancellation options at different points in time when one is trying to decide whether or not project cancellation or continuation is in the best interests of the utility and its customers. Obviously the costs of future cancellation after three or four more years of project investment, approximately [redacted], will be higher than the costs of immediate cancellation of the project, approximately [redacted]. However, since the decision must be made at a particular point in time, the costs of the options must be estimated at the time the decision will be made.

This does not mean that PEF ignored the likely future costs if decisions were made at a different point in time in its discussions evaluating the LNP options before the Company. PEF certainly understood at the time it evaluated these options and made its decision that PEF would be spending more money on this project over the next three to four years and still face potential termination of the project at a future point in time. These costs were discussed at SMC and Board meetings evaluating the presentations on the LNP options facing the Company.

These additional costs are in fact evident in the presentations made to the SMC and the Board. I have reviewed the Company's express estimate of the costs of continuing the project under the partial suspension and cancelling the project shortly after receipt of the COL included as Exhibit No. ___ (JE-6) to Mr. John Elnitsky's rebuttal testimony. Obviously, this option incorporates the costs of the extended partial suspension option the Company selected, which is estimated at approximately [redacted] over the licensing period between 2010 and 2012. This amount is included in the SMC presentation included in Exhibit No. ___ (JL-6) to my direct testimony. In addition, the Company estimates an incremental cost for cancellation at the end of that period of [redacted], for a total estimated cost of [redacted]. This incremental amount includes [redacted], wind down costs, and the estimated balance on long lead equipment (LLE) that can be found within the cancellation option by amount or the nature of the costs in Exhibit No. ___ (JL-6) to my direct testimony. The Company, therefore, was clearly aware of the estimated costs it would incur if it decided to continue the project under the extended partial suspension and cancel the project after obtaining the COL at the time of its evaluation and decision.

Q. Jacobs claims that if the estimated costs of cancelling the project after receipt of the COL are "significantly" higher than the costs of immediate cancellation, the Company should be required to further justify its decision. Do you agree with his argument?

A. No, I do not. As I have already explained, the ultimate weight placed on such future cost scenarios depends on the Company's current assessment of the project risks and uncertainties, the Company's ability to sufficiently mitigate those risks and uncertainties, and the Company's long-term assessment of the future generation needs for the Company and its customers. In other words, the Company must assess the costs and benefits of proceeding with or cancelling the project and that is exactly what the Company did when it made its decision regarding the LNP.

As I explained in my direct testimony, PEF reasonably believes that, in the exercise of its management judgment, the incremental costs of the Company's decision to adopt the COL focus approach are worth incurring to preserve the nuclear generation option for PEF and its customers in Florida. This is a long-term project that will provide PEF and its customers with base load capacity and energy generation over a period of sixty plus years after the LNP is constructed. Over that lengthy time horizon, in the Company's view, future natural gas and other fossil fuel prices will reflect higher demand and fossil fuel source supply constraints and there will be additional environmental costs, in particular greenhouse gas ("GHG") compliance costs of some type, for fossil fuel energy generation. Under this long-term view, preserving the LNP new nuclear generation option with the COL focus approach makes sense. Accordingly, as I explained in my direct testimony, it is the Company's reasonable management judgment, that new nuclear generation is still the appropriate long-term future base load generation for the Company and its customers.

In terms of these future, long-term benefits and even the total project cost to achieve those benefits, the incremental costs of cancelling the project after receipt of the COL compared to immediate cancellation of the project are clearly insignificant on a relative basis. Cancellation after COL is estimated at [redacted] while immediate project cancellation is estimated at [redacted] for a difference of [redacted]. This difference largely reflects the fact that cancellation after COL occurs at least three years later after continued spending on the project over that time period. This difference, however, does not account for the fact that PEF will have completed certain LLE that will be available for salvage value or the fact that, in reality, the balance for disposition of the LLE will actually be lower due to the fact that three years of additional payments will reduce that to an amount lower than the LLE disposition costs estimated upon immediate cancellation which were used in generating the cost estimate upon cancellation after COL receipt. Therefore, the likely difference will be lower than [redacted], although PEF cannot accurately estimate how much lower it will be.

In any event, even if the full [redacted] estimated amount for cancellation after COL is compared to the estimated cost of immediate cancellation [redacted]) and the cost of proceeding with the project under the partial suspension to receipt of the COL [redacted]), the differences are [redacted] and [redacted] respectively. In other words, PEF will incur at most an additional [redacted] if it decides to cancel the project shortly after receipt of COL than if it decided to immediately cancel the project. PEF will also incur an additional [redacted] on the LNP to preserve the project contractual and long-term benefits during the licensing period compared to project cancellation at the end of the licensing period. This amount is only [redacted]) more to pay to preserve these contractual and long-term benefits when proceeding with the project under the partial suspension during the licensing period and terminating the project at the end of that period is compared to the differential between proceeding with the project during the licensing period and immediate project cancellation.

None of these incremental estimated values rise to a magnitude that affects the Company's decision to continue with the LNP or cancel the project. It is simply unreasonable to conclude that a decision as important as project cancellation or continuation will turn on amounts in these ranges no matter which of these incremental comparisons Jacobs believes should be used (which he does not identify in his testimony). These incremental, estimated costs are a small fraction of the total project costs and the total project benefits that will be obtained upon the completion of the investment of those costs in the project. To decide to continue or cancel this project, the decision must turn on an evaluation of the total project costs, benefits, and risks and that is exactly what PEF did.

PEF first determined that the LNP was qualitatively and quantitatively feasible. The quantitative economic feasibility analysis compared the total project costs to the total, quantifiable benefits of the LNP. Once PEF determined the LNP was feasible from a qualitative and quantitative analysis of the LNP project benefits and costs, PEF decided if proceeding with the project was in the best interests of the Company and its customers even if the project was feasible. The Company's assessment of the risks led the Company to focus on the costs of each evaluated option over a three-year project continuation period. This three-year period corresponded to the expected licensing period and, therefore, allowed PEF to focus on deferring capital investment, if possible, during this period to mitigate the risk of exposing substantial capital investment to the uncertainties associated with the licensing on the project. As a result of this analysis, PEF narrowed the options down to project cancellation or continuation under an extended partial suspension to focus work on obtaining the COL. The decision between these two options again depended on PEF's ability to mitigate the regulatory and other project enterprise risks through an amendment to the EPC agreement that preserved the contractual and long-term project benefits of continuing to pursue new nuclear generation [redacted]. PEF reasonably made its decision based on this assessment of the LNP costs, benefits, and risks.

Q. By the way, are you aware that Jacobs has testified on behalf of the Georgia Public Service Commission regarding the Vogtle AP1000 nuclear reactors that Georgia Power Company plans to license, construct, and operate in Georgia?

A. Yes, I am, and I have read his June 2010 testimony in proceedings before the Georgia Public Service Commission regarding the Vogtle AP1000 project. A copy of this testimony is attached as Exhibit No. ___ (JE-7) to the rebuttal testimony of Mr. John Elnitsky.

Q. Does Jacobs assert there that the enterprise risks are so uncertain that they are unlikely to be resolved and that future cancellation is a likely option for that AP1000 project?

A. No. On the contrary, Jacobs apparently believes that AP1000 project can be licensed and constructed on the Company's current schedule. Jacobs asserts that the licensing of the plants is the critical path but he expresses increased optimism compared to his December 2009 testimony that the AP1000 DCD certification will occur in time for the issuance of the Vogtle COL to meet the current project schedule. He testifies that it is possible that Georgia Power might miss the commercial operation dates for the Vogtle plants, but he believes the Vogtle COL will be issued two to three months later than planned and that the project can recover from this delay in the issuance of the COL. Jacobs recommends that the Georgia Public Service Commission approve continued recovery of spending on the Vogtle project.

While Jacobs refers to the project enterprise risks addressed by PEF in evaluating the options for the LNP --- including the financial market and economic rebound, federal policies on carbon, renewables, and coal, and NRC COLA process, among others --- and asserts there has been no additional clarity or certainty with respect to these risks in his testimony in this proceeding (see Jacobs Test., p. 11), he does not even mention these risks in his testimony before the Georgia Public Service Commission in the Vogtle AP1000 matter.

Q. Did the Florida PSC Staff Auditors review the EPC agreement amendments in this proceeding?

A. Yes, they did. The staff auditors reviewed the EPC agreement and its amendments. In particular, the staff auditors reviewed and commented on Amendment 3 to the EPC agreement, which implements PEF's decision to extend the partial suspension and focus work on the LNP COL. Audit staff agreed that PEF was able to preserve the existing contractual benefits of the EPC agreement in Amendment 3. Audit staff notes that Amendment 3 to the EPC agreement (a [redacted] (b) maintains [redacted] (c) maintains [redacted] (d [redacted] and (e) maintains the [redacted] (Staff Audit Report, p. 9). Audit Staff concluded that the Company was able to negotiate a favorable amendment with limited fee impact. (Id.). PEF agrees with the audit staff conclusion that PEF was able to obtain a favorable amendment that preserved the contractual benefits of the EPC agreement with limited fee impact to PEF and its customers.

Audit staff also addressed the mitigation of risk under Amendment 3 to the EPC agreement. Specifically, audit staff concluded that Amendment 3 [redacted] (Id.). PEF, again, agrees that PEF was able to mitigate the risk to the Company and its customers through Amendment 3 to the EPC agreement.

Q. Will PEF continue to evaluate the options for proceeding with the LNP including the option of project cancellation and termination of the EPC agreement?

A. Yes. As audit staff notes in its audit report, the Company's amendment to the EPC agreement allows the Company to continue to [redacted] to the Company and its customers. PEF will, of course, evaluate the project at each important step in the project to determine not only that the project remains feasible but that, even if the project is feasible, it is in the best interests of the Company and its customers to continue with the project. This is simply reasonable, prudent project management that PEF has employed and will continue to employ on the LNP.

Q. Jacobs concludes his testimony regarding the LNP by re-stating arguments he made in the 2009 NCRC proceeding. Do you have any response to these arguments?

A. Yes, I do. At pages 12-15 of his direct testimony, Jacobs opines that (1) it was unreasonable for PEF to sign the EPC agreement when it did on December 31, 2008

(Jacobs Test., p. 12, L. 20-23); (2) "it was unreasonable for PEF to sign the EPC contract without knowing the LWA schedule and that signing the EPC contract would result in extra costs" (Id., p. 14, L. 3-5); and (3) PEF could have achieved the same contractual benefits by waiting to sign the EPC contract until the LWA schedule was known. (Id., p. 14, L. 20-24, p. 15, L. 1). Jacobs made every single one of these arguments in Docket No. 090009-EI. See Exhibit No. ___ (JL-7) including excerpts of Jacobs' testimony in Docket No. 090009-EI asserting these same arguments.

The Commission heard the evidence on these arguments, including Jacobs' testimony, and decided these issues in Order No. PSC-09-0783-FOF-EI in Docket No. 090009-EI. For example, the Commission quotes Jacob's testimony that PEF should not have signed the EPC agreement without the LWA at the bottom of page 26 of the Order. The Commission concluded based on its review of all the evidence, including this testimony, that "PEF management acted appropriately in developing a Levy project construction schedule that included an LWA, because the LWA is a viable construction management tool offered by the NRC." See Exhibit No. ___ (JL-8) to my testimony, Order No. PSC-09-0783-FOF-EI, p. 25. The Commission further concluded that "we are persuaded that PEF's actions and planning regarding an LWA leading up to the signing of an EPC contract were reasonable and consistent with good business practices." (Id. at p. 30.). The Commission found "that the intervenors failed to make a persuasive showing that PEF was unreasonable concerning the timing of its decision to enter into the EPC agreement." (Id. at p. 29.).

The Commission also quotes my testimony and the testimony of Garry Miller regarding the benefits obtained by signing the EPC agreement when PEF did at page

26 of the Order. The Commission then states that "absent concerns with PEF's LWA efforts, <u>no material evidence was presented</u> that PEF should <u>not</u> have otherwise signed an EPC contract at the end of 2008." (Id. at p. 30) (emphasis added). The PSC concluded that "based on the foregoing analysis, we find the timing of PEF's decision to execute an EPC contract at the end of 2008 was reasonable." (Id.).

As a result, the Commission has heard this evidence and decided these issues. OPC through its witness should not be permitted to re-assert testimony and arguments that have been heard and decided.

Q. Both Cooper and Gundersen appear to claim that PEF no longer has an active project. Do you agree with their claims?

A. No, I do not. Cooper claims that PEF is "line sitting" and Gundersen claims PEF is "site banking" in the apparent misunderstanding that PEF does not have an active project. (Cooper Test., p. 11, L. 22-23, p. 12, L. 1-3; Gundersen Test., p. 10, L. 1-6). Gundersen misunderstands what "site banking" is. The NRC uses site banking to refer to applicants that pursue an Early Site Permit ("ESP") without an associated COLA or LWA. In contrast, PEF has a COLA and is pursuing a COL for the LNP. These activities are consistent with the efforts to actively pursue the development and construction of a new nuclear power plant. That is in fact what PEF is doing. PEF has an EPC agreement for the design and construction of the LNP that is still in effect. PEF has only amended that EPC agreement to extend the partial suspension. In other words, PEF has slowed down the project but it is still very much an active project.

Q. Did the staff auditors review PEF's decision based on PEF's evaluations of the LNP options?

A. Yes, they did. The audit staff recognized that the Company evaluated several options, including project cancellation, when considering the future of the project. (Staff Test., p. 4, L. 3-5; Audit Staff Report, pp. 7-8). The audit staff concluded that, "given the uncertainties facing the company, keeping the project progressing without further substantial investment is a reasonable approach at this point in time." (Staff Test., p. 4, L. 6-7; Audit Staff Report, p. 4). PEF agrees with the audit staff that PEF's decision is reasonable under the circumstances.

PEF is not asserting that this is the only reasonable decision that can be made under the circumstances facing the Company on the LNP. Utility management decisions are rarely a choice between right or wrong answers, rather, there is often more than one "right" decision that can be made under the circumstances. Utility management must make decisions before all potential outcomes are known and if utility management waited for complete certainty before making any decision affecting the utility and its customers utility management would never make a decision. Instead, utility management decisions must often be made under circumstances where there is more than one possible decision that can be made and the results of the various potential decisions are uncertain. The LNP is certainly no exception. PEF in fact identified several reasonable options for the LNP and evaluated each one before making a decision.

Choosing among the options available on the LNP depends on the risk assessment and risk mitigation that can be employed for each option. For all the reasons provided in my direct and rebuttal testimony in this proceeding, PEF believes its decision is reasonable and prudent based on PEF's evaluation of the costs, benefits, and risks of the LNP options and PEF's ability to preserve the contractual and long-term project benefits while mitigating the enterprise risks during the licensing period through the amendment to the EPC agreement. Another utility manager may conclude the risks are too great to be mitigated, and that the risks and project costs outweigh the project benefits, and, thus, prefer project cancellation. This does not mean project cancellation is the right decision or a better decision than the decision PEF made. PEF's decision is still a reasonable one. If, however, the Commission believes that project cancellation under the circumstances is a more reasonable option given its risk tolerance under the circumstances, PEF needs to know that now before PEF continues to invest in the project.

III. FEASIBILITY.

Q. Do any of the Intervenor witnesses dispute the reasonableness of PEF's qualitative and quantitative feasibility analysis methodology described in your direct testimony?

A. No. Neither Cooper nor Gundersen dispute the reasonableness of the methodology employed by PEF for its qualitative and quantitative feasibility analysis. They do not argue that PEF's feasibility methodology is flawed or that PEF failed to implement that methodology. They simply disagree with PEF's judgment in applying that feasibility methodology to the circumstances facing the LNP and PEF's decision with respect to feasibility. Jacobs does not even mention feasibility.

Q. Can you summarize SACE's position with respect to the LNP feasibility?

A. Yes. Both Cooper and Gundersen challenge the long-term feasibility of the LNP, arguing the LNP is not feasible, that it should be cancelled, and that PEF's customers should pay no "additional" costs. (Cooper Test., p. 3, L. 1-6; Gundersen Test., p. 3, L. 12-20). They both take credit for PEF's decision, arguing it is consistent with their testimony last year, but that it doesn't go far enough because the increased uncertainty will, in their view, result in more schedule delays and higher costs. (Cooper Test., p. 11, L. 19-23, p. 12, L. 1-19); Gundersen Test., p. 9, L. 8-20). Simply put, Cooper and Gundersen make different judgments about the enterprise risks facing the project and they, therefore, reach the conclusion that the project should be cancelled. Finally, Cooper and Gundersen have different opinions about the regulatory, technical, and economic feasibility of the LNP that involves them substituting their judgment for the Company's judgment.

To begin with their discussion of the project risks, it is no surprise that PEF's decision is consistent with their testimony regarding the uncertainties and risks associated with the project. I testified last year that PEF was aware of these risks and uncertainties and would consider those risks and uncertainties in making its decision. See Exhibit No. ___ (JL-9) to my testimony. Again, Cooper and Gundersen simply evaluate these risks differently. They also fail to address PEF's mitigation of these risks, in particular through Amendment 3 to the EPC agreement.

Gundersen focuses on the regulatory and technical feasibility of the LNP. His opinions are not expressed with any degree of certainty, however, because they have little to no basis in reality. Gundersen argues that the AP1000 design cannot be approved by the NRC based on his own biased and erroneous challenges to that design. He argues that the AP1000 nuclear reactor "may" not be approved for the LNP site based on his distortions of my prior testimony regarding the geotechnical risks and rank speculation unsupported by any independent analysis of the site geology or any analysis of the Company's geologic and geotechnical assessment of the application of the AP1000 design to the LNP site. There is no basis, therefore, for his opinions regarding the regulatory and technical feasibility of the site. Indeed, Gundersen raised similar regulatory and technical feasibility arguments last year and despite those arguments the Commission determined that PEF had demonstrated that the LNP was feasible.

Cooper addresses the economic feasibility of the LNP. Cooper makes different assumptions about future natural gas prices, future demand based on unproven energy efficiency assumptions, and future carbon costs based on uncertain energy efficiency and emission offset assumptions. This is similar if not exactly the same as Cooper's economic feasibility analysis last year. In other words, Cooper substitutes his forecast assumptions for the Company's forecasts that were prepared in the same manner as the forecasts in the feasibility analysis that was approved by the Commission in last year's NCRC docket. Therefore, despite Cooper's same claims last year, the Commission determined that PEF had demonstrated that the LNP was feasible.

Q. Cooper and Gundersen both claim that PEF has "adopted" their testimony from last year. Do you agree?

A. No. Cooper and Gundersen testified last year to generic risks associated with the regulatory license reviews, the siting, and the construction of the LNP that almost always exist on any large construction project and that exist and will always exist on the LNP until all licenses are obtained and the plants are built and operating. Cooper and Gundersen repeat their claims that there "may" be future regulatory delays, schedule shifts, and cost increases. (Cooper Test., pp. 27-28; Gundersen Test., p. 23, L. 1-24). That possibility always exists.

In any event, as I testified last year, such project risks cannot be eliminated; they can only be monitored and managed with appropriate responsive risk mitigation strategies. PEF is in fact aware of these risks, has identified them in PEF's risk management on the project, PEF is monitoring and managing them with appropriate risk mitigation plans. This is simply good project management. No intervenor or Staff witness in this proceeding challenges the reasonableness and prudence of PEF's risk management on the LNP.

Q. Gundersen claims that there are unresolved technical safety issues that affect the AP1000 design review at that NRC. Do you agree?

A. PEF agrees that there is additional uncertainty regarding the NRC LNP COLA schedule. The reasons for this uncertainty are discussed in detail in the direct and rebuttal testimony of John Elnitsky. In fact, this is the reason PEF concluded that the minimum schedule shift was 36 months and by fall 2009 PEF thought that option was optimistic. There is no indication however that Gundersen's alleged technical safety issues will prevent NRC licensing approvals for the AP1000 design.

The first alleged unresolved technical safety issue that Gundersen identifies is the Shield Building inquiry that the NRC initiated by its letter to Westinghouse last October. The issues preventing NRC review of the AP1000 DCD, however, have been addressed and, as a result, the NRC issued a revised AP1000 DCD review schedule on June 21, 2010 that targets a final rule approving the design in September 2011. That review is now in process at the NRC. Gundersen attaches the NRC letter issuing the review schedule for the AP1000 design, but he nowhere mentions in his testimony that this review can only be undertaken now because the issues preventing the NRC review of the AP1000 Shield Building Design have been addressed, enabling the NRC to issue this revised schedule.

The second alleged technical safety issue that Gundersen claims will likely preclude NRC approval of the AP1000 design is his claim that the AP1000 steel containment design is susceptible to corrosion and cracking that cannot be detected through routine visual inspections. (Gundersen Test., p. 19, L. 7-17). Gundersen created this claim himself based on his review of utility safety inspection reports regarding corrosion issues at a limited number of existing nuclear power plants. His claims are not based on any testing or analytical analysis of the AP1000 design.

In addition, the AP1000 design is different from the steel-lined concrete containment structures Gundersen references. In general, those containments have some portions that are not readily accessible by visual inspection methods. The AP1000 steel containment is a free-standing structure and, therefore, it can be visually inspected. In any event, the NRC will review and approve the AP1000 design and the

NRC has not halted that review but is continuing its review of the AP1000 design towards ultimate approval of that design.

Q. Gundersen claims that he was invited to present his report to the NRC Advisory Committee on Reactor Safeguards ("ACRS") and that the ACRS took his report under advisement. Does that mean this issue will likely preclude NRC approval of the AP1000 design as he suggests?

A. No. The ACRS is an advisory body only and it does not have the responsibility for review and approval of the AP1000 nuclear reactor design or any other reactor design. The ACRS obtains reports from interested parties including members of the public and reviews them to determine if they are worthy to report to the NRC licensing review staff for possible consideration. Gundersen or the AP1000 oversight group -- a group of anti-nuclear advocates including SACE -- asked to make a presentation to the ACRS and the ACRS was just doing its job by allowing Gundersen to make his presentation. The ACRS also invited industry representatives to address Gundersen's comments. Again, the ACRS is just doing its job of collecting information for review. The fact that the ACRS indicated to Gundersen that it would take his comments under advisement means just that and nothing more. The ACRS has not advised the NRC staff that action should be taken and the NRC staff has not taken action.

Q. Gundersen claims that you completely reversed your 2009 testimony regarding the geotechnical and geologic risks associated with the LNP site in your direct testimony in this proceeding. Do you agree?

A. No. This is a distortion of my testimony that is evident on the face of Gundersen's testimony. Gundersen points out that the gist of my 2009 rebuttal testimony was that the NRC did not have "serious doubts or concerns" about the geology of the LNP site. (Gundersen Test., p. 21, L. 9-10). That part is correct, but Gundersen fails to mention that this testimony was necessary only because the intervenor witnesses last year --- including Gundersen --- used these very words to suggest that the NRC had a problem with the Company's COLA or LWA because the NRC was asking questions about the geological and geotechnical features of the site through RAIs. My point was, the mere fact that the NRC issued these RAIs did not mean there was a problem with the Company's COLA or LWA. Instead, it meant the NRC was doing its job because the purpose of the NRC's review of the Company's COLA is the application of the AP1000 nuclear power plants to the specific Levy site. Gundersen omits this part of my testimony in his quote from my testimony on page 21 of his testimony. I have included as Exhibit No. __ (JL-10) to my testimony the full excerpt from my 2009 testimony on this point.

Gundersen then claims that I completely reversed my 2009 testimony because I acknowledged that there are "risks" associated with the geology of the LNP site in my direct testimony in this proceeding. (Gundersen Test., p. 22, L. 11-12). It is clear from Gundersen's own references to my testimony that I never said in my 2009 testimony that there were no geological or geotechnical risks associated with the LNP site. What I said was the fact that the NRC was asking geological or geotechnical questions did not mean the NRC had doubts or concerns that indicated the NRC believed there was a geological or geotechnical problem that prevented application of the AP1000 nuclear reactors to the LNP site.

When PEF filed its COLA for application of the AP1000 nuclear reactors to the LNP site PEF made the site geology a project risk. Before PEF can receive the LNP COL the NRC must confirm that the site geology is sufficient to support the AP1000 nuclear reactors. Because this is a determination that must be made by the NRC for the project to proceed toward construction it is identified as a project risk. In fact, the Company's monthly LNP project management reports beginning with the filing of the Company's COLA in July 2008 identified the site geology and geotechnical issues in the Company's risk matrix and established a risk management plan for them. The mere fact that this is identified as a project risk does not mean that it is a problem or that this risk will in fact occur.

The fact that there are such risks associated with the geologic and geotechnical review, however, does not mean that the NRC technical review concluded that an AP 1000 plant could not be located on the LNP site. If the NRC did not determine that a rigorous technical analysis in accordance with NRC regulations had been conducted by PEF, the NRC would not have docketed the LNP COLA for review and the NRC would not be continuing to process the LNP COLA. The NRC, however, is still processing the review of the LNP COLA.

Gundersen misses the point of my 2010 testimony, just as he missed the point of my 2009 testimony. I explained in my direct testimony in this proceeding that the NRC audited the Company's geologic and geotechnical assessments and the NRC staff indicated that the geologic and geotechnical risks associated with the site are receding to the point that the NRC has now characterized them as a low risk. My point is that the claims made by intervenor witnesses last year that there were NRC doubts or concerns with respect to the application of AP1000 design to the LNP site because of NRC questions regarding the site geology are now proven to be incorrect.

Q. Does Gundersen support his opinion that the LNP site "may" not even be licensable due to its geologic risks with any expert technical analysis?

A. No. Gundersen apparently did not perform any independent analysis of the application of the AP1000 design to the LNP site given the geologic and geotechnical characteristics of the site. He nowhere mentions any such analyses in his direct testimony. Instead, Gundersen relies on the reference to my direct testimony to the receding geotechnical and geologic site risks based on our recent interaction with the NRC as the sole basis for his opinion that the LNP site "may" not "be licensable due to its geologic risks." (Gundersen Test., p. 23, L. 3-4). The fact that these risks are receding supports the inference that it is possible to obtain the LNP COL not that it may not be possible to obtain the COL. Thus, even Gundersen's opinion that it is merely possible PEF will not receive the LNP COL because of geologic risks at the site is erroneous. Gundersen further ignores the reality that five nuclear power plants have been built and have been operating in Florida for over thirty years, including one nuclear power plant --- PEF's Crystal River nuclear power plant --- within ten miles of the LNP site.

Q. Cooper claims the LNP is not economically feasible or cost-effective. Do these assertions undermine the Company's quantitative feasibility analysis?

A. No, they do not. Cooper makes the same arguments about natural gas, cost, load, and environmental assumptions that he made last year. He has changed some of his assumptions --- presumably because his assumptions were not accepted by the Commission in last year's feasibility review --- but he makes the same arguments that his assumptions should be substituted for the Company's forecasts. His approach, however, to natural gas, load, and carbon cost forecasts is still inconsistent with the way utilities project such matters and the way PEF projected such matters in the NCRC docket last year and in the proceeding this year. As a result, his forecast assumptions should be rejected for the same reasons that they were last year.

For example, Cooper has changed his natural gas forecasts from NYMEX futures prices to EIA forecasts. This is still inconsistent with the Company's fuel forecasts that were approved in the Need Determination proceeding and that are routinely reviewed and approved in other proceedings before the Commission, including the NCRC docket last year. Cooper isolates on the EIA gas price forecast while PEF includes a range of gas price estimates in its feasibility analysis. PEF reviews several long term fuel forecasts in its development of the range of fuel forecast scenarios included in the feasibility assessment. While the EIA forecast may or may not be considered as one of the forecasts in the review process, it would not be used in isolation, as suggested. Cooper's gas price analysis is too narrow to be a reliable indicator. Furthermore, Cooper's implication (Cooper Test., p. 22, L. 6 and exhibit MCN-7) that gas price volatility was "unique to the last decade: and "may be the exception, not the rule", is premised on a period of very early and limited experience for commoditized energy resources like natural gas and petroleum products. Given the uncertainties surrounding potential global supply and demand on sources of natural gas and the potential for significant reliance on natural gas to offset usage of other fossil fuels like oil and coal in the future, price volatility in the future is more likely than not.

Another example is Cooper's use of Environmental Protection Agency ("EPA") projections of carbon prices in his testimony. Cooper isolates on EPA carbon prices while PEF includes a range of carbon price estimates in its feasibility analysis. Cooper's carbon price analysis then is too narrow to be a reliable indicator. In addition, Cooper fails to mention that the EPA has explicitly cautioned that its carbon price projections are subject to many uncertainties. See EPA Analysis of the American Clean Energy and Security Act of 2009, H.R. 2454 in the 111th Congress, Dated 6/23/09, U.S. Environmental Protection Agency Office of Atmospheric Programs, pp. 7-8, available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_Analysis.pdf. For example, EPA admits its carbon cost projections will increase if the amount of emission offsets that the EPA assumed in its projections is not available. (Id.).

A final example is Cooper's estimates of the energy efficiency impacts on the Company's load forecasts. Cooper uses a national average energy efficiency estimate drawn from the energy efficiency proposals in the Waxman-Markey bill that passed the House but that has not passed the Senate. This is a speculative impact at best. The Waxman-Markey bill is not the law and may never be and even if it is passed by both the House and the Senate and approved by the President there is little certainty that it will remain unchanged. Also, Cooper's estimate of a national average impact is based on uncertain and unproven energy efficiency measures, therefore, there is no basis to conclude this estimate is a reliable estimate of the impacts of the proposed energy efficiency measures on average across the country and certainly not in Florida. This is exactly what Cooper did in his testimony in the 2009 NCRC proceeding, indeed, Cooper asserts that his results of this calculation "are similar to the analyses I provided in the 2009 Nuclear Cost Recovery Proceeding." (Cooper Test., p. 25, L. 1-2). These speculative results were not accepted by the Commission in the 2009 NCRC docket and they should not be accepted in the 2010 NCRC docket.

In sum, Cooper's forecast assumptions are unproven and uncertain and they are not consistent with the way utilities make such projections. PEF performed its projections for its feasibility analysis this year in the same manner that it performed these projections last year and the same manner it typically performs such projections. The Commission determined last year that the analysis PEF provided through discovery and rebuttal testimony supported a conclusion that completing the LNP project is feasible at this time. Order No.PSC-09-0783-FOF-EI, p. 32. The Commission, therefore, approved PEF's feasibility analysis and underlying forecast methods last year and should approve the same analysis and underlying forecast methods this year.

Q. Does Cooper disagree with the Company that future generation decisions must take into account future climate change policy?

A. No, he does not, in fact, Cooper argues that the Commission should take such policy into account. (Cooper Test., p. 22, L. 21-22; p. 23, L. 1-3). Cooper agrees that utilities "must pay attention to the mandates to reduce greenhouse gas emissions." (Id., p. 25, L. 11-12). He acknowledges that "national policy will be promoting the development of low cost, low carbon options." (Id., p. 25, L. 23). He further agrees, then, that "buying time in the current environment" to develop the next low cost, low carbon resource is a key strategy. (Id., p. 25, l. 14-16). He accepts that, over time, the contours of climate policy will become clearer (Id., p. 26, L. 7), and that the uncertainty about federal climate policy is likely to diminish. (Id., p. 27, L. 2). He even agrees that "over the next four years the high degree of uncertainty regarding all the key parameters that affect the decision may be sharply reduced." (Id., p. 39, L. 4-5). These concessions by Cooper are consistent with the Company's approach to the LNP in its decision to extend the partial suspension and focus work on obtaining the COL for the LNP over the next three years.

Cooper and the Company sharply disagree, however, with what decision should be made at this point to prepare for the future, carbon-constrained energy generation environment. Cooper argues that the Company should prepare for this future by abandoning nuclear generation and "buying time" for ten to twenty-five years until the "next" generation of low cost, low carbon resources are developed. (Cooper Test., p. 25, L. 15-16). Cooper identifies undefined, unproven energy efficiency, renewables, carbon storage, and energy storage options that are not technologically developed for commercial applications. (Id., p. 25, L. 17-22). He suggests that the utilities build smaller, less efficient generation units during the interim ten to twenty-five years it will take to develop these futuristic generation options. (Id., p. 36, L. 13-15). In other words, Cooper recommends that the Florida utilities increase their reliance on fossil fuel generation by building a fleet of smaller inefficient units for twenty-five years until technological improvements somehow provide sufficient, commercially applicable renewable, carbon storage, and energy storage options. This is a speculative, highly risky resource plan that no Florida utility is pursuing or should pursue.

Nuclear generation is a current, commercially applicable, low-fuel cost, carbon-free source of energy generation that exists today. Utilities are pursuing nuclear generation in the United States and around the world despite the claims by Cooper and Gundersen to the contrary. Georgia Power Company is currently excavating to build two AP1000 nuclear reactors at the Vogtle site in Georgia. There are twelve additional applications before the NRC to build twenty nuclear power plants in the United States, including PEF's COLA for the LNP. Six AP1000 nuclear reactors are in various stages of design and construction in China. The development of new nuclear generation has been hampered by the world economic recession and other factors but it has not been abandoned. Governments, including the current administration in Washington, and utilities in this country and around the world recognize that investing in nuclear energy remains a necessary step in preparing for the future, carbon-constrained environment.

There is no dispute that it is expensive to build nuclear power plants, but the Company's updated economic feasibility analysis including the latest cost projections continues to show that the LNP is cost-effective and economically feasible over the expected life of the plants. There is no dispute that anticipated carbon costs to comply with GHG regulations contribute to the cost-effectiveness of the LNP, but no intervenor witness, including Cooper, believes there will be no future climate control legislation that places costs of some type on fossil fuel generation. This is a long-term project and the decision to continue with the LNP still depends on the long-term view over this extended period of time. The Company continues to believe that nuclear generation is still the appropriate long-term future base load generation for the Company and its customers.

IV. CONCLUSION.

Q. Do you continue to believe the Company's decision with respect to the LNP is reasonable and prudent?

A. Yes. For all the reasons explained in my direct testimony and in my rebuttal testimony, the Company's decision to continue the project by extending the partial suspension and focusing work on obtaining the LNP COL until the COL is obtained through an amendment to the EPC agreement that preserves the contractual benefits and maintains the risk to the Company and its customers is a reasonable and prudent decision. Staff auditors agreed this amendment allowed the Company flexibility to monitor the project without exposing customers to additional risk and that the Company's decision was a reasonable approach under the circumstances. As I explained in my direct testimony, this is the right decision because it extends over one billion dollars in near-term LNP costs to customers to the period after the licensing of the plants is complete while at the same time preserving the long-term benefits of fuel-diverse, carbon-free, base load nuclear generation for the Company and its customers.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Nuclear Cost Power Plant Recovery Clause	)))	Docket No. 090009-EI FILED: July 15, 2009

REDACTED
(~~CONFIDENTIAL VERSION~~)

DIRECT TESTIMONY

OF

WILLIAM R. JACOBS, JR., Ph.D.

ON BEHALF OF THE CITIZENS OF

THE STATE OF FLORIDA

REVIEW OF PROGRESS ENERGY FLORIDA'S

NUCLEAR COST RECOVERY RULE FILING

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its burden to demonstrate that these risks have been adequately considered when making critical project decisions.

Q. PLEASE DESCRIBE EXAMPLES YOU HAVE IDENTIFIED WHERE PEF HAS FAILED TO DEMONSTRATE THAT IT HAS APPROPRIATELY MANAGED RISK RELATED TO THE LEVY NUCLEAR PROJECT.

A. Examples of where PEF has failed to demonstrate adequate risk management that I have identified at this time include the signing of the EPC contract with many known risks and the failure to perform an adequate feasibility analysis as required by Rule 25-6.0423(5)(c)5 and (8), F.A.C., which is part of the Nuclear Cost Recovery Rule ("NCRR").

ENGINEERING, PROCUREMENT AND CONSTRUCTION (EPC) CONTRACT SIGNING

Q. PLEASE DESCRIBE YOUR CONCERNS WITH THE SIGNING OF THE EPC CONTRACT.

A. PEF executed the EPC contract with the consortium of Westinghouse Electric Company / Shaw, Stone, Webster (WEC/SSW) on December 31, 2008. In the months immediately preceding the time of EPC contract execution, PEF had identified many significant risks to the LNP project. Signing such a huge contract with so many risky issues remaining unresolved or the outcomes not fully understood can lead to renegotiation that can make the overall project cost more expensive. This has now happened less than four months after the signing. These unresolved risky issues include:

1. PEF had not received a schedule from the NRC for the NRC's review and approval of a requested Limited Work Authorization (LWA). The approval of the LWA was needed to construct the project on the schedule included in the EPC contract and upon which the contract pricing was based. This occurred despite the fact that the NRC had expressed serious doubt about the schedule on October 6, 2008. (NRC Letter Brian Anderson to James Scarola dated October 6, 2008, 09NC-OPCPOD3-64-000011; Exhibit WRJ(PEF)-3, Pages 1-10 of 233) Additionally, the NRC's decision was nearly 2 months past the expected 30 day traditional milestone letter delivery date. This alone should have raised concerns.

2. Although PEF had repeatedly identified that commitments from Joint Owners were critical to the success of the LNP and had linked their achievement to execution of the EPC contract, at the time of execution of the EPC contract, and in fact even today no joint owners were or are committed to the LNP. High level management reports repeatedly and consistently stated during the final months of 2008 that "JO work and EPC are closely tied". (Weekly reports to LINC of 9/22, 9/29, 10/6, 10/13, 10/22, 10/27, 11/3, 10/10, 10/17, 10/24, 12/01, 12/08, 12/15, 12/22, 12/29, Exhibit WRJ(PEF)-3, Pages 11-25 of 233.)

3. Receipt from the NRC of a Combined License (COL) to support the schedule was a risk given the status of design certification of the AP 1000 nuclear plant and the NRC's indication that it was unlikely that the NRC would be able to meet PEF's requested schedule.

4. Deterioration in the capital markets, broad economic weakness and legislative uncertainty were also identified by PEF as concerns.

Q. PLEASE DESCRIBE THE IMPACT OF THE COMPANY'S FAILURE TO RECEIVE THE LWA ON THE DESIRED SCHEDULE IN MORE DETAIL.

A. On July 28, 2008 PEF submitted its Combined License Application (COLA) for the LNP project to the Nuclear Regulatory Commission. In its application, PEF requested the following schedule for three of the major approvals from the technical staff review of their COLA:

- Final Environmental Impact Statement (EIS) issued June 2010
- Limited Work Authorization (LWA) issued September 2010
- Combined License (COL) issued January 2012

An October 6, 2008 letter from the NRC accepted the LNP's COLA for docketing but identified concerns related to the LNP site. The NRC's response stated:

> Although our acceptance review determined that the LNP COLA is complete and technically sufficient, the complex geotechnical characteristics of the Levy County site require additional information in order to develop a completed and integrated review schedule.

(NRC Letter Brian Anderson to James Scarola dated October 6, 2008, 09NC-OPCPOD3-64-000011, Exhibit WRJ(PEF)-3, Pages 1-10 of 233)

Concerning the requested schedule, the NRC specifically states:

> Because of the complexity of the site characteristics and the need for additional information, it is unlikely that the LNP COLA review can be completed in accordance with this requested [*by PEF*] timeline

(Explanation added.) (Ibid.)

In this letter, the NRC is clearly informing PEF that it was unlikely that the requested timeline could be met due to the complex geotechnical characteristics of the LNP site. It is not reasonable to assume that given the fact that the NRC made an effort to specifically mention the complexity of the site that it was only suggesting a brief delay in the schedule. This is true when contrasted with the extensive effort PEF made to impress upon senior NRC staff of the need to meet its "aggressive" schedule. On December 31, 2008, PEF executed the EPC contract, which was based, in part, on the assumption that the requested LWA would be issued. Three weeks later during a January 23, 2009, conference call the NRC informed PEF that the "LWA as requested and COLA geotechnical scope require the same critical path duration" and "they do not have the resources to process an LWA." (Levy COL Schedule Jan 23rd 2009 NRC Telecon Preliminary Analysis, Jan 25, 2009 09NC-OPCPOD3-62-000003, Exhibit WRJ(PEF)-3, Pages 26-33 of 233.) As a result, PEF ultimately withdrew its request for an LWA in a May 1, 2009 letter where PEF informed the NRC that Company had decided to no longer pursue an LWA and notified the NRC that they were withdrawing their request. (PEF letter to NRC NPD-NRC-2009-061 dated May 1, 2009 09NC-OPCPOD3-64-000001. Exhibit WRJ(PEF)-3, Pages 34-36 of 233) Shortly thereafter they precipitously changed the project schedule by 20 to 36 months only three months after signing the largest contract in the Company's history and perhaps even the largest construction contract in Florida history.

On April 30, 2009, four months after contract execution, PEF issued a letter to Dr. Shawn Hughes, the consortium project director, requesting a partial suspension of work for the Levy Nuclear Project. (PEF letter from Jeff Lyash to Shawn Hughes dated April 30, 2009, 09NC-OPCPOD3-60-000089 Exhibit WRJ(PEF)-3, Pages 37-39 of 233.) This placed the company in the posture of renegotiating the EPC contract from a very weak position.

Q. IN YOUR OPINION WAS IT REASONABLE FOR PEF TO HAVE EXECUTED THE EPC CONTRACT WITHOUT KNOWING THAT THE NRC WOULD ISSUE THE LWA ON THE REQUESTED TIMELINE GIVEN THE NRC'S STATEMENT THAT IT WAS "UNLIKELY" THAT THE REQUESTED TIMELINE COULD BE MET?

A. In my opinion it was not reasonable. PEF signed what is likely the largest contract in the history of the State of Florida without any assurance that the LWA would be issued. Receipt of the LWA within the requested timeframe was a requirement for implementation of the contract on the schedule contained in the EPC contract. Not only did PEF not have any assurance that the LWA would be issued, the NRC specifically told them in the October 6, 2008 letter that it was unlikely that the requested timeline would be met. Under the totality of the circumstances, PEF should have assumed that an LWA review schedule different than the overall COLA review schedule would not have been adopted by the NRC. To assume otherwise and sign the EPC contract with this cloud hanging over this critical date was not reasonable.

Q. DO YOU HAVE ANY REASON TO BELIEVE THAT PEF WOULD HAVE EXECUTED THE EPC CONTRACT AS IT EXISTS TODAY IF IT HAD KNOWN THAT THE LWA WOULD NOT BE ISSUED?

A. No. This question was posed to Mr. Garry Miller during his deposition. The question and his response follow:

> Q If you had gotten the letter that you got on February 18th, if you had gotten that same letter on December 1st, would you have signed the EPC?
>
> A In the form that it was signed, no. We would have had to modify the EPC agreement for that shift in dates.

REDACTED

Q. WHAT IS THE POTENTIAL IMPACT OF THE COMPANY SIGNING THE EPC CONTRACT WITH THE KNOWN OUTSTANDING RISKS?

A. The economic impact of PEF's execution of the EPC contract is unknown at this time. The Company is currently attempting to renegotiate the EPC contract with the consortium. From an overall project cost standpoint they are clearly in a weaker position to renegotiate the signed contract than if they had delayed signing until the LWA schedule and other risks were known or clarified. [redacted]. As a minimum the Company will incur additional carrying costs due to spending money under the EPC agreement earlier than would have been required if they had not signed. The answer to this question will become clearer once the EPC contract has been renegotiated.

Q. WHAT IS YOUR CONCLUSION REGARDING PEF'S EXECUTION OF THE EPC CONTRACT ON DECEMBER 31, 2008?

A. In my opinion, the Company's decision to sign the EPC contract on December 31, 2008 given the uncertainty that existed with the LWA, the lack of committed joint owners and the myriad of other uncertainties including the deteriorating economy, the chaos in the financial markets and the uncertain federal and state regulatory climate was not reasonable. I do not believe the company has met its burden of demonstrating that this action was reasonable or prudent. This decision may result in significant extra cost to the project that could have been avoided with a more cautious approach given the known risks and uncertainties at the time of signing. At the very least, the Commission does not have sufficient information to determine whether 2009 and 2010 EPC contract related costs are reasonable.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause.	DOCKET NO. 090009-EI ORDER NO. PSC-09-0783-FOF-EI ISSUED: November 19, 2009

The following Commissioners participated in the disposition of this matter:

MATTHEW M. CARTER II, Chairman
LISA POLAK EDGAR
NANCY ARGENZIANO
NATHAN A. SKOP

FINAL ORDER APPROVING NUCLEAR COST RECOVERY AMOUNTS FOR FLORIDA POWER & LIGHT COMPANY AND PROGRESS ENERGY FLORIDA, INC.

BY THE COMMISSION:

BACKGROUND

On March 2, 2009, Florida Power & Light Company (FPL) and Progress Energy Florida, Inc. (PEF) filed petitions seeking prudence review and recovery through the Capacity Cost Recovery Clause (CCRC) of the final true-up costs for certain nuclear power plant projects pursuant to Rule 25-6.0423, Florida Administrative Code, (F.A.C.) and Section 366.93, Florida Statutes (F.S.). On May 1, 2009, FPL and PEF filed petitions seeking approval to recover estimated 2009 costs and projected 2010 costs for both projects through the CCRC. PEF's May 1, 2009 petition also requested implementation of a rate management plan.

FPL's petition addressed two nuclear projects. The first FPL project is composed of uprate activities at its existing nuclear generating plants, Turkey Point Units 3 & 4 and St. Lucie Units 1 & 2. Collectively, these uprate activities are known as the extended power uprate project (EPU Project). FPL obtained an affirmative need determination for the EPU Project by Order No. PSC-08-0021-FOF-EI.[1] The second FPL project is the Turkey Point Units 6 & 7 project (TP67 project). FPL obtained an affirmative need determination for the TP67 project by Order No. PSC-08-0237-FOF-EI.[2]

PEF's petition also addressed two nuclear projects. The first PEF project is an extended uprate at the existing nuclear generating plant Crystal River Unit 3 (CR3 Uprate). PEF obtained

[1] Order No. PSC-08-0021-FOF-EI, issued January 7, 2008, in Docket No. 070602-EI, In re: Petition for determination of need for expansion of Turkey Point and St. Lucie nuclear power plants, for exemption from Bid Rule 25-22.082, F.A.C. and for cost recovery through the Commission's Nuclear Power Plant Cost Recovery Rule, Rule 25-6.0423, F.A.C.
[2] Order No. PSC-08-0237-FOF-EI, issued April 11, 2008, in Docket No. 070650-EI, In re: Petition to determine need for Turkey Point Nuclear Units 6 and 7 electrical power plant, by Florida Power & Light Company.

an affirmative need determination for the CR3 Uprate by Order No. PSC-07-0119-FOF-EI.[3] The second PEF project is the Levy Units 1 & 2 project (LNP). PEF obtained an affirmative need determination for the LNP by Order No. PSC-08-0518-FOF-EI.[4]

Traditionally, all eligible power plant construction projects have been afforded the same regulatory accounting and ratemaking treatment. That is, once a need for a project has been determined, the utility books all expenditures associated with the project into account 107 Construction Work in Progress (CWIP) for that particular project. A monthly allowance-for-funds-used-during-construction (AFUDC) rate is applied to the average balance of this account and the resulting dollar amount is then credited to the account balance. This process continues until the completion of the project.

Once the plant is placed in commercial service, the CWIP account balance is transferred to the appropriate plant-in-service account and becomes part of the utility's rate base. The impacts of including the total project costs in a utility's rate base, as well as the impacts of additional plant operational expenses, are addressed during a subsequent proceeding wherein it is determined whether customer base rate charges should be changed in order to provide the opportunity to recover these costs.

In 2006, the Florida Legislature enacted Section 366.93, F.S., in order to encourage utility investment in nuclear electric generation by creating an alternative cost recovery mechanism. Section 366.93, F.S., authorized us to allow investor-owned electric utilities to recover certain construction costs in a manner that reduces the overall financial risk associated with building a nuclear power plant. In 2007, Section 366.93, F.S., was amended to include integrated gasification combined cycle plants, and in 2008, the statute was amended to include new, expanded, or relocated transmission lines and facilities necessary for the new power plant. The statute required the adoption of rules that provide for, among other things, annual reviews and cost recovery for nuclear plant construction through the existing capacity cost recovery clause. By Order No. PSC-07-0240-FOF-EI, Rule 25-6.0423, F.A.C., was adopted to implement Section 366.93, F.S.[5]

Pursuant to Rule 25-6.0423(4) and (5), F.A.C., once a utility obtains an affirmative need determination for a power plant covered by Section 366.93, F.S., the affected utility may petition for cost recovery using the alternative mechanism. Three types of prudently incurred costs are described in the rule for such consideration.

- Site selection costs are costs incurred prior to the selection of a site. A site is deemed selected upon the filing for a determination of need. (Rule 25-6.0423(2)(e) and (f), F.A.C.)

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[3] Order No. PSC-07-0119-FOF-EI, issued February 8, 2007, in Docket No. 060642-EI, In re: Petition for determination of need for expansion of Crystal River 3 nuclear power plant, for exemption from Bid Rule 25-22.082, F.A.C., and for cost recovery through fuel clause, by Progress Energy Florida, Inc.

[4] Order No. PSC-08-0518-FOF-EI, issued August 12, 2008, in Docket No. 080148-EI, In re: Petition for determination of need for Levy Units 1 and 2 nuclear power plants, by Progress Energy Florida, Inc.

[5] Order No. PSC-07-0240-FOF-EI, issued March 20, 2007, in Docket No. 060508-EI, In re: Proposed adoption of new rule regarding nuclear power plant cost recovery.

- Preconstruction costs are those costs incurred after a site is selected through the date site clearing work is completed. (Rule 25-6.0423(2)(g), F.A.C.)

- Construction costs are costs that are expended to construct the power plant including, but not limited to, the costs of constructing power plant buildings and all associated permanent structures, equipment and systems. (Rule 25-6.0423(2)(i), F.A.C.)

In Order No. PSC-08-0749-FOF-EI, we approved stipulations among the parties to Docket No. 080009-EI, recommending site selection costs be included in and recovered through the Nuclear Cost Recovery Clause (NCRC) in the same manner as pre-construction costs. Pursuant to Rule 25-6.0423(5)(a), F.A.C., all prudently incurred preconstruction costs will be recovered directly through the CCRC. Additionally, Rule 25-6.0423(5)(b), F.A.C., provides for annual recovery of carrying charges on prudently incurred construction costs through the CCRC.

Our first decision implementing Rule 25-6.0423, F.A.C., was in 2008. On May 5, 2008, Order No. PSC-08-0295-DS-EI was issued, granting FPL's request for a declaratory statement that "advance payments made prior to the completion of site clearing work are properly characterized as preconstruction costs to be recovered pursuant to the mechanism provided in Rule 25-6.0423, F.A.C."[6] On November 12, 2008, by Order No. PSC-08-0749-FOF-EI, we addressed FPL's and PEF's first petitions for nuclear cost recovery amounts.[7] On November 26, 2008, by Order No. PSC-08-0779-TRF-EI, we approved a base rate increase addressing the completed phase of the CR3 Uprate known as the measurement uncertainty recapture (MUR).[8] On April 6, 2009, by Order No. PSC-09-0208-PAA-EI, [9] we authorized PEF to defer recovery of $198,000,000 in site selection and preconstruction costs for the LNP. Recovery of these deferred costs is addressed in this proceeding.

Rule 25-6.0423(5), F.A.C., sets forth the process by which we are to conduct an annual hearing to determine the recoverable amount that will be included in the CCRC pursuant to Section 366.93, F.S. This is the second year of this newly established NCRC roll-over docket.

Intervention was granted to the following parties: the Office of Public Counsel (OPC), Florida Industrial Power Users Group (FIPUG), White Springs Agricultural Chemicals Inc. d/b/a PCS Phosphate – White Springs (PCS Phosphate), Southern Alliance for Clean Energy (SACE), and the Federal Executive Agencies (FEA). Testimony and associated exhibits were filed by FPL, PEF, OPC, PCS Phosphate, SACE, and our staff. On August 10, 2009, FPL, PEF, OPC, FIPUG, PCS Phosphate, SACE, and our staff filed prehearing statements.

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[6] Order No. PSC-08-0295-DS-EI, issued May 5, 2008, in Docket No. 080083-EI, In Re: Petition for declaratory statement regarding applicability of Rule 25-6.0423, F.A.C., by Florida Power & Light Company.

[7] Order No. PSC-08-0749-FOF-EI, issued October 12, 2008, in Docket 080009-EI, In Re: Nuclear cost recovery clause.

[8] Order No. PSC-08-0779-TRF-EI, issued November 26, 2008, in Docket No. 080603-EI, In re: Petition for expedited Commission approval of base rate increase for costs associated with MUR phase of CR3 uprate project, pursuant to Section 366.93(4), F.S., and Rule 25-6.0423(7), F.A.C., by Progress Energy Florida, Inc.

[9] Order No. PSC-09-0208-PAA-EI, issued April 6, 2009, in Docket No. 090001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

The evidentiary hearing for the NCRC docket was held on September 8-10, 2009. The intervenors took "no position" on various prudence issues and on issues addressing final 2008 true-up amounts, which allowed staff, FPL, and PEF to present partial stipulations and resolve the issues. We approved the partial stipulations as a preliminary matter during the September 2009 hearing. These partial stipulations are included in Attachment A.

The remaining unresolved issues in this proceeding pertain to implementation policies, certain 2008 project management decisions, long-term feasibility analysis for the TP67 project and the LNP, the reasonableness of estimated 2009 and projected 2010 costs, and PEF's proposed rate management plan.

All parties, excluding FEA, filed post-hearing briefs on September 18, 2009. We have jurisdiction over these matters pursuant to Section 366.93, F.S., and other provisions of Chapter 366, F.S.

DECISION

Carrying charge rate on deferred balances

Our resolution of this issue will establish the carrying charge applicable to an amount that a utility has been authorized to recover through the Capacity Cost Recovery Clause (CCRC), but for which recovery is deferred. Moreover, the resolution of this policy matter is timely because PEF requested approval of a rate management plan that is intended to recover an approved amount over a five-year period rather than over one year. While PEF presented a position in its post-hearing brief, it did not explain why PEF supports the position. OPC's and PCS Phosphate's post-hearing briefs stated "no position" on this issue. FIPUG and SACE did not address this issue in their post-hearing briefs. Therefore, pursuant to the prehearing order, FIPUG and SACE have waived their positions on this issue.

FPL witness Powers asserted that if a utility requests deferral of approved costs and we approve such deferral, then we have effectively created a regulatory asset for future recovery. The regulatory asset remains in the NCRC and continues to accrue carrying charges at the pre-tax allowance for funds used during construction (AFUDC) rate. The regulatory asset does not contribute to over or under recoveries in the CCRC that are subject to the commercial paper rate. Witness Powers explained that by Order No. PSC-04-0393-FOF-EI, a return on a regulatory liability for gains associated with emission allowances was previously allowed. She also explained that, by Order No. 10306, we created a regulatory asset and authorized FPL to charge AFUDC to the deferred amounts. FPL asserted no party presented evidence supporting a different approach or questioned the reasonableness of the approach described by Witness Powers.

We find that FPL presented the appropriate analysis and accurately represented past Commission decisions. On pages 4 and 5 of Order PSC-03-0393-FOF-EI,[10] we stated:

> First, we hold that Florida Power and Light Company should record the cost of emission allowances in Account 158.1, Allowances Inventory. Any gains or losses associated with the disposition of allowances should be recorded in Account 254, Other Regulatory Liabilities, or Account 182.3, Other Regulatory Assets, respectively. The above items are properly included in working capital until the applicable allowances are expensed.

In Order No. 10306,[11] at page 12, we stated:

> . . . we authorize FP&L to charge AFUDC to that amount until such time as the matter is considered in ratemaking proceeding following the resolution of litigation.

In both instances, the company booked amounts which accrued carrying charges and there was no contribution to clause over and under recovery calculations. Consistent with past practices, deferral of recoverable NCRC amounts creates a regulatory asset that should accrue a carrying charge. The applicable NCRC carrying charge is established by Section 366.93(2)(b), F.S., which states in part:

> for nuclear or integrated gasification combined cycle power plant need petitions submitted on or before December 31, 2010, associated carrying costs shall be equal to the pretax AFUDC in effect upon this act becoming law. For nuclear or integrated gasification combined cycle power plants for which need petitions are submitted after December 31, 2010, the utility's existing pretax AFUDC rate is presumed to be appropriate unless determined otherwise by the commission in the determination of need for the nuclear or integrated gasification combined cycle power plant.

Section 366.93, F.S., became law June 19, 2006. Pursuant to the requirements of 366.93, F.S., Rule 25-6.0423(5)(b), F.A.C., was adopted, which states:

> 1. For power plant need petitions submitted on or before December 31, 2010, the associated carrying costs shall be computed based on the pretax AFUDC rate in effect on June 12, 2007;
>
> 2. For power plant need petitions submitted after December 31, 2010, the utility's pretax AFUDC rate in effect at the time the petition for determination of need is filed is presumed to be appropriate unless the Commission determines otherwise in its need determination order; . . .

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[10] Order No. PSC-04-0393-FOF-EI, issued April 6, 1994, in Docket No. 940042-EI, <u>In Re: Environmental Cost Recovery Clause.</u>

[11] Order No. 10306, issued September 23, 1981, in Docket 810002-EU, <u>In Re: Petition of Florida Power & Light Company for authority to increase its rates and charges.</u>

The applicable NCRC carrying charge rate is the same whether a company elects recovery or deferral of recovery. Consequently, for costs associated with qualifying projects currently included in the NCRC, the applicable carrying charge rate shall be the pretax AFUDC rate in effect June 12, 2007. For qualifying projects for which need petitions are submitted after December 31, 2010, the utility's existing pretax AFUDC rate shall be used.

Therefore, we find that the applicable carrying charge rate on an NCRC regulatory asset that has been deferred from recovery shall be the pretax AFUDC Rate in effect June 12, 2007, as set forth in Rule 25-6.0423, F.A.C. For qualifying projects for which need petitions are submitted after December 31, 2010, the utility's existing pretax AFUDC Rate shall be used.

Recognition of different AFUDC rates

We have been asked to determine whether FPL and PEF should account for the difference between the carrying cost set forth in Section 366.93, F.S., and their respective approved AFUDC rates. At issue is whether Section 366.93, F.S., establishes a particular project carrying cost to be applied regardless of changes to the currently approved AFUDC for a utility, or whether the statute merely sets forth the amount (rate) that is permitted for recovery through the annual CCRC, with the difference between that amount and the utilities' approved AFUDC rates being recorded and then recovered later.

In its statement of position, PEF asserted that Section 366.93, F.S., fixes the carrying charge at the last approved AFUDC rate when the need was approved. PEF witness Foster explained that the company's position was based on a plain reading of Section 366.93(2)(b), F.S. PEF did not provide further support of its position in its post-hearing brief.

FPL asserted that utilities should be allowed to track, and eventually recover, the incremental/decremental difference between the carrying charge rate required by the statute and the most currently approved AFUDC rate for that utility. In its brief, FPL argued that Section 366.93, F.S., requires that our rules allow recovery of all prudently incurred costs, and that "costs" as defined by the statute expressly includes "all capital investments, including rate of return." FPL asserted that this means utilities are entitled to recover all carrying costs ultimately through the clause or in rates, and that it is not lawful to exclude any prudently incurred carrying costs. FPL witness Powers argued that utilities should be allowed to recover the approved carrying costs by tracking the incremental/decremental difference between the carrying charge rate required by the statute and the most currently approved AFUDC rate.

FPL witness Powers explained that the nuclear cost recovery rule allows recovery through the CCRC of a carrying charge at a fixed rate based upon the AFUDC rate in effect on June 12, 2007. She further explained that FPL's AFUDC rate is established by Rule 25-6.0141, F.A.C., and is applied to all eligible construction work in progress (CWIP) charges. As FPL is only allowed to recover a carrying charge through the CCRC at the fixed rate specified in the Rule, any resulting incremental/decremental AFUDC amounts will remain in CWIP until the nuclear project is placed into service, at which time any increment or decrement will be transferred to plant in service.

Witness Powers suggested that the incremental/decremental difference should be accumulated and recorded to CWIP and then either recovered or returned through base rates once the plant is placed in commercial service. She explained that this method allows for recovery of FPL's approved carrying cost through the NCRC, while ensuring the customer ultimately only pays for the actual financing costs incurred. Witness Powers asserted that this approach is fair to both customers and the utility.

FPL argued that its position prevents the "very real likelihood of windfall gains or losses to FPL or customers which would arise over time under other parties' interpretations, as a utility's actual AFUDC financing costs vary, either higher or lower, than the carrying cost amount provided by statue and rule for NCRC collections." FPL argued that the other party's position would foster either a permanent over or under-recovery, depending on the difference between a utility's AFUDC rate from time to time and the carrying cost provided for in the Rule. FPL suggested that this unfair result can be easily avoided by the simple approach advocated by FPL. FPL witness Powers stated that the ultimate result of FPL's methodology would be that the company recovers its actual rate of return and the customer pays only the actual rate of return on the nuclear projects, no more and no less. Intervenors in this proceeding took no position on this issue.

Section 366.93(2)(b), F.S., states:

> Recovery through an incremental increase in the utility's capacity cost recovery clause rates of the carrying costs on the utility's projected construction cost balance associated with the nuclear or integrated gasification combined cycle power plant. To encourage investment and provide certainty, for nuclear or integrated gasification combined cycle power plant need petitions submitted on or before December 31, 2010, associated carrying costs shall be equal to the pretax AFUDC in effect upon this act becoming law. For nuclear or integrated gasification combined cycle power plants for which need petitions are submitted after December 31, 2010, the utility's existing pretax AFUDC rate is presumed to be appropriate unless determined otherwise by the commission in the determination of need for the nuclear or integrated gasification combined cycle power plant.

Rule 25-6.0423(5)(b), F.A.C., is our interpretation of Section 366.93, F.S. Rule 25-6.0423(5)(b), F.A.C., entitled "Carrying Costs on Construction Cost Balance," provides:

> A utility is entitled to recover, through the utility's Capacity Cost Recovery Clause, the carrying costs on the utility's annual projected construction cost balance associated with the power plant. The actual carrying costs recovered through the Capacity Cost Recovery Clause shall reduce the allowance for funds used during construction (AFUDC) that would otherwise have been recorded as a cost of construction eligible for future recovery as plant in service.

1. For power plant need petitions submitted on or before December 31, 2010, the associated carrying costs shall be computed based on the pretax AFUDC rate in effect on June 12, 2007;

2. For power plant need petitions submitted after December 31, 2010, the utility's pretax AFUDC rate in effect at the time the petition for determination of need is filed is presumed to be appropriate unless the Commission determines otherwise in its need determination order;

3. The Commission shall include carrying costs on the balance of construction costs determined to be reasonable or prudent in setting the factor in the annual Capacity Cost Recovery Clause proceedings, as specified in paragraph (5)(c) of this rule.

As mentioned above, we must determine whether the statute and rule establish a particular carrying cost to be applied to nuclear projects regardless of changes to the AFUDC rate applied to other construction projects, or whether the utilities are entitled to track and record the difference between the carrying cost specified for NCRC recovery and the currently-approved AFUDC rate. FPL asserted that in "deciding this issue and the appropriate interpretation of the controlling Statute and Rule, the Commission must view the Statute and the Rule in their entirety and harmonize the various provisions to give meaning to the laws as a whole." We agree that this is the appropriate approach. However, the statute or rule should not be used in such a way as to assume a meaning or intent that is not clearly portrayed in the language.

Although FPL's methodology of tracking and recording the incremental/decremental CWIP balance difference resulting from using two rates is not necessarily an unreasonable approach, we are not persuaded that this methodology was contemplated or intended by Section 366.93, F.S., and Rule 25-6.0423, F.A.C. In its brief, FPL asserted that Rule 25-6.0423(5)(b)(1) "expressly contemplates and allows" for FPL's approach to tracking the incremental/decremental difference between its actual AFUDC rate and the rate used for computation of clause recovery. This section of the Rule states:

> The actual carrying costs recovered through the Capacity Cost Recovery Clause shall reduce the allowance for funds used during construction (AFUDC) that would otherwise have been recorded as a cost of construction eligible for future recovery as plant in service.

FPL stated in its brief that the only way to give meaning to the requirement of the statute and rule is to recover the rule-specified carrying cost amount through the NCRC, while recording the increment/decrement "as a cost of construction eligible for future recovery as plant in service" as required by this section of the rule. We disagree. We find that this language was included to guard against double recovery of carrying costs by ensuring that carrying costs are deducted from the utility's total CWIP allowance for all projects as the carrying costs are recovered through the CCRC each year. We are not persuaded that the rule "expressly contemplated" that a portion of the currently approved AFUDC would remain in CWIP, or that a negative would be recorded in CWIP if a carrying cost higher than the currently approved AFUDC rate is recovered through the CCRC.

When a utility's currently approved AFUDC rate is higher than the carrying cost rate permitted by the statute and the rule, it is understandable that one might seek to recover the difference as FPL suggests. However, FPL's approach could lead to the absurd result of purposefully allowing annual recovery of a carrying cost that is higher, with the intent of truing-up the carrying cost when the plant goes into commercial operation. In either scenario, this mechanism of true-up to the Commission-prescribed AFUDC under Rule 25-6.0141, F.A.C., is not presented in either Section 366.93, F.S., or Rule 25-6.0423, F.A.C.

If FPL's approach was intended by the statute or rule, it could have easily been stated as such. Section 366.93(2)(b), F.S., specifically states in part:

> To encourage investment and provide certainty, for nuclear or integrated gasification combined cycle power plant need petitions submitted on or before December 31, 2010, associated carrying costs shall be equal to the pretax AFUDC in effect upon this act becoming law. For nuclear or integrated gasification combined cycle power plants for which need petitions are submitted after December 31, 2010, the utility's existing pretax AFUDC rate is presumed to be appropriate unless determined otherwise by the commission in the determination of need for the nuclear or integrated gasification combined cycle power plant.

(emphasis added)

If the intent was to allow recovery through the CCRC of only a portion, or perhaps in excess, of the utility's currently approved AFUDC rate, the language could have stated that intent. Rather, we agree with PEF that this section of the statute and the corresponding rule language established a fixed carrying cost to be applied to nuclear projects filed prior to December 31, 2010. For projects filed after that date, the utility's existing AFUDC rate would apply. Here, FPL filed its need petition for Turkey Point 6 & 7 project (TP67 project) before December 31, 2010. Similarly, FPL filed its need petition for Turkey Point Units 3 & 4 and St. Lucie Units 1 & 2 uprate (EPU Project) before December 31, 2010. Thus, the associated carrying cost applicable to these project costs is FPL's AFUDC rate in effect when Section 366.93, F.S., became law, which is 7.42 percent.

FPL argued that its position is consistent with the statutory purpose of encouraging development of additional generation to benefit FPL's customers, and that ensuring recovery of only the financing cost actually incurred reduces risk for FPL, investors, and customers. (FPL BR 10) We agree that the statutory purpose of Section 366.93, F.S., is to promote utility investment in nuclear power plants. To do so, the legislature created an alternative cost recovery mechanism. That mechanism includes a fixed carrying cost rate to be applied to project costs for which FPL and PEF seek recovery under the alternative mechanism. Section 366.93(2)(b), F.S., states that in order to "encourage investment and provide certainty," carrying costs shall be equal to the pretax AFUDC rate in effect on June 12, 2007. The legislature provided certainty by establishing a carrying cost rate to be applied to the nuclear projects, and this carrying cost shall be recovered pursuant to Rule 25-6.0423(2), F.A.C., no more and no less.

Moreover, since the enactment of Section 366.93, F.S., we have consistently distinguished the carrying cost associated with the nuclear projects (e.g., TP67 project) from the carrying cost associated with all other utility projects. By Order No. PSC-08-0265-PAA-EI, issued April 28, 2008, in Docket No. 080088-EI, In re: Request for approval of change in rate used to capitalize allowance for funds used during construction (AFUDC) from 7.42% to 7.65%, effective January 1, 2008, by Florida Power & Light Company, we specifically held that the revised AFUDC rate shall be effective as of January 1, 2008, for all purposes except for Rule 25-6.0423, F.A.C. Similarly, in Order No. 09-0377-PAA-EI, issued May 28, 2009, in Docket No. 090108-EI, In re: Request for approval of change in rate used to capitalize allowance for funds used during construction (AFUDC) from 7.65% to 7.41%, effective January 1, 2009, by Florida Power & Light Company, we held that the revised AFUDC rate shall be effective as of January 1, 2009, for all purposes except for Rule 25-6.0423, F.A.C. This emphasizes the point that Section 366.93(2)(b), F.S., establishes a fixed project carrying cost to be applied to all nuclear construction projects with need petitions filed prior to December 31, 2010. We find that any other interpretation of Section 366.93(2)(b), F.S., is incorrect.

FIPUG's and SACE's prehearing positions state they have "not had adequate opportunity to formulate a legal opinion on this issue and will brief it." However, FIPUG and SACE did not address this issue in their post-hearing briefs. Therefore, pursuant to the prehearing order, FIPUG and SACE have waived their positions on this issue.

Based on the record evidence, we find that utilities shall not be permitted to record in rate base the incremental difference between carrying costs established in Section 366.93, F.S., and their respective most currently approved AFUDC rate applicable to all other projects, for recovery when the nuclear plant enters commercial operation. We also find that Section 366.93, F.S., establishes a fixed project carrying cost to be applied to all nuclear construction projects with need petitions filed prior to December 31, 2010.

FPL ISSUES

FPL Project Management

We now turn to the question of reasonableness and prudence of 2008 project management, contracting, and oversight controls incorporated by FPL as part of its EPU project and the TP67 project. Matters related to FPL's assessment of an alternative to a TP67 project engineering, procurement and construction contract (EPC contract) and FPL's TP67 project feasibility and submitted analysis shall be addressed separately.

Aside from the issues mentioned above, no party raised questions concerning FPL's 2008 project management, contracting, and oversight controls for the TP67 project and the EPU project.

OPC's prehearing and post-hearing positions are the same, and state "For Turkey Point Units 6 & 7, see Issue 7A. With respect to the EPU project, no position at this time." FIPUG's position concurs with OPC's position. FIPUG did not address this issue in its post-hearing brief; therefore, pursuant to the prehearing order, FIPUG has waived its position on this issue. SACE took no position prior to hearing and did not address this issue in its post-hearing brief; thus, SACE has waived its position on this issue.

FPL contracted with Concentric Energy Advisors, Inc. (Concentric), an economic advisory and management consulting firm, to review the appropriate prudence standard, review the processes and procedures FPL used to manage the EPU and TP67 projects, FPL's internal controls, and FPL's compliance with its internal procedures and controls. Witness Reed, the Chairman and Chief Executive Officer of Concentric, filed testimony asserting that FPL's policies and procedures were robust and have been adhered to. Witness Reed affirmed that it would be appropriate for us to consider the prudence of a utility's decision based upon the information it knew or should have known at the time the decision was made. Witness Reed presented Concentric's conclusion that FPL had reasonable polices and procedures, FPL adhered to them, and that the project costs were prudently incurred.

Staff witnesses Fisher and Rich sponsored testimony and an audit report examining the internal control procedures by which FPL manages and tracks the costs and the schedules of FPL's two projects. They stated:

> The primary objective of this review was to document project key developments, along with the organization, management, internal controls, and oversight that FPL has in place or plans to employ for these projects. The internal controls examined were related to the following areas of project activity: planning, management and organization, cost and schedule controls, contractor selection and management, and auditing and quality assurance.

The audit report addressed the period April 2008 through June 2009. We reviewed the management audit report, Exhibit 70, to determine whether it contained support for a finding of imprudence, and did not find any. The applied standard for determining prudence is consideration of what a reasonable utility manager would have done in light of conditions and circumstances which were known or reasonably should have been known at the time decisions were made.[12] This is the same standard applied by witness Reed.

Based on the record of evidence, we find that FPL's decisions and actions were in keeping with reasonable business practices, and were prudent. FPL's 2008 project management, contracting, and oversight controls were reasonable and prudent for the Extended Power Uprate project (EPU) and for the TP67 project.

We now address the reasonableness and prudence of FPL's 2008 project management decision to assess an alternative contracting strategy for the TP67 project. One contractual

[12] Order No. PSC-07-0816-FOF-EI, issued October 10, 2007, In Docket No.060658-EI, In Re: Petition on behalf of Citizens of the State of Florida to require Progress Energy Florida, Inc. to refund customers $143 million, at 3.

approach is a comprehensive EPC contract. The alternative approach FPL considered separates the engineering and procurement contract from the construction contract (EP/C contracts). FPL has not entered into EP/C contracts and has not abandoned the option of an EPC contract. Neither has FPL quantified the potential savings of an EP/C approach over an EPC approach. In his March 2, 2009, testimony FPL Witness Scroggs described what FPL considered and determined with regard to the contracting strategy:

> The vendor-proposed business model for new nuclear project deployment of the AP-1000 design involves an EPC contract with Westinghouse/Shaw with defined scope and schedule responsibility. FPL challenged this business model based on several key observations. First, <u>the EPC offered by Westinghouse/Shaw is limited in its ability to provide cost and schedule certainty as to key project elements (such as construction labor)</u> that are not included in the EPC contract scope and pricing. Additionally, <u>the proposed EPC approach does not provide opportunities for other engineering and construction firms to compete directly for components of the work.</u>

(emphasis added)

The proprietary portion of the TP67 project is approximately $3 billion of the approximate total $18 billion project cost. FPL will necessarily be required to sole source the engineering and procurement portion of the project to Shaw/Westinghouse due to the proprietary nature of the AP-1000 design. However, discussion with Shaw/Westinghouse offered limited ability to provide construction cost and schedule certainty. FPL Witness Reed noted that splitting out the construction piece from the engineering and procurement could potentially lead to greater disputes about scope of services and responsibilities compared to combining all three elements together. He also expressed a view that there are potentially very substantial customer benefits related to separating the EP work from the construction work.

Consequently, FPL sought to create the potential for more competitive options for the construction phase of the project. FPL selected a consortium of Black & Veatch and Zachry Construction (BVZ), an engineering firm independent of Shaw/Westinghouse, to perform certain preconstruction planning and design work. The scope of work BVZ was selected to perform is not the EP or C portion of an EP/C contracts. As previously noted, FPL has not entered into EP/C contracts nor has it abandoned the EPC contract option.

In its position statement, FIPUG argued that FPL was not prudent. FIPUG asserted that no nuclear power plant previously developed in the United States by an investor-owned utility has utilized a contracting strategy which separates the construction from the engineering and procurement. FIPUG alleged that continued pursuit of FPL's strategy, without a direct contractual linkage to the construction portion of the project, will likely result in questions and disputes and undoubtedly increase costs of the project. FIPUG argued that FPL's decision is questionable, especially when the purported benefits have not been quantified in a meaningful way.

OPC witness Jacobs expressed a view that "an EPC type contract utilizing a turn-key approach with a single entity clearly reduces the risk for FPL." He asserted FPL's plan for a separate construction contractor may ultimately result in higher costs for this project. His expectation is that FPL's choice may result in unreasonably high costs. He raised this issue now so that it is clear that the potential for increased costs was identified "without the benefit of hindsight in future prudence determinations."

SACE did not address this issue in its post-hearing brief. Therefore, pursuant to the prehearing order, SACE has waived their positions on this issue.

We have reviewed the record evidence for any analysis by witness Jacobs addressing FPL's contract discussions with Shaw-Stone & Webster and Westinghouse (Shaw/Westinghouse) and found none. This is significant because OPC relied on the testimony of witness Jacobs as support for its position that FPL was not prudent. Additionally, Witness Jacobs was the sole witness challenging FPL's contractual actions. As stated, the standard for determining prudence requires a review of the information FPL's management relied on or should have been aware of at the time the decision was made. We found no analysis of FPL's contract discussions apart from FPL's testimony. Therefore, we believe that OPC Witness Jacobs offered a generic statement that does not consider specific matters a reasonable utility manager should have considered at the time of making a decision.

However, a decision regarding the prudence of FPL's possible contract(s) and subsequent contract management is premature. At this time, the terms and conditions of any EPC contract or EP/C contracts are unknown. When and if FPL requests recovery of prudently incurred costs resulting from such contracts, then the terms and conditions that give rise to those costs can be reviewed. At that time FPL will have the opportunity to demonstrate why it believes the contract terms and conditions are prudent and reasonable. FPL's actions are, and will continue to be, reviewed pursuant to Section 366.93, F.S., and Rule 25-6.0423, F.A.C.

Based on the foregoing, we find that FPL's 2008 decision to create the potential for additional competitive opportunity through possible EP/C contracts for the TP67 project was reasonable and prudent.

FPL's Annual TP67 Project Feasibility Analysis

We have reviewed FPL's detailed long-term feasibility of continuing construction and completing the TP67 project as provided for in Rule 25-6.0423, F.A.C. FPL asserted that its 2009 feasibility analysis satisfied the requirements of the rule. FPL further claimed that the analytical approach that was used in the 2009 feasibility analysis for TP67 is the same as the approach used in the 2007 Determination of Need filing and the 2008 feasibility analysis. FPL further contended that the calculation of overnight "breakeven" costs continues to be the appropriate approach to use at this time.

OPC argued that because FPL did not update the capital costs of the proposed nuclear plant, its analysis has only been half-performed. OPC further contended that the chief component of feasibility is the projected capital investment that will be necessary to place the unit into service. OPC asserted that FPL's omission of an updated capital cost estimate creates the impression that it is withholding bad news that would place into question the prudence or wisdom of moving forward with the project.

FIPUG asserted that without legislation, FPL's nuclear project costs would be recovered in base rates by means of a rate case. Furthermore, FIPUG argued that in a rate case, FPL would have to prove the details and prudence of the costs it seeks to recover. FIPUG contended that FPL's failure to provide detailed updated construction costs for the proposed nuclear power plants cannot be overlooked and FPL failed to meet its burden of proof.

SACE contended that FPL's decision to proceed with TP67 was based on important assumptions that have changed since FPL was granted an affirmative determination of need for TP67. SACE argued that FPL used a low estimate of the cost of nuclear reactors, downplayed the contribution that efficiency and renewables can make in meeting the need for electricity, assumed much higher prices for natural gas than are now projected, and assumed a much higher price for carbon dioxide emissions for fossil plants than recent legislation in Congress would impose.

In an effort to mitigate the economic risks associated with the long lead time and high capital costs associated with nuclear power plants, the Florida Legislature enacted Sections 366.93 and 403.519(4), F.S., during the 2006 legislative session. Section 366.93(2), F.S., requires us to establish, by rule, alternative cost recovery mechanisms for the recovery of costs incurred in the siting, design, licensing, and construction of a nuclear power plant. This Commission established Rule 25-6.0423, F.A.C, in order to satisfy the requirements of Section 366.93(2), F.S. Rule 25-6.0423(5)(c)5, F.A.C, states:

> By May 1 of each year, along with the filings required by this paragraph, a utility shall submit for Commission review and approval a detailed analysis of the long-term feasibility of completing the power plant.

On page 29 of Order No. PSC-08-0237-FOF-EI, we provided specific guidance to FPL regarding the requirements necessary to satisfy Rule 25-6.0423(5)(c)5, F.A.C.[13] The Order reads as follows:

> FPL shall provide a long-term feasibility analysis as part of its annual cost recovery process which, in this case, shall also include updated fuel forecasts, environmental forecasts, break-even costs, and capital cost estimates. In addition, FPL should account for sunk costs. Providing this information on an annual basis will allow us to monitor the feasibility regarding the continued construction of Turkey Point 6 and 7.

[13] Order No. PSC-08-0237-FOF-EI, issued April 11, 2008, in Docket No. 070650-EI, In re: Petition to determine need for Turkey Point Nuclear Units 6 and 7 electrical power plant, by Florida Power & Light Company.

The discussed forecasts, information, estimates, and analyses are necessary filing requirements to assess FPL's 2009 TP67 project feasibility analysis.

Updated Fuel Forecasts

FPL used high, medium, and low fuel forecast scenarios in its feasibility analysis. FPL's fuel forecasts provided in this docket are the same as those relied on in the Company's 2009 Ten-Year Site Plan. A comparison of forecasted natural gas costs utilized in FPL's 2009 feasibility analysis with those used in FPL's 2008 analysis shows a general trend of: (i) lower natural gas costs in 2010, (ii) higher natural gas costs in the near-term years of 2015 through 2025, then (iii) lower natural gas costs in the later years of 2030 through 2040.

OPC asserted that FPL appropriately identified changes in key parameters such as gas prices. SACE argued that FPL's natural gas price forecasts were too high. FPL contended that SACE's analysis of long-term natural gas prices was inconsistent and inappropriate. We believe that there is inherent uncertainty surrounding fuel forecasting. FPL's use of third party forecasts is consistent with our practice. Reviewing the TP67 project feasibility using a range of long-term fuel forecasts reasonably accounts for the volatility in the natural gas market. As discussed below, the updated fuel forecasts did not significantly affect the break-even analysis.

Updated Environmental Forecasts

FPL's environmental compliance cost forecasts were based on ICF International's U.S. Emission & Fuel Markets Outlook Winter 2007/2008. From this, FPL produced four sets of projected compliance costs. The set of compliance costs provided a range of potential costs.

OPC asserted that FPL appropriately identified changes in key parameters such as carbon tax. SACE contended that FPL's carbon estimates were too high and that the company's exclusion of an analysis assuming a renewable portfolio standard renders the filing deficient. SACE argued that H.R. 2545, the American Clean Energy and Security Act, should have been considered by FPL. FPL argued that it had to freeze assumptions months ahead of time before the testimony filing date of May 1, 2009. FPL further asserted that it could not project all of the effects of a bill that changed significantly a number of times before passage and still meet the NCRC filing date. There is uncertainty regarding the future legislation of carbon dioxide (CO2), as well as potential issues regarding the timing of filing requirements and on-going legislation. Providing a range of CO2 forecasts is reasonable until legislation is enacted.

Break-Even Costs

OPC asserted that FPL appropriately calculated the break-even capital costs for comparison with an alternative project. SACE contended that FPL's break-even analysis was not a common approach to making the comparison between alternatives. We recognize that the analysis is unique; however, we previously accepted this approach in the TP67 project need determination and such an approach is reasonable today. It is notable that according to FPL's analysis, the TP67 project is the most cost-effective generation alternative at this time. The results of FPL's non-binding estimated range of capital costs in 2007 dollars of $3,108/kw to

$4,540/kw, shows that the projected breakeven capital costs for the TP67 project are above the upper bound of $4,540/kw in 8 of the 9 fuel cost and environmental compliance cost scenarios. In the 9th scenario, which consists of low fuel costs and low environmental compliance costs, the projected breakeven capital costs are at the upper end ($4,414/kw) of this range. We believe that an annual economic analysis can and should be used to track trends and determine the effects of those trends.

Capital Cost Estimates

FPL's capital cost range remained as presented in the TP67 project need determination. OPC contended that FPL's capital cost estimates rely on stale information. FPL witness Sim argued that the capital cost range presented in the TP67 project need determination was still applicable for this analysis. Although several uncertainties regarding the cost of the TP67 project remain, we believe that FPL's presentation of the capital cost estimate as a range is reasonable at this time. As previously discussed, FPL has not completed negotiations regarding its EP/C or EPC contracts. FPL shall file updated capital cost estimates in its next annual NCRC filing.

Based upon the discussion above, we find that the information and analysis provided by FPL are sufficient and satisfactory for compliance with Rule 25-6.0423, F.A.C., and Order No. PSC-08-0237-FOF-EI regarding the annual detailed analysis of the long-term feasibility of the TP67 project. The information and analysis provided allows the necessary review to track potential trends that are paramount in determining the on-going feasibility of the TP67 project. We also find that the analysis supports a conclusion that completing the TP67 project is feasible at this time.

FPL's EPU Project

We next address the question of whether FPL's EPU project costs are separate and apart from the costs that would have otherwise been necessary had there been no EPU project. In Order PSC-08-0749-FOF-EI, at page 29, we approved the following stipulation:

> OPC and FPL stipulate that as it applies to nuclear uprate projects, the NCRC should be limited to those costs that are separate and apart from nuclear costs that would have been necessary to provide safe and reliable service had there been no uprate project. OPC and FPL will work with PSC staff to develop an NFR form for use in the 2009 hearing cycle that specifies the information that a utility will provide in support of its request, that the uprate costs in its NCRC filing are separate and apart from the costs that would have been necessary to provide safe and reliable service without the uprate. For purposes of the 2008 NCRC hearings, OPC will not challenge the prudence of FPL's 2007 uprate costs on the 'separate and apart' issue. OPC's position for the 2007 uprate costs, however, does not prevent OPC from raising the 'separate and apart' issue for any FPL uprate costs incurred subsequent to 2007.

Witness Kundalkar explained that FPL's "separate and apart" analysis focused on:

> (i) determining the scope of modifications required for the uprate conditions through detailed engineering analyses; (ii) reviewing historical nuclear division plans for plant expenditures to validate that none of the modifications necessary for the EPU project were included in prior plans; (iii) reviewing Nuclear Regulatory Commission (NRC) license renewal commitments to validate that none of the modifications necessary for the uprate conditions were included in FPL's existing license renewal commitments; (iv) establishing a cross-functional review team including engineering, accounting, business operations, and others to review uprate activities and confirm these activities are separate and apart from nuclear costs that would have been necessary to provide safe and reliable service had there been no uprate project; and (v) the careful process of recording costs and compiling its Nuclear Filing Requirements, and the many processes and procedures attendant thereto.

FPL witness Reed performed a review of FPL's process for determining how costs are separate and apart and how FPL segregates them. Witness Reed noted that the separate and apart concept is not concerned with whether or not the costs were prudently incurred, but whether they are necessary to the uprate project as opposed to ongoing nuclear capital or maintenance activities. The question solely relates to whether the costs should be included in this proceeding or one of FPL's base rate proceedings.

FIPUG took the position that FPL did not meet its burden of proving that its EPU project costs are separate and apart. However, FIPUG's post-hearing brief did not provide further support of its position. OPC also maintained that FPL did not meet its burden of proof. OPC witness Jacobs stated "it was my understanding [FPL] agreed to provide a 20-year capital analysis of projects that might be needed in order for the plant to run for 20 years, and they have not provided that information." Witness Jacobs offered no other evidence in support of his understanding. OPC argued in its brief that the study is needed to differentiate between those costs needed to continue operating the unit over the long term, which are included in base rates, from the additional costs that would not be incurred "but for" the decision to uprate. OPC urged that we adopt the application of its proposed standard.

FPL witness Kundalkar noted that OPC witness Jacobs did not identify any flaw in FPL's analysis. He described the analysis supported by witness Jacobs as requiring a component-by-component predictive study. Witness Kundalkar asserted the study would be meaningless for decision-making purposes. Due to the speculative nature of such a study, witness Kundalkar opined that it was not useful for the NCRC.

OPC's arguments hinge on a position that the applicable standard is a 20-year component-by-component study. Since FPL did not provide such a study, OPC opined that FPL failed to meet its burden of proof. Rule 25-6.0423, F.A.C., and Order PSC-08-0749-FOF-EI do not require FPL to perform a 20-year component-by-component separate and apart study. However, FPL is required to implement a process that appropriately identifies NCRC costs as separate and apart.

As previously noted, FPL presented its separate and apart methodology. Our review of FPL's petitions and filings in the NCRC has not identified a policy concern with FPL's separate and apart methodology. OPC witness Jacobs did not identify any specific flaws in FPL's methodology. Instead, OPC witness Jacobs maintains that the appropriate analysis is a 20-year component-by-component capital expenditure study. We are not persuaded. The EPU project is estimated to be completed in 2013. Thus, a 20-year analysis period extends well beyond the EPU project commercial operation date. Costs incurred after 2013 are by definition beyond the scope of the EPU project. Consequently, we question the appropriateness of a 20-year study to assess separate and apart costs.

Based on the foregoing, we find that FPL's separate and apart methodology is reasonable and appropriate for identifying NCRC costs. We also find that FPL's 2008 actual, 2009 actual/estimated, and 2010 projected EPU project costs are separate and apart from the nuclear costs that would have been necessary to provide safe and reliable service had there been no EPU project.

We next address FPL's request concerning the reasonableness of its actual/estimated 2009 EPU project costs and the true-up amount. OPC, FIPUG and SACE did not propose adjustments to FPL's estimated 2009 costs or the true-up amount. OPC, FIPUG and SACE took no position on this issue and did not address this issue in their post-hearing briefs. Therefore, pursuant to the prehearing order, OPC, FIPUG, and SACE have waived their positions on this issue.

FPL estimated the St. Lucie Unit 2 gantry crane will enter commercial service October 2009. In Order No. PSC-08-0749-FOF-EI, at page 6, we found that "PEF and FPL shall be allowed to recover through the NCRC associated revenue requirements for a phase or portion of a system placed into commercial service during a projected recovery period." Thus, FPL's inclusion of a base rate revenue requirement for the St. Lucie 2 gantry crane in the estimated costs for 2009 is consistent with our policy. However, an adjustment to FPL's estimated 2009 base rate revenue requirements is needed, based in part upon our decision that Section 366.93, F.S., establishes a fixed project carrying cost to be applied to all nuclear construction projects with need petitions filed prior to December 31, 2010.

In 2007, FPL determined how it would address any differences in AFUDC rates resulting from Rule 25-6.0423, F.A.C., and Rule 25-6.0141, F.A.C. FPL decided to track any resulting incremental or decremental AFUDC amounts remaining on the company's books and records until the projects are placed into service, at which time the cumulative increment or decrement would be transferred to plant in service. On February 8, 2008, FPL requested a change to its AFUDC rate from 7.42% to 7.65%.[14] However, FPL's petition did not request implementation of FPL's internal 2007 decision. On March 6, 2009, FPL requested another change to its

[14] Order No. PSC-08-0265-PAA-EI, issued May 28, 2009, in Docket No. 080088-EI, in Re: Request for approval of change in rate used to capitalize allowance for funds used during construction (AFUDC) from 7.42% to 7.65%, effective January 1, 2008, by Florida Power & Light Company.

AFUDC rate from 7.65% to 7.41%.[15] Again, FPL's petition did not request implementation of FPL's internal 2007 decision. In this proceeding, FPL witness Powers acknowledged that we have not issued an order approving FPL's 2007 internal AFUDC approach. Therefore, we find that FPL has had at least two opportunities to present the matter to us but chose not to do so. FPL's election to wait two years to present this matter and then request that the policy be applied to construction costs incurred in prior periods is not appropriate ratemaking policy. Policies should be applied on a prospective basis.

FPL's AFUDC approach results in an estimated St. Lucie Unit 2 gantry crane base rate revenue requirement of $83,651. The base rate revenue requirement without FPL's AFUDC approach is $83,460. This is a $191 reduction. This adjustment is reflected in the remainder of this analysis. No other matters are disputed with respect to FPL's estimated 2009 EPU project costs and true-up amount.

FPL witness Kundalkar described actual and estimated 2009 EPU activities and costs. FPL witness Powers addressed FPL's accounting, including calculation of revenue requirements and true-up amounts. FPL's actual and estimated 2009 EPU project cost include construction costs of $258,926,772 ($252,317,529 jurisdictional), operation and maintenance (O&M) expenses of $568,000 ($544,467 jurisdictional), and carrying charges of $20,297,390. Based on the prior discussion, there is also a base rate revenue requirement of $83,460. All jurisdictional costs are net of joint owner and other adjustments.

We compared these actual and estimated 2009 costs to the approved 2009 projected NCRC amounts to determine the estimated true-up amount. Order No. PSC-08-0749-FOF-EI, at page 32, identified a projected carrying cost amount of $16,553,019, but no O&M expenses or base rate revenue requirements. Thus, the 2009 true-up is $4,372,298. This amount is the sum of an under estimate of $3,744,371 in carrying charges ($20,297,390 - 16,553,019 = $3,744,371), plus an under estimate of $544,467 in O&M expenses, plus an under estimate of $83,460 in base rate revenue requirements.

Based on the foregoing, we approve as reasonable, actual/estimated 2009 EPU project construction costs in the amount of $258,926,772 ($252,317,529 jurisdictional), O&M expenses of $568,000 ($544,467 jurisdictional), carrying charges of $20,297,390, and a base rate revenue requirement of $83,460. We also approve an estimated 2009 EPU project true-up amount of $4,372,298. These amounts include a $191 adjustment to FPL's requested base rate revenue requirement.

We now turn to FPL's request concerning the reasonableness of projected 2010 EPU project costs and the corresponding recovery amount. OPC, FIPUG and SACE did not propose adjustments to FPL's projected 2010 costs or recovery amount. OPC, FIPUG and SACE took no position on this issue and did not address this issue in their post-hearing briefs. Therefore,

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[15] Order No. PSC-09-0377-PAA-EI, issued May 28, 2008, in Docket No. 090108-EI, <u>in Re: Request for approval of change in rate used to capitalize allowance for funds used during construction (AFUDC) from 7.65% to 7.41%, effective January 1, 2009, by Florida Power & Light Company.</u>

pursuant to the prehearing order, OPC, FIPUG and SACE have waived their positions on this issue.

During 2010, FPL projects that nine different components of its EPU project will enter commercial service at various dates. In Order No. PSC-08-0749-FOF-EI, at page 6, we found that "PEF and FPL shall be allowed to recover through the NCRC associated revenue requirements for a phase or portion of a system placed into commercial service during a projected recovery period." Therefore, FPL's inclusion of projected base rate requirements for these nine components is consistent with the regulatory policy expressed in Order No. PSC-08-0749-FOF-EI. Consistent with our previous decisions herein, an adjustment to FPL's proposed base rate revenue requirements for 2010 is needed.

As previously noted, FPL had ample opportunity to request approval of its AFUDC approach but chose not to do so. We find that new policy shall be implemented on a prospective basis. Consequently, we exclude FPL's AFUDC approach for purposes of this proceeding.

FPL's AFUDC approach results in 2010 base rate revenue requirement of \$15,991,104. Excluding FPL's AFUDC approach results in a lower base rate revenue requirement of \$15,877,677. This is a \$113,427 reduction. This adjustment is reflected in the remainder of this analysis. No other matters are disputed with respect to FPL's projected 2010 EPU project costs.

FPL witness Kundalkar described 2010 EPU activities and costs. FPL witness Powers addressed FPL's accounting, including calculation of revenue requirements and true-up amounts. FPL's projected 2010 EPU project costs include construction costs of \$391,614,248 (\$376,703,895 jurisdictional), O&M expenses of \$2,209,376 (\$2,147,983 jurisdictional), and carrying charges of \$41,594,586. Based on the prior discussion, there is also a \$15,877,677 base rate revenue requirement. All jurisdictional costs are net of joint owner and other adjustments. The 2010 EPU project NCRC recovery amount is the sum of \$2,147,983 in O&M expenses plus \$41,594,586 in carrying charges plus \$15,877,677 in base rate revenue requirements, for a total of \$59,620,246. As previously noted, a \$113,427 downward adjustment has been made to FPL's requested base rate revenue requirement because FPL's request seeks to apply a new policy on costs incurred in prior periods.

Therefore, based on the foregoing, we approve as reasonable, projected 2010 EPU project construction costs in the amount of \$391,614,248 (\$376,703,895 jurisdictional), O&M expenses of \$2,209,376 (\$2,147,983 jurisdictional), carrying charges of \$41,594,586, and a base rate revenue requirement of \$15,877,677. The approved 2010 recovery amount is \$59,620,246. These amounts include a \$113,427 adjustment to FPL's requested base rate revenue requirement.

FPL's TP67 Project

We have reviewed FPL's request concerning the reasonableness of estimated 2009 TP67 project costs and the true-up amount to be included in setting the 2010 recoverable amount. OPC and FIPUG took no position on this question and did not address it in their post-hearing briefs. Therefore, pursuant to the prehearing order, OPC and FIPUG have waived their positions on this issue.

SACE argued FPL failed to comply with the detailed analysis of long-term feasibility requirements of Rule 25-6.0423(5)(c)5, F.A.C. Thus, SACE asserted no costs can be reasonably estimated or incurred. SACE maintained that there should be consequences in the cost recovery framework for failing to demonstrate the long-term feasibility of completing a project. Consequently, SACE urges us to deny recovery of estimated 2009 costs. SACE witness Cooper supported a view that spending more on nuclear reactors and allowing the utilities to recover those costs from ratepayers would be imprudent. However, SACE witness Gundersen said "... the problems are eventually surmountable. There are no show-stoppers." Consistent with our previous decisions in this docket, and review of the record evidence, we find that denial of recovery is an extreme measure that is not warranted because FPL's recovery of 2009 expenditures will be subject to a future prudence review.

No other matters are disputed with respect to FPL's estimated 2009 TP67 project costs. FPL witness Scroggs described 2009 TP67 activities and costs. FPL witness Powers addressed FPL's accounting, including calculation of revenue requirements and true-up amounts. FPL's actual and estimated 2009 TP67 project cost are preconstruction costs of $45,640,661 ($45,444,468 jurisdictional), preconstruction carrying charges of $3,560,771, and site selection carrying charges of $472,938. While site selection activities have ended, these carrying charges result from site selection costs that FPL has not yet recovered through the true-up process.

The 2009 cost estimates were compared to the approved 2009 projected NCRC amounts to determine the estimated true-up amount. Order No. PSC-08-0749-FOF-EI, at page 36, identified projected preconstruction costs of $109,540,915, associated carrying charges totaling $7,344,813, and projected site selection carrying charges of $509,050.

We find that the 2009 estimated true-up amount is negative $67,916,601. The 2009 variance is the sum of an over-projection of $64,096,447 ($109,540,915 - $45,444,468 = $64,096,447), over-projected associated carrying charges of $3,784,042 ($7,344,813 - $3,560,771 = $3,784,042), and over-projected site selection carrying charges of $36,112 ($509,050 - $472,938 = $36,112).

Based on the foregoing, we approve as reasonable estimated 2009 TP67 project preconstruction costs of $45,640,661 ($45,444,468 jurisdictional), preconstruction carrying charges of $3,560,771, and site selection carrying charges of $472,938. We also approve an estimated 2009 TP67 project true-up amount of negative $67,916,601.

We next considered FPL's request concerning the reasonableness of projected 2010 TP67 project costs. OPC and FIPUG took no position on this issue and did not address this issue in their post-hearing briefs. Therefore, pursuant to the prehearing order, OPC and FIPUG have waived their positions on this issue.

SACE argued FPL failed to comply with the detailed analysis of long-term feasibility requirements of Rule 25-6.0423(5)(c)5, F.A.C. Based on our previous decisions in this docket, and a review of the record evidence, we find that denial of recovery is an extreme measure that is not warranted. FPL's recovery of 2010 expenditures will be subject to a future prudence review.

No other matters are disputed with respect to FPL's projected 2010 TP67 project costs. FPL witness Scroggs described 2010 TP67 activities and costs. FPL witness Powers addressed FPL's accounting, including calculation of revenue requirements and true-up amounts. FPL's projected amount is $91,860,995, which includes preconstruction costs of $91,730,615 ($90,654,124 jurisdictional), preconstruction carrying charges of $973,735, and site selection carrying charges of $233,136. While there are no 2010 site selection activities, these carrying charges result from site selection costs that FPL has not yet recovered through the true-up process. Thus, variances identified in 2009 are carried forward into 2010.

Therefore, we approve as reasonable projected 2010 TP67 project preconstruction costs of $91,730,615 ($90,654,124 jurisdictional), preconstruction carrying charges of $973,735, and carrying charges on unrecovered site selection costs of $233,136. The recommended 2010 recovery amount is $91,860,995.

We have been asked to determine the total jurisdictional amount to be included in establishing FPL's 2010 Capacity Cost Recovery Clause factor. This issue is a fall-out issue reflecting decisions on all prior issues that impact FPL's level of recovery in 2010. Both contested and stipulated issues impacting the total amount are identified in the following table.[16]

Topic	FPL	Approved Adjustments
EPU 2008 Final True-up	$-1,118,918	
EPU 2009 Estimated True-up	$4,372,489	$-191
EPU 2010 Projections	$59,733,673	$-113,427
TP67 2007 Final True-up	$-311,955	
TP67 2008 Final True-up	$-23,829,702	
TP67 2009 Estimated True-up	$-67,916,601	
TP67 2010 Projections	$91,860,995	
Subtotals	$62,789,981	$-113,618
Total 2010 Recovery Amounts	$62,789,984	$62,676,366

16 A negative total 2010 recovery amount indicates a refund.

There is a $3 rounding difference between FPL's requested recovery amount and the sum of individual amounts by issue. In calculating the total 2010 recovery amount, the total amount FPL requested was used. OPC, FIPUG, and SACE took no position on this issue and did not address this issue in their post-hearing briefs. Therefore, pursuant to the prehearing order, OPC, FIPUG and SACE have waived their positions on this issue.

Thus, we approve $62,676,366 to be included in establishing FPL's 2010 CCRC factor.

PEF ISSUES

PEF Project Management

We have been asked to determine whether for the year 2008, PEF's project management, contracting, and oversight controls were reasonable and prudent for the Levy Units 1 & 2 project (LNP) and the Crystal River Unit 3 Uprate project (CR3 Uprate).

The applicable standard for determining prudence is consideration of what a reasonable utility manager would have done in light of conditions and circumstances which were known or reasonably should have been known at the time decisions were made. This is the same standard applied by PEF witness Doughty in this matter.

In reviewing the record, we note that none of the parties challenged the prudence of the overall project management, contracting, and oversight controls in placed during 2008 for the LNP and CR3 Uprate projects. OPC, PCS Phosphate, and SACE, however, raised questions concerning certain management decisions made during 2008 by PEF associated with the LNP and CR3 Uprate projects. OPC witness Jacobs questioned the reasonableness of PEF's decision to incur construction cost for the balance of plant construction activities at the CR3 Uprate project without prior NRC approval of the license amendment request (LAR).

The focus of the intervenor's concerns is presented by witness Jacobs in the following question and answer:

> Q. Are you questioning the engineering approach PEF is utilizing in its NRC application?
> A. No. My point is that PEF cannot say for certain that the NRC will approve its request to the extent or in the manner requested.

Witness Jacobs further stated,

> I think from an engineering and operation perspective, the sequence of events is probably reasonable that they undertook, but from a risk management perspective, it results in PEF spending a significant fraction of the money for this project before knowing that the desired outcome will be achievable.

He further clarified this risk by stating that the basis of his concern is on possible denial of the LAR because "[t]his is the first Babcock & Wilcox reactor that has been attempted to be uprated to this magnitude." However, witness Jacobs stated that he was aware that the NRC had not denied any of the 104 uprate requests submitted since 2001.

PEF's witness Franke opined that the company has reasonable assurance the NRC will approve the LAR before the uprate construction activities are completed. He testified that project design, construction, and regulatory risks have been reasonably mitigated given PEF's project management activities. He asserted that the majority of the engineering analysis and solutions proposed for the CR3 Uprate are similar to those in use and approved by the NRC for the Davis-Besse Unit, a Babcock & Wilcox reactor similar to Crystal River Unit. Additionally, other plant modifications, proposed in the LAR, will allow for the removal of certain current NRC operational limits. He also contended that witness Jacobs has not actually reviewed the proposed technical and engineering analysis and solutions that have been developed over the last year and a half that are part of the LAR proposal.

Staff witnesses Coston and Vinson sponsored an audit report that "reviewed the internal controls and management oversight of the nuclear projects underway at Progress Energy Florida." Witnesses Coston and Vinson stated "[t]he primary objective of this review was to document project key development, along with the organization, management, internal controls and oversight that PEF has in place or plans to employ for these projects." The only questions asked of these witnesses concerned the control of project schedule once the LNP combined operating license application (COLA) was filed with the NRC and overall project costs. No party questioned the witnesses on project management, contracting, and oversight controls used for the CR3 Uprate project. We reviewed the management audit report to determine whether it contained support for a finding of imprudence and did not find any.

We find that the concerns identified by OPC witness Jacobs do not support a finding that PEF's project management, contracting, and oversight controls at the CR3 Uprate project during 2008 were unreasonable or imprudent. The concern identified by witness Jacobs, regarding a future NRC decision on the LAR, does not show that project risks were inappropriately addressed by PEF. In fact, witness Jacobs' suggested approach to managing the Uprate project would delay all construction and extend the project schedule. However, witness Jacobs provided no additional analysis addressing possible cost risks, schedule risks, and customer benefit risks of PEF's approach compared to his alternative.

Based on the record evidence, we find that PEF implemented a management approach that supports a reasonable balance between the level of project risk and the timing of project benefits. Therefore, we find that during 2008, PEF's project management, contracting, and oversight controls were reasonable and prudent for the CR3 Uprate project.

Levy Units 1 & 2 Project

As stated above, none of the parties challenged the prudence of the overall project management, contracting, and oversight controls PEF had in place during 2008 for the LNP. However, SACE took issue with the reasonableness and prudence of PEF's decision to incorporate a limited work authorization (LWA) in the schedule developed for the LNP project and included in the COLA.[17] SACE's brief did not explain the position taken apart from project feasibility.

Only PEF witness Thompson provided testimony directly addressing the reasonableness of including an LWA in PEF's LNP COLA. Witness Thompson opined that the NRC intended for licensees to use the LWA process. In discussing his opinion, he pointed to NRC activities in 2007 concerning the revision of the LWA rule and regulations. Witness Thompson stated, ". . . the NRC clearly indicated to the public and the nuclear industry that it was worth spending NRC resources on the LWA process and that the NRC expected the nuclear industry to be in a position to use LWAs, if needed, to meet projected construction schedule needs." Witness Thompson also noted that "by the time PEF had decided to request an LWA, the NRC had not only established a new regulation for reviewing and issuing LWAs, but it had also established an Office that was responsible for conducting those reviews in a timely schedule, provided that an acceptable application had been submitted." No party challenged these statements.

The NRC docketed the LWA and COLA on October 6, 2008. Docketing an application indicates that the application was technically sufficient for NRC review. PEF believed its requested NRC review schedule for the LWA and COLA was necessary to achieve the 2016 and 2017 in-service dates. No party challenged PEF's need to secure its proposed LWA to meet 2016 and 2017 in-service dates. No party asserted PEF was non-responsive to the NRC staff.

Regarding PEF's oversight of the Levy project, we believe that PEF management acted appropriately in developing a Levy project construction schedule that included an LWA, because the LWA is a viable construction schedule management tool offered by the NRC. We also believe that PEF implemented a management approach that supports a reasonable balance between the level of project risk and the timing of project benefits. Therefore, based on the foregoing, we find that during 2008, PEF's project management, contracting, and oversight controls were reasonable and prudent for the LNP project.

We now turn to the questions of whether it was reasonable and prudent for PEF to execute its EPC contract at the end of 2008. While this issue addresses the prudence of PEF to execute its EPC contract, the only disputed matter was the timing of PEF's decision without full knowledge of the NRC's decisions concerning PEF's requested COLA and LWA reviews. The referenced EPC contract has not been submitted for our review. Consequently, we shall only address disputed matters regarding the timing of PEF's decision to enter into an EPC contract.

The dispute addressed is the intervenors' (OPC, PCS Phosphate and FIPUG) contention that PEF prematurely entered into the EPC agreement without full knowledge of the NRC's decisions concerning the COLA review, in particular, the requested LWA review schedule. According to the intervenors, PEF's decision regarding the timing of contract execution was unreasonable given what was or should have been known by PEF in late December 2008.

[17] An LWA allows a utility to do certain site work prior to the issuance of the combined operating license. PEF's LWA request was part of its COLA for review and authorization in advance of the overall issuance of the combined operating license.

SACE's position on this issue was focused on LNP schedule slippage, and the effect this slippage may have on long-term project feasibility.

The applicable standard for determining prudence is consideration of what a reasonable utility manager would have done in light of conditions and circumstances which were known or reasonably should have been known at the time decisions were made. As previously noted, this is the same standard applied by PEF witness Doughty.

As stated by PEF witnesses Miller and Lyash, PEF entered into an EPC contract for the LNP project with Shaw/Westinghouse on December 31, 2008. Witness Lyash asserted that PEF's management approved execution of the EPC agreement in December due to the following reasons:

- After two years of negotiations all outstanding contract issues that needed to be resolved were resolved and the EPC agreement was ready for execution.
- PEF had obtained a number of key contractual benefits from Shaw/Westinghouse that were offered to PEF on a time limited basis.
- Execution of the EPC agreement provided an orderly framework to accommodate potential adjustments to the project schedule.
- Execution of the EPC agreement at this time was necessary to move the project forward to meet the 2016, 2017 LNP in-service dates.

Addressing the question of what PEF knew or should have known about the NRC's potential decision on the LWA request prior to signing the EPC, witness Lyash stated, "in December 2008, the company did not know and should not have known that the NRC would not approve the LWA before issuing the combined license. PEF reasonably and prudently acted on this information that was available at the time, and by so doing was able to preserve the contractual benefits that had been secured through two years of intense negotiations." Witness Lyash further asserted that "[i]n fact had PEF known about the NRC's position with respect to the LWA in December 2008 . . . PEF would have still executed the EPC agreement and proceeded to amend the EPC agreement under the EPC's contract suspension and amendment provision just like PEF is doing now."

OPC witness Jacobs opined that PEF's decision to execute the EPC agreement in December 2008 was not reasonable. Witness Jacobs supported his opinion by stating:

> Receipt of the LWA within the requested timeframe was a requirement for implementation of the contract on the schedule contained in the EPC contract. Not only did PEF not have any assurance that the LWA would be issued, the NRC specifically told them in the October 6, 2008 letter that it was unlikely that the requested timeline would be met. Under the totality of circumstances, PEF should have assumed that an LWA review schedule different than the overall COLA review schedule would not have been adopted by the NRC. To assume otherwise

> and sign the EPC contract with this cloud hanging over this critical date was not reasonable.

The following statement from the NRC's October 6, 2008 letter to PEF, according to witness Jacobs, is what clearly informed PEF that it was unlikely that the requested [NRC review] timeline could be met:

> Because of the complexity of the site characteristics and the need for additional information, it is unlikely that the LNP COLA review can be completed in accordance with this timeline.

Witness Jacobs further asserted:

> It is not reasonable to assume that given the fact that the NRC made an effort to specifically mention the complexity of the site that it was only suggesting a brief delay in the schedule. This is true when contrasted with the extensive effort PEF made to impress upon senior NRC staff of the need to meet its 'aggressive' schedule.

PCS Phosphate expressed similar views on the reasonableness of PEF's decision to execute the EPC before the NRC established a review schedule for the LWA request. In its brief, PCS Phosphate opined that given what was known or should have been known at the time, PEF unreasonably assumed risks in executing the EPC under the circumstances.

We agree with the parties that to make a finding concerning the timing of PEF's decision, the review should be made in light of what was known, or should have been known, at the time the decision was made. In response to staff discovery, PEF provided a listing of key informational points leading up to the NRC's January 23, 2009, announcement on PEF's COLA/LWA review schedule request. No party took issue at hearing with this listing or identified any other key informational points that should have been considered. The key informational points are:

- 1/08, PEF advised the NRC at a public meeting that the COLA for the Levy project would include an LWA request.
- 1/10/08, PEF met with NRC technical staff to review Levy geotechnical issues.
- 2/2008, The NRC stated that applicants should give advance notice of their intent to request an LWA.
- 3/5/08, PEF formally notified the NRC that it intended to request an LWA with its Levy COLA filing.
- 6/30/08, PEF met with NRC managers to discuss the need for Levy and overall plans for the project.

- 7/28/08, PEF met with NRC technical staff on the Levy geotechnical issues.
- 7/30/08, PEF filed its COLA/LWA application with the NRC.
- 9/5/08, The NRC requested that PEF revise the scope of the LWA to include dewatering and permeation grouting.
- 9/9/08, PEF management held a "drop-in" meeting with NRC management to review the overall plan for LNP and the project schedule.
- 9/12/08, PEF supplemented its filings to revise the proposed scope of the LWA as the NRC requested.
- 10/6/08, Brian Anderson (NRC project manager) issued a docketing letter for Levy, which indicates that the application is sufficient for review. Requests for additional information (RAI) relating to geotechnical issues are sent to PEF.
- 11/20/08, PEF submitted its responses to the NRC's RAIs.
- 12/20/08, PEF is advised that it would receive a review schedule before the end of January 2009.
- 12/31/08, PEF entered into the EPC agreement with Shaw/Westinghouse.
- 1/23/09, NRC staff informed PEF that review of the LWA request would take as long as the review of the COLA.

PEF witness Miller asserted, "[t]here was no indication that an LWA would not be issued for the scope requested." Similarly, witness Lyash asserted:

> The NRC never told the Company nor intimated that the NRC would not issue the LWA until it issued the COL. In our experience with the NRC, when the NRC wants to tell us something they do so, they do not leave room for doubt. When the NRC determined in January 2009 that it was going to review the LWA on the same timeline as the COL and not sequentially as PEF had requested that is what the NRC expressly said it was going to do.

OPC witness Jacobs opined that PEF was premature in signing the EPC agreement since PEF did not have a firm schedule for review and approval of the LWA by the NRC at the time that the EPC was signed. Witness Jacobs asserted:

> Prior to signing the EPC contract, the NRC had indicated that it was unlikely that the requested schedule could be met due to the complexity of the site characteristics and the need for additional information. I believe that PEF should not have signed the EPC contract without assurance that the LWA would be approved on the schedule that was needed for the project.

Witness Jacobs further asserted, "[a] more reasonable, cautions[sic] approach given the uncertainty in the LWA schedule and the list of concerns identified above would have been to continue to support development of the COLA while delaying signing of the EPC contract until the issuance of the LWA was known and the above concerns are resolved." Witness Jacobs stated:

> This decision (signing of the contract) may result in significant extra cost to the project that could have been avoided with a more cautious approach given the known risks and uncertainties at the time of signing. At the very least, the Commission does not have sufficient information to determine whether 2009 and 2010 EPC contract costs are reasonable.

PCS Phosphate witness Bradford stated, "[i]n the present proceeding, the Commission needs only determine the prudence of the actual construction cost incurred in 2008. As a result, the Commission does not need to determine costs associated with Progress' decision to enter into the EPC agreement prior to the receipt of the LWA, as the contract was not executed until the end of 2008." Witness Bradford further stated, "Progress has relied heavily on the NRC's meeting of its announced schedules despite the facts a) that the revised licensing process is untested and b) that the industry has presented the NRC with a consistently changing profile rather than a firm commitment to certified designs on which those schedules have been based." Finally, witness Bradford opined that there is a substantial likelihood that PEF should have waited until it had the LWA for Levy before signing the EPC.

Our review of the record finds that the intervenors primarily focused their attention on what PEF should have known concerning the likelihood of obtaining NRC approval of the requested LWA review schedule. We agree that gaining approval of the LWA was an important component of the construction schedule to meet the proposed commercial in service dates for the units. However, it is not the only important component of this schedule. As addressed by witness Lyash, the LWA was a critical milestone. But it is no more or less critical than, for example, the final environmental impact statement, the final safety evaluation report, the license issuance, or the site certification. We concur with witness Lyash that PEF must satisfy all critical regulatory milestones to meet the proposed commercial in service dates for the LNP. All of these milestones could have an influence on the project construction schedule in the same manner as the LWA.

In addition to meeting the project construction schedule, PEF asserted other reasons for signing the EPC were considered at the time of its decision. These reasons are mentioned above, we note that the parties generally did not address these reasons.

Based on our review of what PEF knew or should have known regarding the LWA in late 2008, we find that the intervenors failed to make a persuasive showing that PEF was unreasonable concerning the timing of its decision to enter into the EPC agreement. Consistent with 10 CFR Part 50.3, we believe that the only NRC action that clearly indicates the NRC's intention concerning the review schedule for the LWA was its January 23, 2009, announcement.[18] Based on the foregoing, we believe that the NRC undertook actions necessary to establish a review schedule for PEF's LNP applications. Any other interpretation of the NRC's actions is speculative.

Absent concerns with PEF's LWA efforts, no material evidence was presented that PEF should not have otherwise signed an EPC contract at the end of 2008. As previously noted, PEF's EPC contract has not been submitted for our review. Consequently, we cannot determine PEF's prudence concerning the actual terms and conditions contained within the agreement. However, we are persuaded that PEF's actions and planning regarding an LWA leading up to the signing of an EPC contract were reasonable and consistent with good business practices.

Based on the foregoing analysis, we find that the timing of PEF's decision to execute an EPC contract at the end of 2008 was reasonable. We decline at this time to make a finding regarding PEF's prudence concerning the actual terms and conditions contained within its EPC contract.

<u>PEF's Annual LNP Feasibility Analysis</u>

PEF has submitted, and we have reviewed, its annual detailed analysis of the long-term feasibility of continuing construction and completing the LNP project, as provided for in Rule 25-6.0423, F.A.C., and Order No. PSC-08-0518-FOF-EI (Determination of Need Order).

PEF argued that it has complied with this directive by providing the information upon which the company's management relies in making its determination of a project's feasibility. PEF asserted that the feasibility of completing the LNP project means the project is capable of being completed, i.e., the project is technically and legally feasible. PEF claims that the appropriate analysis is a qualitative analysis not a rote quantitative cost-effective analysis based on year-to-year fluctuations in spot prices, forecasts and projections.

PCS Phosphate argued that PEF's direct filing in May 2009 disregarded statutory and Commission-ordered requirements by not providing an economic analysis of the LNP project. PCS Phosphate further asserted that PEF's fuel price forecasts and emission cost assumptions were outdated. Lastly, PCS Phosphate argued that PEF did not possess updated LNP project cost and schedule information required to perform the required economic assessments. OPC supports the analysis provided by PCS Phosphate in its post-hearing statement. OPC's position is that we should order PEF to file a feasibility analysis per the rule after renegotiation of the EPC.

FIPUG argued that PEF focused on the technological and regulatory feasibility of completing the project, but largely ignored the economic feasibility of completing the project. FIPUG further asserted that long-term feasibility cannot be determined if PEF cannot satisfactorily provide the cost of the project.

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[18] 10 CFR part 50.3 states "Except as specifically authorized by the Commission in writing, no interpretation of the meaning of the regulations in this part by any officer or employee of the Commission other than a written interpretation by the General Counsel will be recognized to be binding upon the Commission."

SACE argued that PEF's feasibility analysis was deficient and did not demonstrate that completion of the LNP is feasible in the long-term. SACE further asserted that PEF's May 1 testimony only contained technical and regulatory feasibility but contained no economic analysis or discussion of project cost as it relates to the feasibility of the LNP. SACE argued that PEF's cumulative present value revenue requirement (CPVRR) analysis, submitted as part of its rebuttal testimony, was based upon assumptions that were outdated and unreasonable.

As previously stated, in an effort to mitigate the economic risks associated with the long lead time and high capital costs associated with nuclear power plants, the Florida Legislature enacted Sections 366.93 and 403.519(4), F.S., during the 2006 legislative session. Section 366.93(2), F.S., requires us to establish, by rule, alternative cost recovery mechanisms for the recovery of costs incurred in the siting, design, licensing, and construction of a nuclear power plant. Rule 25-6.0423, F.A.C., was established in order to satisfy the requirements of Section 366.93(2), F.S. Rule 25-6.0423(5)(c)5, F.A.C., states:

> By May 1 of each year, along with the filings required by this paragraph, a utility shall submit for Commission review and approval a detailed analysis of the long-term feasibility of completing the power plant.

In Order No. PSC-08-0518-FOF-EI, at page 24, we provided specific guidance regarding the requirements necessary for PEF to satisfy Rule 25-6.0423(5)(c)5, F.A.C. The Order reads as follows:

> ORDERED that Progress Energy Florida, Inc. shall provide a long-term feasibility analysis as part of its annual cost recovery process which, in this case, shall also include updated fuel forecasts, environmental forecasts, non-binding capital cost estimates, and information regarding discussions pertaining to joint ownership.

Additionally, at pages 15 and 21, the Order contains the following language lending insight to our intent regarding the long-term feasibility of PEF's LNP project:

> We also find that the CO2 price projections used in the cost-effective analysis represent a reasonable range of forecasts based upon CO2 compliance cost studies available to PEF at the time that the cost-effective analysis was undertaken. Since the price forecasts are based upon on-going federal CO2 legislation, we find it appropriate that PEF provide updated cost information as part of its annual feasibility report.

> We will review the continued feasibility of Levy Units 1 and 2 during its annual nuclear cost recovery proceedings; thus, providing the appropriate checks and balances to ensure that the construction of the nuclear units continues to be in the best interest of PEF's ratepayers.

The discussed forecasts, information, estimates, and analysis are necessary filing requirements to assess PEF's 2009 LNP project feasibility analysis and will provide the basis for the approval or denial of PEF's detailed analysis.

Economic Analysis

PEF contended that a feasibility analysis should not be a type of annual cost-effectiveness analysis that compares the cumulative present value revenue requirements for the LNP to other generation alternatives based on load, fuel, and emission cost forecast changes each year. PEF witness Franke, when giving his definition of feasibility with regard to the CR3 uprates, describes feasibility as "the ability of the project to provide an extended power uprate for Crystal River 3 and achieve an economic benefit for my customers." Such a definition clearly emphasizes the importance of an economic analysis when addressing the feasibility of a project. We find that PEF's lack of an economic analysis for the LNP project contradicts its own definition of feasibility. As stated by PCS Phosphate, "a detailed economic analysis using current and reasonable assumptions should always be required." We agree.

Through discovery and rebuttal testimony PEF provided an economic analysis. It is notable that according to PEF's analysis, the LNP project is the most cost-effective generation alternative at this time. The results of the economic analysis provided in response to discovery are comparable to what was presented in the need determination proceedings for the Levy projects. PEF anticipates presenting the results of its EPC contract change order in the following NCRC proceeding, or perhaps before.

PCS Phosphate indicated that Rule 25-6.0423, F.A.C., neither limits the types of analysis that may be required, nor specifies a particular set of analysis that must be submitted. We agree that Rule 25-6.0423, F.A.C., does not provide a prescriptive list of requirements. PCS Phosphate also asserted that we are the only governing authority that has regulatory authority over the economic impact of the LNP. Given these responsibilities, we find that an economic analysis is required.

PEF contended that it cannot determine the feasibility of completing the LNP based on a year-to-year change in load and fuel forecasts. PEF further contended that these projections can and will change from year to year, especially when the economy is in a recession like this year. Lastly, PEF asserted that if it applied changes in such forecasts to decide whether to stop or restart the project each year, PEF could never build a nuclear power plant. We recognize the unique economic times that are influencing short-term trends, and believe that forecasts such as natural gas price forecasts are inherently uncertain. Thus, we find that the feasibility of a long-term project such as the LNP project cannot be made on instant circumstances. An annual economic analysis can and should be used to track trends and determine the effects of those trends.

Through discovery, the additional information necessary to evaluate the long-term feasibility of the LNP was obtained. The additional analysis provided through discovery and rebuttal testimony support a conclusion that completing the LNP project is feasible at this time. OPC's desire for an updated analysis following the company's negotiation change orders to the

EPC contract will be satisfied through the annual filings in the NCRC. PEF shall be required to file updated capital cost estimates in its next annual NCRC filing.

Updated Fuel Forecasts

PEF used high, mid, and low fuel forecast scenarios in its feasibility analysis. PEF's fuel forecasts provided in this docket were the same as those relied on in PEF's 2009 Ten-Year Site Plan.

SACE argued that PEF's recent analysis reflect a bubble in natural gas prices which has burst and is not likely to return. As pointed out by PCS Phosphate, approximately a year ago PEF assured us that "the likelihood of the low fuel price forecast occurring at all in the future is improbable." We believe that the statements above precisely focuses on the inherent uncertainty surrounding fuel forecasting. PEF's use of third party forecasts is consistent with our accepted practice.[19] Additionally, we believe that reviewing the LNP using a range of fuel forecasts accounts for the volatility in the natural gas market.[20] PEF has described the current forecasts as generally higher than the forecast presented in the LNP need determination.

Updated Environmental Forecasts

PEF provided four CO2 compliance cost scenarios in its feasibility analysis. PEF's environmental forecasts with regard to CO2 costs are numerically the same as in the need determination. PEF's cost-effectiveness analysis, provided in response to a staff interrogatory, additionally included a scenario with no CO2 costs.

SACE argued that PEF's forecasts of CO2 costs were too high and did not reflect current pending legislation. The same witness, however, asserted that the nature and scope of carbon mitigation and compliance costs had yet to be defined. PCS Phosphate argued that the Waxman Markey Bill should have been considered by PEF because the bill was pending in May 2009, and PEF's rebuttal testimony was filed after the bill passed the House. There is uncertainty regarding the future legislation of CO2 as well as potential issues regarding the timing of filing requirements and on-going legislation. We find that providing a range of CO2 forecasts is reasonable until legislation is enacted.

Project Cost Estimate

Although PEF's total project cost estimate remained the same, PEF indicated that it has been updated and refined. PEF further indicated that the total cost estimate may change depending on the outcome of the current change order negotiations with Shaw/Westinghouse, but until those negotiations are concluded, the total capital cost estimate remains the current amount of $17.2 billion. OPC's position is that we should order PEF to file a feasibility analysis per the rule after renegotiation of the EPC. We believe that PEF's anticipated action will satisfy

[19] Order No. 08-0518-FOF-EI, at 4.
[20] Id.

OPC's desire. As this is an annual review, we expect that any updates would be included in PEF's 2010 filings and testimony.

Discussion Pertaining to Joint Ownership

In its May 1, 2009 filing, PEF indicated that it is continuing negotiations with municipal, electric cooperative, and investor-owned utilities regarding potential joint ownership in the LNP. No party disputed PEF's filing with regards to joint-ownership discussions.

Based upon the discussion above, we shall not approve what PEF submitted as its May 1, 2009 annual detailed analysis of the long-term feasibility of completing the LNP project, pursuant to Rule 25-6.0423, F.A.C., and Order No. PSC-08-0518-FOF-EI. However, through discovery and rebuttal testimony, the necessary analysis to evaluate the economics of the long-term feasibility of the LNP project was obtained and we find that there is sufficient evidence in the record to support a conclusion that completing the LNP project is feasible at this time.

We now turn to the question of what additional action should be taken regarding PEF's 2009 detailed long-term feasibility analysis of completing the LNP project. PEF asserted that if we determine that PEF's submissions are for some reason deficient, due process requires that we afford PEF an opportunity to correct any perceived deficiency.

We note that the positions of OPC, FIPUG and SACE relate to our decision in approving PEF's feasibility analysis. PCS Phosphate maintained that we should appoint a special master empowered to take all necessary measures to assure PEF customers of the prudence and reasonableness of PEF decision-making. PCS Phosphate's post-hearing brief did not explain how the action would be implemented under Section 366.93, F.S.

OPC witness Jacobs expressed a view that spin-off dockets to address LNP project feasibility and PEF's prudence related to LNP project schedule changes are needed. While asserted, witness Jacobs did not explain problems that would necessitate departure from the current ongoing review docket pursuant to Rule 25-6.0423, F.A.C.

We find that all disputed matters concerning PEF's LNP project feasibility analysis and prudence are appropriately addressed herein. PEF's actions concerning LNP project schedule changes identified during 2009 will be subject to ongoing review in the NCRC. Thus, we find that additional actions are not necessary at this time.

PEF's CR3 Uprate Project

We now turn to the question of what system and jurisdictional amounts should be approved as PEF's reasonably estimated 2009 costs for the CR3 Uprate project. PEF witness Foster provided support regarding the amounts and method used to determine the requested recovery amounts. PEF witness Franke provided descriptions of the planning and construction activities that are associated with the 2009 period costs. No party challenged the reasonableness of PEF's requested 2009 CR3 Uprate Project costs.

OPC, FIPUG and SACE took no position on this issue and did not address this issue in their post-hearing briefs. Therefore, pursuant to the prehearing order, OPC, FIPUG, and SACE have waived their positions on this issue.

We note that PEF's post-hearing position does not reflect the changes presented at hearing with respect to O&M expenses. PEF witness Foster's initial estimated construction costs were $126,126,306 ($91,712,976 jurisdictional), O&M costs were $8,108,218 ($7,596,559 jurisdictional), carrying charges were $14,920,565, and the base rate revenue requirement was $1,242,555. Witness Foster sponsored the following adjustments to his initially estimated amounts: a decrease in capital costs of $8,588,854 ($7,390,371 jurisdictional), a decrease in O&M expenses of $7,930,580 ($6,824,031 jurisdictional), an increase in carrying charges of $983,108, and a decrease in base rate revenue requirements of $489,766. Thus, PEF's revised estimated amounts are construction costs of $117,537,552 ($84,322,605 jurisdictional), O&M costs of $177,638 ($772,528 jurisdictional), carrying charges of $14,229,591, and a base rate revenue requirement of $752,789. The impact of estimated obsolete inventory is reflected in PEF's revised O&M amounts. If approved, all amounts are subject to a future prudence review and final true-up.

These estimated 2009 costs were compared to the approved 2009 projected NCRC amounts to determine the estimated true-up amount. Order No. PSC-08-0749-FOF-EI, at page 15, identified projected carrying charges totaling $14,920,565 and projected O&M expenses of $304,128. We believe that the 2009 estimated true-up amount is $530,215. The 2009 variance is the sum of over-projected carrying charges of $690,974 ($14,920,565 – 14,229,591 = $690,974), and under-projected O&M expenses of $468,400 ($304,128 – $772,528 = $468,400), and an over-projected base rate revenue requirement of $752,789 ($0 – $752,789 = $752,789).

Based on the foregoing, we approve as reasonable estimated 2009 CR3 Uprate project construction costs in the amount of $117,537,552 ($84,322,605 jurisdictional), O&M expenses of $177,638 ($772,528 jurisdictional), carrying charges of $14,229,591, and a base rate revenue requirement of $752,789. We also approve an estimated 2009 CR3 project true-up amount of $530,215.

PEF's LNP

We now address PEF's request concerning the reasonableness of estimated 2009 LNP project costs and the estimated 2009 true-up amount for the LNP. PEF witness Foster provided support regarding the amounts and method used to determine the requested recovery amounts. Witnesses Furman and Miller provided descriptions of the planning and construction activities that are associated with the 2009 period costs for which PEF requested recovery.

OPC and FIPUG took no position and did not address this issue in their post-hearing briefs. Therefore, pursuant to the prehearing order, OPC and FIPUG have waived their positions on this issue.

SACE argued PEF failed to comply with the detailed analysis of long-term feasibility requirements of Rule 25-6.0423(5)(c)5, F.A.C. Consistent with a preponderance of the record evidence, we believe that denial of recovery is an extreme measure that is not warranted. PEF's recovery of 2009 expenditures shall be subject to a future prudence review.

No other party supported adjustments to PEF's requested amounts. We reviewed PEF's calculations and supporting information. PEF's position presented estimated capital costs of \$316,501,103 (\$279,598,436 jurisdictional), O&M expenses of \$5,513,853 (\$4,931,288) jurisdictional), and carrying charges of \$22,278,969. Capital cost amounts in PEF's position statement include both construction and preconstruction costs. The construction costs are \$24,596,242 (\$17,235,584 jurisdictional) and the preconstruction costs are \$291,904,861 (\$262,362,852 jurisdictional). All amounts are subject to a future prudence review and final true-up.

We compared these estimated 2009 costs to the approved 2009 projected NCRC amounts to determine the estimated true-up amount. Order No. PSC-08-0749-FOF-EI, at pages 20 and 21, identified projected preconstruction costs of \$97,084,049, carrying charges totaling \$49,580,292, and projected O&M expenses of \$1,243,114. We find that the 2009 estimated true-up amount is \$141,665,654 based on PEF's revised estimate of 2009 costs. The 2009 true-up variance is the sum of over-projected carrying charges of \$27,301,323 (\$49,580,291 – \$22,278,969 = \$27,301,323), and under-projected O&M expenses of \$3,688,174 (\$1,243,114 – \$4,931,288 = \$3,688,174), and under-projected preconstruction costs of \$165,278,803 (\$97,084,049 – \$262,362,852 = \$165,278,803).

After a review of PEF's calculations and supporting information, we approve as reasonable estimated 2009 LNP project construction costs of \$24,596,242 (\$17,235,584 jurisdictional), preconstruction costs of \$291,904,861 (\$262,362,852 jurisdictional), O&M expenses of \$5,513,853 (\$4,931,288) jurisdictional), and carrying charges of \$22,278,969. The Commission should approve an estimated 2009 LNP project true-up amount of \$141,665,654.

We next consider PEF's request concerning the reasonableness of its projected 2010 project costs for the LNP. PEF witness Foster provided support for the amounts and method used to determine the requested recovery amounts. Witnesses Furman and Miller provided descriptions of the planning and construction activities that are associated with the 2010 period costs for which PEF is requesting recovery.

OPC and FIPUG took no position on this issue and did not address this issue in their post-hearing briefs. Therefore, pursuant to the prehearing order, OPC and FIPUG have waived their positions on this issue.

SACE argued that PEF failed to comply with the detailed analysis of long-term feasibility requirements of Rule 25-6.0423(5)(c)5, F.A.C. Consequently, SACE urged us to deny recovery of projected 2010 costs. PCS Phosphate urged us to suspend cost recovery until PEF completes its assessments of project schedule, contracts, total project costs, and feasibility. No other party supported adjustments to PEF's requested recovery amounts.

The concerns of SACE and PCS Phosphate related to PEF's long-term feasibility analysis. Consistent with a preponderance of the record, we find that denial of recovery, as suggested by SACE, is an extreme measure that is not warranted. Uncertainties will exist until PEF has completed its EPC contract change order negotiations with Shaw/Westinghouse due to LWA matters. PEF witness Miller asserted the change order results may be well within the Cumulative Present Value Revenue Requirement (CPVRR) analysis presented in rebuttal by witness Lyash. We believe that until PEF completes its EPC contract change order negotiations, PEF will not have substantive updates for cost and schedule information. PEF anticipates presenting the results of its EPC contract change order in the following NCRC proceeding, perhaps before. Additionally, we note that the NCRC prudence review and true-up process provide customers protection if it is ultimately determined that PEF imprudently incurred 2010 costs. Consequently, we are not persuaded that suspension of PEF's 2010 recovery, as suggested by PCS Phosphate, is the appropriate response to uncertainties rising from PEF's EPC contract change order negotiations and possible impacts to the LNP project feasibility. We find that the appropriate response is to follow the NCRC prudence review and final true-up process.

PEF witness Foster presented two projections of 2010 LNP costs. One projection excludes a rate management plan and the other is based on implementing a rate management plan. However, these do not reflect PEF's stipulation to exclude CCRC sales forecast variances from the NCRC. Witness Foster provided updated total 2010 projected amounts consistent with the stipulation.

PEF's position regarding projected 2010 costs presented capital costs of $188,549,039 ($149,520,191 jurisdictional), O&M expenses of $5,201,011 ($4,433,053 jurisdictional), and carrying charges of $53,620,827. The capital cost amount in PEF's position statement includes both construction and preconstruction costs. The construction costs are $64,796,549 ($43,397,584 jurisdictional) and the preconstruction costs are $123,752,490 ($106,122,607 jurisdictional). These amounts are calculated consistent with a proposed rate management plan.

For purposes of implementing PEF's rate management plan, the projected 2010 LNP recovery amount is $164,176,487. ($53,620,827 + $4,433,053 + $106,122,607 = $164,176,487) Not implementing PEF's rate management plan reduces the carrying charges that accrue during 2010 from $53,620,827 to $26,094,107. The 2010 LNP recovery amount is $136,649,767. ($26,094,107 + $4,433,053 + $106,122,607 = $136,649,767) All projected amounts are subject to a future prudence review and final true-up.

Based on the foregoing, we approve as reasonable projected 2010 LNP project construction costs of $64,796,549 ($43,397,584 jurisdictional), preconstruction costs of $123,752,490 ($106,122,607 jurisdictional), O&M expenses of $5,201,011 ($4,433,053 jurisdictional), and carrying costs of $53,620,827. We also approve the projected 2010 LNP recovery amount of $164,176,487.

PEF's Total Recoverable Amount for the 2010 CCRC

In its petition and supporting testimony, PEF has proposed a rate management plan designed to decrease the rate impact that would otherwise occur if the entire approved nuclear cost recovery amount were to be included in 2010 rates. In its brief, PEF urged us to approve PEF's alternative cost recovery schedule due to both the current economic climate and to provide the ratepayer some immediate relief. PEF has proposed to defer certain site selection and preconstruction costs approved for recovery through the NCRC, and collect those costs over the next five years. Under PEF's proposal, a carrying charge would be applied to the deferred balance pursuant to the Statute and Rule. PCS Phosphate supported approval of a rate management plan, provided the 2009 preconstruction costs to be deferred are deemed reasonable. No other party took a position on this issue in their post-hearing briefs.

We agree that PEF's proposed rate management plan could provide relief to ratepayers by decreasing rate impact during 2010 and that PEF shall be permitted to defer recovery of costs that have been approved for recovery through the NCRC. However, while PEF's proposal suggests recovery of the deferred balance over a five-year period, we find that greater flexibility to manage rates shall be retained and that PEF shall be permitted to annually reconsider changes to the deferred amount and recovery schedule. Our approval of PEF's rate management plan requires PEF to file rate management plan testimony and schedules with its annual NCRC final true-up, estimated true-up, and projection testimony.

Consistent with our previous decisions herein, we find that the deferred balance shall be treated as a regulatory asset with a carrying charge applied pursuant to Section 366.93(1)(f), F.S., and Rule 25-6.0423(5)(a), F.A.C.

PEF's updated position includes a proposed deferral amount of $273,889,606. This amount would be the 2010 beginning balance of a regulatory asset. As revised, PEF's plan includes recovery of $36,618,113 of that regulatory asset during 2010. PEF proposes to recover the entire regulatory asset by 2014.

Therefore, we approve a rate management plan whereby PEF will be permitted to defer recovery of certain approved site selection and preconstruction costs and then collect those costs during subsequent years. The deferred costs shall be treated as a regulatory asset with carrying charges applied pursuant to Section 366.93(1)(f), F.S., and Rule 25-6.0423(5)(a), F.A.C. We approve $273,889,606 as the January 1, 2010, beginning balance of the regulatory asset with $36,618,113 of that balance being approved for inclusion in rates in 2010.

We next consider the question of what is the total jurisdictional amount to be included in establishing PEF's 2010 Capacity Cost Recovery Clause factor. This issue is a fall-out issue reflecting decisions on all prior issues that impact PEF's level of recovery in 2010. Based on our discussion above, we approve $206,907,726 to be included in establishing PEF's 2010 CCRC factor. Below is a chart depicting the approved total jurisdictional amount to be included in establishing PEF's 2010 Capacity Cost Recovery Clause factor:

Topic	PEF	Approved Adjustments
CR3 2008 Final True-up	$43,006	
CR3 2009 Estimated True-up	$6,860,904	$-6,330,689
CR3 2010 Projections	$5,539,905	
LNP 2007 Final True-up	$0	
LNP 2008 Final True-up	$-65,776,048	
LNP 2009 Estimated True-up	$141,665,654	
LNP 2010 Projections	$164,176,487	
Subtotals	$252,509,908	$-6,330,689
Order No. PSC-09-0208-PAA-EI	$198,000,000	
Total Recoverable Amounts	$450,509,908	$444,179,219
PEF's Deferral – 2010 Beginning Balance	$-273,889,606	
Projected 2010 Recovery Schedule	$36,618,113	
Net 2010 Recovery Amount	$213,238,415	$206,907,726

OPC, FIPUG and SACE took no position and did not address this issue in their post-hearing briefs. Therefore, pursuant to the prehearing order, OPC, FIPUG and SACE have waived their positions on this issue. PCS Phosphate provided a post-hearing position that adopts OPC's position, which is no position. However, PCS Phosphate supports PEF's cost recovery proposal to the extent PEF's estimated costs are deemed reasonable.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the stipulations and findings set forth in the body of this Order are hereby approved. It is further

ORDERED that the applicable carrying charge rate on a NCRC regulatory asset that has been deferred from recovery is the pretax AFUDC rate in effect June 12, 2007, as set forth in Rule 25-6.0423, F.A.C. For qualifying projects for which need petitions are submitted after December 31, 2010, the utility's existing pretax AFUDC rate shall be used. It is further

ORDERED that utilities shall not record in rate base the incremental difference between carrying costs established in Section 366.93, F.S., and their respective, most currently-approved AFUDC rate applicable to all other projects, for recovery when the nuclear plant enters commercial operation. It is further

ORDERED that Section 366.93, F.S., establishes a fixed project carrying cost to be applied to all nuclear construction projects with need petitions filed prior to December 31, 2010. It is further

ORDERED that Florida Power & Light Company's 2008 project management, contracting, and oversight controls were reasonable and prudent for the EPU project and for the TP 67 project. It is further

ORDERED that Florida Power & Light Company's 2008 decision to create the potential for additional competitive opportunity through an EP/C contractual approach to the TP67 project was reasonable and prudent. It is further

ORDERED that Florida Power & Light Company shall file updated capital cost estimates in its next annual NCRC filing. It is further

ORDERED that Florida Power & Light Company's 2008 actual, 2009 actual/estimated and 2010 projected EPU project costs are separate and apart from the nuclear costs that would have been necessary to provide safe and reliable service had there been no EPU project. It is further

ORDERED that Florida Power & Light Company is hereby authorized to include the nuclear cost recovery amount set forth herein to be used in establishing its 2010 capacity cost recovery factor. It is further

ORDERED that during 2008, Progress Energy Florida, Inc.'s project management, contracting, and oversight controls were reasonable and prudent for the Levy Units 1 & 2 and Crystal River Unit 3 Uprate projects. It is further

ORDERED that the timing of Progress Energy Florida, Inc.'s decision to execute an EPC contract at the end of 2008 was reasonable. It is further

ORDERED that this Commission makes no findings at this point regarding prudence concerning the actual terms and conditions contained within the EPC contract executed by Progress Energy Florida, Inc. It is further

ORDERED that a rate management plan whereby Progress Energy Florida Inc. will be permitted to defer recovery of certain approved site selection and preconstruction costs and then collect those costs during subsequent years is approved. The deferred costs shall be treated as a regulatory asset with carrying charges applied pursuant to Section 366.92(1)(f), F.S., and Rule 25-6.0423(5)(a), F.A.C. It is further

ORDERED that Progress Energy Florida Inc. is hereby authorized to include the nuclear cost recovery amount set forth herein to be used in establishing its 2010 capacity cost recovery factor.

By ORDER of the Florida Public Service Commission this 19th day of November, 2009.

ANN COLE
Commission Clerk

By: Dorothy E. Menasco
Dorothy E. Menasco
Chief Deputy Commission Clerk

(S E A L)

KY

DISSENTS BY: COMMISSIONER ARGENZIANO

COMMISSIONER ARGENZIANO dissents except on the following issues: *Carrying Charge Rate on Deferred Balances and Recognition of Different AFUDC Rate.*

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

APPROVED STIPULATED ISSUES

Policy and Legal - Category II Stipulated Issue among FPL, PEF, and Our Staff

ISSUE 1: **Should over or under collections in the Capacity Cost Recovery Clause be included in the calculation of recoverable costs in the NCRC?**

STIPULATION: No. Rule 25-6.0423 defines the appropriate costs to be recovered in the NCRC. That definition does not included CCRC over or under collections. Over and under collections in the CCRC should remain in the CCRC, because they are the result of over/under collections of actual sales revenues that are greater than or less than costs to be recovered in the CCRC, and will incur interest at the commercial paper rate. Prospectively, if the Commission approves deferral of collection of certain NCRC costs and thereby removes them from rates, they should not be reflected in the Capacity Cost Recovery Clause over or under recovery. Differences between the NCRC actual costs incurred and the actual/estimated or projected costs will be included in the calculation of recoverable costs in the NCRC, and will accrue a carrying charge at the fixed rate provided for pursuant to Section 366.93, F.S., until recovered in a future period.

Florida Power & Light Company - Category II Stipulated Issues between FPL and Our Staff

ISSUE 4: **Should the Commission find that for the years 2006 and 2007, FPL's accounting and costs oversight controls were reasonable and prudent for the Turkey Point Units 6 & 7 project?**

STIPULATION: For the years 2006 and 2007, FPL's accounting and costs oversight controls were reasonable and prudent for the Turkey Point Units 6 & 7 project.

ISSUE 5: **Should the Commission find that for the years 2006 and 2007, FPL's project management, contracting, and oversight controls were reasonable and prudent for the Turkey Point Units 6 & 7 project?**

STIPULATION: Yes. For the years 2006 and 2007, FPL's project management, contracting, and oversight controls were reasonable and prudent for the Turkey Point Units 6 & 7 project.

ISSUE 6: **Should the Commission find that for the year 2008, FPL's accounting and costs oversight controls were reasonable and prudent for the Turkey Point Units 6 & 7 project and the Extended Power Uprate project?**

STIPULATION: Yes. For the year 2008, FPL's accounting and costs oversight controls were reasonable and prudent for Turkey Point Units 6 & 7 project and the Extended Power Uprate project.

ISSUE 9: **Should the Commission approve what FPL has submitted as its annual detailed analyses of the long-term feasibility of completing the EPU project, as provided for in Rule 25-6.0423, F.A.C.?**

STIPULATION: Yes. The analyses support a conclusion that completing the EPU project is feasible.

ISSUE 10: **What system and jurisdictional amounts should the Commission approve as FPL's final 2008 prudently incurred costs for the Extended Power Uprate project?**

STIPULATION: The 2008 prudently incurred system EPU costs are $99,754,304 in expenses and $269,184 in O&M expenses. The resultant jurisdictional costs, net of joint owner and other adjustments, are $95,097,049 for capital expenses, $2,357,995 in carrying charges, and $256,091 in O&M expenses.

For purposes of the CCRC, the final 2008 NCRC true up amount, is an over estimate of $1,375,009 in carrying costs plus an under estimate of $256,091 in O&M expenses. The net amount of -$1,118,918 should be included in setting the allowed 2010 NCRC recovery.

ISSUE 14: **What system and jurisdictional amounts should the Commission approve as FPL's final 2006 and 2007 prudently incurred costs for the Turkey Point Units 6 & 7 project?**

STIPULATION: The 2006 and 2007 prudently incurred system Turkey Point Units 6 & 7 costs are $8,651,370 ($8,615,263 jurisdictional) in expenses and $0 in O&M expenses. The resultant jurisdictional carrying costs are $155,189.

For purposes of the CCRC, the final 2007 NCRC trueup amount, is an over estimate of $304,739 in expenses and $7,216 in carrying costs. The net amount of -$311,955 should be included in setting the allowed 2010 NCRC recovery.

ISSUE 15: **What system and jurisdictional amounts should the Commission approve as FPL's final 2008 prudently incurred costs for the Turkey Point Units 6 & 7 project?**

STIPULATION: The 2008 prudently incurred system Turkey Point Units 6 & 7 costs are $47,215,633 ($47,049,854 jurisdictional) in expenses and $0 in O&M expenses. The associated 2008 jurisdictional carrying costs are $2,886,482.

For purposes of the CCRC, the final 2008 NCRC true up amount, is an over estimate of $22,658,001 in expenses and $1,171,701 in carrying costs. The net amount of -$23,829,702 should be included in setting the allowed 2010 NCRC recovery.

Progress Energy Florida, Inc. - Category II Stipulated Issues between PEF and Our Staff

ISSUE 19: **Should the Commission find that for the years 2006 and 2007, PEF's accounting and costs oversight controls were reasonable and prudent for the Levy Units 1 & 2 project?**

STIPULATION: Yes. For the years 2006 and 2007, PEF's accounting and costs oversight controls were reasonable and prudent for the Levy Units 1 & 2 project.

ISSUE 20: **Should the Commission find that for the years 2006 and 2007, PEF's project management, contracting, and oversight controls were reasonable and prudent for the Levy Units 1 & 2 project?**

STIPULATION: Yes. For the years 2006 and 2007, PEF's project management, contracting, and oversight controls were reasonable and prudent for the Levy Units 1 & 2 project.

ISSUE 22: **Should the Commission find that for the year 2008, PEF's accounting and costs oversight controls were reasonable and prudent for the Levy Units 1 & 2 project and the Crystal River Unit 3 Uprate project?**

STIPULATION: Yes. For the year 2008, PEF's accounting and costs oversight controls were reasonable and prudent for Levy Units 1 & 2 project and the Crystal River Unit 3 Uprate project.

ISSUE 24: **Should the Commission approve what PEF has submitted as its annual detailed analysis of the long-term feasibility of completing the Crystal River Unit 3 Uprate project, as provided for in Rule 25-6.0423, F.A.C.?**

STIPULATION: Yes. The analyses support a conclusion that completing the Crystal River Unit 3 Uprate project is feasible.

ISSUE 25: **What system and jurisdictional amounts should the Commission approve as PEF's final 2008 prudently incurred costs for the Crystal River Unit 3 Uprate project?**

STIPULATION: The 2008 prudently incurred total system costs are \$65,137,303 for capitalized expenses and \$180,076 in O&M expenses. The resultant jurisdictional costs are \$43,898,888 for capital expenses, \$6,133,922 in carrying charges, and \$166,588 in O&M expenses. For purposes of the CCRC, the final 2008 NCRC trueup amount, is an under estimate of \$64,444 in carrying costs plus an over estimate of \$95,044 in O&M expenses plus an under estimate of \$73,606 for base rates associated with a completed phase of the project. The net amount of \$43,006 should be included in setting the allowed 2010 NCRC recovery.

ISSUE 27: **What system and jurisdictional amounts should the Commission approve as PEF's reasonably projected 2010 costs for the Crystal River Unit 3 Uprate project?**

STIPULATION: A reasonable projection of 2010 system Crystal River Unit 3 Uprate costs are \$49,872,156 for capitalized expenses and \$244,268 in O&M expenses. The resultant jurisdictional costs, net of joint owner and other adjustments, are \$58,380,739 for capital expenses, \$5,325,702 in carrying charges, and \$214,203 in O&M expenses. The net amount of \$5,539,905 should be included in setting the allowed 2010 NCRC recovery.

ISSUE 28: **What system and jurisdictional amounts should the Commission approve as PEF's final 2006 and 2007 prudently incurred costs for the Levy Units 1 & 2 project as filed in Docket No. 080009-EI?**

STIPULATION: The 2006 and 2007 prudently incurred system Levy Units 1 & 2 project costs are \$87,406,779 (\$71,828,329 jurisdictional) in expenses and \$707,867 (\$547,473 jurisdictional) in O&M expenses. The resultant jurisdictional carrying costs are \$2,965,965.

Mr. Small has testified that there are three methodologies to allocate costs for the Lybass parcel, and that PEF has used one of those methodologies to make that allocation. Mr. Small does not testify that one methodology is preferable to any other methodology.

The final true up of \$19,780,695 was included in setting PEF's 2009 NCRC recovery amount. Consequently, the net true up amount of \$0 should be used in setting the allowed 2010 NCRC recovery amount.

ISSUE 29: **What system and jurisdictional amounts should the Commission approve as PEF's final 2008 prudently incurred costs for the Levy Units 1 & 2 project?**

STIPULATION: The prudently incurred 2008 system Levy Units 1 & 2 project costs are \$155,306,978 (\$138,609,648 jurisdictional) in expenses and \$4,167,550 (\$3,784,810 jurisdictional) in O&M expenses. The associated 2008 jurisdictional carrying costs are \$20,717,072.

For purposes of the CCRC, the final 2008 NCRC true up amount is an over estimate of \$65,763,507 in expenses plus an under estimate of \$2,305,178 in O&M expenses plus an over estimate of \$2,317,719 in carrying costs. The net amount of -\$65,776,048 should be included in setting the allowed 2010 NCRC recovery.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Cost Recovery Clause

DOCKET NO. 090009

Submitted for filing:
August 10, 2009

REDACTED

~~CONFIDENTIAL~~

REBUTTAL TESTIMONY OF JEFF LYASH

**ON BEHALF OF
PROGRESS ENERGY FLORIDA**

[redacted] Now, however, finalization of any joint ownership participation agreement will, again, depend on the costs and schedule in the amended EPC agreement. We expect to reach joint ownership participation agreements only after we have an amended EPC agreement.

Q. Are the impacts of the economy on the capital markets, financing, and regulatory and legislative uncertainty risks that the Company has considered and will consider in making its decisions with respect to the LNP?

A. Yes. These risks were identified by management as part of the Company's risk management practices and policies, there were risk mitigation strategies developed for these risks, and those strategies have been employed by the Company throughout the course of the LNP so far. Notably, neither the Staff witnesses nor the intervenor witnesses assert that PEF's risk management practices and policies, or PEF's application of those policies with respect to the risk mitigation strategies the Company developed, are not reasonable or not prudent.

These risks cannot be eliminated; they can only be monitored and managed with appropriate responsive risk mitigation strategies. These risks also exist, however, for any generation or other utility project and certainly they exist for any long term, base load generation project like the LNP. It is unreasonable to expect a utility to eliminate these risks or obtain certainty with respect to these risks for a nuclear power plant project. If that was the expectation, no utility would build a nuclear power plant.

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In re: Nuclear Cost Recovery Clause

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Non-Confidential Excerpts

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issued in accordance with PEF's requested schedule. The only reasonable reading of this language is that the specifically requested dates for the FEIS, LWA, and COL that PEF requested might slip by weeks or a few months. But, nothing in that letter could be reasonably interpreted as suggesting that the NRC was not going to issue a LWA at all. That is the way PEF interpreted the October 6, 2008 docketing letter.

Q. The intervenors also reference the NRC's statements about the complexity of the site characteristics in this October 6, 2008 letter and the NRC's request for additional information as reasons for concern regarding the Company's LWA request. Do you agree?

A. No. It is important to remember that the purpose of the NRC's review of the Company's COLA is the application of the AP1000 nuclear power plants to the specific Levy site. NRC review of the AP1000 design itself is already underway under a separate reference COLA. As a result, the NRC will focus its review of the PEF COLA on the site characteristics to determine how that AP1000 design for the nuclear power plants will actually be built on the Levy site. This review requires the NRC to ask geotechnical questions through RAIs. The fact that the NRC issues RAIs means the NRC is doing its job. It does not mean the NRC has "doubts" or "concerns" --- or that there were problems with the Company's COLA or LWA --- in the way the intervenor witnesses seem to use these words.

The mere fact that the NRC was asking geotechnical questions and questions about the site characteristics does not mean that the NRC was not going to issue the LWA. To the contrary, by docketing the Levy COLA, including the LWA, the NRC indicated that it believed the application was technically sufficient to indicate that the AP1000 design could in fact be applied to the Levy site despite the complex geotechnical and site characteristics. The NRC would not have docketed the PEF COLA if the NRC had "serious doubts" or "concerns" about building the AP1000 nuclear power plants on the Levy site because of the site geology or other site characteristics.

The fact that the NRC acknowledged the complexity of the site also does not mean there was a problem with PEF's COLA or LWA. Designing, engineering, and building nuclear plants is complex; however, it has been done numerous times in the past, including on many "Greenfield" sites, and there are five nuclear power plants operating for decades in Florida today that were built on complex sites, including the one at Crystal River within 10 miles of the Levy site and closer to the coast. PEF addressed the Levy site complexity in a detailed geotechnical review to arrive at the site sub-foundation and foundation design that took eighteen (18) months to complete. Under its requested timeline, PEF provided the NRC approximately thirty (30) months to review and issue the LWA. This was, in PEF's view, more than enough time to review all the information that PEF had developed in eighteen (18) months and issue a decision.

Before January 23, 2009, the NRC never said that the geotechnical review scope required the same duration for the LWA review as the COL review. In fact, the NRC never said on January 23, 2009 that the site complexity or geotechnical questions alone meant the LWA could not be issued. Rather, the NRC linked the review of the geotechnical scope to the NRC's lack of resources to process the LWA sequentially rather than concurrently with the COL. See Exhibit WRJ(PEF)-3, p. 28 of 233. There is no dispute that this was the first time that the NRC had stated that lack of resources would cause a lengthy delay in processing PEF's LWA request. More important, given that PEF was able to complete its geotechnical analysis in eighteen months, there was no reason for PEF to believe at the time it executed the EPC agreement that lack of NRC resources would necessitate such a long delay in processing the LWA.

Q. Was there some reason to expect PEF's requested review schedule was in jeopardy because the NRC did not issue the review schedule thirty days after the PEF COLA was docketed on October 6, 2008?

A. No. The NRC in fact told us in that letter that the NRC was not going to issue the review schedule until the NRC received additional information from the Company. The October 6, 2008 letter included RAIs that were answered by the Company on November 20, 2008. So, there was no reason to expect a review schedule from the NRC before November 20, 2008 or some reasonable time after that date to allow the NRC time to review the additional information and develop a review schedule. At that point, however, the release of the review schedule by the NRC was impacted by the holidays; it had nothing to do with the substance of PEF's requested review schedule. Even Jacobs, OPC's expert, agreed that there is no NRC requirement to issue a review schedule thirty days after the COLA is docketed, no NRC statement voluntarily committing to such a release schedule,