BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: NUCLEAR POWER PLANT COST RECOVERY CLAUSE

Docket No. 090009-EI

ATTACHMENT B

COM
ECR I
GCL
OPC
RCP
SSC
SGA
ADM
CLK

14849571.1

DOCUMENT NUMBER-DATE
08392 AUG 12 8
FPSC-COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 090009EI

FILED: June 26, 2009

--X

IN RE: NUCLEAR COST RECOVERY CLAUSE.

--X

PLACE: 4221 W. Boy Scout Blvd., Suite 1000
Tampa, Florida

DATE: July 10, 2009

TIME: 1:37 p.m. - 3:45 p.m.

REPORTED BY: Robert A. Dempster
Registered Professional Reporter

DEPOSITION OF JON FRANKE

Pages 1 - 83

DEMPSTER BERRYHILL & ASSOCIATES
1875 NORTH BELCHER ROAD, SUITE 102
CLEARWATER, FLORIDA 33765
(727) 725.9157

APPEARANCES

CHARLES REHWINKEL, ESQ.
OFFICE OF PUBLIC COUNSEL
ASSOCIATE PUBLIC COUNSEL
111 West Madison Street, Room 812
Tallahassee, Florida 32399-1400
Attorney for Citizens of the State of Florida

DIANE TRIPPLETT, ESQ. & MICHAEL WALLS, ESQ.
CARLTON FIELDS LAW FIRM
4221 W. Boy Scout Blvd, Suite 1000
Tampa, Florida 33600
Attorney for Progress Energy

JAMES BREW, ESQ.
Brickfield, Burchette
1025 THOMAS JEFFERSON ST. NW,
8th Floor, West Tower
Washington DC 20007

Attorney for

JOHN BURNETT, ESQ.
PROGRESS ENERGY SERVICE COMPANY, LLC
P. O. Box 14042
St. Petersburg, Florida 33733-4042

Attorney for Progress Energy Service Company

JON MOYLE, JR., ESQ. (Telephonically)
FLORIDA INDUSTRIAL POWER USERS GROUP
118 N. Gadsden Street
Tallahassee, Florida 32301

KEINO YOUNG, ESQ. (Telephonically)
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

JAMIE WHITLOCK, ESQ. (Telephonically)
GARY A. DAVIS & ASSOCIATES
1720 S. Gadsden Street MS 14, Suite 20
Tallahassee, Florida 32301

PROCEEDINGS

Thereupon:

JON FRANKE

was called as a witness and having been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. REHWINKEL:

Q Can you state your name --

MR. REHWINKEL: First of all, before we get started with the questions, I talked to counsel for Progress Energy and I think that the questioning in this deposition, at least from what I'm going to be working from, will not involve much confidential information. There are some documents that may have confidential information, but I think it would be a prudent course of action for us to ask the questions, and among the witness and his counsel, ask them to be on guard for any information that might be confidential and alert us at that time, rather than all of the deposition confidential. So we'll work on an exception basis that it is not confidential unless we specifically identify some of that information.

For that reason, I don't know that we really need to go through the qualifying of the confidentiality, the participants. We can deal with that when we get to it.

BY MR. REHWINKEL:

Q So, if you would, Mr. Franke, state your name and employer for the record.

A My name is Jon Albert Franke and my employer is Progress Energy Florida.

Q And are you the Jon Franke who filed direct testimony on May 1st in docket 090009?

A That is correct.

Q And you also are adopting the direct testimony of Steve Huntington that was filed on March 2nd in the same docket?

A That is correct.

Q At this time do you know of any changes or corrections to your testimony or the testimony you've adopted?

A No.

Q Would you just give me a run through of your educational and employment background starting with your educational background first.

A Yes. I'm a graduate of the US Naval Academy in Annapolis with a mechanical engineering degree.

I also have a master's degree from the University of Maryland in mechanical engineering, and master's of business administration from the University of North Carolina at Wilmington.

Additionally in conjunction with this testimony, it's probably worth me mentioning also have held a senior reactivator operator license from the Nuclear Regulatory Commission, not for Crystal River 3 but for a different power plant.

I was employed by the US Navy until 1991, and in that role, in that -- held various positions as a junior officer on destroyers and nuclear aircraft carriers including supervising the direct operation of a two-unit nuclear propulsion system for aircraft carriers.

I joined Carolina Power and Light in 1991 as an engineering supervisor and held various roles in operations, project management and engineering until 2002.

I left the Brunswick Nuclear Plant which is where I had been stationed since 1991 as the engineering manager, and since that time I've been assigned to the Crystal River Nuclear Plant after the formation of Progress Energy when Carolina Power and Light and Progress Energy merged.

And since 2002, I've served as the plant manager, director of site operations, and now fairly recently been promoted to vice president of that station.

Q What station is that?

A Crystal River Nuclear Plant.

Q And who do you report to?

A I report to Jim Scarola, the Chief Nuclear Officer and Senior Vice President for Nuclear Generation Group.

Q What caused you to have to adopt Mr. Huntington's testimony?

A Mr. Huntington no longer works for Progress Energy. He's looked in the industry for other work right now.

Q How would you contrast your job today from what Mr. Huntington did? What are the differences?

A Mr. Huntington was the manager of major projects, and in that role he was in direct supervision of the project management aspects of this up rate project for Crystal River three. In my previous role at the time I adopted the testimony prior to my May 1st filing, I was director of site operations for the station, and Mr. Huntington and his projects reported indirectly to me as the on-site manager over those projects. They directly reported to the vice president of nuclear engineering, but for purposes of implementation of those projects they reported to my position as the director of site operations.

And that continues today in my new role as vice president of the station. My former position of director of site operations is currently vacant; therefore, those responsibilities are still mine.

Q In your current position and your immediately previous position, director of site operations, CREC or CR3 --

A Crystal River 3.

Q Okay. Did you have occasion to interact with the NRC staff?

A Yes, on numerous occasions, almost daily I see an NRC resident inspector.

Q Would you have reason to interact with NRC staff other than the resident inspector or an NRC inspector?

A Yes. We have made trips with regard to issues in this testimony involved with the extended power operating license activities in DC and I've attended those trips.

Q Do you interact with the NRC with respect to operations and operator licensing?

A Yes, I do.

Q What about operating reactor licensing?

A Yes, for licensing changes to the existing facility at Crystal River 3 I have interacted with the NRC concerning those opportunities. And I would also add I interact with NRC inspectors who come to the facility who may not be residents, inspecting a particular field of operation or maintenance of the facility.

Q Okay. Now, the operator reactor licensing interaction, would that be related to any licensing of uprate activities?

A No. Operator licensing activities are specifically activities licensing individuals who are going to individually be given an individual license for their use as employee of the company operating the reactors.

Q But your operating reactor licensing activities, interactions with the NRC staff, would be related to the uprate licensing?

A That is correct. That is the activities that are ongoing with the NRC concerning maintaining the plant to operate under the license the NRC has given us to operate the facility.

Q Okay.

A And note that license gets changed and that causes interactions.

Q Now, any interactions with the NRC staff relating to operating reactor licensing, would those have been necessary before you started the uprate process?

A They are ongoing since the original licensing of the plant. So the operating license activities occur every year for a vast array of reasons.

Q Now, what kind of approval do you need to get from NRC to do the uprates?

A Fundamentally, there are portions of the uprates that require the actual power generated by the reactor to be increased. We are currently licensed to operate the reactor at 2609 thermal megawatts. In order to execute the final phase of the uprate for Crystal River 3, we will be asking the NRC to increase that thermal rating of the reactor to over 3,000 megawatts thermal.

Q You said over 3,000?

A Yes.

Q Now, with respect to the uprate process, what kind of interactions do you have with the NRC staff?

A Directly myself I have been involved with managing the employees who prepare and submit the licensing application requests, or LARs, that will be required in order to increase the reactor output, as well as I have attended, I believe, two meetings in the last year-and-a-half in Washington DC speaking with the technical staff of the NRC to support their reviews and our efficient submittal of those licensing documents.

Q I'd first like to get you to turn to your testimony filed on May 1st. And if I could ask you to turn to page three. Actually I apologize, get you to turn to page four. Starting on line 16, page four through line 14 at page five, you use the terms "reasonable and prudent" several times, and I just would like to ask you if you could first give me a definition of reasonable as you intended in this testimony.

A In this testimony I consider reasonable to be costs that would be expected and controlled in a manner that minimized costs but can achieve the result required.

Q How about the word "prudent?"

A Prudent means that in my mind it is proper and wise to spend that money because the result would be a good result for the customer at the time knowing the information that you have at the time.

Q Okay. How does the concept of risk management play into the definition of either of those terms?

A Risk management is the understanding of uncertainty involved with the project, minimizing that uncertainty and weighing it in when you're making your decision, be they both prudent and reasonable.

Q Just so I understand, on page five of your testimony starting on line seven on down through line 14, you are asking for the commission to approve costs from January to March of 2009, costs incurred as well as projections for the remainder of 2009 and all of 2010. Is that correct?

A That is correct.

Q And your basis for approval is that the costs are reasonable?

A That is correct.

Q So the definition you gave me as to reasonable applies to these costs?

A Yes.

Q And that's because the commission is not making a final determination as to prudence for these particular costs for these periods; is that right?

MS. TRIPPLETT: Object to the form.

THE WITNESS: I would not know what the commission is doing. That's not in my purview.

BY MR. REHWINKEL:

Q Are you asking the commission to make a determination of prudence as to these costs, or just as to reasonableness?

MS. TRIPPLETT: Object to the form.

Answer if you can.

THE WITNESS: I believe I am.

BY MR. REHWINKEL:

Q As to prudence?

A I'm here to speak to the costs and my belief that they're reasonable and prudent.

Q Okay.

A I did not file the -- well, as filed in the testimony, I believe they're reasonable and prudent.

Q Okay.

Let me ask you to turn, if you would, to page 14 of your testimony. Here starting on line ten through page 17, it seems you are asking the commission to -- well, you're providing testimony on the feasibility of completing the uprate project; is that correct?

A That is correct.

Q Can you give me a definition as is intended in your testimony as to what feasible means.

A I believe feasible means that it is reasonable to expect that the end result of the uprate or the goals of the uprate can be achieved, and based on the current status of the technical and licensing requirements to meet that objective, we believe that it is reasonable to expect that it is feasible to complete the uprate, meaning the goals that we set forth.

Q Okay. Does cost have a role in feasibility determination?

A I think the word feasible alone means can the task be achieved.

Q Does it mean it can be achieved without respect to what it costs?

A Well, in my testimony I talk a lot about costs and I give the best information available with regard to what the costs should be, and if you're asking me if it is feasible to achieve it at that specific cost, I would say that the cost estimates in the testimony are those best available today. Those costs may go up or may go down some.

Q Well, starting on line 13 -- well the question starting on line 13 and continuing on line 18, those two questions --

MS. TRIPPLETT: Are you on page 14?

MR. REHWINKEL: Yes, I'm still on page 14.

BY MR. REHWINKEL:

Q You referenced the integrated project plan or IPP dated March 2nd --

A Yes.

Q -- is that right?

A Yes.

Q In the second question there starting on line 18 on page 14, the question poses is the CR3 uprate project's completion feasible.

A That is correct.

Q And you say that, yes, as reflected in the update IPP?

A Yes.

Q On page 14 -- page 15 up at the very top, can you read out loud those two sentences on lines one and four and tell me what they mean to you.

A Lines one to four?

Q One through four.

A Yes. "Updated cost estimates are provided in the IPP for both capital and operating and maintenance, O and M, costs. The total current cost estimates remains bounded by the initial business analysis package for the project issued November 10th, 2006."

Q Now, the business analysis package, is that the old version of the IPP?

A I don't know the exact transition in the language between how we got from '06 to today's process, but there were many elements in the old business analysis package that is now incorporated in the IPP process.

Q Okay. But these sentences here refer to costs, and you're saying essentially that the costs are consistent with the original business analysis package?

A Yes. I have not referred to the business analysis package for sometime. I would prefer checking before knowing for certain, but I believe actually the latest IPP costs are below the originally business analysis package by a fairly good margin.

Q Okay. On the next paragraph on page 15 you mention that the IPP includes potential risks and strategies for managing the risk with respect to the uprate; is that right?

A Yes, that is correct.

Q And you say there that there is -- on line seven and eight -- "that there is no indication of any risks that would affect the project's feasibility."

A That is correct.

Q Is your testimony there that there aren't any risks, or that there aren't any risks that you can't manage such that you can accomplish this in a feasible manner?

A The purpose of that sentence is to say we believe now, knowing what we know now, that we see no risks that would prevent implementation of the project that there's a lot of ways to measure the project's success. In this case it's to complete the uprate and to implement the uprated power level at the facility.

Q And in the next paragraph, and specifically on line 17 through 19, you state that you plan to file a license amendment request for the EPU in the fall of 2009; is that right?

A Could you ask that again, please?
Q Yes. On line 17 through 19, you state that you plan to file a license amendment request for the EPU in the fall of 2009.
A That is correct.
Q Is that still your expected filing date?
A We're continuing to evaluate when that submittal will be provided to the NRC. We are confident that it will be submitted well in time to support the uprate into 2011.
Q Is there some thinking at this time that it may not be filed in the fall of 2009, the license amendment request?
A Right now we believe it will be filed in the fall of 2009, depending on how some internal reviews go. We know that the latest it really needs to be filed is probably the summer of 2010.
Q What type of internal reviews are you referring to?
A We have ongoing assessment of the current status being performed both by my internal engineering group, and we've brought a number of external peers and consultants to review the status so that we can get the best opportunity for success with that submittal. And without knowing what the

results of those reviews are, as we get those results of those reviews, we'll reflow the work required to provide that submittal.

Q Okay. Now, you did an IPP in March of 2009 for this project?

A That's correct.

Q Are these internal reviews discussed in this IPP?

A I don't remember.

Q Could you just take a second.

A Let me take a minute and take a look at it.

Q Please. And I'm looking at document OPCPOD1-4-000001, which is the Crystal River unit 3 extended power uprate integrated project plant dated March 2nd, 2009.

A I have that document in front of me.

(Pause.)

Q While your reviewing that, if I could ask you, since the comment that I referred you to is considered confidential, please be conscious of whether anything you say to me reflects confidential information.

A All right. I will. Thank you.

(Pause.)

I found one location where there is a discussion under the risk category for NRC approval of licensing activities.

Q Can you refer me to the page.

A That's page 18 of 26. There's actually two items that appear to be dealing with the licensing activities. One is risk number 229 on the table at the top of page 18 of 26. Actually, that is not -- I'm sorry -- that is not dealing with licensing activities. It's the next one. I believe -- it's difficult to read the number, but it's AIMS (phonetic) number 1009, and then the risk number looks like it's -- I want to say that's 253 I'm just trying to figure out why it's out of order, but it's 253.

It says: "If the NRC approval of REA methods is not received before June of 2009, then it would delay the EPU LAR's submittal and subsequently its approval.

Q Can you tell me what that means.

A Yes. And I can give you an update from this schedule date.

In order for the NRC to approve our extended power uprate license amendment request, which we are currently working on and I discussed being reviewed by outside peers and my engineering staff, there was a change in method of a specific engineering analysis that needed to be reviewed by the NRC. So this risk was not a -- it's characterized in the risk matrix but it was really a risk of delaying NRC's approval of that subsequent extended power uprate amendment request.

The submittal that we're talking about has been submitted. It is in review. It is July now and we have not received the NRC review of that submittal, but they are in the process of writing up their safety evaluation report, which is their legal document and technical document that accepts our license amendment request. That does not mean we know we will receive it, but it means they are writing up their receipt of it. We have good confidence that we will receive the answer that this methodology is acceptable.

This would have delayed our submittal of the extended power uprate if we had intended to submit it before today. As I just testified, we don't need to submit it for some time. We have a lot of margin on that schedule. I think what's important with regard to this risk to understand is that we need the license amendment request prior to increasing the actual reactor power, which is at the end of my 2011 outage. And any delay beyond that would only delay when we could actually achieve the megawatts. It would not stop any other activity associated with the extended power uprate.

The NRC has a commitment through their processes to review and either approve or deny any submittal within a -- well, essentially it's 12 months after they accept the application. Their procedures allow up to a month to accept the application.

So even a submittal as late as, let's say July, 2010 would mean we would expect at the latest an approval, should that submittal be accepted, by early September, 2011 before the outage even started. So there's quite a bit -- many months of margin in this schedule. This risk was characterized as -- I can't see what it is. The risk green -- and the reason for that is the consequences of this appears to be very low. It looks like there's a G over a green, but it's a low risk.

Q The rank there, is that a six?

A That may be a 6. Is that a 6? That's a 6. But it is not a high risk; it's a low risk.

Q While we are on this, what is the scale for risk in this?

A Well, I believe they have inserted a table different from -- that may come from a different tracking mechanism. In this case the risk of it occurring would likely be in a medium, but the consequences are very low. So under the way the IPP characterizes risks on the table of page 15 of 26, this would be a green risk activity in my mind.

Q Okay. Now, when we first started talking about the internal review, you said -- I think you used the term "a number of factors." I could be wrong. Is this the only thing that would cause you to do the internal reviews, this item 253?

A No.

Q What would some of the others be?

A It's part of our process. Your specific question before I reviewed this, by the way, was: does this IPP talk about our reviews of the license amendment request.

Q That's correct.

A And I wasn't sure of that. Just to let you know, I do not see anything in specific that talks about that detail in this IPP.

Q Okay.

A But that is a detail I would have been surprised to have been in the IPP.

Q So does that suggest then that there are factors or circumstances that have occurred since the preparation of this IPP that are causing you to do the internal reviews?

A No. No. The internal reviews have long since been part of our license amendment request process. It's a rather rigorous approach from the vendor's information to acceptance and review of that vendor information by our own engineering and licensing staff personnel. The development of the language, working in this case with AREVA because the information is so tied to their information about the basic design of the facility, and then once our engineers review it, because this submittal is fairly large and very complicated and crosses a large number of technical areas, we chose to bring in an outside assessment -- I say an outside assessment -- a self assessment of that license amendment request to include personnel that had experience with these types of submittals. So that review process -- I think the added use of as large a number of external peers is unusual for a license amendment request, but certainly not unusual for this type of license amendment request because of its size and the technical depth it went into. But there was nothing knew we have learned. It's part of our process.

Q When did you bring in the external peers?

A I believe they arrived in the last few weeks.

Q Can you tell me who they are.

A I can get you those names.

Q Let me just ask for a Late File Number 1. Late File Deposition Exhibit Number 1.

And this would be --

A I know some names but I don't know them all.

Q Okay. This would be the external review peers for the L-A-R. Is that good enough? Do you know what I'm looking for?

A Yes, I know exactly what you're looking for.

Q Okay. Would there be some sort of a document or a memo where you're describing what you want them to do, or a work authorization, or something like that that would be related to this work activity?

A I'm uncertain as to what document that they started to work with.

Q It would be likely then for a vendor to come in that you would have some documentation that then describes what you want them to do and the price?

A This isn't -- there is some vendor activity with this, but some of these outside peers -- I say outside, I mean outside from Crystal River 3 -- we've also brought in expertise from our other facilities. We have implemented and extended power uprate at the Brunswick units, and I know the licensing staff associated with that submittal from years ago have been brought down as well. This is a team. Some of them are on contract, some of them are from other utilities that would be -- I believe there are some from other utilities. They would not charge us for that work. You know, we help them out, they help us out, and then some of them are from our own other facilities.

Q I guess what I'm looking for is some document that describes kind of the plans, the internal and external review of this L-A-R, and there likely would be something like that, would there not?

A There is likely something like that. I have not seen it.

Q I guess that is Late Filed Number 2. Late Filed Deposition Exhibit Number 2, L-A-R Internal, slash, External Review.

And what I'm looking for is the document that describes the process that you just described that describes -- I guess it outlines, sets out the objectives that you're trying to achieve.

A I understand.

MS. TRIPPLETT: I just want to say for the record that we would produce it to the extent it exists.

MR. REHWINKEL: I understand.

THE WITNESS: We do have procedures for LARS in general. We may just be following that procedure.

BY MR. REHWINKEL:

Q Okay.

We started off talking about page 15, lines 17 through 19 in your testimony.

A Yes.

Q It says -- you say starting on line 18 "That obtaining the regulatory approval from the NRC remains feasible and on schedule." Do you see that?

A Yes.

Q Is that still accurate?

A I believe it is still accurate and so long as the schedule is as required to support the extended power uprate.

Q Okay. So do you mean by that, as long as you get the license amendment prior to the producing the power from the uprate?

A That is correct.

Q Because what you're saying is you don't need any licensing or authorization from the NRC to do the work, it's just to turn up the power?

A Yes, that is correct. And we do not intend to -- we do not expect to turn up the power until after my fall 2009 outage, and there is sufficient margin in the schedule described -- spoken about on line 19 currently to have confidence that we would meet that schedule.

Q You said 2009. Did you mean --

A 2011. The increased power occurs in 2011. That's correct. I'm sorry. Thank you.

Q Okay.

If I could ask you to turn to page 16 of your testimony.

A Yes.

Q And here the question on line seven is asking about your awareness of any major issues with respect to the CR3 uprate.

A Yes.

Q And you identify in this answer, I believe, one. Is that correct?

A There is one issue which is significant in that it might affect the final power and the schedule upon which we increase the power of the plant, and that is in dealing with this issue, yes.

Q That's the DC Cook plant?

A Yes, following the operating experience from DC Cook, yes.

Q Now, what is your definition of major then, I guess I should ask? And the question is you only identified one that would be a major issue. What do you mean by a major issue there?

A It's a significant technical problem to work through and it may impact either the final implementation schedule or the final power rate achieved by the project.

Q Is that in the IPP risk document that we just discussed, PLU risk status report?

A I believe the presentation when this was presented in March went in to management and this was presented and included information concerning the low pressure turbine rotor issue, yes.

Now, I don't know if it's written up in this IPP or not.

Q Okay. Based on the way you just described it in this question and answer on page 16 and 17, is it something that would qualify for then to be included on the PLU risk status report?

A Likely it should be. This risk matrix is a living document. This was a snapshot. So I believe this issue has been put on that risk matrix that we're using today, yes.

Q Okay. Are you familiar with any issue related to LPI Crosstie?

A Yes, I am.

Q Is that considered a major issue?

A No. You mean a major risk issue? No, we do not believe that's a major issue.

Q Could you give me a brief explanation of what the issue is.

A I'll try.

Q Okay.

A I'll do it at the level that I feel comfortable doing.

Q Okay. That's all I can ask.

A There is a specific accident scenario

which has to be evaluated by the NRC that deals with a loss of coolant or a reactor system leak in conjunction with a very specific electrical failure that it has to be postulated under the rule.

At current power levels, the plant designed -- as it is currently designed, it is able to mitigate that accident and meet all of the regulatory requirements.

At the higher power level, we have to make changes. Early in the project there were several options being looked at. The current solution is LPI Crosstie, which is a modification to the facility that we have scheduled for the 2011 outage which installs a section of pipe between our low pressure injection systems inside my reactor building, which with that pipe installed, and a number of valves and control systems would mitigate this accident and meet the design requirements -- we believe would meet the design requirements at the High power level. Why we don't see this as a significant risk is there are several other facilities that have already installed this modification successfully and we understand the capabilities of that modification.

Q Can you name the facility?

A I know that it exists at Oconee.

Q O-C-O-N-E-E?

A Yes. It's a Duke Power facility.

Q Is it a Babcock and Wilcox --

A Yes, it is.

Q -- reactor?

A Yes, it is. They have three units similar to Crystal River 3. I personally have seen the modification at Oconee. I know it is at some others. I am not personally familiar with the other facilities it exists in.

Q Have you had any conversations with NRC about this particular issue?

A I have not personally, but we have spoken with them about this.

Q Have you gotten any feedback from them?

A Their feedback would be preliminary, and I don't want to speak for them. I can say that based on our conversations, we still have confidence that this is a success path.

Q At Oconee, was there a power uprate involved?

A I'm not aware of the conditions under which they installed it at Oconee.

Q Would you be surprised if it was not

associated with a power uprate?

A No, that would not surprise me.

Q What about any other facilities? You said there were several others. Would any of those involve a modification associated with an LPI Crosstie modification based on an uprate?

A I'm not certain of any of the installations as to what drove the installations at those facility. Some of them may have even been installed as original design. I do not know. The way plants are licensed, the rules you live to are a snapshot and those rules change. So a facility licensed after an earlier facility might be under different rules. I believe that may have drove some of these why some plants are different than others.

Q Would you be aware of whether any of the other facilities other than Oconee that where this LPI Crosstie modification was made were B and W reactors?

A I'm only speaking of B and W reactors. This would be a design which would be unique for a B and W reactor.

Q Is it publicly known or in the NRC database as far as whether these modifications were made and where?

A It is possible that they -- well, actually they would be in the publicly -- it is likely the description of this system would exist in their final safety analysis report as updated, their updated FSAR, which is available in public reading rooms. So those facilities, you would be able to find whether this system was installed at those facilities likely by reading those UFSARs.

Q Do you have Mr. Huntington's testimony?

A Yes, I do.

Q Starting on page -- well, actually page 21 of his testimony there's a question and an answer about project risks identified or deemed to have a high probability of affecting the uprated project. Do you see that?

A Yes.

Q Are you familiar with the issue that is identified in this testimony?

A If you're referring to page 21, lines 7 through 18 --

Q That's correct.

A -- the issue at hand was -- and we have a single turbine building crane and a lot of activities that require crane use in the turbine building. So this risk I would characterize as a schedule risk. In other words, not whether or not we could implement the work, but whether or not the schedule -- if there was risk to the schedule being extended in this case due to a crane failure. Since so much activity depended on the crane use, that it needed to be reliable.

In this case we have upgraded the crane. We have done a significant amount of maintenance to the crane. We have looked at crane parts availabilities and validated that vendor support, and our own personnel were well-trained to quickly respond to any crane issues or failures. So we have mitigated the risk of a crane failure to the schedule of the implementation.

What I mean by schedule, I don't mean whether or not we could implement in 2009 and 2011, but whether or not it's a 75-day outage or a 100-day outage. It's duration of the outage is what this was a risk of.

Q Okay. So this was resolved and basically reduced or eliminated as a risk?

A It has been reduced. The risk of having a crane failure have a large impact on schedule has been reduced.

Q Now, is this risk that you talk about --

or what Mr. Huntington talks about on page 21 -- is that analogous to the discussion we talked about in your testimony related to the DC Cook Plant?

A Similar. The DC Cook Plant, as I indicated in my testimony, might affect in a small way -- let me refer to my testimony real briefly.

Q Sure.

A Right. The fundamental difference as described in my testimony on 17, the lines five through eight, the risk of this piece deals with the schedule of when we could expect how many megawatts and whether or not the final megawatt achievement is as high as we predicted. It's a relatively small amount relative to the whole project of megawatts, but it may change the schedule somewhat, and rather than get 180 megawatts out of all three phases, we may get some slightly smaller number. That's the risk here.

Q Do you know what the megawatt amount is that would be your risk?

A At risk? I don't know the specific number, but it is -- I can estimate it in percentage of the total 180 megawatts. It is roughly -- it is less than seven percent of the total megawatts of the whole uprate.

Q All right. Thank you.

I kind of got ahead of the EPU project, but I'd like to go back and talk a little bit about that and help me understand.

The EPU project is being accomplished over two refueling outages; is that right?

A That's correct. And I may be using the language a little fluidly. We did a measurement on recovery which is included in the IPP for the current project. The words extended power uprate typically reflect the work we're doing in phases two and three as an industry. In our IPP for extended power uprate, we included the 2007 scope which was actually what we call a measurement uncertainty recapture uprate, which is an industry language and is technically called an extended power uprate.

Q And just give me an overview of the strategy behind the split of the second and third stages over two outages.

A The intension was to capture those specifically some thermal efficiencies which did not require NRC review. They could be achieved on the steam side of the plant as quickly as possible. Those modifications were installed -- or are planned to be installed in the 2009 outage. Additionally, some of those modifications which might not involve a plant efficiencies but may be required in order to use the extra power coming from the reactor after 2011, some of those modifications are of a very long duration. So the intention was for the benefit of the customer to install those in 2009 while we knew the plant would be shut down for an extended period anyway due to our steam generator replacement, which happens to be scheduled in 2009 as well. So the duration of a steam generator replacement outage is very long and it allowed us to install some modifications not needed until 2011 early in order for the customer not to have to have two large lengthy outages in both 2009 and 2011. So those were the two drivers: Thermal efficiencies not requiring NRC approval, and taking advantage of the steam generator outage duration to minimize the number of days offline.

Q Now, does the replacement of the steam generator, this is the once-through steam generator?

A Yes, that's correct.

Q Or OTSG?

A Yes. OTSG is the acronym for Once Through Steam Generator.

Q Okay. Is that considered to be part of the uprated project?

A No.

Q And are there any costs for the OTSG included in what you're asking to recover as a part of your testimony?

A No.

Q Now, the first part of this EPU project deals with preparing the steam cycle and electric power producing parts of the plan, or the balance of the plan; is that right?

A That is correct.

Q And the second part deals with upgrading the nuclear steam supply to increase the power level to over 3,000 megawatts thermal; is that right?

A That is correct, in general terms.

Q Now, what type of reactor is CR3?

A It's a Babcock and Wilcox reactor.

Q Babcock and Wilcox?

A That was the original company that designed the reactor system. B and W.

Q Do you know how many other reactors are operating at this time?

A Realizing that each reactor is a little different, there are three units at Oconee; there is one at Davis Bessie; there is one at Arkansas

Nuclear 1; and there is one at Three Mile Island operating today.

Q Is it true that because of the relatively low volume of water in the steam generators as compared to the Westinghouse reactors, that -- or as compared to Westinghouse -- that the safety margins are more difficult to maintain for a B and W reactor?

A I would not agree to that, no.

Q Would you characterize these reactors as ones that are designed with a lower margin of safety --

A Absolutely not.

Q -- as compared to the Westinghouse?

A Absolutely not. In fact, there is a quantifiable means of measuring safety that's become an industry standard called probability risk assessment. My plant has one of the lowest factors as analyzed by the probability risk assessment in the industry today, and that's based on design.

Q What is a PWR?

A Pressurized water reactor. It uses a high pressure -- a pressurizer, which is a tank to maintain the reactor coolant in the reactor vessel in liquid form at high temperatures by maintaining a high pressure on the reactor.

Q And that's what the B and W reactor, CR3 is?

A CR3 is a pressurized water reactor.

Q How many PWRs have been upgraded or uprated in the United States?

A There have been quite a few that have been uprated in particular using the measurement uncertainty recovery. I don't know the exact number.

Q How about the analogous uprate that are in steps two and three of your project, how many have been done that way?

A I would say some have seen -- it would be difficult to know the number that have done the step two type uprate, but I would say many, and I would say very few have gone to the step three, which was actually significant increases to the reactor power. I'd say very few. I'm aware of GINNA. I believe there are some other facilities, but I don't know. I know of one, but I would say few.

Q Could you spell GINNA.

A G-I-N-N-A.

Q Okay. Have any been uprated over 3,000 megawatts?

A Any PWRs?

Q Yes.

A I don't know.

Q Would you be surprised if any had been to that extent?

A There were a lot of PWRs that were originally licensed over 3000 megawatts. So you're asking if they've been uprated to that level, there are several reactors around the United States whose original license was greater than 3,000 megawatts thermal. Realizing we're talking about thermal megawatts, not electric megawatts.

Q What about B and W PWR?

A This would be the first B and W PWR to be uprated over 3,000 megawatts.

Q Do you know for a B and W reactor that had been upgraded -- or uprated -- what has been the level of upgrades implemented in terms of percent in power?

A I don't know. I don't know. I know some of the other facilities' power level is higher than ours currently. So some of the added power that we are is to catch up to the power level of those facilities, realizing each facility is unique to some degree.

Q Is it possible that when you were planning the uprates for CR3 that you or somebody on your behalf looked at the percent upgrades of the other B and W reactors?

A I'm certain there are members of my staff that can answer this fully.

Q What would have been the purpose for doing that?

A We would benchmark other facilities' activities to ensure that the lessons learned from those activities were fully understood by our plant. And, more specifically, this uprate required close coordination with the current original equipment manufacturer, OEM, in this case AREVA, who now owns the design for the B and W reactors, and we work extensively with them to understand the capabilities of the reactor system to safely produce the new power level.

Q Would you look at the lessons learned, if you will, for these other upgrades of the B and W reactors in order to do any risk assessment for the likelihood of success of your project?

A Yes. We would look for any findings from those lessons to determine if feasibility was still true. We'd also look for cost savings, and anywhere

where we could take advantage of any previously produced evaluations so that they would not have to be duplicated.

Q How have you assessed the risks for your project with regard to the fact that it is the first B and W reactor that you would seek to take above a 3,000 megawatt of threshold?

A We have looked extensively, and working primarily with AREVA, to understand the technical challenges of this uprate through extensive engineering evaluation to validate that this would be feasible and would be agreeable to the NRC. So we have worked -- additionally, we looked at the uprate experiences for both PWRs and BWRs for licensing challenges. And particularly, we have worked to understand the GINNA experience with their extended power uprate from both a licensing and technical standpoint so that we could foresee any challenges in either of those areas to gauge the feasibility and risks associated with our uprate.

Q GINNA, was that a B and W?

A No. That's a Westinghouse.

Q All right.

Is the uprate, would you go into 3014?

A That sounds like the right number. Hold on. Let me refer.

Yeah, right now I would say it's approximately 3014 is what the license submittal we'll be asking for.

Q So would the increase to 3014 megawatts for Crystal River 3 be on a relative sense pushing the envelope more than what they did in GINNA?

MS. TRIPPLETT: Object to the form.

BY MR. REHWINKEL:

Q Do you know what I'm asking?

A With regard to the question, I don't know the answer. I know that it is not -- there are B and W experiences which are a few percent below this, I don't know the exact number. I believe Davis-Bessie is above us significantly right now. So it's not necessarily pushing the envelope too far from what the B and W experience is. I know that this is by no means pushing the envelope compared to the boiling water reactor extended power uprate experience. And I also know that as of today, all our technical evaluation shows that this is well within the capability to safely operate this reactor.

Q Davis-Bessie, can you spell that.

A D-A-V-I-S, dash, I believe it's

B-E-S-S-I-E.

Q Okay.

A I believe. The first energy plant.

Q Okay. What do you know about the NRCs view of what you are seeking to do with the CR3 reactor?

A As with any approval authority, they do not give a final determination til the reviews are complete. I know based on my conversations with them and from discussions with my own staff concerning the NRC, that as of now we see no -- that we are unaware of any concerns that the NRC has that would challenge our ability to uprate the unit. But their process is their process. After we submit, they will review our submittal. We spend a lot of time talking to them ahead of time so that we give them the information we know they need, and typically in these types of situations, they will give us heads up on special concerns they may have, and I am unaware of any special concerns about what we are proposing that the NRC may have today.

Q Have you assessed any probability of success with respect to the NRC?

MS. TRIPPLETT: Objection. Are you talking about NRCs approval?

BY MR. REHWINKEL:

Q This is with respect to the NRCs granting of the LAR.

A I would say right now we believe the probability is high of success.

Q Now, let's go back to the step two of the EPU project. What is the amount of the megawatt increase?

A For step two?

Q Yes.

A Currently it is -- let me refer.

Q Sure.

A You mean electrical? The thermal megawatts is not increased in step two.

Q Electrical. That would be the MW, little E, right?

A That is correct, MW, little E.

I believe it's 24 megawatts electric. They have 28 here. Yes, 28 megawatts electricity. I'm sorry.

Q Do you know what the cost of the BOP or Balance of Plan portion of the project is?

A That's a broad question. I know -- my testimony is the current cost in 2009. Realize we have Balance of Plan modifications ongoing in 2011 in addition to the N triple S changes. So I don't know what the exact figure is for all Balance of Plan modifications. I know from my testimony what the numbers we are projecting for 2009 for the R16 outage.

Q And what is that?

A It's already docketed. I don't know. I'd have to refer to the tables provided I believe in Greg Foster's testimony.

Q Okay. Well, we can come back to that.

What is the Balance of Plan amount for the 2011? Do you have a rough idea of what that is?

A I don't know that number off the top of my head.

Q If you looked at this portion of the project alone, the Balance of Plan aspect of the project -- and I'm talking about the second step of the EPU -- and you looked at that without completing the second part, what would the feasibility be of the cost versus the improved benefits of the increased output and efficiency?

A I haven't seen a cost benefit which did not include the extended power uprate portion, but I have confidence that it would easily pay for itself.

Q What gives you the basis for that?

A Well, you're asking me to kind of run the numbers in my head here. I don't have them. But our fuel cost to the customer is roughly $5.00 a megawatt. Coal runs 35 to 60, depending on transportation costs; and natural gas widely varies. In general, a megawatt of nuclear power is very worthwhile to the customer particularly looking at another 30 years of service by Crystal River 3 -- it's not quite 30, I guess it's 28 more years of service for CR3. So in general -- I don't run the numbers for this modification -- but in general the cost for Balance of Plan upgrades across the nation have proved to be very cost effective for the customers.

Q And you're saying you're confident that would be the case even if you don't do anything other that the Balance of Plan part of it?

A Yes.

Q Earlier I think I gave you ahead of time a document from the NRC. There are two documents that we got off of the Adams system. One was a document ML081480504, and I think it's dated May 19, 2008, Summary of a Meeting with Progress Energy Florida regarding power uprates in Crystal River unit 3. Do you see that?

A Right. It's the summary of the May 19th meeting dated June 9th, 2008?

Q Yes.

A Is that it?

Q Yes.

A Okay. I understand.

Q You were in attendance at this meeting, were you not?

A I believe I was.

Q I think your name is shown on the page three of five?

A Yes, I was. That is correct.

Q Are you familiar with this document?

A I'm certainly familiar with the meeting, and I've briefly reviewed this document.

Q Well, I'm going to ask you some questions about it, and if you need more time to review it to answer them, please take that.

First of all, I want to direct your attention on the discussion section on that page one of five on the printout. In the second full paragraph, I think the NRC uses the number of 2069 megawatt thermal for 3014 megawatt thermal.

A Yes.

Q Is that a typo. Is it 2609?

A It should be 2609. It looks like a typo to me.

Q Do you agree that the facts are related by the NRC in this document accurate as far as you know?

A With the exception of the typo you caught, from my review it appeared to be a fair representation of the meeting, although very summary in nature.

Q Okay. In this sentence that's got the typo in it, it starts off with "If approved." Do you see that?

A Yes.

Q Is there any question in your mind as far as whether the LAR will be approved?

A I have a high confidence that the LAR will be approved.

Q But there are some risks that it will not be?

A There's no such thing as zero risk.

Q So why would the NRC put if approved in this?

MS. TRIPPLETT: Object to the form.

BY MR. REHWINKEL:

Q If you know.

A The NRC never speculates on whether or not they will approve a document in a public document has been my experience.

Q Okay. Have you given any kind of a percentage probability of getting approval for this LAR?

A Based on my experience I'd say there's a very good chance, a very high probability. I couldn't put a number to it.

Q Okay.

A You've asked this a lot, and maybe I can help explain why.

Q Okay.

A The NRC works to rules that we know and understand. There is clear criteria for the evaluations required to demonstrate why an uprate condition is allowable. That being said, we have worked with AREVA and we have a full understanding of how our facility will match those guidelines, those rules, those limits, and as such that gives us confidence that once the NRC reviews those rules and those limits, that the criteria are met in our analysis, the NRC needs to review the documentation of how that is met, and once they perform that review, we know that we will meet their criteria so we expect to get approval. Does that make sense?

Q I understand.

A This isn't a blind test. We know what the grade is. We know what the answer sheet says. And once we do the analysis and see that that analysis shows we meet that criteria, then we have every confidence the NRC will see that those numbers line up against their criteria in that manner.

Q So basically what you're saying is that you have a pretty good track record of identifying your probability of success with NRC approvals?

A No. It means that I know for this uprate we know what evaluation and accident analysis criteria will be applied, and we are far enough along in our understanding of that criteria to have confidence we will meet that criteria.

Q The second paragraph on page two of the document, it starts, "The licensee is considering four potential issues." Do you see that?

A Yes.

Q What does that mean, that you're considering four potential issues that may require licensing actions?

A During this meeting we were discussing the licensing strategy for our extended power uprate, and we had identified a number of issues that might require a license request, and we were seeking advice from the NRC concerning the best way to approach those issues. And what I mean by that is many times in dealing with this, there are changes to the plant that could be made, and after those changes are performed, no NRC action or approval would be required to deal with a specific issue.

And in other cases you might ask for a change in your license so that at the new power level, that issue doesn't exist in licensing space because there is a technical reason why it doesn't need to be. Does that make sense?

Q Yes.

A So what we wanted to discuss with them early in the process was four areas where we had evaluated might get into the area in which a license change might be required, and we wanted to discuss with them how they saw their reviews -- what they understood from their information how those reviews might best be performed to help us aim at a strategy for dealing with each of these technical issues.

Q The first item here about the need for an exemption for core flood line break with concurrent bust failure.

A Yes.

Q This says that you're considering seeking an exemption. Is that still what your strategy is?

A No. After this meeting -- in fact, this is exactly what moved us towards installing the LPI Crosstie modification. This is the case of an extremely small probability accident, extremely small, and in the new regulatory world you can do what's called a risk base submittal which says the chances of this ever happening are so ridiculous, there's no reason to make a change in the facility. The NRC guidance to us in this case was for this particular area they were not receptive to that; that they would rather us either submit a license change or mitigate the issue in a different manner. And we determined the best cost effective way to gain confidence that the eventual amendment request would be approved would be to install the modification and, therefore, no longer require NRC approval of this exemption.

Q So did you make that submittal?

A There is no submittal required now. We will be installing the LLP Crosstie and that modification will prevent us from needing a licensing change to uprate the power in answer to this technical issue.

Q So, just so I can try to understand it, instead of making a submittal, you changed your strategy about how to deal with the problem?

A Yes. And we're now installing the LPI Cross Tie instead of requesting an exemption from a specific design scenario.

Q And will an amendment to the license be required as a result of that change?

A No.

Q It will not?

A No.

Q The next paragraph second issue is a small break loss of coolant accident, parenthesis, LOCA, L-O-C-A, with a manual --

A And, by the way, let me be clear.

Q Okay.

A No separate license amendment request. Any issue associated with the -- the modification can be installed without it, but the feasibility of the plant to mitigate that design accident at new power levels will take advantage of that modification being installed. Does that make sense?

Q Run that last one by me again.

A We can install the system without a

license amendment request.

Q Okay.

A But that modification is required, we believe, without a different license activity to approve the final uprate.

Q Okay. Now let's go to the LOCA, L-O-C-A, issue. Are you familiar with that issue?

A I have some understanding of this technical issue.

Q Can you give me an explanation within your realm of understanding?

A Yes. In this case we will be -- the higher power level will require a different mitigation strategy for small reactor coolant system leak response scenarios. As such, we will be going to a different strategy with regard to safety relief valve views. It's changing some valves out to a different kind of valve and different control system. In this case we have determined that a license amendment request -- a separate one -- was not required.

Q So there was not a submittal in August for this?

A There was not a submittal in August, and our discussions with the NRC, they agree that a separate submittal was not required for the changes in this case.

Q Okay. But will this be subsumed in a one amendment request that you make at some point?

A It will be part -- any issues associated with this will be part of our final license amendment request.

Q The thing we talked about at the very beginning, whether it happens in the fall or --

A That's correct. Any issues involving this will be covered there. I don't remember the reasons why, but I do know that we have decided that this issue does not require separate licensing activity and had to do with how it had been previously reviewed by the NRC.

Q Okay. So the inclusion of these first two items in the one amendment request that you're going to make and whenever you make it, is it your view that doing it that way as opposed to individual submittals will increase the probability of the NRC approving?

A Well, the way you've worded the question implies I haven't fully communicated to you yet. There is no specific technical issue that requires a separate approval for these technical issues. And why this was important is there are some kinds of submittals currently under the NRCs new rules, fairly relatively new, that you have to address certain issues up front before you submit something like an extended power uprate request. A good example would be the one that we have submitted early. We changed the method in which an accident would be analyzed. It was an old computer program and an old model that had been used to evaluate a specific scenario in order to come to modern methods of evaluation which were required to understand the higher power levels, we wanted the NRC to approve that method of evaluation. So we had to submit that actually a year ahead of time -- well, in time so that that review could be approved prior to our submittal of the final version, the final use of that analysis. And so we wanted to discuss with the NRC when these -- if these issues were required before the submittal of the actual license amendment request or could be done as part of the extended power uprate license amendment request, and that's what these discussions were about.

Does that make sense?

Q Yes.

A Okay. So the first two issues are being dealt with by either not needing -- no longer needing NRC approval at all, or could be sufficiently covered in the extended power uprate request itself.

Q I appreciate that clarification. I was trying to get at the --

A Yes.

Q -- and the one time is ultimately because of the way you've addressed the problem a different way. And you feel like it is a much lower risk than what you were seeking to address the problem initially?

A In essence, in discussions with the NRC, they've agreed this is the right way to get through the licensing process.

Q It seems to me you're saying it's not a matter of an engineering solution as much as navigating the regulatory waters; that the regulator is saying here's a better way to do it.

A That is correct.

Q And you're following that guidance?

A That is correct. You have to realize that the NRC process is not just a technical process; it's a legal process, and as such there are legal requirements and procedures and processes the NRC follows. The technical issues may be dealt with a number of ways, and some of those ways limit themselves to one legal strategy to getting through the process, others lend to a different way. And so you have to understand both of those to move forward.

Q Let's go to the third issue here, the withdrawal reactivity insertion method. Are you familiar with that?

A Absolutely.

Q Can you give me a quick explanation of that.

A Well, it's a specific scenario where a control rod is postulated to fly out of the reactor and how the reactor system is protected from that accident. In this case we have submitted that new analysis, and in this case it was considered an analysis that the NRC wanted to review prior to the extended power uprate submittal, and the NRC has, in a -- I believe this was the '08 meeting, in our last meeting was very confident that they understood and had a good submittal from us, and to date they are in the process of writing the approval paperwork for that license amendment request. We haven't seen it yet but we are far enough along to have very high confidence we should see that approval within the next month or so.

Q The next paragraph regarding boron precipitation.

A Yes.

Q Can you explain that to me.

A To a small degree. This is a specific post accident issue where the boron comes out of solution under certain conditions and can -- so it's a very narrow technical issue within accident analysis phase.

What this sentence is saying is the current method will be evaluated at under 10 50.59 and if it is required, we were planning for submitting something in October, '08.

In this case our strategy has been to make a very small change to the plant that we believe has been -- it has been evaluated -- that can be installed under this 10 C.F.R. 50.59 referenced in the paragraph and, therefore, not require NRC approval.

Q Is that an assessment that is subject to NRCs review of or blessing, if you will?

A Not blessing. The NRC -- the 10 C.F.R. 50.59 process is how the company is allowed to change the facility without asking the NRC. If we follow the set of rules under that regulation, we don't have to ask for approval. Everything that we do under that process is always under NRC review, and we provide a licensing document called a 10 C.F.R. 50.59 evaluation, which we have produced in this case. That is subject to review by the NRC should they want to review it, but it doesn't require their blessing for us to move ahead.

Q So in other words, the bottom line here is you did not make a submittal?

A We did not make a submittal, do not believe we will need to make a submittal. We've actually discussed this with the NRC, and they see no problems with our approach.

Q These four items that you initially contemplated make go submittals, or a submittal on, you ended up finding ways to skin the cat a little differently, is that it?

A That's correct with the one exception with the rod ejection analysis, which has been submitted.

Q Would you characterize the way you navigated those regulatory waters as being more difficult than you originally contemplated when you embarked on this?

A No. In fact actually I think the solutions we came up with made it easier in the end.

Q Okay.

A The purpose of this meeting was to help work through these issues to help give us direction. This is why -- I mean if you think about it, this meeting was in 2008, in the spring of 2008 for a submittal that wasn't even required to be for our schedule submitted until, as I just indicated, you know, 2010. So we were getting ahead of it so that we knew because of that long timeline, you know, what we would need to do to be able to be successful.

Q Let me ask you to turn to the other Adams document, which is an April 1st, 2009 summary or meeting with Progress Energy. Do you have that in front of you?

A I have that in front of me.

Q This is about almost a year later than the meeting we were talking about earlier.

A That is correct.

Q Actually, I think we're done with what we need to do with those.

Let me ask if you have one of these -- do you have a POU risk status report? This is one -- I

don't know if the document you have -- what is
the -- is it 017532?
MS. TRIPPLETT: Correct. It's dated
Monday, June 9th, 2008.
BY MR. REHWINKEL:
Q This is OPC1-47-017532.
A Yes.
Q I think you earlier stated that this would
be a snapshot?
A Yes. Obviously it's a year old.
Q In the rank column, we touched on this
earlier, but is nine the highest rank of a risk that
you use in this report?
A I have to admit I don't know the basis for
the numbers. I'm used to the green, yellow red
program.
Q Well, if you look at the document, it's in
color here, you have --
A I can tell from looking at it that the
higher risk numbers have a higher number.
Q And they are also in an orange or red?
A Yes.
Q Whereas the zeros in the later pages are
in green.
A I have not had a chance to review this

beforehand.

Q I understand.

A And as such -- but from looking at it, it is clear that the higher number is a higher risk item.

Q Okay.

A And I want to be careful in how we discuss this if I can.

Q Okay.

A The risk is not necessarily to whether or not you can be successful with the uprate. It may be a financial risk or a schedule risk that is discussed, if that makes sense.

Q So if I ask you about anything that's on this document, would you be able to tell me which types of risk that it was?

A I may be able to, depends on what you ask.

Q Fair enough.

In the column labeled risk number, which is the second column --

A Yes.

Q -- the top three on that page 1 of 16 are numbers 241300 and 239. Do you see that?

A Yes.

Q Are any of these issues related to the items we discussed in the May 19th, 2008 meeting summary of the NRCs?

A I am sure that -- I believe that 239 is the issue involving the LOCA in conjunction with the loss of EBUS (phonetic) that led us to do a low pressure injection system Crosstie modification.

Q Okay.

A So that one was mitigated by the decision to do the Crosstie modification.

It is possible that risk 300 dealt with the boron precipitation issue, but I am not certain of that.

And I suspect 241 dealt with the -- I suspect -- I haven't mapped these necessarily, but 241 appears to deal with the issue concerning ultimate depressurization.

So, yes, it does look like these were the ones that we needed a year ago to lay out the strategy for dealing with.

Q Okay. Let's now look at your EPU -- IPP, the March 2nd, IPP. Again, this is the risk section which starts on page 17 of that report.

A Yes.

Q Is the analogous snapshot of your risk status report sometime contemporaneous with the

March 2nd, 2009 IPP? Is that fair?

A It should be.

Q Are these items 241, 300 and 239, are they in this PLU risk status report?

MS. TRIPPLETT: And by this, you mean the one reflected in --

MR. REHWINKEL: Yes. Correct. On March 2nd.

THE WITNESS: I see the 241 item.

BY MR. REHWINKEL:

Q Look right above that is the 239.

A That is 239, yes.

Q And look on the next page.

A 300 is shown on the next page, yes.

Q 239 and 241 still looks like they have nines assessed as their ranks?

A Yes.

Q The 300, which is the boron precipitation issue is a six now.

A That's correct.

Q Okay. At the time this IPP was produced in the March, 2009 time frame, are you still identifying the LPI Crosstie as a number nine or a --

A I know by this date we had chosen the

strategy. In fact you'll notice they changed the words to implement the course of action.

Q Okay.

A I don't understand the basis for the nine. Did not participate in that. Or if there was a conscious decision to not change the risk number.

Q This as a risk, is this a financial risk or a licensing risk? What would the risk be here in the March IPP?

A I don't know. It may represent a schedule risk. I have heard this project discussed as a challenge to our current schedule for the 2011 outage because of the requirement and what it takes to install it, but I'm not familiar with any risks whether or not it would be feasible to meet uprate requirements at all.

Q Well, can you explain to me a little bit about the challenge risk with respect to the 2011 step.

A I will tell you I'm not certain why this is in this box at a nine. Okay? I certainly can check that. I have heard discussions that this will be a schedule activity which could affect the critical path of the outage, so we're looking at can it be installed in the outage duration currently scheduled for our 17 in 2011. This testing activities and to have both low-pressure injection systems down requires certain plant conditions. So it adds complexity to the outage schedule but certainly nothing that can't be performed.

Q In discovery we had asked interrogatory 71, and I think we just got an answer in the last few days, and I think I have here an e-mail version of it that I'll hand it to you. That is exact -- I didn't print out the response that was filed, but that is exactly the answer that you gave in the interrogatory.

Are you familiar with that information in that interrogatory 71? I think it was filed in the last two days.

A Yeah. I don't know this great detail other than what is said here.

Q Now, is anything confidential in that?

A I don't believe so.

MS. TRIPPLETT: No.

BY MR. REHWINKEL:

Q Do all of the items that are listed there that will be included in the updated PLU risk status report, are those challenges to the 2011 schedule?

A I don't know the details about these as to how they became on the risk matrix as to what risk they represent.

Q Okay.

A You have to realize when we start on the EPU risk, I mean there may been 400 items that were identified as potential risks, anything from labor rates to availability of a specific technical skill. So we're very rigorous in our look to verify that we understand all our challenges. So with regard to these four, you know -- actually I guess there's five here listed, the answer is that they were associated with the 2011 outage. I don't know whether they're schedule risk or cost risk. I am unfamiliar with any risks that challenge our ability to implement the uprate.

Q The risks that are here, we asked that risk 473, 239, 241, 475 and 474 have been resolved or mitigated, and the answer here appears to be that the resolution and mitigation plans have been developed but are not completed at this time. Is that your understanding?

A That is my understanding.

Q So would it be fair to say that your assessment and understanding of these risks as they affect the project as planned now is not final?

A Yes.

Q So 475 -- and I'm going back to page 17 in the March IPP -- do you understand this item?

A No.

Q So you're unfamiliar with this issue?

A I'm not familiar with that issue.

Q And what about -- we talked a little earlier item 300, the boron issue, it went from a nine to a six over the time frame that we were looking at these two documents, do you know what occurred to --

A No. I know that in June of '08 we had not decided on our strategy, and by now we have.

Q Do you expect that resolutions, if any, for the issues in 473, 475, 474, 241 and 239, will they be addressed in any way in your LAR submittal?

MS. TRIPPLETT: Object to the form.

THE WITNESS: I'm not sure.

BY MR. REHWINKEL:

Q And I think I know the answer to this but I'm going to ask it anyway. Is NRC committed to amending the license in time for 2011 outage for any of these risk items that you had planned to address in your LAR?

MS. TRIPPLETT: Objection to form.

BY MR. REHWINKEL:

Q You can still answer it.

A The NRC has a very strict process of reviewing submittals for acceptability within a time frame, typically four weeks, and once they have reviewed that submittal for sufficiency, they are committed to a twelve-month period to approve at a maximum those submittals.

I believe the NRC will -- and from our conversations, they are committed to achieving that schedule.

Q In your opinion would you have to address these issues that are listed in question 71, interrogatory 71, would you have to address those before you can get NRCs approval for your LAR?

A Because I don't know the details of them, I don't know. Some of them may be required in that submittal, some may have nothing to do with the NRC.

Q So with respect to those items in question 71, would you agree that at least some of them present a risk with respect to your NRC approval of your LAR?

A I can't agree to that. I am unaware of any risk to my NRC submittal. While I don't know the specific actions, I have asked the question are there risks to our EPU submittal that we are aware of, and as of now, we have confidence that that LAR submittal will be sufficient and will meet the requirements of the NRC.

Q Do you believe that there is any risk that the amounts that you have spent, or costs that you have incurred for steps two and three of your uprate will -- let me rephrase the question.

Do you believe that there is any risk that the amounts that you have spent for steps two and three will be at risk in the sense that the NRC does not allow you to make the full power uprate that you're seeking?

MS. TRIPPLETT: Object to the form.

BY MR. REHWINKEL:

Q Do you understand my question?

A I do. The only fair answer I have is I believe the costs, based on our understanding of risks, were prudently spent at the time the money was spent. As of now, while I cannot guarantee what any regulator will do, I have confidence that we will receive, eventually receive approval to uprate the reactor more than sufficiently to justify any costs.

Q What is the remaining MWE increase that you are seeking above the MUR for steps two and three?

A It is -- hold on -- 168 megawatts electric.

Q Is there a percentage of that that if you don't receive the authorization to increase to, that the project would still be considered feasible and prudent?

A Well, certainly if we didn't achieve any megawatt increase, it would be disappointing. But you're asking a question of prudency, and prudency in my mind is based on the information available at the time the decision is made.

So the only fair answer to the question based on my understanding of every decision point we had gone through is that every cost decision was made in a prudent manner based on the best information available to us associated with all risks associated with the project.

MR. REHWINKEL: I appreciate your patience. Hold on one second. Excuse me.

(Thereupon, a pause in the proceedings took place.)

BY MR. REHWINKEL:

Q Just one last line of questions hopefully.

[redacted]

Approximately. Were I to delay that to 2011, recognize it costs my customers a large amount of money -- can I say that much?

MS. TRIPPLETT: Yes, you can say that much.

THE WITNESS: It costs my customers anywhere from 1,000,000 to $2,000,000 a day for every day I'm offline. So if I were to execute that scope in 2011 it would likely cost my customers more than the cost of the project in fuel costs. So, no, it doesn't make sense to even evaluate delay in those costs because, one, I get the benefit and they're going to get the benefit of those megawatts whether the NRC approves it or not, and the cost of delay doubles the price of the project to the customer. And I suspect you'd be a lot more critical of my decision had I done that.

BY MR. REHWINKEL:

Q Is there any document that you have provided already that says what you just said to me about the -- I guess what --

A The IPP covers the megawatt increases as well as the fact that we're taking advantage of the steam generator duration to prevent that cost to the customer in subsequent outages. That is covered in there as some of the reasons for the schedule.

Q So is there anything that talks about the total dollars associated with the BOP changes and looks at the benefits to the customer?

A I don't know if there's been -- I'm not aware of any submittal that has not included the extended power uprate portions which required the license submittal.

Q That's broken it out?

A No.

Q Can I get you to look at page 12 of the March, 2009 IPP.

A Yes.

Q Okay. If you look under 2009 column, I guess under the grand total, is that number confidential?

A Are you talking about the --

Q See where it says grand?

A Grand total 2009. I see that number, yes.

Q Is the cumulative total of the dollars under -- can you figure out a BOP number or an approximation there?

A No. Recognize that this is what makes it difficult: The budget numbers I'm familiar with and that we have presented are annually based for the whole project. We are doing Balance of Plan upgrades in 2011. The HP turbine rotator, for example, is scheduled to be replaced in 2011. Well, that can be done without the NRC approval and there are megawatts to the customer. I don't know what those megawatts are because it requires a full analysis without the power uprate, with this turbine installed. You can understand what I'm saying. There is a thousand different scenarios you can analyze for but there are megawatts to the customer for that project separate from the NRC licensing and there are costs associated this year in 2010 and 2011 for that HP turbine replacement project in 2011.

Additionally, in this number in 2009 it includes a significant amount of money associated with the licensing activities for the 2011 licensing engineering work that's being done in conjunction to support that LAR that will not be implemented until 2011. So I can't break it out.

Q That's fair. Okay.

MR. REHWINKEL: Now, that is actually all the questions. Thank you. Thank you very much.

MS. TRIPPLETT: Staff, do you have any questions?

UNIDENTIFIED PERSON: We do not.

MS. TRIPPLETT: Jamie Whitlock?

Anyone else? Going once? Okay, I have no direct, and we will read.

(Thereupon, the deposition was concluded at 3:45 p.m.)

READ AND SIGN

I have read the foregoing pages and, except for the corrections or amendments I have indicated on the sheet attached for such purposes, I hereby subscribe to the accuracy of this transcript.

____

SIGNATURE OF DEPONENT

____

DATE

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF PINELLAS)

I, ROBERT A. DEMPSTER, Court Reporter, Registered Professional Court Reporter, Notary Public at Large,

DO HEREBY CERTIFY that I was authorized to and did stenographically report the foregoing Deposition of JON FRANKE taken before me at the time and place set forth in the caption thereof; that a review of the transcript was requested; that the proceedings of said Deposition were stenographically reported by me in shorthand, and that the foregoing pages, numbered 1 through 83, inclusive, constitute a true and correct transcript of my said stenographic report.

I FURTHER CERTIFY that I am not a relative or employee or attorney or counsel of any of the parties hereto, nor a relative or employee of such attorney or counsel, nor do I have any interest in the outcome or events of this action.

ROBERT A. DEMPSTER
Registered Professional Reporter

CERTIFICATE OF OATH

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I, the undersigned authority, certify that JON FRANKE personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 12th day of July, 2009.

____

Notary Public, State of Florida

A

D

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

~~(CONFIDENTIAL VERSION)~~ REDACTED

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

J.R. Kelly
Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 W. Madison Street
Room 812
Tallahassee, FL 32399-1400

Attorney for the Citizens
Of the State of Florida

TABLE OF CONTENTS

EXHIBITS

DIRECT TESTIMONY

Of

WILLIAM R. JACOBS JR., Ph.D.

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 090009-EI

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is William R. Jacobs, Jr., Ph.D. I am a Vice President of GDS Associates, Inc. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia, 30067.

Q. DR. JACOBS, PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received a Bachelor of Mechanical Engineering in 1968, a Master of Science in Nuclear Engineering in 1969 and a Ph.D. in Nuclear Engineering in 1971, all from the Georgia Institute of Technology. I am a registered professional engineer and a member of the American Nuclear Society. I have more than thirty years of experience in the electric power industry including more than twelve years of power plant construction and start-up experience. I have participated in the construction and start-up of seven power plants in this country and overseas in management positions including start-up manager and site manager. As a loaned employee at the Institute of Nuclear Power Operations ("INPO"), I participated in the Construction Project

Evaluation Program, performed operating plant evaluations and assisted in development of the Outage Management Evaluation Program. Since joining GDS Associates, Inc. in 1986, I have participated in rate case and litigation support activities related to power plant construction, operation and decommissioning. I have evaluated nuclear power plant outages at numerous nuclear plants throughout the United States. I am currently on the management committee of Plum Point Unit 1, a 650 MWe coal fired power plant under construction near Osceola, Arkansas. As a member of the management committee, I assist in providing oversight of the EPC contractor for this project. My resume is included as Exhibit WRJ(PEF)-1.

Q. WERE YOU ASSISTED BY OTHER GDS PERSONNEL IN THIS EFFORT?

A. Yes I was. The GDS team involved in the review and evaluation of the requests for authorization to recover costs consisted of me, Mr. James P. McGaughy, Jr., a former nuclear utility executive with over 37 years or experience and Mr. Cary Cook, a Certified Public Account with extensive experience in utility regulation. The resumes of Mr. McGaughy and Mr. Cook are attached to this testimony.

Q. WHAT IS THE NATURE OF YOUR BUSINESS?

A. GDS Associates, Inc. ("GDS") is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Corpus Christi, Texas; Manchester, New Hampshire; Madison, Wisconsin, Manchester, Maine; and Auburn, Alabama. GDS provides a variety of services to the electric utility industry including power supply planning, generation support services, rates and regulatory consulting, financial analysis, load forecasting and statistical services. Generation support services provided by GDS include fossil and nuclear plant monitoring, plant ownership feasibility studies, plant management audits, production cost modeling and expert testimony on matters relating to plant management, construction, licensing and performance issues in technical litigation and regulatory proceedings.

Q. WHOM ARE YOU REPRESENTING IN THIS PROCEEDING?

A. I am representing the Florida Office of Public Counsel.

Q. WHAT WAS YOUR ASSIGNMENT IN THIS PROCEEDING?

A. I was asked to assist the Florida Office of Public Counsel to conduct a review and evaluation of requests by Progress Energy Florida (PEF) for authority to collect historical and projected costs associated with extended power uprate ("EPU") project being pursued at Crystal River Unit 3, and historical and projected costs associated with PEF's Levy County Units 1 and 2 project ("LNP") through the capacity cost recovery clause.

II. SUMMARY OF AUTHORIZATION TO COLLECT COSTS REQUESTS FOR

Q. PLEASE SUMMARIZE PEF'S REQUEST FOR COST RECOVERY IN THIS DOCKET UNDER THE NUCLEAR COST RECOVERY CLAUSE.

A. PEF is requesting in its original filing recovery of $446.3 million in 2010. This includes projected total revenue requirements of $142.2 million for calendar year 2010 and recovery of the actual/estimated under recovery from 2009 of $303.8 million. In addition, PEF has stated its willingness to amortize the year end under-recovery balance for 2009 over a 5 year period. This would reduce PEF's revenue requirements for 2010 from $446.3 million to $236.4 million.

III. METHODOLOGY

Q. PLEASE DESCRIBE THE METHODOLOGY THAT YOU USED TO REVIEW AND EVALUATE THE REQUESTS FOR AUTHORIZATION TO COLLECT COSTS SUBMITTED BY PEF UNDER THE NUCLEAR COST RECOVERY CLAUSE.

A. I first reviewed the Company's filings in this docket and assisted in the issuance of numerous interrogatories and requests for production of documents. To evaluate the contracting process employed by the Company, I reviewed requests for proposals issued by the Company, the bid evaluations conducted on proposals received in response to the requests for proposals and the contracts awarded to the winning bidders. For single or sole source contracts, I reviewed the single or sole source justifications to ensure that they met the requirements of the governing company procedures.

To evaluate the issues related to project schedule and risk management, I reviewed many internal documents, status reports and correspondence with regulatory authorities.

Following my review of the documents produced by PEF, I assisted Office of Public Counsel attorneys in deposing PEF witnesses to further explore areas of interest.

Q. HOW DID YOU DETERMINE IF THE COSTS REQUESTED FOR RECOVERY BY THE COMPANIES WERE PRUDENT AND REASONABLE?

A. The Company must employ prudent contracting and project management and risk management procedures and practices to ensure that the costs are prudently incurred. The scope of work must be reasonable and the Company must ensure that the costs are reasonable by means of competitive bidding or other methods such as comparisons with similar projects for which the cost is known. I also reviewed the project management procedures and practices that will be used in an effort to prudently manage the projects as they move into the implementation stage.

In addition to the above reviews, Mr. Cary Cook reviewed the requests to ensure proper accounting treatment and accurate calculation of the various amounts requested for recovery by the Company.

Q. PLEASE DESCRIBE YOUR REVIEW OF THE PROJECT MANAGEMENT PROCEDURES AND PRACTICES UTILIZED BY PEF.

A. As the projects move into the implementation phase, prudent project management and risk mitigation will be important to ensure that projects are completed on schedule and within budget. Project management procedures and practices reviewed include establishment of project budgets, monitoring of budget variances, corrective actions for budget variances, establishment of project schedules, and monitoring of project schedule variances and corrective action for schedule variances.

IV. ISSUES AND CONCERNS

Q. PLEASE DESCRIBE THE ISSUES AND CONCERNS THAT YOU IDENTIFIED FROM YOUR REVIEW OF PEF'S REQUEST

A. I have identified issues and concerns in both the LNP and the EPU projects that raise questions concerning the sufficiency of PEF's demonstration that its risk-related decision making was adequate under the circumstances. While the Company has identified numerous risks with both projects, it is not clear that the Company has met 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").

<u>ENGINEERING, PROCUREMENT AND CONSTRUCTION (EPC) CONTRACT SIGNING</u>

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. HAVE ANY OTHER UTILITY COLA FILINGS FOR A NEW NUCLEAR PLANT INCLUDED A REQUEST FOR AN LWA IN THEIR COLA APPLICATION?

A. No they have not. The most somewhat similar filing is Georgia Power's request for an LWA in their Early Site Permit application for Vogtle Units 3 and 4. However, the Vogtle site is an existing nuclear plant site with well known geology and the geology at the Vogtle site is much less complex than the geology at the LNP site. It really holds little analogous value for the LNP site. PEF effectively had no precedent upon which to assume that the NRC would not take a conservative position regarding the review of the requested LWA especially in light of all the factors surrounding the October 6, 2008 letter.

Q. DID THE PEF CONTRACTOR RESPONSIBLE FOR THE GEOTECHNICAL INVESTIGATIONS AT THE LEVY SITE HAVE QUALITY ASSURANCE PROBLEMS?

A. Yes they did. PEF's subcontractor, CH2MHILL experienced numerous quality assurance breakdowns that required PEF to issue a stop work order until the deficiencies were corrected. In addition, there were other delays in completing the geotechnical work upon which the LWA and safety-related COLA determinations were jointly based. Although not known at this time, these quality assurance concerns and delays possibly could have impacted the NRC staff's willingness to accept the data to meet the very aggressive schedule for a unique and complex site. At a minimum the mere possibility of NRC concerns should have alerted PEF to proceed conservatively in its risk mitigation actions.

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.

(Miller Deposition Transcript, Volume 1, page 43, lines 10-14, Exhibit WRJ(PEF)-3, Pages 40-41 of 233.)

The EPC contract would have required extensive revisions to the cost and schedule if the Company had known that the LWA would not be issued. It would have also not placed them in the weak renegotiating position in which they now find themselves.

Q. THE COMPANY APPEARS TO BLAME THE SUSPENSION OF THE PROJECT TOTALLY ON NOT RECEIVING THE LWA. DID YOU FIND EVIDENCE THAT THERE WERE OTHER REASONS FOR THE SUSPENSION?

A. Yes. PEF was clearly concerned about their capital plan for new nuclear units given the known risks.

In an April 15, 2009 letter to the Progress Energy Board of Directors, William D. Johnson, Progress Energy Chairman, President and Chief Executive Officer states:

[redacted]

[Emphasis Added]. (William D. Johnson letter to Progress Energy Board of Directors dated April 15, 2009 09NC-OPCPOD3-61-000049 Exhibit WRJ(PEF)-3, Pages 42-62 of 233.)

It is clear from this letter to the PGN Board and the Levy Nuclear Project Update dated April 17, 2009 (and attached to that letter) that many other factors contributed to the need to adjust the capital plan for new nuclear units.

Q. WHAT ARE THE "LANDSCAPE CHANGES" THAT ARE IDENTIFIED IN THE APRIL 17, 2009 BOARD PRESENTATION?

A. The April 17, 2009 presentation to the Progress Energy Board of Directors identifies the following "Landscape Changes" that have potential to impact the Levy project.

- **Capital Market Deterioration**
  - Share price near or below book value
  - Our sector no longer holding up
  - Debt market concerns (unsecured)
- **Federal Energy Policy Landscape**
  - Climate change
  - Nuclear/coal policies
  - Renewables
  - Environmental regulation
- **Broad economic indicators continue to show weakness**
  - Prospects for late 2009 / early 2010 recovery uncertain
  - Impact on load/energy
  - Customer ability to pay
- [redacted]
- **Florida regulatory / legislative climate**
  - Price Impact
  - Potential legislation

These landscape changes reveal a large number of concerns held by Progress Energy executive management. These concerns were evident even before the EPC contract was signed. Some of these concerns were evident as far back as September 2008 when a schedule contingency strategy was being discussed, continuing up through the 2009 EPC cost spending caps imposed in the fourth quarter of 2008.

Q. WHAT CONDITIONS ARE IDENTIFIED TO PROCEED WITH THE LEVY PROJECT?

A. The April 17 Board presentation identifies the following conditions to proceed with the Levy project:

- [redacted]

- [redacted]

Q. DOES THE APRIL 17 BOARD PRESENTATION IDENTIFY BENEFITS OF THE PROPOSED SCHEDULE DELAY FOR LNP?

A. Yes it does. The presentation identifies the benefits of delaying the LNP schedule including providing additional time for and certainty on:

- Obama Administration nuclear position
- Financial market and economic rebound
- Customer/policy maker support
- PEF rate case, first NCRC prudence hearing
- Federal policies on carbon, renewables and coal
- JO participation
- NRC COLA process
- Commodity/labor stabilization

Q. WHAT IS THE RELEVANCE OF THE ABOVE FACTORS TO THE COMPANY'S DECISION TO EXECUTE THE EPC CONTRACT?

A. These concerns are not new. They were all known well before (and on) December 31, 2008 when PEF executed the EPC contract. A more reasonable, cautions 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. Although the incremental impact of the signing of the EPC contract may not be known at this time, the Company believes that it is likely that the overall cost of the project will increase. At this time the Commission does not likely have sufficient information to determine the short or long-term impacts of the premature signing of the EPC contract.

Q. PLEASE DISCUSS THE COMPANY'S FAILURE TO HAVE FIRM COMMITMENTS FROM JOINT OWNERS AT THE TIME OF THE SIGNING AND THE IMPACT OF THIS FAILURE.

A. Many project documents indicate that acquiring joint owner partners is a critical factor in the success of the project and that a strong tie existed between having joint owners committed to the project and execution of the EPC contract. The October 2008 and December 2008 Nuclear Plant Development Performance reports identify "Finalizing Joint Ownership decisions" and "Joint Ownership Discussions" as Key Issues. (Progress Energy Nuclear Plant Development Performance Report October 2008, page 5, 09NC-OPCPOD1-47-019364 and Progress Energy Nuclear Plant Development Performance Report December 2008, page 5, 09NC-OPCPOD1-47-013518, Exhibit WRJ (PEF)-3, Pages 63-109 of 233). The April 17, 2009 Board presentation discussed above identifies "Sufficient co-ownership" as a necessary condition to proceed with the project. As I discussed above, the Levy Integrated Nuclear Committee was told repeatedly that the joint owner negotiation and the signing of the EPC contact were closely tied. (See, Exhibit WRJ(PEF)-3, Pages 12-25 of 233.)

Inexplicably, despite these factors, PEF signed the EPC contract with no joint owner commitments.

Q. DID YOU FIND EVIDENCE THAT THESE RISKS WERE APPROPRIATELY ANALYZED AND THE INFORMATION WAS TRANSMITTED TO THE BOD?

A. No I did not. The December 10, 2008 Chairman's Report describes Mr. Johnson's discussion of the Levy Project with the Board. The report states that Mr. Johnson reviewed the conditions to proceed with the Project including an appropriate level of joint ownership. He also reviewed the status of co-owner negotiations. From this summary of the December 10 Board meeting, it is not evident that Mr. Johnson informed the Board of the lack of an LWA or the possible impact on the project of the failure to receive an LWA on the schedule requested by PEF. It is also not apparent that the Board was informed that no co-owners were likely to have committed to the project at the time the EPC contract would be signed. (Minutes of Regular Board of Directors Meeting, December 10, 2008, Chairman's Report 09NC09NC-OPCPOD7-89-000038, Exhibit WRJ(PEF)-3, Pages 110-111 of 233.)

Q. COULD THE COMPANY HAVE WAITED UNTIL THE NRC'S DECISION ON THE LWA WAS KNOWN AND JOINT OWNERS COMMITTED BEFORE SIGNING THE EPC CONTRACT?

A. Yes. The Company could have continued to support necessary activities such as support of the COLA and site characterization under existing agreements with the project contractors until the LWA schedule and joint owner participation was known. In addition, this would have allowed for additional clarity related to other concerns identified by the Company including the capital market deterioration, the indications of broad economic weakness and the legislative and regulatory climate.

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?

[redacted]. 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.

<u>INADEQUATE FEASITILITY STUDY</u>

Q. DID THE COMPANY CONDUCT AN ADEQUATE FEASIBILITY STUDY AS REQUIRED BY THE NUCLEAR COST RECOVERY RULES?

A. No, they did not.

Q. WHAT ARE THE RELEVANT REQUIREMENTS OF THE RULES?

A. Rule25-6.0423(5)(c)5, F.A.C., provides that:

> 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 the project.

Rule 25-6.0423(8), F.A.C., provides that,

> A utility shall, contemporaneously with the filings required by paragraph (5)(c) above, file a detailed statement of project cost sufficient to support a Commission determination of prudence…

Q. PLEASE DESCRIBE YOUR CONCERNS WITH THE COMPANY'S FEASIBILITY STUDY IN MORE DETAIL.

A. Mr. Miller in his testimony and in his deposition of July 2, 2009 stated that the project is feasible. He offers general statements concerning similar projects in China, project success in schedule, less greenhouse gases, energy diversity, less vulnerability to supply disruptions and foreign government influences and other favorable attributes. He offers no detailed costs as required by the rule except for an update of the fuel and emission costs with no discussion of the effects of such updates on overall feasibility. The Company simply did not conduct a detailed analysis of the long term feasibility of the project as required by the Rule.

Q. WHAT DOES PEF CLAIM TO CONSIDER IN ITS FEASIBILITY CONSIDERATIONS?

A. In Mr. Miller's deposition, he states:

> When we consider feasible, we consider is it technically feasible? Is the AP1000 design as deployed at this site, the Levy site, are there any technical issues that suggest that will not work? We also consider regulatory feasibility or, if you will, the legal feasibility. Can you secure all of the permits, approvals, authorizations, licenses, like zoning permits and comprehensive -- comprehensive land use amendment, things like that? And in those cases and for both the technical and, as I described, this regulatory feasibility, the project still is feasible. Now we also consider cost, and so as we go forward, as we said earlier, on an ongoing basis, we will always consider the total project cost and make informed decisions of moving the project forward.

(Miller deposition 7/2/2009, Volume I, page 82, Exhibit WRJ(PEF)-3, Pages 112-114 of 233.)

Q. IS MR. MILLER CORRECT IN HIS ASSESSMENT OF THE LONG TERM FEASIBILITY OF THE PROJECT?

A. There is not enough information provided for Mr. Miller or the Commission to reach such a conclusion. He states that there are three areas of consideration by PEF: technical feasibility, regulatory feasibility and cost feasibility. There are major questions in each area.

Q. PLEASE EXPLAIN THESE MAJOR QUESTIONS.

A. I will address each area separately:

- Technical feasibility. In the EPC contractor's report of May2009, the contractor states [redacted] Letter from Shawn Hughes, Westinghouse-Shaw, to Jeff Lyash, May 11, 2009, page 6 of 52 of attachment. Exhibit WRJ(PEF)-3, Pages 115-168 of 233.)

- Regulatory Feasibility. The site problem discussed above is also a regulatory problem. Additionally, Mr. William D. Johnson, Chairman, President and CEO of Progress Energy told his Board of "Landscape Changes" affecting the project. These changes include federal energy policy landscape and Florida regulatory/legislative climate. (Letter from William D. Johnson to PEF Board, April 15, 2009, page 4 of attachment. Exhibit WRJ(PEF)-3, Pages 42-43 of 233.)
- Cost Feasibility. Mr. Miller states that they are sticking with their last year's (2008) cost estimate because they won't have an updated cost estimate that until after the EPC contract is renegotiated. The truth is that PEF does not currently have an accurate cost estimate. Among other things, to have such a plant cost estimate PEF will have to have a project schedule and a renegotiated EPC contract, and they have neither. Additionally, Mr. Johnson pointed out to his Board that in the document discussed above that there are other "Landscape Change" that are affecting cost feasibility. These include financial partner negotiations (no joint owner's as of yet) and capital market deterioration.

Q. IS MR. MILLER TELLING THE COMMISSION THE SAME THING THAT MR. JOHNSON IS TELLING HIS BOARD?

A. It appears not. Mr. Miller in his May 1 testimony states that "...the essential reasons the Company selected the LNP to meet customer needs for future generation capacity have not fundamentally changed." (Miller testimony, May 2, 2009, page 26, lines 5-7. Exhibit WRJ(PEF)-3, Pages 169-170 of 233.) A few days earlier, Mr. Johnson was telling his Board that there are now conditions for PEF to consider in deciding whether and when to proceed with the Levy project. Among these conditions are a renegotiated EPC agreement, sufficient co-ownership, credible financing plan and continued regulatory support. He points out "landscape changes" and that a 20 or 36 month schedule change will allow "additional time for certainty" on a number of issues including Obama administration nuclear position, joint owner participation, and financial markets. A project is not feasible in just a theoretical sense; instead, Levy must be feasible to the Florida ratepayers and to PEF. Mr. Johnson pointed out to his board a number of reasons why the project may not feasible for PEF and PEF has apparently made a decision to take a 20 or 24-36 month hiatus to allow further clarity on a number of key issues.

Q. IN HIS RESPONSE TO OPC'S INTERROGATORY 47, MR. MILLER CLAIMS THAT "THE COST OF A PROJECT IS NOT PER SE DETERMINATIVE OF PROJECT FEASIBILITY." DO YOU AGREE?

A. No. While project cost is not the sole factor in determining if a project is feasible, if the cost of a project is high enough, the cost may, in fact, determine the feasibility of the project. Cost cannot be ignored in the Commission's determination of feasibility.

Q. WHAT DO YOU CONCLUDE ABOUT PEF'S ANALYSIS OF PROJECT FEASIBILITY?

A. My conclusions are as follows:

- The requirements of the NCRR have not been met. At this time, there is no accurate plant cost data and no detailed analysis as required by the Nuclear Cost Recovery Rule.

- The feasibility of the project cannot be determined without an estimate of the project cost.
- Serious questions concerning plant technical feasibility exist.
- Mr. Johnson has raised other serious feasibility questions with his Board that Mr. Miller has not discussed with this Commission.

The Commission should either: (1) enter a finding rejecting the Company's claim of feasibility, (2) spin the issue off for a feasibility determination based on a more detailed inquiry or (3) defer its determination of this issue until next year.

<u>CRYSTAL RIVER 3 EPU PROJECT</u>

Q. PLEASE BRIEFLY DESCRIBE THE CRYSTAL RIVER UNIT 3 EXTENDED POWER UPRATE PROJECT.

A. The Crystal River 3 extended power uprate project adds a total of 180 MWe to the existing plant. This is accomplished by increasing reactor power output and thus steam output, increasing the size and efficiency of the steam turbine and generator and increasing the accuracy of instrumentation in the plant's steam system. The project is being carried out in three phases. The Phase 1 improved the steam plant measurement accuracy of process parameters and allowed the power output to be increased by about 12 MWe. These improvements were made in 2007 and were placed in service on January 31, 2008. Phase 2 of the project will replace large portions of the steam turbines and the electric generator thus increasing efficiency and output from the current steam flow while also giving the plant the ability to utilize more steam. Using the current ability of the reactor to produce steam, phase 2 will add 28 MWe additional output because of increased efficiency. Phase 2 will be completed in 2009. Phase 3 will increase the reactor output of steam by an additional 15.5%. This additional steam will then utilize the increased capacity installed in phase 2 to provide an additional 140 MWe for a total 1080 MWe and an overall increase of 180 MWe. (Information from Crystal River Unit 3, Extended Power Uprate, Integrated Project Plan, 09NC-OPCPOD1-4-000001, Exhibit WRJ(PEF)-3, Pages 171-197 of 233.)

Q. DID YOU IDENTIFY AREAS RELATED TO THE CR3 EPU THAT YOU BELIEVE ARE EVIDENCE OF INADEQUATE RISK MANAGEMENT?

A. Yes. The CR3 reactor is manufactured by Babcock & Wilcox (B&W). CR3 is the first B&W reactor attempted to be uprated to power levels up to 1080 MWe. The B&W design incorporates steam generators with significantly less water in the steam generators than Westinghouse or Combustion Engineering plants and this means that in some accident analyses there is less capacity for reactor cooling by boiling water out of the steam generators in an accident scenario. This does not mean that the plant is unsafe, by any means, but the safety analysis for the CR3 uprate is different for than for the other pressurized water reactor designs. This size of uprate to a B&W reactor has never before been reviewed by the NRC. The outcome is not a foregone conclusion.

Q. ARE YOU QUESTIONING THE ENGINEERING APPROACH PEF IS UTILIZING INT ITS NRC APPLICATIONS?

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.

Q. **DOES PEF RECOGNIZE THAT THESE RISKS EXIST?**

A. Yes. In their Integrated Project Plan, PEF lists five NRC licensing related items as 'Rank 9', the highest category of risk. These issues must be resolved and the solutions approved by the NRC before Phase 3 of the uprate can be implemented. If the resolutions (changes to plant equipment or operating procedures) are not approved, then the result could be a lower approved uprate level or no allowed uprate in reactor power. If that occurs, then the money being spent for phase 2 in 2009 and for phase 3 in 2010 would be largely wasted.

Q. **HOW IS PEF DEALING WITH THIS RISK?**

A. PEF is planning to file License Amendment Requests (LAR's) with the NRC only after phase 2 is mostly or completely finished. Review and approval of the LAR's could take a year or more. If all goes well in the review, the upgrade should proceed as scheduled.

Q. **ARE THERE REASONS TO BE CONCERNED?**

A. Yes. On May 19, 2008 PEF met with the NRC staff to discuss the upgrade project. At that meeting there were four reactor system issues discussed that would require filings with the NRC for review. Two filings were promised for August 2008, one for October 2008 and another for February 2009. Of these four promised dates, only the February date was achieved as PEF has decided to combine the remaining three filings with the License Amendment Request to be filed at a later date. (NRC Summary of meeting, Adams ML081480504, Exhibit WRJ(PEF)-3, Pages 198-203 of 233.) This deferral to the LAR filings possibly indicates that PEF is having difficulty in meeting NRC requirements. On the original schedule for filing the LAR's, PEF could have had an approval or at least a good indication on likely approval before spending the money for phase 2. At this point, the money will be spent before PEF knows if their proposed solutions will be approved. The NRC noted in its meeting summary that "This project will position Crystal River Unit 3 as the first Babcock & Wilcox plant to operate at over 3000 MWth (1080 MWe)", thus recognizing the unusual nature of the expected request. PEF's response to OPC Interrogatory 71 states that as of July 8, 2009 the resolutions of these issues are not complete and will not be filed with the NRC until the fall of 2009. (PEF response to OPC INT Question 71, received 7/8/2009, Exhibit WRJ(PEF)-3, Pages 204-205 of 233.)

Q. WHAT ARE THE COSTS ASSOCIATED WITH THE EPU PROJECT?

A. Costs from a March 2009 management review are as follows:

Year	Cost (millions $ w/oAFUDC)		%of Total
2006	2.3	(actual)	0.5%
2007	38.4	(actual)	9.0%
2008	65.1	(actual)	15.2%
2009	141.4		33.1%
2010	85.5		20.0%
2011	89.2		20.9%
2012	4.6		1.1%
Total	426.6		

(Nuclear Project Management Review, March 31, 2009-09NC-OPCPOD1-7-000071, Exhibit WRJ(PEF)-3, Pages 206-233 of 233.)

Q. DID PEF FILE THE REQUIRED FEASIBILTY ANALYSIS?

A. No. PEF submitted the annual costs.

Q. HOW MUCH OF THE CR3 EPU BUDGET WILL HAVE BEEN SPENT BEFORE THE COMPANY KNOWS WHETHER OR NOT THE NRC WILL ISSUE A LICENSE FOR THE FULL UPRATE REACTOR POWER?

A. Assuming they will know the results of the NRC review by the end of 2010, approximately 80% of the money will have been spent before it is known if the NRC will grant the full requested power uprate.

Q. COULD THE COMPANY HAVE REDUCED THE RISK BY RESOLVING THE NRC LICENSING ISSUES BEFORE SPENDING THE LARGE SUMS TO MODIFY THE SECONDARY PLANT?

A. Yes. As I stated above, if they had been able to resolve the high risk issues in accordance with the schedule given to the NRC on May 19, 2008.

Q. WHAT ARE YOUR CONCLUSIONS CONCERNING THE EPU PROJECT?

A. Proceeding with phase 2 without completing the NRC review of what PEF themselves have said are high risk issues is comparable to building almost everything in a nuclear power plant except the reactor before knowing if the NRC will approve building the reactor. PEF has not carried its burden of showing that it has accurately assessed the possibility that the NRC will not approve of the full power uprate requested. A lower risk option would have been to receive reasonable assurance of NRC approval prior to spending large sums of money in the implementation of the phase 2 uprate.

V. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR CONCLUSIONS CONCERNING PEF'S FILING IN THIS DOCKET?

A. 1. PEF has not demonstrated that it appropriately considered the known risks to the project when the EPC contract was signed.

2. Premature signing of the EPC contract has exposed the Company to potentially significant additional costs over the life of the LNP project.

3. The cost of the work suspension and the costs during the remainder of 2009 and 2010 are unknown.

4. Since the impact of the suspension of the EPC contract is not known, PEF has not met its burden of demonstrating that the projected costs for 2009 and 2010 are reasonable.

5. PEF's analysis of the continued feasibility of the project is inadequate.

6. The CR3 EPU project faces significant licensing risks which may render the project uneconomic if the NRC does not allow the requested plant modifications to allow the uprate to the full reactor power requested.

Q. WHAT ARE YOUR RECOMMENDATIONS CONCERNING PEF'S FILING IN THIS DOCKET?

A. I recommend the following concerning PEF's filing in this docket:

1. PEF's total revenue requirements should be reduced to reflect elimination of carrying costs related to all estimated EPC costs in 2009 and 2010. Once actual costs are known the related carrying costs can be included in the true up during the next NCRC proceeding.

2. The Commission should consider opening a separate docket to evaluate the long-term feasibility of the LNP and also concurrently order PEF to conduct a detailed feasibility analysis once the EPC contract costs are known.

3. The Commission should order PEF to determine the additional costs that have resulted from signing the EPC contract in December 2008 compared to signing the EPC contract once the actual project schedule was known.

4. The Commission should inform PEF that a prudence review of phase 2 EPU costs will be conducted if the NRC does not grant a license amendment for the full requested uprated reactor power.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DOCKET NO. 090009-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the CONFIDENTIAL Direct Testimony of William R. Jacobs, Jr.,Ph.D. has been furnished by *hand delivery or U.S. Mail to the following parties on this 15th day of July, 2009.

John T. Burnett/Alexander Glenn
Progress Energy Service Company, LLC
P.O. Box 14042
St. Petersburg, FL 33733-4042

James W. Brew/F. Alvin Taylor
1025 Thomas Jefferson St. NW, 8th
Flo, West Tower
Washington, DC 20007

*Mr. Paul Lewis, Jr.
Progress Energy Florida, Inc.
106 East College Ave, Suite 800
Tallahassee, FL 32301-7740

*Anne Cole
Commission Clerk
Room 100, Easley Building
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

J. Michael Walls/ Diane M. Tripplett
Carlton Fields Law Firm
P.O. Box 3239
Tampa, FL 33601-3239

Southern Alliance for Clean Energy, Inc
E. Leon Jacobs
1720 South Gadsden Street MS 14, Ste 20
Tallahassee, FL 32301

Vicki G. Kaufman/Jon C. Moyle, Jr.
Florida Industrial Power Users Group
118 North Gadsden Street
Tallahassee, FL 32301

Charles J. Rehwinkel
Associate Public Counsel

October 6, 2008

Mr. James Scarola, Senior Vice President
and Chief Nuclear Officer
Progress Energy, Inc.
P.O. Box 1551
Raleigh, NC 27602

SUBJECT: ACCEPTANCE REVIEW FOR THE LEVY COUNTY NUCLEAR POWER PLANT UNITS 1 AND 2 COMBINED LICENSE APPLICATION

Dear Mr. Scarola:

By letter dated July 28, 2008, Progress Energy Florida, Inc. (PEF) submitted its application to the U.S. Nuclear Regulatory Commission (NRC) for a combined license (COL) for two AP1000 advanced passive pressurized water reactors in accordance with the requirement contained in 10 CFR Part 52, "Licenses, Certifications and Approvals for Nuclear Power Plants." This letter informs you that the NRC staff has completed its acceptance review and has determined that your application is acceptable for docketing. These reactors will be identified as Levy Nuclear Power Plant (LNP) Units 1 and 2 and are to be located at a site in Levy County, Florida. The docket numbers established for LNP Units 1 and 2 are 52-029 and 52-030, respectively.

The LNP combined license application (COLA) incorporates by reference Appendix D to 10 CFR Part 52 and the AP1000 Design Control Document submitted by Westinghouse as Revision 16. As allowed by 10 CFR 52.55(c), at your own risk, you have referenced a design *certification application that has been docketed but not granted.* Therefore, your COL review schedule is dependent on the review schedule for the design certification. In addition, as a subsequent combined license applicant, your COL application review schedule is also dependent on the review schedule for the Tennessee Valley Authority's Bellefonte Units 3 and 4 COLA (the reference COLA for the AP1000 design center). Because it utilizes the standard content contained in the reference COL application (R-COLA), *it is incumbent upon PEF to* remain cognizant of the resolution of the standard technical issues that will be addressed during the NRC review of the Bellefonte R-COL application. If you determine that it is necessary to resolve a standard issue differently for the LNP Units 1 and 2 COLA, you must notify the NRC immediately so that we may determine the review impact of this standard issue being considered as site specific.

As discussed with your staff, the date that we intend to publish a schedule for review can not be determined until additional information is provided by you. 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 complete and integrated review schedule. Enclosure 1 contains this Request for Additional Information (RAI).

As necessary, other RAIs will be issued separately. Because of the scheduling uncertainty in the areas of geotechnical science and structural engineering, the NRC staff does not intend to commence a review of these areas until all associated RAIs are sufficiently answered. For all other sections of the LNP COLA, the NRC staff intends to commence reviews based on the availability of resources.

Your application submittal letter requested that the NRC consider the following milestones when preparing our complete and integrated review schedule: Final Environmental Impact Statement issuance in June 2010, Limited Work Authorization issuance in September 2010, and COL issuance in January 2012. 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 timeline. The NRC staff expects to interact with you as the safety and environmental review schedules are developed.

Enclosure 2 is a notice of acceptance for docketing. This notice is being forwarded to the Office of the Federal Register. A separate notice will be published in accordance with the provisions of 10 CFR 2.104, regarding the hearing.

Should you have any questions, please contact me at (301) 415-9967 or send an e-mail to Brian.Anderson@nrc.gov.

Sincerely,

/RA/

Brian Anderson, Lead Project Manager
AP1000 Projects Branch 1
Division of New Reactor Licensing
Office of New Reactors

Docket Nos. 52-029
52-030

Enclosures:
1. Request for Additional Information
2. Federal Register Notice

As necessary, other RAIs will be issued separately. Because of the scheduling uncertainty in the areas of geotechnical science and structural engineering, the NRC staff does not intend to commence a review of these areas until all associated RAIs are sufficiently answered. For all other sections of the LNP COLA, the NRC staff intends to commence reviews based on the availability of resources.

Your application submittal letter requested that the NRC consider the following milestones when preparing our complete and integrated review schedule: Final Environmental Impact Statement issuance in June 2010, Limited Work Authorization issuance in September 2010, and COL issuance in January 2012. 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 timeline. The NRC staff expects to interact with you as the safety and environmental review schedules are developed.

Enclosure 2 is a notice of acceptance for docketing. This notice is being forwarded to the Office of the Federal Register. A separate notice will be published in accordance with the provisions of 10 CFR 2.104, regarding the hearing.

Should you have any questions, please contact me at (301) 415-9967 or send an e-mail to Brian.Anderson@nrc.gov.

Sincerely,

/RA/

Brian Anderson, Lead Project Manager
AP1000 Projects Branch 1
Division of New Reactor Licensing
Office of New Reactors

Docket Nos. 52-029
52-030

Enclosures:
1. Request for Additional Information
2. Federal Register Notice

ADAMS Accession No.: ML082760352

OFFICE	DNRL/NWE1:LA	DNRL/NWE1:PM	OGC	DNRL/NWE1:BC
NAME	KGoldstein R. Butler for	BAnderson	SBrock	SCoffin
DATE	10/02/08	10/02/08	10/06/08	10/02/08

OFFICIAL RECORD COPY

Request for Additional Information
Levy County Units 1 and 2
Progress Energy Florida, Inc.
Docket No. 52-029 and 52-030

QUESTIONS for Geosciences and Geotechnical Engineering Branch 1 (RGS1)
SRP Section: 02.05.01 - Basic Geologic and Seismic Information
Application Section: SRP 2.5.1

02.05.01-1
Please summarize the information being used as the technical basis for the dissolution rates presented, including documentation of the basis for indicating that dolomitized limestone dissolves less readily than non-dolomitized limestone, to enable an adequate assessment of karst development as a potential future geologic hazard. Include any references necessary.

02.05.01-2
Reference is made to a "subset" of the regional fracture system which apparently exhibits the same orientation as fractures in the regional fracture system (Attachment 2, pg. 4 of supplement, Karst Discussion).

Please qualify whether these "subset" fractures are simply smaller-scale features (i.e., having a shorter length along strike but the same orientation) than the regional fractures, and discuss whether or not they could exercise local control on dissolution. Please also discuss the pertinence of the observed fracture spacings in the outcrops relative to the regional fracture sets.

02.05.01-3
The supplement states that grouting will inhibit the development of karst by preventing the flow of groundwater through the grouted zones beneath the nuclear island (Attachment 2, pg. 15 of supplement, Permeation Grouting Discussion).

Please address the potential issue of how altering the groundwater flow regime by grouting could affect dissolution below and around the periphery of the grouted zone to assure that this aspect has been considered.

02.05.01-4
The supplement refers to a "shelf" within the Avon Park Formation defined by lowered shear wave velocity measurements (Attachment 2, pg. 15 of supplement, Permeation Grouting Discussion).

Please qualify this "shelf" in the Avon Park Formation to clearly indicate lithology involved relative to composition, thickness, lateral distribution, and material properties.

Enclosure 1

02.05.01-5
The supplement lists assumptions and postulations used to calculate lateral dimensions of borehole features (Attachment 2, pg. 7 of supplement, Karst Discussion - Excess Grout Takes), and states that 9.9 ft is the maximum lateral extent of dissolution cavities at depth. Considering a fracture spacing of 19 ft., if dissolution developed along two parallel fractures with this spacing, then the resulting cavity could easily exceed 9.9 ft. if the two cavities coalesced at depth.

Please discuss the uncertainty involved in the estimate of a 9.9 ft. maximum lateral extent for dissolution cavities and the potential for coalescing dissolution cavities at depth.

02.05.01-6
The supplement cites Dr. A. Randazzo (Attachment 2, pg. 7 of supplement, Karst Discussion - Excess Grout Takes) as supporting the statement that the horizontal dimension of dissolution features associated with vertical fractures is a fraction of the vertical dimension, but does not summarize the information documenting the statement that lateral extent of dissolution features developed along fractures is about 20% of the vertical dimension.

Please summarize the evidence, with appropriate references, for the statement that lateral extent of dissolution features related to fractures is only about 20% of their vertical dimension.

02.05.01-7
The supplement refers to estimates as "conservative" for definition of a 10-ft. maximum lateral extent for dissolution voids at any depth (Attachment 2, pg. 8 of supplement, Karst Discussion - Excess Grout Takes), even though subsurface investigations do not appear to clearly document this lateral limit due to borehole spacing and depth.

Please summarize the evidence leading to the conclusion that dissolution cavities will be no greater than 10 ft. in lateral extent, since that dimension is used as the basis for design of the RCC. Please discuss whether or not it is anticipated that voids of that size presently exist within the proposed grout zone and explain the approach that will be followed if large voids are discovered based on grout takes.

QUESTIONS for Geosciences and Geotechnical Engineering Branch 1 (RGS1)
SRP Section: 02.05.02 - Vibratory Ground Motion
Application Section: SRP 2.5.2

02.05.02-1
Please describe your plans for ensuring the shear wave velocity post-grouting was appropriately represented in the site response analyses you performed in your previous calculation of the GMRS.

02.05.02-2
Please provide additional justification why geophysical tools, such as resistivity, microgravity, and seismic tomography, were not used to characterize the extent of subsurface voids at depth. Please also describe your plans for any post-grouting geophysical testing to assure that dissolution cavities are filled and demonstrate post-grouting uniformity of the site.

QUESTIONS for Geosciences and Geotechnical Engineering Branch 1 (RGS1)
SRP Section: 02.05.04 - Stability of Subsurface Materials and Foundations
Application Section: SRP 2.5.4

02.05.04-1
Please provide a sufficiently detailed discussion to justify that the borings adequately characterize karst at depth at the site, and that the existing borehole spacing is sufficient to characterize the lateral dimension of dissolution cavities and assess their correlation and interpreted lack of connectivity between boreholes.

02.05.04-2
The Avon Park Formation may contain dissolution voids, soil-filled dissolution voids, and highly variable strengths of subsurface rock materials based on Rock Quality Designation (RQD), shear wave velocity measurements, and compressive strength test results from intact samples.

a. Please provide a more detailed explanation of how the supporting rock profile was modeled in the Finite Element (FEM) analysis. Include a detailed explanation of how the material properties for subsurface materials supporting the RCC were determined for application in the FEM. Indicate how variability in the rock mass, voids and low density soil-filled voids were modeled in the FEM.

b. Please describe how the results from the FEM were compared with shear strength in the Avon Park Formation in the static and dynamic bearing capacity calculations. Please provide sample calculations.

c. Please describe how rock mass properties were determined for use in the U.S Army Corps of Engineers (USACE) bearing capacity equations you referenced, and provide a sample calculation for bearing capacity using the USACE method for static and dynamic loads.

d. Please indicate how the limestone supporting the RCC meets the uniformity requirements for subgrade reaction.

02.05.04-3
The supplement states that, because incremental shear stresses at El -150 ft were only 2 psi, characterization of subsurface conditions below this depth were considered to be adequate and, consequently, settlement magnitudes were deemed to be appropriate.

a. Given the small number of borings, please discuss the basis for the conclusion that larger voids which may collapse and consequently affect settlement do not exist below El -150 ft.

b. Please provide a sketch of the rock profile assumption, including rock mass elastic properties used in the elastic settlement analyses. Provide a sample calculation using the Boussinesq stress distribution down to 2B. Please indicate how rock mass elastic properties for the settlement calculation were determined and how karst features were incorporated into the rock mass property determinations for settlement analysis.

QUESTIONS for Structural Engineering Branch 1 (AP1000/EPR Projects) (SEB1)
SRP Section: 03.08.05 - Foundations
Application Section: 3.8.5.1

03.08.05-1
Under, SRP Section 3.8.5, "Foundations," the staff reviews the adequacy of foundations of all Seismic Category I structures. A foundation is a structural element that connects the superstructure and the supporting medium, such as soils or rocks. The purpose of the foundation is to hold the superstructure in place and to transmit all loads of the superstructure to the underlaying soils or rocks.

Levy FSAR Section 3.8.5.1, "Description of the Foundations," references FSAR Section 2.5.4, "Stability of Subsurface Materials and Foundations," for a description of the foundation depth of overburden and depth of embedment. FSAR Section 2.5.4 describes that, below the NI basemat, a 35-foot thick RCC bridging mat will be used to transmit the NI loads under static and dynamic conditions to the karst foundation. However, details regarding how this bridging mat will transform the NI loads to the karst foundation are not provided.

Staff requests the applicant to:

(a) Describe the methods used to transmit the static and dynamic loads of the NI through the bridging mat to the karst foundation, and justify the use of the RCC bridging mat between the NI basemat and the karst foundation.
(b) Provide requirements of material, installation, and compaction for the RCC bridging mat, and the analysis and design methods for the bridging mat.

COL Progress Energy - Levy County Mailing List (Revised 09/29/2008)
cc:

Ms. Michele Boyd
Legislative Director
Energy Program
Public Citizens Critical Mass Energy
and Environmental Program
215 Pennsylvania Avenue, SE
Washington, DC 20003

Ms. Georgia Cranmore
Assistant Regional Administrator
NOAA Fisheries Southeast Regional Office
9721 Executive Center Drive North
Saint Petersburg, FL 33702

Mr. James Scarola
Sr. Vice President and
Chief Nuclear Officer
Progress Energy, Inc.
P.O. Box 1551
Raleigh, NC 27602

COL Progress Energy - Levy County Mailing List

Email

APH@NEI.org (Adrian Heymer)
awc@nei.org (Anne W. Cottingham)
brian.mccabe@pgnmail.com (Brian McCabe)
BrinkmCB@westinghouse.com (Charles Brinkman)
chris.burton@pgnmail.com (Chris Burton)
chris.maslak@ge.com (Chris Maslak)
CumminWE@Westinghouse.com (Edward W. Cummins)
cwaltman@roe.com (C. Waltman)
david.lewis@pillsburylaw.com (David Lewis)
david.waters@pgnmail.com (Dave Waters)
dlochbaum@UCSUSA.org (David Lochbaum)
garry.miller@pgnmail.com (Garry D. Miller)
greshaja@westinghouse.com (James Gresham)
gzinke@entergy.com (George Alan Zinke)
jgutierrez@morganlewis.com (Jay M. Gutierrez)
jim.riccio@wdc.greenpeace.org (James Riccio)
JJNesrsta@cpsenergy.com (James J. Nesrsta)
joe.w.donahue@pgnmail.com (Joe Donahue)
John.O'Neill@pillsburylaw.com (John O'Neill)
Joseph_Hegner@dom.com (Joseph Hegner)
KSutton@morganlewis.com (Kathryn M. Sutton)
kwaugh@impact-net.org (Kenneth O. Waugh)
lchandler@morganlewis.com (Lawrence J. Chandler)
Marc.Brooks@dhs.gov (Marc Brooks)
Margaret.Bennet@dom.com (Margaret Bennet)
maria.webb@pillsburylaw.com (Maria Webb)
mark.beaumont@wsms.com (Mark Beaumont)
matias.travieso-diaz@pillsburylaw.com (Matias Travieso-Diaz)
media@nei.org (Scott Peterson)
Mike.Halpin@dep.state.fl.us (Mike Halpin)
mike_moran@fpl.com (Mike Moran)
MSF@nei.org (Marvin Fertel)
nirsnet@nirs.org (Michael Mariotte)
patricial.campbell@ge.com (Patricia L. Campbell)
paul.gaukler@pillsburylaw.com (Paul Gaukler)
Paul@beyondnuclear.org (Paul Gunter)
phinnen@entergy.com (Paul Hinnenkamp)
pshastings@duke-energy.com (Peter Hastings)
RJB@NEI.org (Russell Bell)
RKTemple@cpsenergy.com (R.K. Temple)
robbrinkman@cox.net (Rob Brinkman)
robert.kitchen@pgnmail.com (Robert H. Kitchen)
roberta.swain@ge.com (Roberta Swain)
ronald_m_bright@bellsouth.net (Ronald Bright)

COL Progress Energy - Levy County Mailing List

sabinski@suddenlink.net (Steve A. Bennett)
sandra.sloan@areva.com (Sandra Sloan)
sfrantz@morganlewis.com (Stephen P. Frantz)
Tansel.Selekler@nuclear.energy.gov (Tansel Selekler)
twinkletoesdms@aol.com (Robert and Deborah Smith)
Vanessa.quinn@dhs.gov (Vanessa Quinn)
VictorB@bv.com (Bill Victor)
wwebb3@tampabay.rr.com (Winn Webb)

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

Levy COL Schedule
Jan 23rd, 2009 NRC Telecon

Preliminary Analysis

Jan 25, 2009

Progress Energy

Jan 24th NRC Schedule Telecon
Summary

Date Comparison

	Date Requested in COLA submittal Letter (July 30th, 2008)	Dates from NRC via Telecon on Jan 23rd, 2009
Final EIS issued	June 2010	Sept 22, 2010
LWA Approval	Sept 2010	Dec 5, 2011
COL issued	Jan 2012	Dec 5, 2011

- Four (4) phase process, i.e. without a draft SER (with open items)
- NRC schedule includes 75 days of "management reserve"
- Assumes 30 day response to RAIs
- Allows 7 months for COL hearings
- Assumes review of DCD revision 17 and "standard COLA" (Bellefonte) do not delay Levy review

Jan 24th NRC Schedule Telecon *Summary (continued)*

- PGN requested LWA March 5th, 2008, in advance of the COLA submittal on July 30th, 2008
- NRC states "SER development critical path is governed by Levy geotechnical review"
- NRC states "PGN must meet aggressive RAI response due dates of 30 days"
- NRC states that "LWA [as requested] and COLA geotechnical scope require same critical path duration" and "they do not have the resources to process an LWA"
- Preliminary analysis indicates a ~ 14 to 15 month impact on the Unit 1 inservice date, SSW is confirming analysis
- NRC proposes to transmit schedule on Friday, Jan 30th, 2009

Jan 24th NRC Schedule Telecon
Specific Dates

Environmental Impact Statement (EIS) – (~ 24 months)

	Milestone Description	Estimated Milestone Date
Phase 1	EIS Scoping Complete	May 28, 2009
Phase 2	Draft EIS Issued	Oct 26, 2009
Phase 3	Response to Draft EIS	April 6, 2010
Phase 4	Final EIS Issued	Sept 22, 2010

Safety Evaluation Report (SER) – (~ 31 months)

	Milestone Description	Estimated Milestone Date
Phase 1	RAIs Transmitted to PGN	Feb 11, 2010
Phase 2	Advance SER with No Open Items	Sept 30, 2010
Phase 3	ACRS Review	Feb 20, 2011
Phase 4	FSER issued	May 5, 2011
	COL Issued	Dec 5, 2011

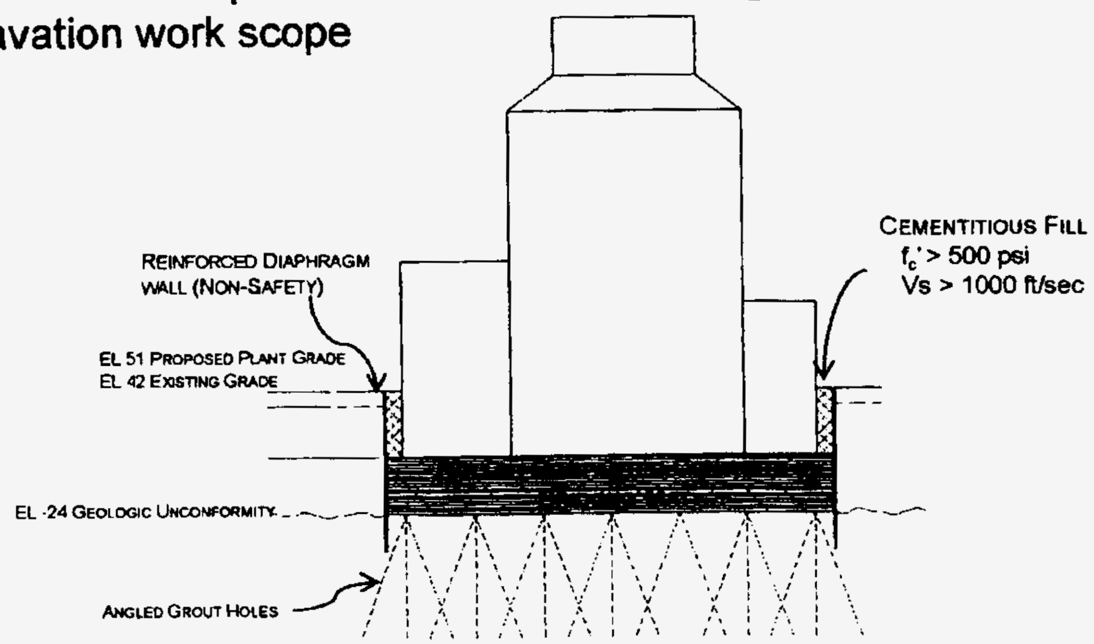
PGN LWA Scope
September 12th 2008 Updated Request

- **Install and retain perimeter diaphragm wall.**
- **Install and retain permeation grouting in the Avon Park Formation**
- Prepare nuclear island foundation surface with dental concrete
- Place RCC under the nuclear islands
- Install mud mat beneath each nuclear island
- Install waterproofing beneath the mud mat under each nuclear island
- Install rebar in the nuclear island concrete foundations
- Erect safety-related concrete placement forms
- Install Turbine Building, Annex Building, and Radwaste Building foundation drilled shafts
- ~~Install circulating water piping between the cooling tower basins and the entrance point to the turbine building condensers~~. *(not required to be LWA)*
- ~~Install the raw water system intake structure and make-up line to the cooling tower basin.~~ *(not required to be LWA)*

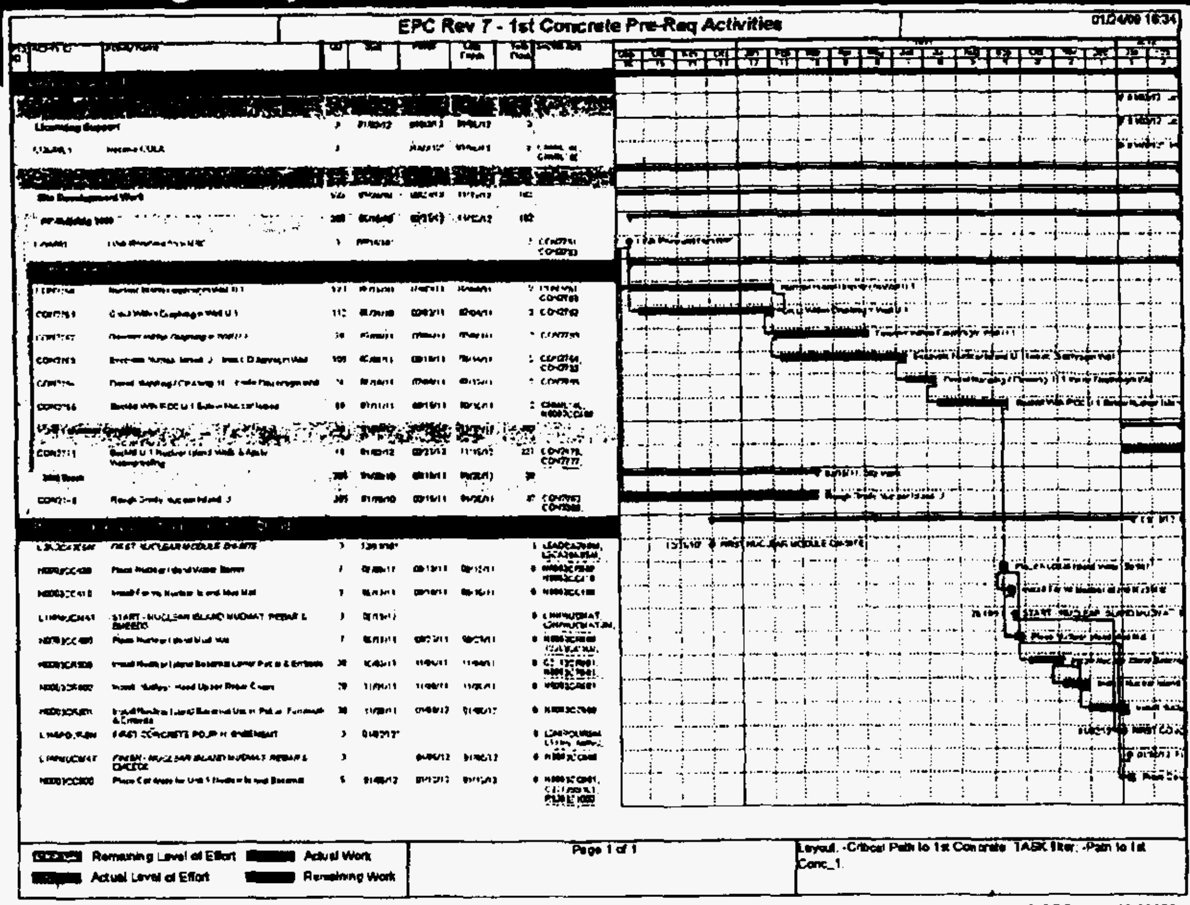
Progress Energy

Recommendations

- Reduce LWA request to include only non-safety related diaphragm wall and grouting scope
- This would then permit non-LWA dewatering and excavation work scope



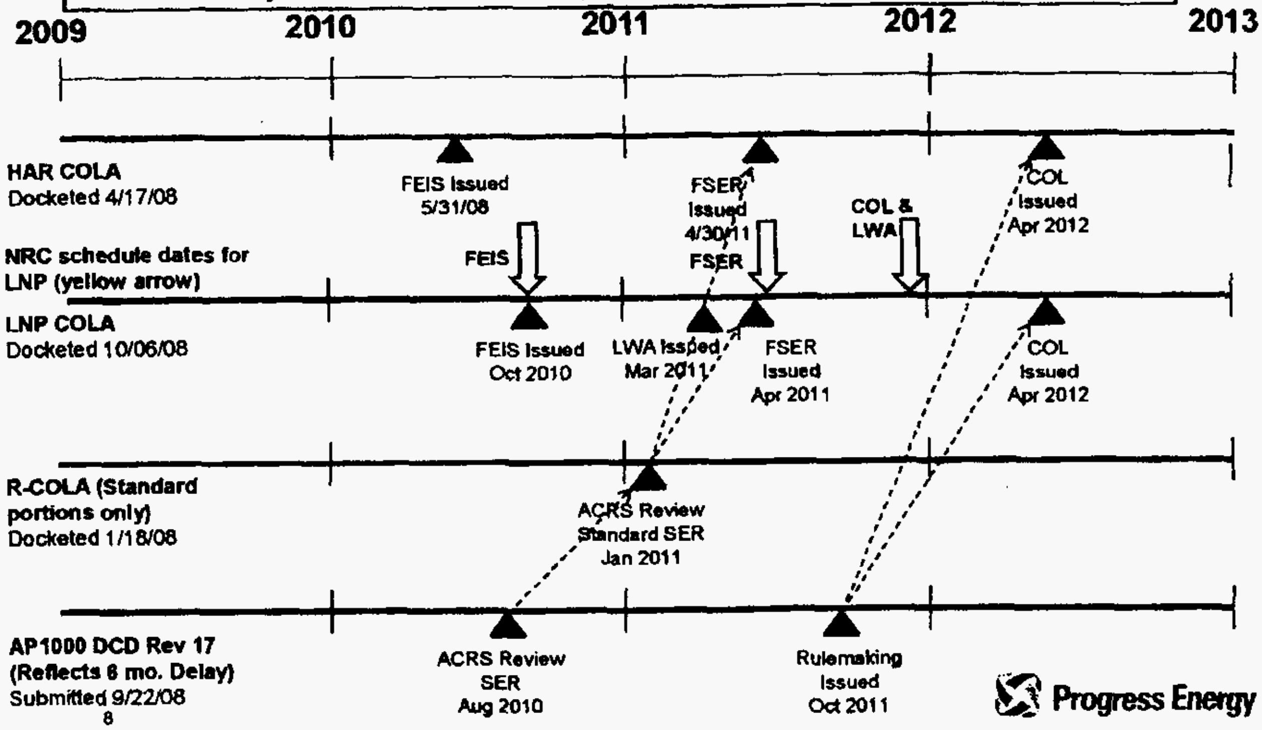
Existing Levy EPC Revision 7 Logic



09NC-OPCPOD3-62-000007

Levy and Harris Interface with AP1000 DCD and Reference COLA

This chart shows what was expected by PGN in Dec 2008 (shown with red darts) versus the Levy dates communicated by the NRC on Jan 23rd, 2009 (yellow arrows).



Progress Energy

09NC-OPCPOD3-62-000006

Progress Energy

Serial: NPD-NRC-2009-061
May 1, 2009

Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Subject: **Levy Nuclear Power Plant, Units 1 and 2**
Docket Nos. 52-029 and 52-030
Notification to Withdraw Request for a Limited Work Authorization

References:
1. Letter from James Scarola (PEC) to NRC (NPD-NRC-2008-022), dated July 28, 2008, "Application for Combined License for Levy Nuclear Power Plant Units 1 and 2, NRC Project Number 756"
2. Letter from James Scarola (PEC) to NRC (NPD-NRC-2008-031), dated September 12, 2008, "LNP COLA Supplemental Information"
3. Letter from Brian Anderson (NRC) to James Scarola (PEC), dated February 18, 2009, "Levy County Nuclear Power Plant Units 1 and 2 Combined License Application Review Schedule"

Ladies and Gentlemen:

Progress Energy Florida (PEF) submitted an application (Reference 1) for a combined license for two AP1000 passive pressurized water reactors to be located at a site in Levy County, Florida.

As part of that application, PEF requested a Limited Work Authorization (LWA) under 10 CFR 50.10(d) be issued before issuance of the Combined License (COL) to allow the early performance of safety-related construction activities. The scope of construction activities requested to be included in the LWA is addressed in Part 6 of the COLA, "Limited Work Authorization and Site Redress Plan." In that application, Progress requested the NRC consider the following milestones:

* June 2010 - Final Environmental Impact Statement (FEIS) Issued
* September 2010 - LWA Issued
* January 2012- COL Issued

PEF did not include in the original LWA scope work to install the Diaphragm Wall and Grouting required for excavation. Because these activities are a necessary prerequisite to excavation at Levy without excessive dewatering, PEF considered these activities to be pre-construction activities under 10 CFR 50.10(a)(2)(v). These activities were to only be

Progress Energy Carolinas, Inc.
P.O. Box 1551
Raleigh, NC 27602

employed as a means to limit groundwater intrusion into the excavation for the nuclear island and do not have a reasonable nexus to radiological health and safety or common defense and security. As agreed in discussions with the NRC as needed to find the COLA acceptable for docketing, PEF revised the COLA to include the diaphragm wall and grouting in the scope of the LWA request, but stated if further NRC review resulted in a determination that the diaphragm wall and grouting may be conducted as pre-construction work, PEF's intent would be to remove these activities from the LWA scope in order to achieve schedule and cost efficiency benefits associated with the originally proposed LWA work (Reference 2).

The NRC published the review schedule for the Levy COLA on February 18, 2009 (Reference 3). That letter identified that the FEIS would be issued no earlier than September 2010. In that letter, NRC stated the following: "During a January 23, 2009, teleconference call, we discussed with members of your staff how the complex geotechnical characteristics of the Levy County site relate to the LWA review. We understand now that you plan to modify the scope of activities requested in the LNP LWA. Upon receipt of your letter which identifies the current planned scope of LWA activities, we will prepare a review schedule related to the LNP Units 1 and 2 LWA. As such, the dates provided in Table 1 represent milestones related to COL issuance alone."

Subsequent to NRC issuing the February 18, 2009 letter, PEF has studied how the scope of LWA activities could be modified and still provide a meaningful schedule advantage and construction cost efficiencies compared to starting construction activities once a COL was issued. Because the originally requested LWA activities cannot be commenced before the COL, the schedule benefits and efficiencies in construction work originally envisioned by Progress cannot be achieved. Furthermore, there is no significant benefit to performing the diaphragm wall as an LWA activity without the grouting work as that would not allow excavation to proceed. As stated in the NRC schedule letter of February 18, 2009, Progress's suggested milestones and proposed scope for LWA activities are not feasible due to the timeframe for the NRC to review the complex geotechnical characteristics of the Levy site. Therefore, there appears to be no significant benefit in continuing to pursue an LWA.

Progress remains committed to meeting the identified need of its Florida customers for efficient and effective baseload power that also accomplishes the State's objectives for adequate fuel diversity and security, reducing greenhouse gas emissions, lessening reliance on more volatile priced fossil fuels, and increasing reliable baseload power plant capacity. PEF continues to believe that maintaining the option of constructing nuclear power plants at Levy is important to achieving these objectives. It appears there is no significant benefit for an LWA to balance the schedule risk that could arise from splitting effort between LWA and COL reviews. PEF concludes that the objectives of preserving the option for nuclear power to meet its Florida customers' needs can be facilitated by concentrating review efforts on issuing the COL, particularly because it is clear an LWA would not accomplish the objectives of Progress's original proposal. As a result, PEF has decided to no longer pursue an LWA, and is hereby notifying NRC that it is withdrawing its request for an LWA and requests that the NRC not continue to perform any review activities associated with an LWA.

Conforming changes to the COLA to reflect the removal of the LWA are not being proposed at this time, but will be included in the annual update of the FSAR and accompanying changes to the environmental report and other COLA Parts.

If you have any questions, or need additional information, please contact me at (919) 546-6107 or Bob Kitchen at (919) 546-6992.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on May 1, 2009.

Sincerely,

Garry D. Miller

Garry D. Miller
General Manager
Nuclear Plant Development

cc : U.S. NRC Director, Office of New Reactors/NRLPO
U.S. NRC Office of Nuclear Reactor Regulation/NRLPO
U.S. NRC Region II, Regional Administrator
Mr. Brian C. Anderson, U.S. NRC Project Manager

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: NUCLEAR POWER PLANT COST RECOVERY CLAUSE / Docket No: 090009

DEPOSITION TRANSCRIPT

Volume I, Pages 1-103

DEPOSITION OF: GARRY DALE MILLER

TAKEN AT: Carlton Fields
4221 W. Boyscout Boulevard, Suite 1000
Tampa, Florida

DATE & TIME: July 2, 2009
Commencing at 9:00 a.m.

REPORTED BY: Penny M. Appleton, RPR
Notary Public

Berryhill & Associates, Inc.

501 E. Kennedy Boulevard, Suite 775

Tampa, Florida 33602 (813) 229-8225

expectation.
Q Okay. If you had gotten -- just for purposes of this discussion, it's true that you signed the engineering procurement and construction contract with the consortium of Shaw Stone & Webster and Westinghouse Electric Company on December 31st?
A That is correct.
Q Okay. Of 2008. Is that right?
A That is correct.
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.
Q Okay. All right. Do you have an idea how it would have been modified?
A Probably, similar to what we're doing right now in our ongoing negotiations.
Q Would you have signed it by the end of 2008?
A I do not know whether we could have concluded the changes necessary to finish those changes in advance of December 31st.
Q Okay.
A For your scenario of December 1st.
Q Right. And that's purely hypothetical. I

Progress Energy

William D. Johnson
Chairman, President
and Chief Executive Officer

April 15, 2009

BOARD OF DIRECTORS
PROGRESS ENERGY, INC.

CONFIDENTIAL

We will use the attached presentation in our Board conference call this Friday, April 17, at 1 p.m. (call-in number: 888-363-4735; access code 5814305). The purpose of the call is to discuss our near-term plan and year-end options regarding the Levy nuclear project in Florida.

[redacted]

[redacted]
- [redacted]
- [redacted]

[redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

P.O. Box 1551
Raleigh, NC 27602

T > 919 546 6463
F > 919 546 3210

CONFIDENTIAL

CONFIDENTIAL

[redacted]

Redacted - Non-responsive

[redacted]

If you have questions before our call, please let me know.

Sincerely,

WDJ/dj

CONFIDENTIAL

Levy Nuclear Project Update

April 17, 2009

Progress Energy

CONFIDENTIAL

Today's Agenda/Decisions

- Input on options for Levy based on NRC schedule and other issues
- Impact of public announcement of schedule shift
- Key 2009 milestones and decisions to be made before 12/31/09
- Customer impact and other economic effects of schedule shift
- Related regulatory and other rate filings
- Other potential impacts

CONFIDENTIAL

CONFIDENTIAL

Conditions to Proceed with Levy Project

Levy Project Success Factors

[redacted]

Levy Project Must Support Our Financial Success Factors

[redacted]

CONFIDENTIAL

Landscape Changes

	Potential Implications
Capital market deterioration Share price near or below book value Our sector no longer holding up Debt market concerns (unsecured)	**Ability to raise capital**
Federal energy policy landscape Climate change Nuclear/coal policies Renewables Environmental regulation	**Timing and support for new nuclear**
Broad economic indicators continue to show weakness Prospects for late 2009/early 2010 recovery uncertain Impact on load/energy Customer ability to pay	**Resource planning impacts/ challenging rate environment**
[redacted]	CONFIDENTIAL [redacted]
Florida regulatory/legislative climate Price impact Potential legislation	**Timing and support for new nuclear**

CONFIDENTIAL

Adjustments to Strategy

- Minimize nuclear capital expenditures prior to issuance of combined operating license (COL)
- Reduce external capital requirements over next two to three years to allow financial markets to recover
- Provide time for greater clarity in federal climate change policy

CONFIDENTIAL

Levy Options

- Option 1 – 20-month shift for Levy 1, Unit 2 follows 18 months
- Option 2 – 36-month shift for Levy 1, Unit 2 follows TBD
- Option 3 – 36-month shift for Levy 1, Unit 2 follows 18 months
- Option 4 – Preserve COLA

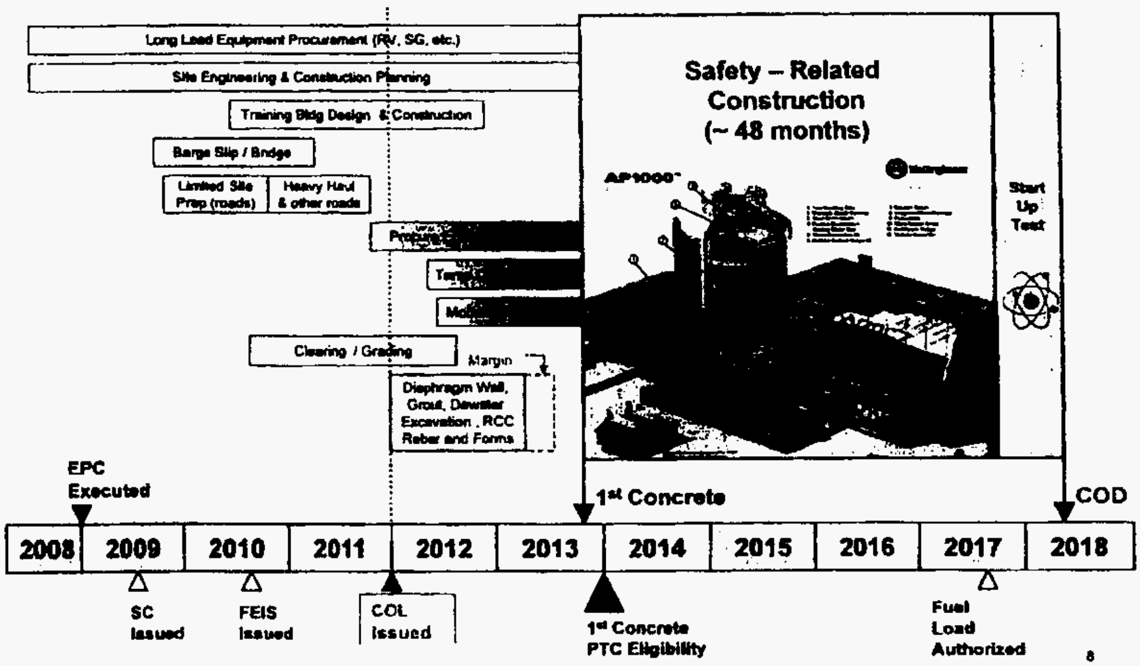
CONFIDENTIAL

20-Month Shift Alternative

- Alter Levy construction schedule
  - Shift Unit 1 by 20 months – April 2018
  - Unit 2 completion to follow by 18 months
  - Transmission shift remains flexible
- Outcome
  - Accommodates expected LWA outcome
  - Provides additional time for and certainty on:
    - Obama Administration nuclear position
    - Financial market and economic rebound
    - Customer/policymaker support
    - PEF rate case, first NCRC prudence hearing
    - Federal policies on carbon, renewables and coal
    - JO participation
    - NRC COLA process
    - Commodity/labor stabilization
  - [redacted] CONFIDENTIAL
  - Minimizes near-term customer price impact

CONFIDENTIAL

20-Month Shift – Levy Schedule
Adjusted Pre-Construction Activities (dates are approximate)



8

CONFIDENTIAL

CONFIDENTIAL

Levy Regulatory Milestones and Illustrative Cash Flows

[redacted]

CONFIDENTIAL

36-Month Shift Alternative

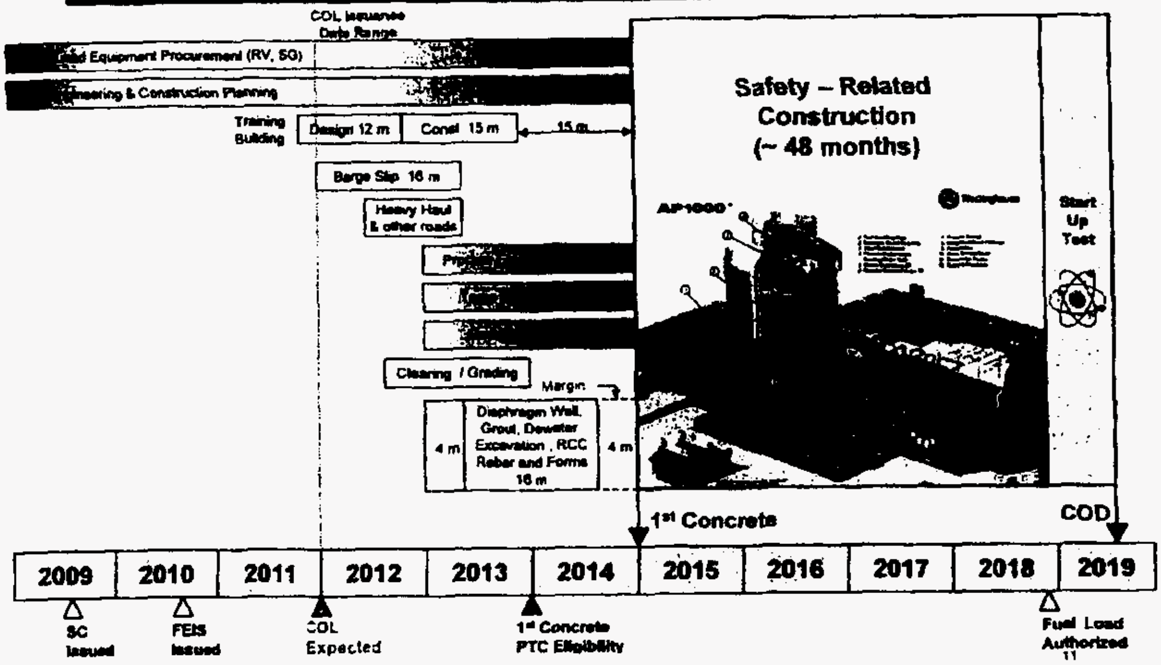
(Bold Italics denotes differences from 20 month shift)

- Alter Levy construction schedule
  - ***Shift Unit 1 to June 2019 (~36 months)***
  - Unit 2 completion to follow by 18 months
  - Transmission shift remains flexible
- Outcome
  - Accommodates expected LWA outcome
  - Provides additional time for and certainty on:
    - Obama Administration nuclear position
    - Financial market and economic rebound
    - Customer/policymaker support
    - PEF rate case, first NCRC prudence hearing
    - Federal policies on carbon, renewables and coal
    - JO participation
    - NRC COLA process
    - Commodity/labor stabilization
  - [redacted] CONFIDENTIAL
  - Minimizes near-term customer price impact

CONFIDENTIAL

36-Month Shift – Levy Schedule (COD mid-2019)

Adjusted Pre-Construction Activities (dates are approximate)



CONFIDENTIAL

CONFIDENTIAL

Illustrative Example Only

Consolidated Financial Impact ($ millions)

Capital Markets Requirements – 2 Units @ 50%, 36-Month Shift

[redacted]

CONFIDENTIAL

Nuclear Cost Recovery Filing – May 1

- Annual Nuclear Cost Recovery Clause (NCRC) filing on May 1
- Primary issues

Redacted - Privileged

[redacted]

CONFIDENTIAL

Next Steps

CONFIDENTIAL

- [redacted]
- [redacted]
- [redacted]
- File nuclear cost recovery petition on May 1
- Make public announcement of schedule shift on May 1
- [redacted]

CONFIDENTIAL

Summary

- **Levy nuclear remains vital to PE's Balanced Solution**
- **Basis for shift in planned commercial operation**
  - Necessary to align project timing with NRC LWA schedule
- **Provides additional benefits**
  - Reduces near-term capital expenditures
  - Provides near-term customer price relief
  - Allows for more certainty in federal electric industry policy
  - Allows settling of economy and financial markets
- **PE remains committed to new nuclear in FL**
  - Strongest state on policy support for new nuclear
  - Early local, regional and state support have aided project
- **Ongoing evaluation and deliberate, cautious approach are prudent given our risk environment**

CONFIDENTIAL

Alternative Strategic Investment Options for PEC

Redacted - Non-responsive

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

Redacted - Non-responsive

[redacted]

CONFIDENTIAL

Redacted - Non-responsive

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

Progress Energy

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

CONFIDENTIAL

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: NUCLEAR POWER PLANT COST RECOVERY CLAUSE /

Docket No: 090009

DEPOSITION TRANSCRIPT

Volume I, Pages 1-103

DEPOSITION OF: GARRY DALE MILLER

TAKEN AT: Carlton Fields
4221 W. Boyscout Boulevard, Suite 1000
Tampa, Florida

DATE & TIME: July 2, 2009
Commencing at 9:00 a.m.

REPORTED BY: Penny M. Appleton, RPR
Notary Public

Berryhill & Associates, Inc.

501 E. Kennedy Boulevard, Suite 775

Tampa, Florida 33602 (813) 229-8225

year project that you have to start and maintain a commitment to go through. If we were to stop and start every year based on the changes in those tables, that would be unproductive and inefficient and not in the best interest of our rate payers.

Q Okay. Well, I guess we'll get into those when we talk about the feasibility analysis that -- that you've done, but you state here on Line 20 -- 20, starting with, PEF accordingly remains committed to the project, and the LNP remains feasible. What is your definition of feasible as is used in your testimony here?

A When we consider feasible, we consider is it technically feasible? Is the AP1000 design as deployed at this site, the Levy site, are there any technical issues that suggest that will not work? We also consider regulatory feasibility or, if you will, the legal feasibility. Can you secure all of the permits, approvals, authorizations, licenses, like zoning permits and comprehensive -- comprehensive land use amendment, things like that? And in those cases and for both the technical and, as I described, this regulatory feasibility, the project still is feasible.

Now we also consider cost, and so as we go forward, as we said earlier, on an ongoing basis, we will always consider the total project cost and make informed decisions of moving the project forward.

Q Okay. So is this term "feasible" that's on Line 22 of Page 15 -- is that the same as is used in Section 6 or Roman Numeral 6 of your testimony, Page 25, Lines 7 and 8? Is that the same definition of feasible?

A Okay. Give me the lines again, please.

Q I'm sorry. Page 25.

A Right.

Q And the question and answer on 7 and 8, Lines 7 and 8.

A Right. Is the Levy Nuclear Project still feasible? Yes. And if you drop down and look at Line 16 --

Q Uh-huh?

A -- the technology continues to represent a viable and feasible choice. And then Line 18, which is feasible as from a project milestone prospective, this has to do with -- it's inferring that you're able to secure the regulatory approvals you need to continue that -- the project, except the LWA as noted.

Q Okay. Is -- is cost a factor in that Q and A that starts on Line 10 and continues -- of Page 25 and continues on to Page 26?

A Well, it shows up -- if you look at this question, you can see the way it's structured. You see Line 11 starts with sort of a technology feasibility. Line 18 is going

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

09NC-OPCPOD3-60-000029

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

09NC-OPCPOD3-60-000039

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

09NC-OPCPOD3-60-000050

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Cost Recovery Clause

DOCKET NO. 090009
Submitted for filing:
May 1, 2009

CONFIDENTIAL

DIRECT TESTIMONY OF GARRY MILLER IN SUPPORT OF ACTUAL/ESTIMATED AND PROJECTED COSTS

ON BEHALF OF PROGRESS ENERGY FLORIDA

Company. There will be a schedule shift, but there is no reason now to believe that the SCA, COL, or any other permit needed for the LNP will not be issued and, therefore, the Company is confident the LNP can be completed.

Additionally, the essential reasons the Company selected the LNP to meet customer needs for future generation capacity have not fundamentally changed. PEF continues to need base load capacity in the future and new, advanced-design nuclear power remains the best available technology to provide reliable, base load electric service and to make significant reductions in greenhouse gas emissions. PEF and Florida continue to need a more diverse energy portfolio to reduce their reliance on fossil fuels such as coal, natural gas, and oil that can be volatile in price, subject to supply disruptions, and susceptible to foreign government and market influences. The LNP, accordingly, continues to be the best base load generation option, taking into account all the reasons PEF committed to the project in the first place.

Q. **Does the project remain feasible despite the schedule shift?**

A. Yes, it does. The Company has analyzed the schedule shift, and it remains committed to the LNP to bring new nuclear generation to the State of Florida and its customers. Shifting the project for this time period is a reasonable and prudent course of action, given the unexpected events that have transpired.

Crystal River Unit 3

Extended Power Uprate

Integrated Project Plan

MASTER NUMBER: 20058849

Sponsoring Business Unit:	Nuclear Engineering
Funding Legal Entity:	Progress Energy Florida
Date Prepared:	March 02, 2009

Treasury Control No.	**20061181**

Key Project Contacts:

Role, Department / Group	Name	Phone No.
Sponsor, VP Nuclear Engineering	Joseph Donahue	770-3638
GM-NP	Steve Huntington	240-4800
Major Projects Manager, EPU	Steve Huntington	240-4752
EPU Engineering Superintendant,	Ted Williams	240-4356
EPU Implementation Superintendant	Paul Ingersoll	240-1076
Regulatory	TBD	240-4983
Project Controls	Terry Hobbs	240-4746

Plan Revision Control

Rev No.	Primary Author(s)	Revision Description	Rev Date
0	Ted Williams	Initial publication	3/18/2008
0	Mark Hickman	Initial Publication	3/18/2008
Updated	Steve Huntington	Update for 2009 March SMC Review	3/3/2009

The following sections were updated:

Key Project Contacts
Plan Revision Control
Review & Approval
Project Overview/Recommendation
NP EPU Milestone Variance Report
Funding Requirements & Update
Economic Evaluation
PLU Risk Status Report
Contracting & Procurement Strategy
Environmental Plan
External Stakeholders
Internal Stakeholders
Project Assurance Plan
Communication Plan/Next Steps

Review & Approval

This section contains formal sign-offs for both review & approval of the IPP. "Reviewing" applies to any party reviewing the IPP for accuracy & clarity, while "Approving" applies to those parties responsible for approving project milestone progression & funding.

Reviewing Party	Reviewing Position	Rev Reviewed	Signature	Date
T. Williams	Engineering Superintendant, EPU			
T. Hobbs	Manager, Major Projects Project Controls		[illegible]	3/24/09
J. Terry	SGR Project Manager		[illegible]	3/24/09
S. Huntington	Manager, Major Projects - EPU		[illegible]	3/31/09
J. Franke	Director Site Operations CR3			
L. Hatcher	Crystal River Plant Manager- Fossil			
J. Donahue	VP, Nuclear Engineering		[illegible]	3/31/09

Approving Party	Approving Position	Rev Approved	Signature	Date
Tom Sullivan	VP, Treasurer & CRO			
Jeff Corbett	Sr. VP Energy Delivery Carolinas			
Michael Lewis	Sr. VP Energy Delivery Florida		Michael V. Lewis	3/5/09
Jeff Lyash	President and CEO, PGN Florida		[illegible]	3/6
Lloyd Yates	President & CEO PGN Carolinas			
John McArthur	Sr. VP Corporate Relations & General Counsel			
Mark Mulhern	Sr. VP Finance			
Paula Sims	Sr. VP Power			
Jim Scarola	Sr. VP & CNO			
Peter Scott	President & CEO Service Co., CFO PGN			
William Johnson	Chairman, CEO, and President PGN			

Approving Party	Approving Position	Rev Approved	Signature	[illegible]
Tom Sullivan	VP, Treasurer & CRO			
Jeff Corbett	Sr. VP Energy Delivery Carolinas			
Michael Lewis	Sr. VP Energy Delivery Florida		See previous page	
Jeff Lyash	President and CEO, PGN Florida		See previous page	
Lloyd Yates	President & CEO PGN Carolinas			
John McArthur	Sr. VP Corporate Relations & General Counsel			
Mark Mulhern	Sr. VP Finance		Mark S Mulhern	3/3/09
Paula Sims	Sr. VP Power			
Jim Scarola	Sr. VP & CNO		J. Scarola	3/5/09
Peter Scott	President & CEO Service Co., CFO PGN			
William Johnson	Chairman, CEO, and President PGN			

AGENDA

1. Project Overview / Recommendation:

Crystal River Unit 3 (CR3) was initially licensed to operate at a maximum core thermal power level of 2452 MWt. In Technical Specification Amendment 41, dated July 21, 1981, the NRC approved operation of CR3 up to 2544 MWt. Subsequently, Amendment 228 was issued by the NRC on December 26, 2007 approving a steady-state maximum core power level increase to 2609 MWt.

The implementation of the CR3 Power Uprate Project is an important element of the Progress Energy Balanced Solution. A Measurement Uncertainty Recapture (MUR) power uprate was completed in January 2008. The MUR modifications allow CR3 to operate up to 2609 MWt and have delivered an increase of approximately 12 MWe gross from 899 to 911 MWe gross. NPC is pursuing thermal efficiency improvements at CR3 scheduled for implementation in 2009 for an additional 28 MWe gross for a total station output of approximately 940 MWe gross, and an Extended Power Uprate (EPU), which raises reactor power 15.5% from 2609 MWth to 3014 MWth with an expected increase of gross electrical output of 140MWe gross for a total station output of 1080MWe gross. The completion of the final steps of the EPU is scheduled for implementation in 2011.

The CR3 Uprate Project will result in economic benefits to customers and the community by providing additional clean energy at low cost to Progress Energy Florida (PEF) consumers. The corresponding electrical output increase of the plant's gross output from 899 MWe to 1,080 MWe can serve the equivalent of an additional 110,700 homes. The need for the project is based on projected load demand and an economic need to provide fuel savings for consumers. The CR3 Uprate Project is expected to save customers more than $2.6 billion in gross fuel costs through 2036.

The MUR project element has been completed and resulted in the expected plant power up-rate to 911 MWe. The remaining scope elements of the CR3 EPU project will be installed during the next two refueling outages in 2009 (R16) and 2011 (R17). The R16 phase will increase the steam plant efficiency. The R16 upgrades have been scheduled for implementation during the 2009 planned refueling outage to take advantage of the steam generator replacement project schedule window. The R16 turbine center line component design improvements will increase the efficiency of power production resulting in decreased consumer costs. The low pressure turbines and electrical generator and exciter will be replaced in 2009. The #3A and B Condensate heat exchangers, turbine cycle steam moisture separators, and other steam cycle improvement modifications will also be implemented in 2009. The net impact of these modifications is a substantially more efficient (approximately 3%) secondary plant. Thus, while the Nuclear Regulatory Commission (NRC) licensed power level will remain constant at 2609 MWth, the gross electrical power generation increase from current levels of 911 MWe through the R16 phase is expected to be an additional 28 MWe.

Prior to implementing the planned power up-rate in the R17 outage, CR3 will need to obtain an NRC license revision to allow operation at the increased output of approximately 3014 MWt excluding reactor coolant pump heat. The set of project scope elements to be implemented during R17 will result in an additional 140 MWe of power. This will require revisions to the various control systems set points, the High Pressure Turbine and a large number of smaller yet substantial modifications to the Booster Feed Water pumps, Condensate pumps, and various valves and piping segments to assure the capability and long term reliability of all plant systems at the conditions necessary to support this higher licensed power level.

No alternative generation option exists that can supply the benefits of additional, reliable, base load at an equivalent net savings to PEF customers. The CR3 Uprate Project will also increase the level of nuclear production in the fuel supply mix of PEF's system, resulting in increased fuel diversity for PEF and the State of Florida. The total cost for the up-rate is estimated to be $462 million. This total cost includes the construction of new forced draft cooling towers to meet PEF's Environmental Stewardship and regulatory requirements. The Co-Owners responsibility of 8.2% of costs will offset the final costs to PEF.

Additional cooling towers are needed to remove thermal energy from the discharge canal. Furthermore it is necessary to limit or avoid increased circulating water flow into the discharge canal.
PEF will also develop and implement a long-term solution replacing or making permanent the additional discharge canal cooling currently being addressed by the Modular Cooling Towers (MCT) installed in 2006 for CR Units 1 and 2. The MCT project was determined to be recoverable through the Environmental Cost Recovery Clause (ECRC) in Docket 060162, Order No. 07-0722. PEF will seek recovery of the funds for the MCT permanent solution through the ECRC. This will partially offset the associated costs for the MCT portion of this project.

The business case for the CR3 power up-rate was developed to seek funding from either corporate sources or through the Fuel Adjustment Clause. On February 8, 2007 the Florida Public Service Commission (FPSC) approved the Petition for Determination of Need for Proposed Expansion of Crystal River Unit 3 Nuclear Power Plant (Docket No. 060642-EI). The determination of need included the request for approval to utilize the Fuel Adjustment Clause as a source of funding for the EPU Project. Subsequent interaction with the FPSC resulted in a redirection to instead seek recovery through the New Nuclear Clause.

The volume of work to be implemented in the two outage cycles and the resultant challenges to logistical and resource management will require the use of some new and advanced project management tools. Examples include 4 dimensional modeling for critical staging and work areas and the development of creative solutions for personnel ingress and habitation scenarios

2.0 Scope Statement:

The MUR installation and testing was completed in January 2008. Since the initial IPP was approved, we have determined that the turbine bypass valve mufflers will be replaced as part of this project.

In order to support EPU Steam Cycle Efficiency Improvements the following Modifications will be implemented during the 2009 16R Refueling. This outage affords the advantage of a longer than normal refueling outage because of steam generator replacement.

- 16R Refueling Outage 2009 BOP Efficiencies
    - Turbine/Generator (940 MWe)
        - (2) Low Pressure Turbine replacements
        - Generator Stator Winding and Core Iron replacement (63 days)
        - Generator Rotor replacement
        - Exciter Replacement
    - (2) Turbine Generator Lubricating Oil Cooler tube bundle replacements
    - (4) Moisture Separator Reheater replacements
    - (2) Condensate Heat Exchanger replacements
    - (8) Heater Drain Valves and piping segment replacements
    - (2) Secondary Cooling Heat Exchanger, Pump Impeller and Motor replacements

- (2) Moisture Separator Reheater "Belly Drain" Heat Exchanger additions
- Iso-phase Bus Duct Cooler and Fan Housing Replacement
- ICS updates
- Plant Process Computer (PPCS) modifications
- Replacing the Turbine By-Pass Valves and Mufflers

- 17R Power Uprate 2011. (RX + 15.5%,TG 1080MWe)
  - High Pressure Turbine replacement
  - ICS updates and Safety System Modifications
  - De-aerator Bypass line addition or new De-aerator
  - (2) Atmospheric Dump Valve replacements
  - (2) Booster Feed Pumps Impellers and Motor replacements
  - (2) Condensate Pumps
    - Variable speed direct drive
    - May require two additional 6.9KV Breakers to be installed
  - (2) Emergency Feed Water Pump Steam admission and instrumentation upgrades
  - LPI Cross-tie for Core Flood Line Break mitigation
    - Core Offload required to support implementation
  - Plant Process Computer modifications

- Point Of Discharge Cooling and Flow Mitigation
  - Mitigate the thermal load introduced into the Discharge Canal
  - Provide a long term solution to the temporary Modular Cooling Towers

CONFIDENTIAL

[redacted]

[redacted]:

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted] (1) [redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted].

CONFIDENTIAL

[redacted]

CONFIDENTIAL

[redacted]

CONFIDENTIAL

4.0 Funding Requirements & Update:

CR3 EPU Proposed IPP:

[redacted]

Project Costs	[redacted]
Direct Cost	
Contingency	
Burdens / Allocations	
Financial View Total	
AFUDC	
Total Project Cost	
Joint Owner *	
Total Project Cost including AFUDC net Joint Owner	

**Point of Discharge/Cooling Tower Work is not Joi* [redacted]

[redacted]

Project Costs	[redacted]
Direct Cost (Surplus Inventory/Incremental Cost)	
Burdens / Allocations	
Financial View Total	

[redacted]

CONFIDENTIAL

[redacted]:

[redacted]

[redacted]

[redacted]

[redacted] derates [redacted] with low [redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL

Progress Energy [redacted]

[redacted]

[redacted] R16 [redacted] R17 [redacted]

[redacted]

[redacted]

[redacted]

09NC-OPCPOD1-4-000015

CONFIDENTIAL

Progress Energy [redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

09NC-OPCPOD1-4-000016

CONFIDENTIAL

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]:

- [redacted].
- [redacted].
- [redacted].
- [redacted].
- [redacted].
- [redacted].

CONFIDENTIAL

[redacted]

CONFIDENTIAL

Progress Energy

[redacted]

[redacted]

[redacted]

Contract/PO Purpose	Subcontractor Selected	Status
NSSS/BOP Engineering Services	AREVA	Issued
Turbine Generator Fabrication and Installation	Siemens	Issued
Moisture Separator Reheaters, MSRs	Thermal Engineering International	Issued
Condensate and Secondary Cooling Heat Exchangers	YUBA	Issued
16 R SC Pump and Motor	Flow Serve	Issued
16R/17R Rigging	Barnhart Crane & Rigging Co.	Issued
16R/17R Disposal and Storage	MHF Logistical Solutions	Issued
17R Installation	TBD	Pending
17 R Pumps and Motors	TBD	Not Started
Leading Edge Flow Meter	Cameron	In Close Out
Turbine Bypass Valves	Areva	Pending
EPU Large Bore Welding	Pending	Pending
CR3 POD Cooling Towers Engineering, Procurement and Construction	Eng. Vendor: Mesa P&C: Evaptech	In Process
16 R CWO's fpr BOP Installation of all Secondary Side Components in 2009	Atlantic	In Process

Two MSR Shell Drain Heat Exchangers	Holtec International	Issued
ISO Phase Bus Duct Cooling Unit	Powell Delta/Unibus	Issued
Turbine Generator Lube Oil Cooler Tube Bundles	Holtec International	Issued
Installation of Secondary Side Insulation	ESI Group, Inc.	Issued
Qual of SG @ EPU Conditions 3030 Mwth	BWC	Issued

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

6.2.2 [redacted]

[redacted]

6.3 Regulatory Strategy:

6.3.1 Permitting

There are two primary regulatory 'permits' required: 1) Site Certification from the Florida Department of Environmental Protection (FDEP), and 2) License Amendment from the NRC. PEF received an amended "Conditions of Certification" or COC for Units 3, 4, and 5, in August 2008. CR3 was not issued a separate COC. The COC recognizes PEF's intention to construct a new cooling tower to mitigate thermal impacts from the EPU in order to maintain compliance with the existing NPDES permit.

The primary approval for the Extended Power Uprate change in Rated Thermal Power by the NRC will be an extensive license amendment request scheduled to be filed in mid 2009. As other separable items or issues are identified they will be pursued earlier and separately to allow the EPU to be as straight-forward as possible. The initial effort will be to meet with the appropriate NRC staff to determine if formal review and approval is necessary.

The inputs to the EPU LAR as well as any other regulatory approvals are addressed in the overall project schedule and controlled like any other project task.

6.3.2 Public Service Commission History

In 2006, PEF filed for a Determination of Need from the Florida Public Service Commission (FPSC). On February 2nd, 2007 the FPSC granted the Need Determination. In 2008, the PFSC issued a declaratory statement that determined the Uprate FPL was planning, could be recovered under the provisions of Section 366.93, Fla. Stat., and Rule 25-6.0423, F.A.C. This statement was determined to be applicable to our Uprate as well and allows PEF to recover the carrying costs associated with the Uprate through the Capacity Cost Recovery Clause while under construction and provides for an increase in base rates once the Uprate is placed in-service.

Pursuant to the requirements of the above legislation and Rule, PEF must file testimony each year presenting our actual costs from the prior year for a decision on their prudence as well as actual estimated costs for the current year and projected costs for the coming year. In 2008, PEF asked for recovery of approximately $24 million in carrying and other costs associated with the Uprate. PEF also requested a base rate increase effective the first billing cycle of 2009 for the MUR portion of the Uprate that was placed in-service in January of 2008. The FPSC approved PEF's requests and determined that costs spent through the end of 2007, had been prudently incurred. In 2009, PEF will again be filing the above referenced items with the FPSC requesting a determination of prudence on 2008 expenditures and in support of our 2010 rates.

[redacted]

[redacted]

CONFIDENTIAL

Progress Energy

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

7.0 External Stakeholders:

- *Nuclear Regulatory Commission-License Amendments*
- *Florida Department of Environmental Protection - Site Certification and Permits*
- *Florida Public Service Commission-Recovery Through Special Clauses or Base Rates*
- *PEF Customers*
- *CR3 Co-owners*
- *Local Leaders*
- *AREVA Engineering Services - NSSS/BOP/Fuels America*
- *Worley Parsons-Subcontracted to AREVA*
- *Heat Exchange Services-Subcontracted to AREVA*
- *Dresser Industries subcontracted to AREVA*
- *Siemens-Turbine Generator*
- *Thermal Engineering International - MSRs*
- *YUBA Heat Exchanger- CDHE/SCHE*
- *Flow Serve - Pumps and Motors*
- *B&W Canada-ROTSG Reconciliation*
- *Barnhart- Heavy Hauling*
- *Atlantic Construction - Field Implementation*
- *MHF - Disposal of Old Components*
- *Sargent & Lundy - Cooling Tower Study Phase*

8.0 Internal Stakeholders:

- *Progress Energy Florida*
  - *Jeff Lyash, President*
- *Progress Energy NGG*
  - *Jim Scarola, Chief Nuclear Officer*
- *Nuclear Projects*
  - *Sr. Management*
    - *General Manager, Steve Huntington*
    - *Manager, Project Controls Terry Hobbs*
    - *Manager, Extended Power Uprate Steve Huntington*
    - *Manager SGR Replacement, Jim Terry*
  - *Project Controls-Scheduling*
    - *Supervisor Gene Flavors*
  - *Project Controls-Financial*
    - *Supervisor Ivy Wong*
- *Crystal River 3*
  - *Sr. Management*
    - *VP Dale Young*
    - *DSO Jon Franke*
    - *PGM Jim Holt*
  - *Line Management*
    - *Operations Manager Chuck Morris*
    - *Maintenance Manager Bill Brewer*
    - *Engineering Manager Steve Cahill*
    - *Outage and Scheduling Manager Ivan Wilson*
  - *Engineering*
    - *Design Engineering Harry Oates*
    - *Systems Engineering Barry Foster*
    - *Technical Services Blair Wunderly*
  - *Fossil Operations*
    - *Larry Hatcher*
    - *Mike Olive*

Internal Stake holders and resources will be required to support the project with design meeting reviews, Engineering Change milestone sign offs in Passport, and owner acceptance of completed modifications and configuration deliverables. Coordination between the Steam Generator Replacement Project and the Extended Power Uprate is vital to ensure the new replacement generators will be qualified to operate safely at the new uprate power level. Project Control and Project Support interface is essential to properly monitor schedule adherence with schedule development, key performance indicators, and financial reporting.

CONFIDENTIAL

Progress Energy

[redacted]

[redacted]

[redacted]:

[redacted]:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted].

[redacted]

CONFIDENTIAL

Key Performance Indicators and Milestones

Key Performance Indicators (KPIs) and Milestones will be established and identified on the Project schedule. Milestones and KPIs are controlled by the Project Manager and coordinated through the Project Controls - Functional Lead.

[redacted]:

[redacted].

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		

09NC-OPCPOD1-4-000026

APPENDIX

Definitions & Acronyms:

AIMS: Action Item Management System – A database developed to track internal action items of SGR project team members.

CAF. Containment Access Facility – The structure or area specifically designed to regulate the ingress and egress of radiation workers required to enter the containment building (also known as the reactor building) to accomplish work.

DTP. Detailed Task Plans – Specific plans (modeled after project plans) taken to the task level to provide details on specific tasks required to support the overall project to replace the steam generators.

EC: Engineering Change – A formal document developed by design engineering personnel that provides the technical and administrative controls to ensure modifications made the nuclear facility are compliant with all applicable Progress Energy requirements and the Code of Federal Regulations for nuclear facilities.

EPU: Extended Power Uprate – An increase in developed reactor power and electrical output derived from a combination of steam efficiencies, margin harvest, and reactor power increase.

ERP: Environmental Resource Permit – A permitting process required by state regulations to ensure activities are controlled within environmental standards.

INPO: Institute of Nuclear Power Operations – The organization specifically formed to provide oversight and support to commercial nuclear power stations.

ITS: Improved Technical Specifications – The licensing document that outlines the equipment required to remain operable for operation of the reactor in all modes of operation.

KPI: Key Performance Indicators – visual indicators that are used to provide insights that specific parameters key to the project success are measured and used by management to take corrective actions when these parameters are not s expected.

NBC: Net Benefit to Cost Ratio

NRC: Nuclear Regulatory Commission – The regulatory body that oversees safe operation of commercial nuclear facilities.

NSOC: Nuclear Security Operations Center – The structure that serves as the entry point and exit point for entry into the CR3 protected area.

OTSG/OTSG's: once through steam generators- heat exchangers designed to transfer heat from the reactor coolant system into steam used to drive the steam turbine in the generation of electricity.

QA. Quality Assurance – A specific function internal to the project, designed to ensure activities performed on the nuclear facility or components fabricated in support of operation of the nuclear facility meet the established requirements for quality.

RB: reactor building – one of three designed fission product barriers designed to protect the health and safety of the public from the release of reactor coolant system inventory during a postulated emergency.

SGR: Steam Generator Replacement – The acronym used to describe the project.

WBS. Work Breakdown Structure – The fundamental building block that defines the scope of the steam generator replacement project

June 9, 2008

LICENSEE: Florida Power Corporation

FACILITY: Crystal River Unit 3

SUBJECT: SUMMARY OF MAY 19, 2008, MEETING WITH PROGRESS ENERGY FLORIDA, INC., TO DISCUSS POWER UPRATES AT CRYSTAL RIVER, UNIT 3 (TAC NO. MD8530)

On May 19, 2008, the Nuclear Regulatory Commission (NRC) staff conducted a Category 1 public meeting with Florida Power Corporation, now doing business as Progress Energy Florida, Inc. (the licensee), at NRC Headquarters, One White Flint North, 11555 Rockville Pike, Rockville, Maryland. The purpose of the meeting was to discuss the licensee's plans for an extended power uprate (EPU) for Crystal River Unit 3 and its integration with the license renewal application, balance of plant efficiency improvement, and other EPU-related licensing actions. Enclosure 1 contains a list of attendees. The licensee's slide presentation may be accessed from the NRC's Agencywide Documents Access and Management System Accession No. ML081410862.

DISCUSSION

At the beginning of the meeting, the NRC staff informed the licensee of the recent issuance of a new Office of Nuclear Reactor Regulation (NRR) LIC-109, "Acceptance Review Procedures," which was signed on May 2, 2008, for implementation by the staff. This office instruction, along with its attached document, "A Guide for Performing Acceptance Reviews," provides all NRR staff (and other staff supporting NRR work) a basic framework for performing an acceptance review upon receipt of a requesting licensing action. The NRC staff advised the licensee that linked amendment requests will not pass acceptance.

During the meeting, the licensee provided an overview of the proposed modifications, analyses, and licensing activities that will be performed in support of the power uprates. The measurement uncertainty recapture power uprate that increased thermal power by 1.6 percent was approved on December 26, 2007 and implemented in January 2008. A package of balance of plant efficiencies that will increase thermal power by 0.9 percent is planned for installation in the third quarter of 2009. The licensee is planning to submit an application for Crystal River in the third quarter of 2009. If approved, the licensee would implement this uprate during the 2011 refueling outage that would raise the plant's rated thermal power from 2069 Mwt to 3014 Mwt (~15.5 percent). This project will position Crystal River Unit 3 as the first Babcock & Wilcox plant to operate at over 3000 Mwt.

The licensee is planning to commence plant modifications for power uprate during the 2009 refueling outage and finishing EPU-related modifications in the 2011 refueling outage. In addition, steam generator replacement will take place during the 2009 refueling outage.

Although an independent effort, a license renewal application for Crystal River Unit 3 will also be submitted during the 2009 timeframe.

During the discussions, the NRC staff advised the licensee to provide submittals that contained all necessary information to perform the required reviews, as opposed to submittals which would require multiple rounds of requests for additional information, thus drawing out the approval process. Also, the NRC staff noted that although an environmental assessment will be performed for the license renewal, a separate albeit similar assessment will need to be performed for the EPU. The licensee was also asked by the staff to provide a markup of the RS-001, "Review Standard for Extended Power Uprates," matrix to show how their current licensing basis relates to the guidance.

The licensee is considering four potential issues that may require licensing actions. The first is the need for an exemption for core flood line break with concurrent bus failure on the other train. The NRC advised the licensee to submit the exemption as non-risk-informed for scheduling purposes. The submittal is expected in August of 2008.

The second issue is the small-break loss-of-coolant accident (LOCA) with manual action/mitigation. The licensee will replace the atmospheric dump valves (ADVs) with larger safety relief valves and will expand manual actions to change steam generator level setpoints to also open ADVs, resulting in faster depressurization. The licensing amendment request (LAR) submittal is expected in August 2008.

The third issue is the rod withdrawal (reactivity insertion) methods. Results with the current methods are not acceptable. AREVA plans to submit an operating plant topical report in the fall of 2008. After the NRC provides requests for additional information on similar topical reports for new reactors, the licensee will submit a plant-specific LAR in February 2009.

The last issue is the boron precipitation methods. Current methods will be evaluated under 10 CFR 50.59. If an LAR submittal is required, it is planned for October 2008. Other potential issues are setpoint methodologies, evacuation time estimates, source term, and dispersion factor calculation methodology.

The staff and the licensee are planning additional pre-application meetings on the EPU environmental report plan and technical discussions of the some of the EPU-related licensing activities (e.g., core flood line break and secondary depressurization) in July 2008. Steam generators replacement and its impact on EPU will be discussed in a separate meeting in August 2008.

No commitments or regulatory decisions were made by the NRC staff during the meeting.

Although members of the public were invited, none were in attendance. Public Meeting Feedback forms were not received.

Please direct any inquiries to me at 301-415-1447, or farideh.saba@nrc.gov.

/RA/

Farideh Saba, Senior Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-302

Enclosure: List of Attendees

cc w/encl: See next page

Please direct any inquiries to me at 301-415-1447, or farideh.saba@nrc.gov.

/RA/

Farideh Saba, Senior Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-302

Enclosure: List of Attendees

cc w/encl: See next page

DISTRIBUTION:
PUBLIC
Lpl2-2 R/F
RidsNrrDorlLpl2-2
RidsNrrLACSola (hard copy)
RidsNRRPmFSaba
RidsRgn2MailCenter
RidsAcrsAcnw&mMailCenter

ADAMS Accession No. Meeting Notice: ML081190715
Summary: ML081480504/Slides: ML081410862 Package:ML081480524 NRC-001

OFFICE	LPLII-2/PM	LPLII-2/PM	LPLII-2/LA	LPLII-2/BC
NAME	TOrf:sp	MVaaler for FSaba	CSola	TBoyce
DATE	06/04/08	06/04/08	05/30/08	06/09/08

List of Attendees
U. S. Nuclear Regulatory Commission
Public Meeting with Progress Energy Florida, Inc.
Regarding Crystal River Power Uprates
May 19, 2008

U. S. NUCLEAR REGULATORY COMMISSION

T. Alexion
T. Boyce
E. Brown
Y. Chung
G. Cranston
J. Gavula
A. Hiser
N. Iqbal
S. Jones
B. Kemper
E. Lenning
L. Lund
K. Manoly
R. Mathew
G. Miller
T. Orf
F. Orr
B. Parks
J. Quichocho
F. Saba
C. Schulten
S. Tingen
G. Wilson

PROGRESS ENERGY FLORIDA, INC.

J. France
M. Heath
S. Huntington
D. Varencer
L. Wells
T. Williams
K. Wilson

AREVA NP, INC.

T. Beckham
J. Seals

Enclosure

Progress Energy Florida, Inc.

Crystal River Nuclear Plant, Unit 3

cc:

Mr. Dale E. Young, Vice President
Crystal River Nuclear Plant (NA1B)
ATTN: Supervisor, Licensing
& Regulatory Programs
15760 W. Power Line Street
Crystal River, Florida 34428-6708

Mr. R. Alexander Glenn
Associate General Counsel (MAC-BT15A)
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733-4042

Mr. Michael J. Annacone
Plant General Manager
Crystal River Nuclear Plant (NA2C)
15760 W. Power Line Street
Crystal River, Florida 34428-6708

Mr. Jim Mallay
Framatome ANP
1911 North Ft. Myer Drive, Suite 705
Rosslyn, Virginia 22209

Mr. William A. Passetti, Chief
Department of Health
Bureau of Radiation Control
2020 Capital Circle, SE, Bin #C21
Tallahassee, Florida 32399-1741

Attorney General
Department of Legal Affairs
The Capitol
Tallahassee, Florida 32304

Mr. Craig Fugate, Director
Division of Emergency Preparedness
Department of Community Affairs
2740 Centerview Drive
Tallahassee, Florida 32399-2100

Chairman
Board of County Commissioners
Citrus County
110 North Apopka Avenue
Inverness, Florida 34450-4245

Mr. Stephen J. Cahill
Engineering Manager
Crystal River Nuclear Plant (NA2C)
15760 W. Power Line Street
Crystal River, Florida 34428-6708

Mr. Jon A. Franke
Director Site Operations
Crystal River Nuclear Plant (NA2C)
15760 W. Power Line Street
Crystal River, Florida 34428-6708

Senior Resident Inspector
Crystal River Unit 3
U.S. Nuclear Regulatory Commission
6745 N. Tallahassee Road
Crystal River, Florida 34428

Ms. Phyllis Dixon
Manager, Nuclear Assessment
Crystal River Nuclear Plant (NA2C)
15760 W. Power Line Street
Crystal River, Florida 34428-6708

David T. Conley
Associate General Counsel II - Legal Dept.
Progress Energy Service Company, LLC
Post Office Box 1551
Raleigh, North Carolina 27602-1551

Mr. Daniel L. Roderick
Vice President, Nuclear Projects &
Construction
Crystal River Nuclear Plant (SA2C)
15760 W. Power Line Street
Crystal River, Florida 34428-6708

Mr. David Varner
Manager, Support Services - Nuclear
Crystal River Nuclear Plant (SA2C)
15760 W. Power Line Street
Crystal River, Florida 34428-670

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: NUCLEAR POWER PLANT COST RECOVERY CLAUSE

Docket No. 090009-EI
Served: July 8, 2009

PROGRESS ENERGY FLORIDA, INC.'S SUPPLEMENTAL RESPONSE TO CITIZENS' SIXTH SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA, INC. (No. 71)

Progress Energy Florida, Inc. provides its Supplemental Response to Citizens' Sixth Set of Interrogatories to Progress Energy Florida, Inc. (No. 71) as follows:

INTERROGATORY

Question 71.

At 09NC-OPCPOD1-4-000018 (confidential) risks associated with the CR3 EPU project are identified. How have Risk #'s 473, 239, 241, 475, and 474 been resolved or mitigated? Has the NRC accepted the PEF's proposed resolution of these risks?

Answer

Risks 473, 239, 241, 475, and 474 are EPU risks that are associated with the 2011 project activities. These risks have been evaluated in accordance to the Nuclear Projects Guidance Document NPGD-002 "Information and Process Management". The resolution and mitigation plans have been developed but are not complete at this time.

The NRC has not been formerly requested to accept the resolution strategy. Those requiring NRC review and approval will be included in the EPU License Amendment Report that is scheduled to be submitted the fall of 2009.

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF CITRUS

BEFORE ME, the undersigned authority duly authorized to administer oaths, personally appeared Jon A. Franke, who being first duly sworn, deposes and says that the foregoing answers to Interrogatory No 71 of OPC's Sixth Set of Interrogatories (Nos. 64-72) to Progress Energy Florida, Inc. in Docket No. 090009-EI, are true and correct to the best of his knowledge, information and belief.

(Signature)
Jon A. Franke

THE FOREGOING INSTRUMENT was sworn to and subscribed before me this 8 day of July, 2009 by Jon A. Franke. He is personally known to me, or has produced his ________ driver's license, or his ________ as identification.

Carolyn E Portmann
(Signature)
Carolyn E Portmann
(Printed Name)
NOTARY PUBLIC, STATE OF FL
Mar 1 2010
(Commission Expiration Date)

(Serial Number, If Any)

(AFFIX NOTARIAL SEAL)

CAROLYN E. PORTMANN
Notary Public - State of Florida
My Commission Expires Mar 1, 2010
Commission # DD [illegible]
Bonded By National Notary Assn.

CONFIDENTIAL

Extended Power Uprate Project

Nuclear Projects Management Review

March 31, 2009

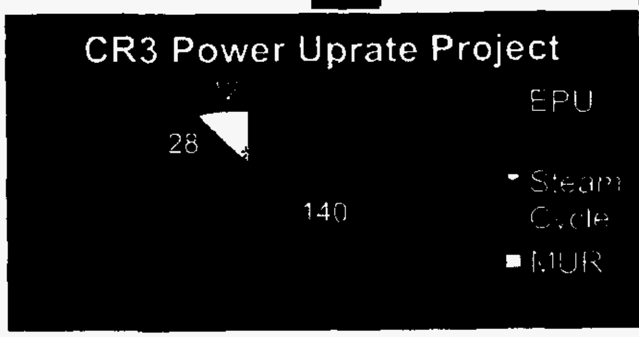
NGG Nuclear Generation Group

Progress Energy

CONFIDENTIAL

Project Overview

- EPU Project Overview
  - Initial Authorization November 2006, [redacted] Financial View BAP
  - Completed Measurement Uncertainty Recovery + [redacted] MWe
  - Steam Cycle Efficiency [redacted] MWe in 2009
  - Extended Power Uprate (EPU) + [redacted] MWe in 2011
  - Point of Discharge (POD) Mitigation concurrent with EPU
  - CR3 Increases Output from [redacted] to [redacted] MWe total
  - IPP Update in March 2008 to [redacted] M EAC. Delivers [redacted] in fuel savings



CONFIDENTIAL

Agenda

- Project Schedule Performance
  - Metric Dashboard Panel
  - Individual Project Task Report
- Risk Management
  - Status Matrix
- Project Cost Performance
- Project Scope Management
- Regulatory / Licensing Activities
- EPU Staffing Progress
- Other Concerns
- Summary

CONFIDENTIAL

Schedule Performance

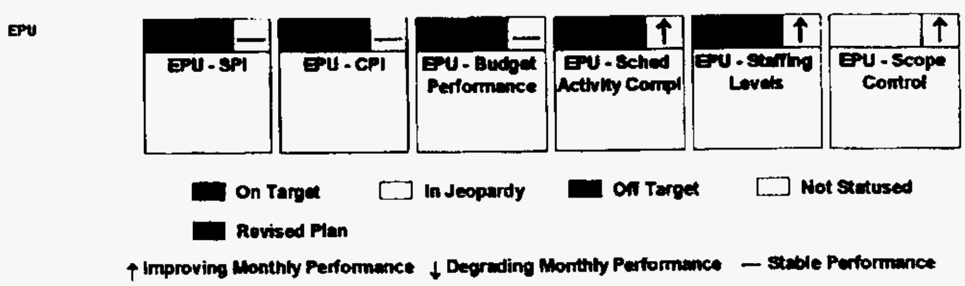
- Schedule Compliance Metric (Activity Started / Completed per project schedule):
  - 100% - 95% = Green, 95%-90% =   , <90% =RED
- Completed new project and task metrics dashboard that will be used for the EPU Project monthly and for the individual project tasks reports. Examples of these are provided on the following slides.
- Metrics include raw cost versus budget, SPI, and EVA analysis per project task and for overall project.
- Overall Project SPI is at [redacted]%

CONFIDENTIAL

Metric Dashboard Panel for EPU

Nuclear Projects EPU Annunciator Panel

February 2009



Progress Energy

09NC-OPCPOD1-7-000075

CONFIDENTIAL

Metric Dashboard Panel for Overall Project (Feb 2009)

EPU Task Overview

[redacted]

Progress Energy

CONFIDENTIAL

Metric Dashboard Panel for Overall Project (Feb 2009)

[redacted]

CONFIDENTIAL

Metric Dashboard Panel for Overall Project (Feb 2009)

[redacted]

CONFIDENTIAL

Schedule Performance
Major Schedule Performance Issues

- Engineering EC Completion schedule originally called for all ECs to be PGM approved by 12/5/2008. *Extended milestone to match* the Outage Milestone date of 1/29/2009. Remaining ECs were completed by the milestone date with the exception of the following:
  - Isophase Bus - PGM approval completed 2/19/09.
  - ICS Rescale - PGM approval completed 2/19/09
  - Turbine Generator - PGM approval completed 2/20/09.
  - Kickoff Meeting for the TBV EC was held on Feb 17th, which resulted in a an agreement to complete the TBV EC by 6/26/2009.
- $ on Line ECs also require attention. Fiber optic backbone, temp power for TB, Turbine Crane uprate, and overall 16R EPU summary EC for margin management.
- Turbine component manufacture schedule held for last 3 months, *but no improvement* from initial slips. Wit[redacted].
- Licensing performance revised Rod ejection analysis LAR submittal 4 weeks. Now scheduled for *February 28, 2009*. Slipped 4 weeks due to new methodology test question data not applicable or representative of actual conditions at CR3. Left no margin at certain accident scenarios. AREVA revising test question now to support CR3 LAR evaluation.
- Insufficient schedule maturity and level of detail developed for Facilities / logistics pre outage efforts, and also for In Processing work. New detailed level 3 schedules are to be published and used for management of the pre outage logistics and in processing work by Thursday of this week.

CONFIDENTIAL

Schedule Performance

Significant Events in February

- Component Engineering work scope is being executed per the schedule.
- Rev. 0 for Turbine and Isophase EC packages complete. Rev. 1 planned (ground straps).
- Pre-outage command center activated on March 1.
- Metrics for pre-outage work established/being tracked.
- POCC team coordinating pre-outage efforts.
  - Temp power
  - Rad tool shake-out
  - Logistics
- Level 3 pre-outage schedule not fully developed.
- Preparation for 180 day Outage Readiness Review is in progress (April 8 & 9)
- 18M2 Turbine Evaluation is in progress; draft for final report is due April 5

Schedule Performance
Vendor Oversight Actions

NGG

Progress Energy

CONFIDENTIAL

Schedule Performance
Vendor Oversight Actions

- Established Detailed Vendor Oversight Plans per major contract
- Established scheduled inspection and oversight events at each of the vendor facilities plus weekly schedule review calls and monthly management oversight meetings.

[redacted]

CONFIDENTIAL

Risk Management

- **Total Risks Identified to date = [redacted]**
- **Red Risks = [redacted]**
- **Yellow Risks = [redacted]**
- **Green Risks = [redacted]**
- **New Risks Uncategorized = [redacted]**

- **Risk mitigation plans are being developed for each red risk and are being reviewed by the Risk Management Team**
  - **Risk categories have been redefined and reassigned**
  - **Meeting membership and dates revised to enable project controls and *project management attendance***
  - **Defined Red Risk Approval at PM level**
  - **Reviewing all open RED Risk Mitigation strategies for appropriate level of approval and ICF / Schedule input.**
  - **Planned task Level Shakedown to generate construction phase risk items**

CONFIDENTIAL

Risk Management

- 19 Red Risks identified in the Evaluation Process
- 239 - 10CFR50.46 criteria may be exceeded at EPU conditions during a CFLB.
- 241 - HPI flow inadequate at EPU conditions for some SBLOCAs
- *229 – NRC Part 26 Fatigue Management*
- 253 - Rod Ejection Analysis Licensing strategy and timeline, NRC Approval Required for Reactivity Insertion Analytical Methods
- 300 - Shutdown Margin Minimum boron requirements
- 355 - Lube Oil Cooler SC System Control Valve Undersized
- 397 - Safety risk of dropped objects
- 421 - Condensate System Flow Balance with MSR Belly Drain installed
- 232 – TBV and Mufflers
- 250 - Reconciliation of ROTSG for EPU conditions may delay License submittal.
- 298 - Decay Heat Pump 1B degraded performance
- 515 - Post Mod testing and integrated start up testing impacts
- *362 - Vendor delivery delays of major components*

CONFIDENTIAL

Risk Management

- 473 - Refuel boron Concentration following R-17
- 475 - Unacceptable Analysis results for Steam Line Break
- 474 - Unacceptable Analysis results for PSC7-78 (Steam Line Break)
- 518 - Vendor Quality not maintained
- 511 – DC Cook Rotor Failure Analysis
- 251 – LPI XTIE not currently in Scope (Refer to Risk 239)

CONFIDENTIAL

Costs Results for February 2009

Financial View Budget for EPU work **for February YTD** is [redacted]1 [redacted]ith actuals of [redacted]for a favorable **variance o**[redacted].

- *POD YTD is under budget by approximately* [redacted] *and will be re-projected per the Engineering and Procurement contracts. After POD contracts are in place and re-projected some portion of the POD budget will be added to the contingency fund.*
- *The insulation contract was budgeted at* [redacted] *for February. No payment is due until pre-outage activities begin. The signed contract is under the budgeted amount.*
- *Facilities is under budget by approximately* [redacted]*. The associated activities are scheduled for completion and payment March-June.*
- *Company & Contract Labor positions including indirect support were favorable* [redacted] *and are be re-cashflowed through second half of 2009;*
- *The contracted services such as Guidant are approximately* [redacted] *under budget and are being re-cashflowed through second half of 2009.*

CONFIDENTIAL

Project Cost Forecast March 2009

[redacted]

PROJECT PLAN
(Updated in March 2009)
(AFUDC for 2009 was re-forecast; AFUDC for 2010-2010 forecast will be reviewed; Plan is subject to change between Financial View/AFUDC with no change to total of $461.5M)

[redacted]

PROJECT LIFE TO DATE ACTUALS

[redacted]

CONFIDENTIAL

Scope Additions

- Common – Storm-water System Design Consultant
- Component Logistics Supervisor / Scheduler added to staffing level
- Update PMAX and Displays
- RV Service Structure Fans
- Revise PSA Analysis
- Fund Design Control Scheme Change
- Add Scope to revise DOSE calculations
- Evacuation Study Required
- Removal of Old Guard Shacks
- Perform revision to SCP EC
- Storm Water Pond Expansion
- 10 additional desks for EPU Trailer 4

CONFIDENTIAL

Environmental Activities

- **Site Certification Modifications or Other Approvals Underway for Related Activities**
  - **Batch Plant/South Lay-down (Mammoet) Approved**
  - **Office Trailers Impact on Storm Water Management Resolved BUT need to Complete related improvements (legacy issue with storm-water pond size)**
  - **Rail Areas Being Resolved**
  - **Cooling Tower Impacts Being Addressed**

CONFIDENTIAL

LAR Challenges

- Rod Ejection Accident Related LAR Submitted this Week
- Required Modification Conceptual Designs Needed (later slide)
- Environmental Qualification Contracts in Place and Progressing. Evaluation, Phase 1, needed for LAR. Schedule will be a challenge. (Details in Later Slide).
- ROSTG Qualification for 3030 MWt
  - RCS Functional Specification Revision Completed
  - BWC Qualification of ROTSG to 3030 MWt Activities
    - Lengthy Commercial Process
    - Master Services Contract Now In Place
    - Currently EPU LAR Critical Path

CONFIDENTIAL

Required Modifications

- **Atmospheric Dump Valves (ADV) Being Replaced with Larger, Safety-Related Valves for Secondary Depressurization**
  - **Need to Complete Conceptual Design**
  - **Related Modifications (to EFIC) and Failure Modes and Effects Need to be Completed and Summarized in EPU LAR**
- **Low Pressure Injection Cross Tie Coupled with Hot Leg Injection will Resolve Core Flood Line Break as well as Boron Precipitation**
  - **Conceptual Design from AREVA Complete**
  - **NPC/CR3/NFM&SA Review Underway**
- **Turbine Bypass Valve**
  - **[redacted] design challenge on time (4/1/09)**
  - **Valve manufacturing and development is on schedule**

CONFIDENTIAL

Environmental Qualification

- An Example of Evolving NRC Expectations
- Monticello EPU Delayed Due, in-part, to Incomplete EQ Reviews
- We Have Rescheduled Required EQ Work from 2010
  - We Have Obtained Support for Dose Model (RPM) Update
  - We Have Obtained Support for EQ Study
  - Responsibility Transferred to EPU and CR3 Engineering
- Balance of EQ Work Will Follow Evaluation Phases
  - Finalized Calculations
  - Updated Vendor Qualification Packages
  - Implementation of PM or Other Changes

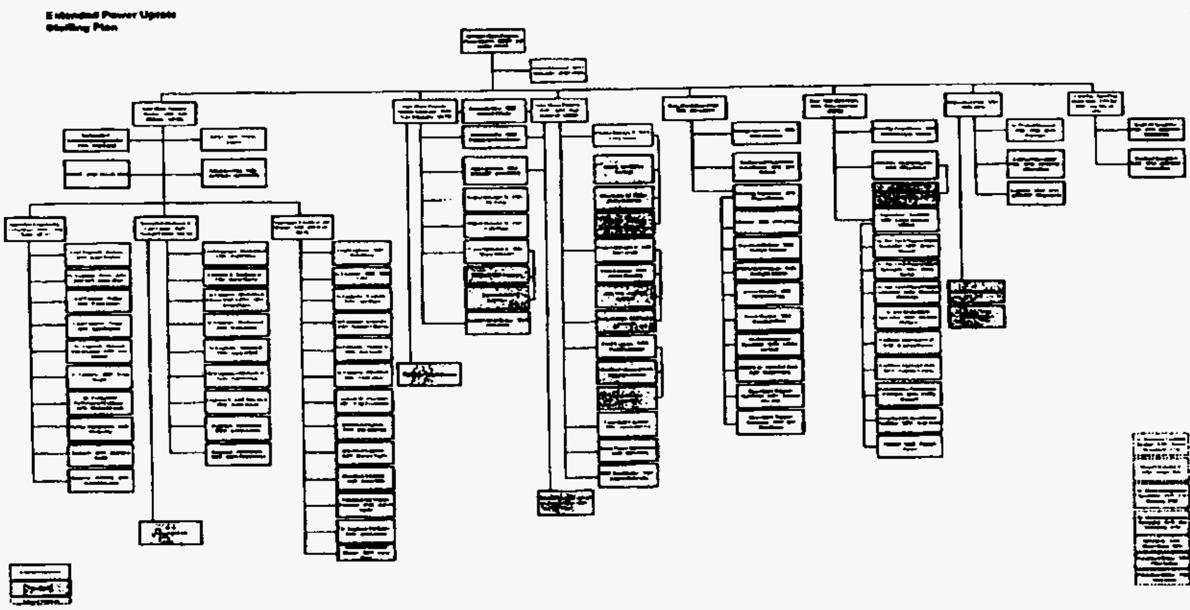
CONFIDENTIAL

Licensing Reform Activities

- Set-point Methodology
  - Being Unsuccessfully Addressed by TSTF-493, Revision 3
  - NRC/NEI Management Working to Resolve
  - Unresolved BUT is Imposed on ALL ITS Set-point Changes
  - Previous CR3/EBWR Proposal May Be Acceptable to PE-Fleet, Industry and NRC
- Evacuation Time Estimate Will be Updated As Part of Next Transportation Update
- *Dose Calculations* are Being Redone Based on Source Term Changes. Some Changes (updated X/Q) will be Implemented Prior to EPU LAR.

CONFIDENTIAL

Project Staffing



CONFIDENTIAL

[redacted]

CONFIDENTIAL

Project Staffing

- **February Activity**
  - **Ed Avella – Manager Major Projects**
  - ***Larry Tobin – Component Engineering* Supervisor**
  - **Jimmy Edward– Temporary Power Coordinator**
  - **Superintendent Yard Operations – Mike Anderson**

CONFIDENTIAL

Other Concerns

- Engineering Change (EC) late completion impact on downstream activities.
- Work Order planning quality is questionable based on QHSA.
- The Logistics plan is incomplete and jeopardizes the in-processing and access of contract resources.
- CR3 outage performance indicators currently may not give adequate warning with respect to required course corrections.
- Ability to attract, develop and retain qualified staff.

CONFIDENTIAL

Current Status of EPU Project Works

ENGINEERING

[redacted]

PROCUREMENT

All EPU components are in the design and fabrication process at various vendor-shop locations.

CONSTRUCTION

Detailed implementation task plans (rev 1) are approved and being executed. Heavy Rigging Plans are in engineering review.

POINT OF DISCHARGE

Design contract has been issued to Mesa Associates and Evaptech. Evaptech will construct cooling towers (above CT basin).

TOTAL PROJECT % COMPLETE

[redacted]