

# **Official Transcript of Proceedings**

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UNITED STATES OF AMERICA  
NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS  
(ACRS)

+ + + + +

POWER UPRATES SUBCOMMITTEE

+ + + + +

OPEN SESSION

+ + + + +

FRIDAY

JUNE 22, 2012

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory  
Commission, Two White Flint North, Room T2B1, 11545  
Rockville Pike, at 8:30 a.m., Joy Rempe, Chair,  
presiding.

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2

SUBCOMMITTEE MEMBERS PRESENT:

3

JOY REMPE, Chair

4

SANJOY BANERJEE

5

CHARLES H. BROWN

6

STEPHEN P. SCHULTZ

7

GORDON R. SKILLMAN

8

9

NRC STAFF PRESENT:

10

WEIDONG WANG, Designated Federal

11

Official

12

TRACY ORF

13

MICHELE EVANS

14

DOUG BROADDUS

15

SAM MIRANDA

16

BENJAMIN PARKS

17

TIM MOSSMAN

18

NORBERT CARTE

19

20

ALSO PRESENT:

21

JOE JENSEN

22

JACK HOFFMAN

23

STEVE HALE

24

TODD HORTON

25

JAY KABADI

1 DAVE BROWN  
2 RUDY GIL  
3 JESSICA TATARCZUK  
4 DOUG ATKINS  
5 KIM JONES  
6 JEFF BROWN (via telephone)

7  
8 TERRY JONES

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## A G E N D A

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## P R O C E E D I N G S

8:30 a.m.

Opening Remarks

CHAIR REMPE: Good morning. This meeting will now come to order. This is a meeting of the Power Upgrades Subcommittee, a standing subcommittee of the Advisory Committee on Reactor Safeguards. I'm Joy Rempe, the Chairman of the Subcommittee.

ACRS members in attendance include Dick Skillman, Stephen Schultz, Sanjoy Banerjee and Charlie Brown. Our ACRS consultants, Graham Wallis and Mario Bonaca are also present, and Weidong Wang of the ACRS staff is the Designated Federal Official for this meeting.

In this meeting, the Subcommittee will review the St. Lucie Unit 2 license amendment request for an extended power uprate. We'll hear presentations from the NRC and the representatives from the licensee, Florida Power and Light Company.

We've received no written comments or requests for time to make oral statements from members of the public regarding today's meeting. For the agenda items on Safety Analyses and Thermal Conductivity Degradation, the presentations will be closed, in order to discuss information that's

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1        proprietary to the licensee and its contractors,  
2        pursuant to 5 U.S.C. 552(b)(C)(4).

3                Attendance at this portion of the meeting  
4        that deals with such information will be limited to  
5        the NRC staff and its consultants, Florida Power and  
6        Light Company, and those individuals and organizations  
7        who have entered into an appropriate confidentiality  
8        agreement with them.

9                Consequently, we need to confirm that we  
10       have only eligible observers and participants in the  
11       room for the closed portion.

12               Today, the Subcommittee will gather  
13       information, analyze relevant issues and facts and  
14       formulate proposed positions and actions as  
15       appropriate, for deliberation by the full Committee.  
16       The rules for participation in today's meeting have  
17       been announced as part of the notice of this meeting,  
18       previously published in the *Federal Register*.

19               A transcript of the meeting is being kept  
20       and will be made available, as stated in the *Federal*  
21       *Register* notice. Therefore, we request that  
22       participants in this meeting use the microphones  
23       located throughout the meeting room when addressing  
24       the Subcommittee. The participants should first  
25       identify themselves and speak with sufficient clarity

1 and volume so that they may be readily heard.

2 We'll now proceed with the meeting, and  
3 I'd like to start by calling upon Mr. Trace Orf from  
4 the staff.

5 MR. ORF: I'd like to introduce Michelle  
6 Evans.

7 Introduction

8 MS. EVANS: Good morning, thank you. My  
9 name is Michelle Evans. I'm the Director of the  
10 Division of Operating Reactor Licensing in the Office  
11 of Nuclear Reactor Regulation. I appreciate the  
12 opportunity to brief the ACRS Power Uprate  
13 Subcommittee this morning.

14 In the interest of time, my opening  
15 remarks will be brief. At this meeting, the NRC staff  
16 will present to you the results of our safety and  
17 technical review of the licensee's application. Our  
18 review was supported by pre-application meetings and  
19 other meetings, audits and several conference calls  
20 with the licensee.

21 Through these numerous interactions,  
22 technical concerns were identified, discussed and  
23 resolved in a timely manner. Some of the more  
24 challenging review areas that you will hear about  
25 today include safety analyses of inadvertent opening

1 of a PORV, and CFCS malfunctions.

2 As was discussed during recent ACRS  
3 meeting, the staff became aware of an emerging issue  
4 regarding the fuel thermal conductivity under-  
5 prediction that may affect the best estimate upper  
6 tolerance limit of the peak climbing temperature for  
7 PWR, large-break loss of cooling accidents.

8 The licensee will provide a presentation  
9 on how this issue impacted the ECCS evaluation for the  
10 St. Lucie for the St. Lucie EPU, and its resolution  
11 for this issue. The staff will be available to  
12 address any questions.

13 A draft safety evaluation was provided to  
14 the ACRS on May 31st. We'd like to thank the ACRS  
15 staff who assisted us with the preparations for this  
16 meeting, especially Weidong Wang. At this point, I'd  
17 like to turn over our discussion to our NRR project  
18 manager, Trace Orf, who will introduce the  
19 discussions. Thank you.

20  
21 MR. ORF: Good morning. As Michelle said,  
22 my name is Trace Orf. I'm the NRR project manager for  
23 St. Lucie. Today, you will hear presentations from  
24 Florida Power and Light and the NRC staff, and the  
25 objective of those presentations is to provide you

1 sufficient information related to the details of the  
2 EPU application, and the evaluation supporting the  
3 staff's reasonable assurance determination that the  
4 health and safety of the public will not be endangered  
5 by operation of the proposed EPU.

6 Before I continue with the discussion of  
7 today's agenda, I would like to present some  
8 background information related to the staff's review  
9 of the St. Lucie Unit 2 EPU.

10 On February 25th, 2011, the licensee  
11 submitted its license amendment request for the St.  
12 Lucie Unit 2 EPU. The proposed amendment will  
13 increase the unit's licensed core power level from  
14 2,700 megawatts thermal to 3,020 megawatts thermal.

15 This represents a net increase in license  
16 core thermal power of approximately 12 percent,  
17 including a ten percent power uprate and a 1.7  
18 percent measurement uncertainty recapture. This is an  
19 18 percent increase from the original licensed thermal  
20 power.

21 The staff's method of review was based on  
22 Review Standard RS001, which is NRC's review plan for  
23 EPU's. As you know, it provides the safety evaluation  
24 template, as well as matrices that cover the multiple  
25 technical areas that the staff is to review.

1           While there were no linked licensing  
2 actions associated with the EPU application, the spent  
3 fuel pool and new fuel storage evaluations and  
4 analyses were separated out for scheduling purposes.  
5 There were numerous supplements to the application,  
6 responding to multiple staff RAIs.

7           Overall, there were approximately 80-  
8 supplemental responses that supported our draft safety  
9 evaluation. Also, the staff completed several audits  
10 to complete its review and resolve open items.

11           CHAIR REMPE: What's the estimated date on  
12 completing the fuel storage pool evaluation?

13           MR. ORF: It will be completed concurrent  
14 with the EPU.

15           CHAIR REMPE: Which date is?

16           MR. ORF: Oh, I'm sorry. Let's see. The  
17 full committee is scheduled for --

18           CHAIR REMPE: July?

19           MR. ORF: --for July. So it generally  
20 takes about 60 days afterwards to complete the EPU  
21 amendment. So that would be around the end of August.

22           CHAIR REMPE: Okay.

23           MEMBER SKILLMAN: Trace, you mentioned  
24 that there were about 80 supplemental items. Is that  
25 a large number or a small number for an EPU?

1 MR. ORF: That's approximately -- there's  
2 generally between 40 and 100.

3 MEMBER SKILLMAN: Thank you, thank you.

4 MR. ORF: You're welcome. Okay. Part of  
5 the large number was in order to expedite the review  
6 of the review, instead of sending out RAI sets in  
7 batches. As the questions arose during the review,  
8 each item was sent separately to the licensee, so the  
9 licensee could begin a response.

10 MEMBER SKILLMAN: Thank you.

11 MR. ORF: You're welcome. The current  
12 slide lists the topics for today's discussion.  
13 Florida Power and Light will begin by providing an  
14 overview of the EPU, and the NRC staff will then each  
15 make the presentation. FP&L and the NRC staff will  
16 each make their presentations on fuel and core and  
17 safety analyses. Lastly, Florida Power and Light will  
18 present information on steam generators.

19 Finally, at the conclusion of the meeting,  
20 as needed, we can discuss any additional questions in  
21 preparation for a full committee meeting. Also to  
22 note, the majority of the afternoon sessions will be  
23 closed. If there is any proprietary information that  
24 needs to be discussed, it can be deferred to the  
25 designated closed session.

1 This concludes my presentation as far as  
2 the introduction, and unless there are any further  
3 questions, I would like to turn over the presentation  
4 to Mr. Joe Jensen and FP&L. Mr. Joe Jensen is the  
5 Site Vice President for the St. Lucie nuclear power  
6 plant.

7 (Pause.)

8 EPU Overview

9 MR. JENSEN: Okay. Now that we've  
10 overcome that technical difficulty, I'll get started.  
11 Good morning. My name is Joe Jensen. I am the Site  
12 Vice President for the St. Lucie nuclear power plant.  
13 I want to thank the Subcommittee for the opportunity  
14 to speak on behalf of Florida Power and Light  
15 regarding the extended power uprate of St. Lucie Unit  
16 2.

17 Here today to share information about the  
18 St. Lucie Unit 2 EPU or Jack Hoffman, our licensee  
19 manager for the St. Lucie EPU; Rudy Gil, who will be  
20 presenting towards the end of the day on the steam  
21 generators, who is the manager of our major components  
22 inspection group; Jay Kabadi, manager of Nuclear Fuels  
23 Group for St. Lucie; and Chris Wasik, licensing  
24 manager.

25 This is a significant undertaking for our

1 company, that will not only license, that will not  
2 only increase the output of the plant, but will also  
3 provide equipment upgrades to improve plant  
4 reliability and availability, without cutting into any  
5 of our margins, and improving overall performance of  
6 the plant, and Jack Hoffman will discuss that later.

7 A little bit about the plant. St. Lucie  
8 is located on Hutchinson Island, southeast of Fort  
9 Pierce, Florida, and is the primary electrical  
10 generation source for St. Lucie County. It's a  
11 Combustion Engineering plant with Westinghouse turbine  
12 generators. The original architect engineer was  
13 Ebasco, and the nuclear fuel supplier is Westinghouse.

14 The gross electrical output of the plant  
15 is 907 megawatts electric prior to the EPU  
16 modifications. However, note that since we replaced  
17 the LP turbines during the last refueling outage,  
18 we've gained another 31 megawatts electric, and our  
19 current gross electrical output is 938 megawatts  
20 electric.

21 With regard to some of our key milestones  
22 and major equipment replacements for the St. Lucie  
23 Unit 2 plant, the original operating license was  
24 issued in 1983. In 2003, a renewed operating license  
25 was issued for Unit 2, extending operation of the



1 plant until 2043.

2 Also in 2003, a new single failure-proof  
3 crane was installed to support our spent fuel storage  
4 operations, and steam generators were replaced in  
5 2007. Additionally in 2007, the reactor vessel head  
6 was replaced to address Alloy 600 issues.

7 Finally, we replaced two of the four  
8 reactor coolant pumps in 2007, excuse me, reactor  
9 coolant pump motors in 2007 and 2011, and we intend to  
10 replace the other two in 2012 and 2014.

11 The original licensed power for Unit 2 was  
12 2,560 megawatts thermal. An approximately six percent  
13 stretch power uprate was implemented in 1985,  
14 increasing the licensed core power to 2,700 megawatts.  
15 This was accomplished with relatively few hardware  
16 modifications to the plant.

17 The extended power uprate we're discussing  
18 today will increase the licensed core power of Unit 2  
19 to 3,020 megawatts thermal, which represents an  
20 additional 100 megawatts of clean nuclear energy.  
21 This completes what I intended to cover as far as my  
22 introduction, and what I'd like to do now is turn some  
23 time over to Jack Hoffman, who will summarize the  
24 changes to the plant. Thank you.

25 MR. HOFFMAN: Thank you, Joe. Good

1 morning. My name is Jack Hoffman and I'm the  
2 licensing manager for the St. Lucie Unit 2 extended  
3 power uprate project. As stated earlier, FPL has  
4 submitted a license amendment request for an  
5 approximate 12 percent license core power increase for  
6 St. Lucie Unit 2.

7 This proposed power increase is consistent  
8 with that recently approved for St. Lucie Unit 1, and  
9 consists of a ten percent uprate from the current  
10 power level of 2,700 megawatts thermal to a power  
11 level of 2,970 megawatts thermal. In addition, the  
12 amendment request includes a 1.7 percent core power  
13 increase as a result of a measurement uncertainty  
14 recapture.

15 Together, these power increases raise the  
16 license core power level to 3,020 megawatts thermal.  
17 Also for the EPU, for St. Lucie Unit 2, the emergency  
18 core cooling pump net positive suction head or NPSH  
19 was analyzed using classic analytical methods.  
20 Sufficient pump NPSH margin exists at EPU conditions  
21 without taking credit for containment overpressure.

22 A grid stability impact study was  
23 performed to evaluate the impact of the EPU on the  
24 reliability of the electric power grid. The study was  
25 performed for the most limiting configuration of both

1 St. Lucie units at the proposed EPU power level, and  
2 results of the grid simulations indicate acceptable  
3 grid performance for the most extreme event.

4 Finally, the remaining modifications to  
5 support operation of St. Lucie Unit 2 at the uprated  
6 power level will be implemented in 2012.

7 CHAIR REMPE: Have you started? Go ahead.  
8 Okay. Have you started the implementation? Are you  
9 putting modifications into the plant now or where are  
10 you, because --

11 MR. HOFFMAN: Currently, the plant's  
12 operating. Our next outage will be in August of this  
13 year. But the last St. Lucie Unit 2 outage we took  
14 the advantage of that outage to implement a number of  
15 required EPU modifications, such as the electrical  
16 generator modifications and the lower pressure  
17 turbines.

18 That was the required inspection outage  
19 for those components. So it just made sense to -- we  
20 had to perform the inspections. We had to take that  
21 hardware apart. So it just made sense to make those  
22 major modifications at that point in time. So we have  
23 been operating almost the whole cycle with the main  
24 generator upgrades, and also, as Joe mentioned, with  
25 the low pressure turbine changeout.

1           So for St. Lucie Unit 2, it's a two outage  
2           implementation, with the remainder being implemented  
3           in the fall of this year.

4           CHAIR REMPE:   Okay, thank you.

5           MEMBER SKILLMAN:   An NPSH question, Jack.

6           MR. HOFFMAN:   Yes.

7           MEMBER SKILLMAN:   I read in the RAI "The  
8           methodology for adjusting the NPSH required values is  
9           based on an article in *Pumps and Systems* magazine,  
10          August 2009, by Terry Henshaw, P.E., Do pumps require  
11          less NPSH on Hydrocarbons Stepping NPSH or to  
12          different speeds."

13          Can you explain why your team used a  
14          magazine article for NPSH requirement, versus  
15          Hydraulics Standards Institute, guidelines or other  
16          ASME-type guidance?

17          MR. HOFFMAN:   Sure. Let me explain what  
18          we did with NPSH. When we did -- first, the base NPSH  
19          analyses were the analyses we performed as a  
20          requirement for generic Safety Issue 191, GSI 191, the  
21          sump issue.

22          For EPU, we took those analyses and we  
23          actually added additional conservatism to determine  
24          what our actual limiting margin was for our two most  
25          limiting pumps, which are containment spray and high

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1 pressure safety injection.

2 What we did is for the NPSH required,  
3 which is typically off of a vendor curve, performance  
4 curve that's done in the shop, we wanted to adjust  
5 that curve for NPSH required, again conservatively,  
6 based on what our technical specification allowable  
7 diesel generator frequency tolerance is. We're  
8 allowed a plus or minute one percent tolerance on  
9 diesel frequency, which affects pump speed, which will  
10 affect pump performance.

11 So we conservatively adjusted the NPSH  
12 required, which typically comes off a manufacturer's  
13 curve. The actual NPSH analyses, where you determine  
14 NPSH available, were done using classical ASME or  
15 Hydraulic Institute standard NPSH analyses.

16 We just simply adjusted the required NPSH  
17 an additional amount, to see what that margin would  
18 be, and the only available source we could find within  
19 the industry on how to adjust an NPSH-required curve  
20 was in that article. And at the end of the day, with  
21 all the conservatism that we had factored into the  
22 analyses, we still have approximately 28 percent  
23 margin, NPSH margin for our high pressure safety  
24 injection pumps, and about 36 percent margin for our  
25 containment spray pump.

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1                   MEMBER SKILLMAN:   Okay, and that would be  
2                   at the run-out conditions?

3                   MR. HOFFMAN:   That is correct.   Actually,  
4                   extreme run-out conditions.   Again, diesel over  
5                   frequency, IST margin instrument uncertainty, and we  
6                   used those extreme flows to calculate the actual head  
7                   loss, which is factored into the NPSH available.

8                   So we robbed on both ends.   We minimized  
9                   NPSH available; we adjusted NPSH required to minimize  
10                  that margin, and at the end of the day, we still had  
11                  in excess of 27 percent for our limiting pump.

12                  MEMBER SKILLMAN:   Thank you, Jack.

13                  MR. HOFFMAN:   Okay, next slide.   The St.  
14                  Lucie EPU license amendment request was developed  
15                  using guidance contained within RS001.   The amendment  
16                  addressed lessons learned from previous pressurized  
17                  water reactor EPU submittals, including Ginnae, Beaver  
18                  Valley, Comanche Peak, Point Beach and Turkey Point.

19                  In accordance with RS001, the St. Lucie  
20                  EPU analyses and evaluations were performed consistent  
21                  with the St. Lucie Unit 2 current licensing basis.  
22                  Also, the impact of EPU on license renewal was  
23                  evaluated in each licensing report section.   These  
24                  analyses and evaluations address system structures and  
25                  components or SSCs, subject to new aging effects due

1 to changes in operating environment, SSCs that have  
2 been added or modified to support EPU operating  
3 conditions, and also the impact of EPU on license  
4 renewal time-limited aging analyses was also  
5 evaluated.

6 As mentioned previously, the proposed  
7 uprate includes the measurement uncertainty recapture.  
8 The MUR submittal follows the guidance of NRC  
9 Regulatory Issue Summary or RIS 2002-03, and the St.  
10 Lucie Unit 2 MUR methodology is identical to the  
11 uprates recently approved for Turkey Points Units 3  
12 and 4, and St. Lucie Unit 1.

13 MEMBER BROWN: Before you go on, are you  
14 going to have any discussion on your architectural  
15 installation or how LEFM is installed, what it feeds,  
16 how it is to be used? I guess I have a few questions  
17 --

18 MR. HOFFMAN: Sure.

19 MEMBER BROWN: --relative to that. But  
20 let me make sure I understand its use first.

21 MR. HOFFMAN: Sure.

22 MEMBER BROWN: Obviously, you have to do  
23 a calorimetric at some point --

24 MR. HOFFMAN: That's correct.

25 MEMBER BROWN: --to get your reactor power

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1 and your actual plant power, thermal power  
2 coordinated.

3 MR. HOFFMAN: Correct.

4 MEMBER BROWN: Is this system used to  
5 automatically correct the NIs on a continuous basis?

6 MR. HOFFMAN: No.

7 MEMBER BROWN: So how is it -- I mean from  
8 what I read, just to make sure I get this stated  
9 correctly here, I'm going to read it out of the LAR.  
10 It says "The LEFM checklist system communicates with  
11 the DCS, which is a distributed control system"?

12 MR. HOFFMAN: That is correct.

13 MEMBER BROWN: Via a digital  
14 communications interface. There's two CPUs involved  
15 with the system. The data is sent. It's limited to  
16 values actually used in the calorimetric calibrations,  
17 fine, the calculations rather. It goes on to say that  
18 the mass flow rate temperature is to be integrated  
19 into appropriate DCS calorimetric display screens.

20 I presume somewhere there's algorithms  
21 that work on all this stuff to get you the answers you  
22 want --

23 MR. HOFFMAN: Absolutely.

24 MEMBER BROWN: --processing in the DCS  
25 system, as opposed to the LEFM system; is that



1 correct?

2 MR. HOFFMAN: Right, right.

3 MEMBER BROWN: Okay, and then it said  
4 "hard wire alarms go to the main control enunciators,"  
5 which it's installed in the main control room." It  
6 then goes on to say "the LEFM checklist system will  
7 also communicate with the PI system," which has no  
8 discussion, no definition and not even a definition of  
9 the acronym in the LAR. What is the PI system?

10 MR. HOFFMAN: We call that the "pie  
11 system," and it's simply a display of various  
12 parameters within the power plant. There's a number  
13 --

14 MEMBER BROWN: It's the main control room?

15 MR. HOFFMAN: It's in the main control  
16 room, and it's actually on engineering work stations,  
17 and it's just a useful tool for operators and  
18 engineers to pick out whatever parameter they want to  
19 see, and they can pick the time, time span, you know,  
20 whether it's a day, the last month. It's just a  
21 historian for data and a display for data.

22 MEMBER BROWN: All right, I got that.  
23 Then it says let's see, "will communicate via a  
24 digital communications interface with appropriate  
25 cybersecurity safeguards."

1 MR. HOFFMAN: That's correct.

2 MEMBER BROWN: Okay, and that's all that's  
3 stated relative to cybersecurity safeguards.

4 MR. HOFFMAN: Right, right.

5 MEMBER BROWN: These PI system  
6 communication links will provide the same high level  
7 data to the DCS, the DCS as well as LEFM performance  
8 and diagnostics, you know, for performance monitoring.  
9 I guess my question is okay, now it's in the DCS. Is  
10 it -- at some point, does the DCS communicate with the  
11 outside world via, because you talk about Ethernet  
12 connections throughout those discussions.

13 You never say where they go or who they  
14 talk to, or what the level of communication is, one  
15 way, bi-directional. Ethernet is typically bi-  
16 directional, and can be controlled from outside, by  
17 outside sources who hack in.

18 MR. HOFFMAN: Right, right.

19 MEMBER BROWN: So in the absence of  
20 diagrams and some architectural representation of  
21 where this information goes to, it gives the clear  
22 impression it just disappears out of the plant and  
23 gets siphoned off via some Ethernet connection to  
24 outside world, the Internet, corporate world,  
25 whatever.

1           There was no mention, relative to the  
2           cybersecurity, what type of reg guides or what  
3           interfaces govern, for instance, RG 5.71, which lays  
4           out a level of isolation for critical plant data,  
5           which this is. It also leaves open the question about  
6           whether somebody could get in and modify that data as  
7           it is being presented to the operators, if you've got  
8           an Ethernet connection coming into the DCS.

9           So I don't know how you're going to  
10          explain all that in this particular meeting, but I did  
11          want to make you aware that somewhere along the line,  
12          I would like to get a clear understanding of why  
13          nobody is ever going to be able to get in. RG 5.71  
14          makes it fairly clear that if you're going to  
15          communicate outside the main plant, it should be a one  
16          way only communication link.

17                 MR. HOFFMAN: That's correct, that's  
18                 correct.

19                 MEMBER BROWN: And Ethernet does not --  
20                 and ideally, as it's stated, although it's not  
21                 required because it's a Reg Guide, ideally it should  
22                 be what I would call -- it's not necessarily analog,  
23                 but a digital surreal data link of some type that is  
24                 only one way, for instance, LEDs and an optocoupler-  
25                 type arrangement where it can go one way but it can't

1       come in the other way.

2                   MR. HOFFMAN:   Sure, sure.

3                   MEMBER BROWN:   So anyway, those are --  
4       that's kind of the high level point, in order to try  
5       to understand why this system is not compromisable by  
6       outside forces, where even though it's not  
7       automatically updating, and I'll get to that question  
8       here in a minute. I'm kind of verbose at some points.

9                   You can't, in other words, provide  
10       misleading information, which would lead the operators  
11       to take some action, which is not consistent with the  
12       actual power level in the plant.

13                   MR. HOFFMAN:   Right.

14                   MR. HALE:   This is Steve Hale, Florida  
15       Power and Light.

16                   MEMBER BROWN:   I was waiting for you to  
17       stand up.

18                   MR. HALE:   I just, I think the point we  
19       need to make clear is that, you know, these are  
20       existing systems in the plant.

21                   MEMBER BROWN:   I got that. I'm not living  
22       and dying by existing systems. Right now, we're going  
23       and jacking up the plant tower. We're, how you're  
24       using better instrumentation to utilize it, which I  
25       have no problem with. It still says now, and

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1 fundamentally we're operating at higher power levels  
2 with the same design core, utilizing the information  
3 we have.

4 So it doesn't mean we should just  
5 grandfather everything without an understanding,  
6 without an understanding of how that is being taken  
7 care of. It's not encompassed in the LER in any  
8 place, and not addressed by the staff in the SER as  
9 well.

10 MR. HALE: But I think that, you know, in  
11 terms of cybersecurity, there's certain activities  
12 ongoing right now with regards to improving overall  
13 cybersecurity plant-wide. You know, the point I was  
14 just trying to make here is that, you know, we really  
15 didn't change the availability of data and the  
16 communication of data as a result of this, you know.  
17 It's really the interface with the plant computer  
18 system, and that's -- which exists today.

19 MEMBER BROWN: That's fine. I haven't had  
20 a chance to look at this stuff ever until these last  
21 few and cyber becoming a more interesting issue as we  
22 move forward, as we try to define how that function is  
23 going to be satisfied for all the plants, one way or  
24 another.

25 So no, I understand. I appreciate your

1 point. So don't, I'm not denigrating your point.  
2 Don't take it that way.

3 MR. HALE: All right, thank you.

4 MR. HOFFMAN: Yeah. Let me just add on to  
5 what Steve has said. Several years back, going from  
6 analog to digital technology, we implemented a  
7 distributed control system is what we call it or DCS  
8 in the control room, that provides the operator --  
9 there's a number of different systems that communicate  
10 with the Distributed Control System in the control  
11 room, to provide operators with much better  
12 information, touch screens and what-not, and that is  
13 isolated from the outside world.

14 That is a system that is specific and does  
15 not communicate outside the control room. The way we  
16 implemented the Leading Edge Flow Meter modification  
17 is we simply, using the DCS as the what I'll call the  
18 brains to do the calorimetric calculation, the outputs  
19 of the LEFM provides the inputs into the DCS to do the  
20 calorimetric calculation.

21 The calorimetric information is displayed  
22 in the control room. The calculated calorimetric  
23 information is displayed in the control room, and  
24 that's not communicated with the outside. That  
25 information, correct me if I'm wrong Todd, is used by

1 the operators to validate power, NI power.

2 MR. HORTON: Yes. Good morning. Todd  
3 Horton, Florida Power and Light. I oversee the  
4 operating crews. The PI system in which we were  
5 talking about earlier, that is not a system that the  
6 operating crews utilize to operate the power plant.  
7 They utilize the Distributed Control System and our  
8 normal, in this case power, would be our normal wide  
9 range nuclear instrumentation and safety channel,  
10 linear range safety nuclear instrumentation.

11 The PI system is more of a tool for the  
12 Engineering Group and management outside the control  
13 system, to look at those same-type indication is that  
14 the operators would use, and it gives us the ability  
15 to trend that information.

16 MEMBER BROWN: Okay. Let me, let me  
17 continue from page 2.4 dash .8, where it says "Each  
18 LEFM CPU will communicate with a dedicated DCN front-  
19 end Ethernet interface module. The active CPU data  
20 source for the DCS calorimetric calculations will be  
21 automatically swapped by the DCS when necessary, based  
22 on quality status flags originating from the LEFM, and  
23 from the Ethernet interface module," whatever that  
24 means, wherever that's coming from, whoever has access  
25 to it.

1 I'm not interested in saying DCS is not  
2 okay. I'm not interested in saying it can't be used.  
3 That's not -- my point is that Ethernet interface,  
4 where does it go and who has access to it?

5 MR. HOFFMAN: That Ethernet connection is  
6 strictly between the LEFM hardware in the turbine  
7 building, and the CPUs in the control room, all within  
8 the power block. There's no external communication.  
9 That's simply the internal Ethernet connection between  
10 field hardware and --

11 MEMBER BROWN: Does the DCS connect out to  
12 the outside world via any communication at all?

13 MR. HOFFMAN: I'm not aware of that. We  
14 can validate that.

15 MEMBER BROWN: If you could do that, that  
16 would be a nice --

17 MR. HOFFMAN: That's part of -- we can  
18 take that action. Steve will just validate. What  
19 does communicate with the outside is what Todd said,  
20 it's the PI system, which is --

21 MEMBER BROWN: How does the DCS and other  
22 stuff communicate with the PI system?

23 MR. HOFFMAN: That I don't know, but --

24 MEMBER BROWN: Well, that would be the  
25 other point of vulnerability, because that's a



1 potential external --

2 MR. HOFFMAN: Yeah, and as Steve said,  
3 that's existing, and you know, we've had the PI system  
4 and DCS --

5 (Simultaneous speaking.)

6 MEMBER BROWN: Existing or not, I would  
7 like to know whether that's truly a one-way --

8 MR. HOFFMAN: I understand.

9 MEMBER BROWN: Or whether it has access,  
10 people can actually access it and tell the PI system  
11 to do things or provide information to them. Because  
12 if you're connecting with that via the Ethernet system  
13 as well, then you're just daisy-chaining the dual bi-  
14 directional communications all the way into the plant.

15 MR. HOFFMAN: Well, I know that's not the  
16 case with LEFM.

17 MEMBER BROWN: So if that could be shown.

18 MR. HOFFMAN: Sure.

19 MEMBER BROWN: Or something provided that  
20 illustrates that, figuratively, functionally or what  
21 have you, that would be appreciated.

22 MR. HOFFMAN: Yeah. That scheme again is  
23 all part of the bigger cybersecurity issue that's  
24 germane to everything. You know, LEFM is a small  
25 piece that's been added on to that platform. I

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1 understand the question. We'll have that information  
2 for you later today.

3 MEMBER BROWN: Okay. Thank you very much.

4 MR. HOFFMAN: Sure.

5 MEMBER BROWN: Thank you, Joy. I didn't  
6 see any other place to bring this up, and I did see  
7 all the rest of the slides.

8 MR. HOFFMAN: No, this is the right place.

9 (Simultaneous speaking.)

10 MR. HOFFMAN: You picked the right spot.

11 MEMBER BROWN: Okay, thank you.

12 MR. HOFFMAN: Yeah, okay. Next slide,  
13 Chris. Okay. Moving on. Comprehensive engineering  
14 analyses were --

15 MEMBER BROWN: I take that back. I did  
16 have one other comment.

17 MR. HOFFMAN: Sure.

18 MEMBER BROWN: Because I didn't see this  
19 addressed either, and maybe the staff will address  
20 this later. But utilizing this system allows you to  
21 pick up an extra 1.7 percent, based on your earlier  
22 slides and based on the LARs.

23 MR. HOFFMAN: That's correct.

24 MEMBER BROWN: You then go through a  
25 discussion, and the staff did in their SER also, of

1 when it's out of service.

2 MR. HOFFMAN: That's correct.

3 MEMBER BROWN: However, there's 48 hours  
4 allowed. So it can go out of service, and you can  
5 continue to operate for some period of time, even  
6 though now you don't have this ability to "normalize"  
7 the old system, the old alternate venturi DP cell  
8 temperature system that feeds the calorimetric  
9 calibrations. You can't normalize it anymore.

10 And then in addition to that, you go  
11 through a chain, which says well, if we just got a  
12 little piece of this is out, then we can do this and  
13 a little piece of that then it's this, and a little  
14 piece of that.

15 I guess I have a hard -- maybe the staff  
16 is going to have to convince me later, but I have a  
17 hard time figuring out that if my main calibration of  
18 saying I'm okay for this higher power is out of  
19 service for two days, that it's okay to just, from my  
20 background, at least in the Naval nuclear program, if  
21 I had this go out, we would have been down to the  
22 lower power in a heartbeat, without saying well gee,  
23 we know it was okay when it broke and everything was  
24 all right.

25 But we're just going to trust the will of

1 electronics and all the goodness of physics, to say  
2 that we're okay for a couple of days, and then we'll  
3 do some incremental downgrades or what -- I just, that  
4 may, it may even fall within the 48 hours. I don't  
5 know, don't remember that detail.

6 MR. HOFFMAN: Right, right.

7 MEMBER BROWN: So anyway I'd like at some  
8 point, if people are going to talk about that, that  
9 would be useful also. Or if the staff would like to  
10 answer that later when they're talking, that's --

11 MR. HOFFMAN: Well, I'll take a stab at  
12 it. Now would be the time. The out of service or  
13 AOT, Allowed Out of Service Time scheme that is being  
14 proposed for St. Lucie in a two, is basically  
15 consistent -- I don't want to say basically. It is  
16 consistent with the manufacturer's recommendations.  
17 If you look back at previous MURs --

18 MEMBER BROWN: Well, but manufacturers  
19 love their stuff.

20 MR. HOFFMAN: But if you look back at  
21 previous licenses that put in MURs, the out of service  
22 time, the AOT for the recently-approved St. Lucie Unit  
23 2; for the Turkey Point EPU, they put in an MUR also.  
24 The strategy was looked at extensively by the staff  
25 and by our INC group, to come up with the AOT times

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1 that you see in the final draft SE.

2 So St. Lucie isn't an outlier. We're  
3 consistent with what's, you know, come ahead of us  
4 that may not be sufficient to satisfy you. But we're  
5 not doing anything different.

6 MEMBER BROWN: Well of course, I was not,  
7 I'm not a member of the Uprate Subcommittee. If I'd  
8 seen this in St. Lucie 1, I would have asked the same  
9 questions.

10 MR. HOFFMAN: Sure. But those, it did get  
11 a lot of scrutiny, and the staff maybe, you know,  
12 Trace can lean in, because actually we had proposed  
13 something a little bit different. The staff came back  
14 and tightened up --

15 (Simultaneous speaking.)

16 MEMBER BROWN: Well, they changed. Yeah,  
17 I felt they changed it a little bit.

18 MR. HOFFMAN: Right.

19 MEMBER BROWN: But I didn't see a clear  
20 basis, I didn't understand their basis for the change.

21 MR. HOFFMAN: And you have to understand  
22 too, without knowing the hardware, it's not like the  
23 entire Leading Edge Flow Meter system is out for a 48-  
24 hour period and you're flying blind. It's not that.  
25 It's just a very small subset of the system, and you

1 have 48 hours, similar to what you do with a technical  
2 specification LCO. Yes, Todd.

3 MR. HORTON: Yeah, Jack. If I could add  
4 to it. Todd Horton, Florida Power and Light. I  
5 oversee the crews. One additional piece that wasn't  
6 mentioned by Jack is each night on the mid-shift, the  
7 operating crew in the control room will check the  
8 output of the older system, the feed water flow  
9 venturis, and make adjustments on those to keep the  
10 output aligned with the higher sensitivity of the  
11 LEFM.

12 So if the LEFM was to go out of service,  
13 the feed water flow venturis will have just been  
14 recently calibrated within that 24 hour window with  
15 the LEFM.

16 MEMBER BROWN: Okay, and that brings me  
17 back, which following back to the initial question  
18 that I asked, which I forgot to come back to. I asked  
19 if it was continuously upgraded, and you're saying --  
20 based on your comment, it sounds like the LEFM system,  
21 through whatever displays you have, then is used to do  
22 your gain adjusts or whatever tweaking you to do the  
23 reactor power system, in order to bring those into a  
24 normalized or conforming --

25 MR. HORTON: The older feedwater flow

1 venturis, the output of those is calibrated each night  
2 by the operating crews.

3 MEMBER BROWN: Again the LEFM?

4 MR. HORTON: That's correct.

5 MEMBER BROWN: Okay, and does the old  
6 system also feed into the DCS system to do  
7 calorimetrics?

8 MR. HORTON: It will feed --

9 MEMBER BROWN: Or display to the operator?

10 MR. HORTON: The output is available to  
11 the operators, that is correct.

12 MEMBER BROWN: Okay. Now does that -- how  
13 is that connected into your nuclear instrument system,  
14 or whatever generates your reactor trips?

15 MR. HOFFMAN: It's not.

16 MR. HORTON: It is not. That is the wide  
17 range nuclear instrumentation and the linear arranged  
18 nuclear instrumentation that is not impacted by this,  
19 that actually feeds into those trips.

20 MEMBER BROWN: Okay. So you don't  
21 calibrate those against -- you don't calibrate those  
22 against your thermal calorimetric calibration?

23 MR. HORTON: That is not something the  
24 operating crew would be doing shiftly with the output  
25 of the LEFM. The nuclear instrumentation is

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1 calibrated by the Instrument Controls Division with  
2 Reactor Engineering, that's done on a different  
3 frequency with a different set of parameters.

4 MEMBER BROWN: Okay. I guess I'm a little  
5 confused. Let me hearken back to my old days, and you  
6 tell me where I lack understanding. In the plants I  
7 was familiar with, we would go to a secondary system  
8 calorimetric, determine the actual power being  
9 generated by the plant.

10 Then we would adjust nuclear instrument  
11 gain, so that they corresponded to a calibrated point  
12 of operation thermally at various, you know, within a  
13 pressure, temperature and flow configurations. Then  
14 all your trips were then generated from that, and you  
15 calibrated the NIs power to the thermal power that's  
16 being generated.

17 MR. HORTON: That's right, you're correct.  
18 Those gain adjustments we do do on a nightly basis --

19 (Simultaneous speaking.)

20 MEMBER BROWN: Okay. That's what I was  
21 asking. So you do those against the calorimetric  
22 calculations that were done by the DCS.

23 MR. HORTON: Right. You're absolutely  
24 right.

25 MEMBER BROWN: So that's how you keep the



1 plant normalized, not only between alternate and the  
2 LEFM, but you also calibrate the NIs every night?

3 MR. HOFFMAN: Right.

4 MR. HORTON: That's correct.

5 MEMBER BROWN: Okay. Thank you very much.

6 MR. HOFFMAN: And again, now we have two  
7 diverse means of measuring feedwater flow. Primary  
8 will be the continuous DCS calorimetric count by a  
9 Leading Edge Flow Meter. We will still have the  
10 calibrated venturis as a backup. They're part of that  
11 allowed out of service time in the coordination with  
12 the NIs.

13 MEMBER BROWN: Yeah, I got that. Okay,  
14 thank you.

15 MR. HOFFMAN: Okay.

16 CHAIR REMPE: But for follow-up action  
17 items on that, I think I heard you wanting to know  
18 more information about the allowed outage time --

19 MEMBER BROWN: Yeah. Well, they proposed  
20 one thing, and then the staff came through with a  
21 brief discussion of no, we don't -- you went too far.  
22 So they toned it down a little bit, from what I could  
23 --

24 (Simultaneous speaking.)

25 MR. HOFFMAN: --tighten it up.

1 MEMBER BROWN: From what I could see.

2 CHAIR REMPE: That's another basis --

3 MEMBER BROWN: I'd like to know the basis  
4 for tightening it up and why, if it was needed to be  
5 tightened a little bit, why didn't it need to be  
6 tightened all the way?

7 CHAIR REMPE: Sure, okay.

8 MEMBER BROWN: Even though it's already  
9 been done before. Kind of what's the basis for that?  
10 So the staff could address that --

11 MR. BROADDUS: This is Doug Broaddus.  
12 We're looking to see if we can, if the reviewer is  
13 available to come down and discuss that, and so we'll  
14 find some time a little bit later.

15 MEMBER BROWN: Okay. That would be  
16 helpful. Thank you very much.

17 MR. HOFFMAN: We have the action for the  
18 --

19 MEMBER BROWN: Yeah. I'd still like to  
20 see a confirmation of, you know, a functional diagram  
21 at some sort that shows that there are no connections  
22 anywhere, and that there's no what I would call back  
23 door path via whatever the PI system feeds externally,  
24 that can work its way back in.

25 It would just be nice to see a nice knife-

1 edge break between that and what gets to the  
2 operator's desk, as to what they're doing when they're  
3 tweaking the NIs all the time, every night.

4 MR. HOFFMAN: Okay.

5 MEMBER BROWN: Thank you for your  
6 patience, Joy.

7 CHAIR REMPE: No problem.

8 MR. HOFFMAN: Okay, moving along.

9 Comprehensive engineering analyses were performed on  
10 all affected primary side and secondary side systems,  
11 structures and components that are impacted by the  
12 proposed EPU. The analyses were performed at the most  
13 limiting EPU design conditions.

14 Secondary side heat balances were  
15 developed assuming a bounding NSSS power level of  
16 3,050 megawatts thermal, which is consistent with the  
17 power level assumed in the EPU fuel-related safety  
18 analyses. Detailed hydraulic analyses were performed  
19 for the feedwater condensate and heater drain systems  
20 at this bounding NSSS power level.

21 A thorough review of the secondary side  
22 dynamic response to events such as fast valve closures  
23 was also performed as part of EPU. An analytical  
24 model of the St. Lucie primary and secondary control  
25 systems was developed for EPU. This model was used to

1 evaluate the plant's response to EPU normal, off-  
2 normal and transient conditions. EPU control system  
3 changes are based on the model results.

4 The licensing process used by St. Lucie  
5 included a detailed review of the operating experience  
6 for each license application section, including a  
7 review of other uprate license applications, the  
8 industry RAI database, industry operating experience  
9 and INPO guidance.

10 Next slide. This table provides a  
11 comparison of the primary and secondary plant  
12 parameters for St. Lucie Unit 2. As Joe Jensen  
13 mentioned, St. Lucie Unit 2 was originally licensed in  
14 1983 at a core power level of 2,560 megawatts thermal.  
15 An approximate five and a half percent stretch power  
16 uprate to 2,700 megawatts thermal was approved and  
17 implemented in 1985.

18 The proposed EPU is identical to that  
19 recently approved for St. Lucie Unit 1, and consists  
20 of a 320 megawatt thermal core power increase above  
21 the current power level of 2,700 megawatts thermal.  
22 The EPU thermal design flow remains unchanged from the  
23 current value of 187 --

24 CONSULTANT WALLIS: Can you explain that  
25 to me?

1 MR. HOFFMAN: I'm sorry?

2 CONSULTANT WALLIS: You give this in gpm?

3 MR. HOFFMAN: Yes.

4 CONSULTANT WALLIS: At what temperature is  
5 that gallon?

6 MR. KABADI: That's based on the cold leg  
7 temperature.

8 CONSULTANT WALLIS: So there has been a  
9 change, because the temperature's changed? It's the  
10 same volume, but it's a different mass?

11 MR. KABADI: Right. From the analysis  
12 point of view, as far as -- you are right. In terms  
13 of mass, it will change. The cold leg, this value is  
14 based on the cold leg temperature in the safety  
15 analysis. That's is correct.

16 MR. HOFFMAN: Okay. 178,000 gallons per  
17 minute per reactor coolant loop, and the Combustion  
18 Engineering St. Lucie unit does have two loops. I  
19 will note that this reactor coolant system design flow  
20 is identical to that being implemented for EPU on Unit  
21 1.

22 The proposed EPU cold leg temperature is  
23 being increased by two degrees Fahrenheit, from a  
24 current value of 549 degrees F, to a value of 551 F.

25 This temperature increase results in an

1 EPU predicted steam generator pressure close to that  
2 experienced at today's power level. A bounding hot  
3 leg temperature of 606 degrees Fahrenheit is predicted  
4 for the EPU. This EPU hot leg temperature is  
5 identical to the St. Lucie Unit 1 EPU value, and is  
6 well below the industry experience for similar PWR  
7 uprates.

8 The EPU analyses have concluded that the  
9 existing Alloy 600 program is sufficient to manage  
10 potential aging effects at these increased EPU  
11 temperature conditions.

12 CHAIR REMPE: Just to make sure, because  
13 I saw differences between the LAR and the SE, you have  
14 no net change and you still have 47 degrees across the  
15 core, right? I think I have the right number on that.  
16 At the core, there's still no net change in the LAR  
17 across the core?

18 The inlet temperature went up, the core  
19 outlet temperature went up to 607.9 degree F still,  
20 and you guys are holding with those numbers, right?

21 MR. HOFFMAN: Where is that?

22 (Simultaneous speaking.)

23 CHAIR REMPE: Okay, but it's still inlet  
24 temperature is 551 F; outlet is 607.9, and those are  
25 the numbers you're going with, because I saw different

1 numbers in the staff's SE.

2 MR. HOFFMAN: Right, and just to clarify,  
3 these numbers that you see here are Westinghouse,  
4 what's called PCWG, which is Performance Capability  
5 Working Group, consistent methodology that was used in  
6 Seabrook, Turkey Point, Point Beach. That's what  
7 these numbers represent.

8 Now for fuel-related analyses, there was  
9 an additional margin added, an uncertainty added to  
10 those numbers. So the 607.9 is actually what you'd  
11 see in the Chapter 15 safety analyses, adding  
12 additional uncertainty to the PCWG numbers.

13 CHAIR REMPE: So when I saw core,  
14 different temperatures across the core, perhaps the  
15 staff could use some different values?

16 MR. HOFFMAN: They were really looking at  
17 -- I don't know what context that is. That may be in  
18 context of Chapter 15, which made the delta even  
19 bigger, based on uncertainties that they used in the  
20 Chapter 15 safety analyses.

21 CHAIR REMPE: And again, I'm talking core  
22 vessel and vessel inlet and outlet is what I was  
23 talking about. Okay, thank you.

24 MR. HOFFMAN: Correct, yeah. I just want  
25 to make one clarification. You know, these are all

1     analytical numbers. The reality is our best estimate  
2     flow is approximately 200,000 gallons per minute per  
3     loop currently. That number is not changing. That's  
4     reality. That number's not changing for EPU, and when  
5     you look --

6                 We call that the best estimate prediction,  
7     and when you look at that flow rate, the actual flow  
8     rate, the hot leg temperature, the predicted hot leg  
9     temperature is 602.6. So that's what we physically  
10    expect to see in the field when we implement the  
11    uprate, and these analytical values are simply  
12    conservative numbers for use in the appropriate  
13    analyses.

14                CHAIR REMPE: Okay.

15                CONSULTANT WALLIS: These are not  
16    realistic numbers here?

17                MR. HOFFMAN: These are what I'd call,  
18    these numbers define the engineering box that we used  
19    to do our analyses. That's --

20                CONSULTANT WALLIS: It would make more  
21    sense to me if you said the reality was this, but you  
22    know, this may be something else.

23                MR. HOFFMAN: Yeah. This is just  
24    consistent with the way the material is presented in  
25    previous EPU license amendments requests, and again,



1 these are the bounding numbers --

2 CONSULTANT WALLIS: Well, it gets  
3 confusing when you have sort of three sets of numbers.

4 MR. HOFFMAN: Sure, sure.

5 MEMBER SKILLMAN: Jack, let me push back  
6 a little bit. You say the bogus number for flows, the  
7 mass flow rate associated with T-cold at 187,500  
8 gallons a minute. You're thinking flow; I'm thinking  
9 reactor coolant pump motor horsepower, and I'm  
10 thinking fuel temperatures.

11 Then you say that number is really not  
12 187-5. It's 12,500 gallons a minute more than that,  
13 with a density of T-cold. That tells me that what we  
14 might be talking about thermal conductivity  
15 degradation might be different than what we're really  
16 going to talk about.

17 So if you're telling me that it's really  
18 200,000 gallons a minute per loop and it's not 187-5,  
19 I say to myself what are we looking at here? I'm with  
20 Dr. Wallis. Is this a comic book number or is this  
21 the real deal?

22 MR. HOFFMAN: If you look at our technical  
23 specifications, thermal design flow is defined in the  
24 technical specifications, and the thermal design flow,  
25 minimum thermal design flow in the technical

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1 specifications that we have to use to meet all of our  
2 safety analyses, that number is 187,500.

3 That's the number today in the tech specs.  
4 That's the number for EPU in the tech specs. There's  
5 margin obviously. You want to take what your best  
6 estimate flow is, and you want to ensure that you have  
7 flow margin in your analyses for uncertainty and what-  
8 not, measurement uncertainty.

9 And again, these numbers are the PCWG  
10 numbers that define what I would call the engineering  
11 or design envelope for subsequent engineering  
12 analyses. Jay, maybe you can talk about the impact on  
13 TCD.

14 MR. KABADI: Yeah, right. I'm Jay Kabadi  
15 for FPL. Our actual major flow for St. Lucie 2 is  
16 actually in the range of about 405,000 for both loops.  
17 So per loop is coming about 202. When you said these  
18 flow for the analysis, we account for the amount of  
19 plugging we allow, because right now we have two  
20 plugging, which is close to probably very, very low  
21 number.

22 MR. HOFFMAN: Zero.

23 MR. KABADI: And all these analyses are  
24 done with ten percent two plugging. So we look at  
25 what the floor would be with the ten percent plugging,

1 and then allow margin for uncertainty and some  
2 additional margin, and that's how this flow of 187,500  
3 is set up.

4 So real flow is much higher, but all the  
5 safety analyses which are conservative, if you use the  
6 lower flow, we bounded with these numbers. So as long  
7 as -- we measured the flow for each cycle, as long as  
8 they are a bounded flow, we meet all the safety  
9 analysis requirement.

10 In the real sense, exactly as you said,  
11 for the field performance and all, really get much  
12 better numbers. So thermal conductivity by the  
13 reactor temperatures will be lower than what is  
14 analyzed. So then exactly there is some original  
15 margin. But since we do these analyses for DCD, LOCA  
16 and other things one time, we take the worse  
17 conditions and analyze that.

18 So as long as our flow remains about this  
19 value, we meet the requirement of the effects of the  
20 LOCA.

21 MEMBER SKILLMAN: Thank you, understand.

22 CONSULTANT WALLIS: So if I wanted to make  
23 an independent calculation of something, to satisfy  
24 myself that something is okay, which number should I  
25 use?

1 MR. KABADI: When we look for our actual  
2 operating parameters, we can look at the reactor  
3 measured flow, which is done every cycle. We measure  
4 that at the beginning of every cycle of the actual  
5 reactor cooling system flow.

6 So if you use that flow and fit into all  
7 the thermohydraulic equations, you will get the actual  
8 conditions of what the T-cold, I mean what the T-hot  
9 temperatures are.

10 So although, for example, for one specific  
11 cycle, you want to do the best estimate of analysis,  
12 those numbers are available, based on -- are available  
13 in the sense of could be easily generated --

14 CONSULTANT WALLIS: What would help me in  
15 the future or maybe not, if you had a different table  
16 which said these are best estimate values.

17 MR. HOFFMAN: We certainly have those, and  
18 again, we just wanted to establish, for example, with  
19 this slide --

20 MEMBER BANERJEE: Can you just supply  
21 that, what the 187,500, you know, best estimates.

22 MR. HOFFMAN: Sure. Steve, do you want to  
23 take that? We'll just provide a table of the -- I  
24 think we actually have a calculation, and it's a best  
25 estimate calculation.

1 CONSULTANT WALLIS: That would be good.

2 MEMBER BANERJEE: So if you were looking  
3 at the stored energy in the fuel for LOCA, based on  
4 187,500 is what you're doing. That's ten percent --

5 MR. KABADI: Right, that's correct. So  
6 the analysis is done conservatively.

7 MEMBER BANERJEE: Yeah, conservatively.  
8 So what is the difference compared to what your best  
9 estimate would be?

10 MR. KABADI: Yeah. I think actual numbers  
11 we'll provide.

12 MEMBER BANERJEE: Yeah. If you can  
13 provide --

14 MR. KABADI: There will be a few degrees  
15 loss.

16 (Simultaneous speaking.)

17 MEMBER BANERJEE: -- percent, right?

18 MR. KABADI: Temperatures will be in the  
19 range of at least 600 instead of 606, whatever  
20 mentioned here. But actual numbers we will provide.

21 MEMBER BANERJEE: Okay.

22 MR. HOFFMAN: I actually have the  
23 calculations.

24 MEMBER BANERJEE: I think that's where I'm  
25 --

1 (Simultaneous speaking.)

2 MR. HOFFMAN: I'll talk to you on break.

3 MR. HALE: Jay, this is Steve Hale,  
4 Florida Power and Light. I think it's also important  
5 to point out when we do safety analysis, we not only  
6 use the minimum flow number, but we use a range of  
7 temperatures to make sure that we bound the low end  
8 and the high end.

9 And if it's more conservative to run at  
10 low temperature, that's the analysis we run, and if  
11 it's more conservative to run at a higher temperature,  
12 we run it at that.

13 MEMBER BANERJEE: So we are going to visit  
14 this TCD issue later, and the effect on LOCA?

15 MR. KABADI: That's correct. That's in  
16 the afternoon closed session.

17 MEMBER SKILLMAN: I accept your answer and  
18 I appreciate what you have said. Had this slide been  
19 titled "Analytical Assumptions," perhaps neither Dr.  
20 Wallis nor I would have asked the question.

21 MR. KABADI: Understood.

22 MEMBER SKILLMAN: But when they're  
23 presented as the actual -- it sounded like they were  
24 presented as the actual.

25 MR. HOFFMAN: Yeah. They're design

1 parameters.

2 MEMBER SKILLMAN: We have a tendency to  
3 stumble. So thank you.

4 MR. HOFFMAN: It confuses the operators,  
5 because they look and this is not what I see in the  
6 plant. But they're numbers that we in Engineering  
7 need to use, to make sure we do bounding conservative  
8 analyses.

9 MEMBER SKILLMAN: For analyses?

10 MR. HOFFMAN: Correct.

11 CONSULTANT WALLIS: But the trouble is  
12 that what's conservative for one thing may not be  
13 conservative for another?

14 MR. HOFFMAN: For another. It makes it,  
15 that's the challenge we have, is to make sure we're  
16 picking --

17 MR. KABADI: And we look at it as part of  
18 the analysis, like some, for example, fuel liftoff and  
19 we use max flow. We cannot use this minimum flow to  
20 calculate the liftoff of the fuel.

21 MEMBER SKILLMAN: We're looking at the  
22 same thing. So yep. Thank you.

23 MR. HOFFMAN: Okay. Any other questions  
24 on the parameter slide? If not, we'll move forward.  
25 Several EPU modifications shown on this slide have a

1 beneficial safety impact. For example, the second  
2 modification on the list resolves a long-standing low  
3 margin issue for St. Lucie Unit 2.

4 Unlike Unit 1, the control room air  
5 conditioning condensing units are cooled by the  
6 safety-related closed cooling water system. This  
7 design limits the maximum allowable ultimate heat sink  
8 temperature, and becomes challenging during the summer  
9 months.

10 The proposed EPU modification upgrades the  
11 air conditioning skid to accommodate elevated heat  
12 sink temperatures well above that expected during  
13 normal plant operation. The last modification on the  
14 slide increases the reactor protection system steam  
15 generator low level trip setpoint to improve the  
16 unit's plant risk profile for beyond design basis  
17 events.

18 The risk impact of EPU was calculated  
19 using the St. Lucie Unit 2 internal events, PRA model  
20 and the results concluded that the EPU results in a  
21 slight decrease in risk or a risk benefit.

22 MEMBER BANERJEE: So if you go and look at  
23 this, install Leading Edge, you're already taking  
24 advantage of that by getting your uncertainty down.  
25 So in some way, you can double-count it, because



1       you've already taken that advantage. It's not like if  
2       you didn't take the advantage, that would enhance  
3       safety?

4               MR. HOFFMAN: Correct.

5               MEMBER BANERJEE: But in this case, that's  
6       really pushing it too far, to say it supports safety.  
7       You're doing what you can to get the benefits of it.

8               MR. HOFFMAN: Sure.

9               MEMBER BANERJEE: Right, okay.

10              MR. HOFFMAN: We believe it's a more  
11       accurate way of calculating --

12              MEMBER BANERJEE: Sure, but you're also  
13       getting --

14              MR. HOFFMAN: --which ultimately gets to  
15       NIs and --

16              MEMBER BANERJEE: Yeah, but you're also  
17       taking advantage of it.

18              MEMBER SKILLMAN: At one point -- you're  
19       jacking the power up by 1.7 percent.

20              MR. HOFFMAN: No question. It is far more  
21       accurate then --

22                       (Simultaneous speaking.)

23              MEMBER SKILLMAN: It just allows you to  
24       maintain an equivalent safety posture, not  
25       improvement.

1 MEMBER BANERJEE: And you know, this  
2 committee has had continuing debates on the accuracy  
3 of these things, because it's very, very tricky and  
4 we've sort of finally, after many go-arounds, agreed  
5 to this in some sense.

6 But there are concerns, because it has to  
7 be installed precisely. You can't do the calibrations  
8 of these, you know, *in situ* very easily. So it's a  
9 difficult problem. The staff has taken a certain  
10 position. We've agreed to it, but let's not push it  
11 too far.

12 MR. HOFFMAN: Understand.

13 MEMBER BROWN: Just my reading of the  
14 installation and the basis was that you were not  
15 doing, using this based on analytical extrapolations,  
16 that what you actually tested with the appropriate  
17 number of pipe diameters or whatever it is from the  
18 terminology is upstream and downstream and where the  
19 thing is located, and you actually did a calculation.

20 MR. HOFFMAN: That's right.

21 MEMBER BROWN: It was fairly --

22 (Simultaneous speaking.)

23 MEMBER BANERJEE: Yeah. Let's not go  
24 there. This is a --

25 MEMBER BROWN: Well, I know. That's why

1 I didn't, since I figured you had already caved  
2 somewhere along the line.

3 MEMBER BANERJEE: I didn't cave. Graham  
4 Wallis caved.

5 MEMBER BROWN: Okay.

6 (Laughter.)

7 MEMBER BANERJEE: This goes back  
8 historically.

9 MEMBER BROWN: But at least it was not an  
10 extrapolation. They were doing it based on actually  
11 testing their --

12 MR. HOFFMAN: The actual spools that we  
13 put in the field were tested --

14 MEMBER BROWN: They were testing those in  
15 a calibrated facility, to make sure they've got the  
16 right data. So --

17 MEMBER BANERJEE: The Reynolds numbers  
18 effects, all sorts of things.

19 MEMBER BROWN: All that good stuff, yeah,  
20 yeah.

21 (Simultaneous speaking.)

22 MEMBER BANERJEE: Over and done with.

23 MEMBER BROWN: Yes.

24 MEMBER SKILLMAN: I'd like to drop out of  
25 the stratosphere for a second and ask one or two

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1 questions.

2 MR. HOFFMAN: Absolutely.

3 MEMBER SKILLMAN: When we talked a little  
4 bit earlier about NPSH, part of that answer is we've  
5 tightened up the tolerances on the emergency diesel  
6 generators for the tolerance on frequency and on  
7 voltage.

8 MR. HOFFMAN: That's correct.

9 MEMBER SKILLMAN: And from my experience,  
10 that is a big deal, because it affects every 4160  
11 component in the plant, your ECCS buses. How did you  
12 do that? Did you change your governors, or did you  
13 just credit what you know is the real experience at  
14 load for your EDGs?

15 MR. HOFFMAN: Actually, those actually  
16 numbers, and this came out of a previous NRC  
17 inspection, component design basis inspection, and we  
18 ultimately corrected -- we had the long-term  
19 corrective action to fix the problem from that  
20 previous NRC inspection.

21 If you looked at our original technical  
22 specifications, and they're consistent with the rest  
23 of the industry, the original frequency, allowed  
24 frequency on the diesel was plus or minus two. We've  
25 gone to plus or minus one.

1           So we've tightened up on that and, more  
2           importantly, we've done an extensive amount of  
3           analyses as part of the EPU project, to look at all  
4           the components that are speed-dependent, pumps,  
5           valves, and ensuring that in all the safety analyses  
6           we can support again plus or minus, depending on which  
7           is conservative.

8           So all that analytical work was done as  
9           part of the EPU and I'll call them hydraulic or system  
10          analyses. The voltage was tightened up from plus or  
11          minus 10 to plus or minus 5, and a similar electrical  
12          evaluation was done at all of the bus level, whether  
13          it was 41.60, 480, 120, to show that, you know, the  
14          pumps actually can operate at minus 25 percent.  
15          They're spec'd out and designed to voltage.

16          MEMBER SKILLMAN: Thank you. Let me just  
17          pursue this a little bit further. Have the  
18          surveillances been changed in your tech spec for the  
19          engines, so that the acceptance criteria for the  
20          output reflects the tightened tolerances for voltage  
21          and for frequency?

22          MR. HOFFMAN: As part of the technical  
23          specification change package for EPU, those new  
24          tightened requirements are in our surveillance  
25          requirements.

1                   MEMBER SKILLMAN: Thank you. Let me ask  
2 one more. While the spent fuel pool criticality work  
3 has been pushed off as a supplement, there is a set of  
4 words I would like to ask, because I don't see another  
5 place to ask the question.

6                   The wording is the tech spec 561 Alpha 3  
7 is changed from a nominal 8.96 center to center  
8 between fuel assemblies, to a nominal of 8.965 inches,  
9 a five thousandths of an inch change. To those that  
10 have handled fuel, you have a hard time finding five  
11 thousandths of an inch. If you put them in the racks,  
12 you'll never find five thousandths of an inch.

13                   What's with that, please? What is this  
14 change?

15                   MR. KABADI: Yeah, I think at this point  
16 I can answer. That was the number which was in the  
17 current tech spec. Actually, this is a correction.  
18 This should have been the correct number in the tech  
19 specs. Now whether you could get the tolerance to  
20 that, what you mentioned, I cannot answer now.

21                   But the correction to tech spec was  
22 changed, mainly because to correct what was in the  
23 previous tech spec. Actually, they're not changing --

24                   MEMBER SKILLMAN: So this is an admin  
25 change in the tech spec?

1 MR. KABADI: Yeah. When we, since we were  
2 at the time doing EPU analysis, when we found that  
3 they actually, I think previous, the current tech spec  
4 had a number which is slightly different. So this is  
5 right time, and we're redoing all the criticality  
6 analyses, and when this number was identified as being  
7 this, this will change.

8 MEMBER SKILLMAN: Thank you.

9 MR. KABADI: So it is not a real change at  
10 the plant.

11 CONSULTANT WALLIS: Well, is there any  
12 point in having a tech spec which you cannot verify,  
13 because you can't measure it, because it's too, you  
14 know, it's too fine? It doesn't seem to make sense.

15 MR. KABADI: No. I think what I said, I  
16 can answer it now. Whenever this configuration was  
17 done, they looked at all the specs to see the racks  
18 are laid out and what tolerances it should be. That's  
19 the real number that should have been in the tech  
20 specs.

21 CONSULTANT WALLIS: But it's something  
22 that you can't verify?

23 MR. KABADI: Right. Those are the numbers  
24 used in the analysis.

25 CONSULTANT WALLIS: It's used in an

1 analysis, but you can't verify that it's a reality.

2 MR. KABADI: No. Well, I did not say  
3 that. I did not know how that, when the racks were  
4 put in the system, I right now do not have knowledge  
5 how those were verified, that are within that spec.

6 CONSULTANT WALLIS: You have Leading Edge  
7 measurement system in your spent fuel pool, which  
8 enables you to measure within five thousandths of an  
9 inch.

10 MR. KABADI: We can look at that and see  
11 what the spec is. But this is -- we are not changing  
12 the actual rack configuration in this criticality  
13 analysis. That number was just a correction, and  
14 criticality analysis has been done with the same  
15 numbers as before. Only changes we did in the  
16 criticality analysis were putting slightly higher  
17 enrichment and putting more margin in terms of --

18 MEMBER SKILLMAN: Well, I think we'll get  
19 another chance to look at this on the spent fuel  
20 analyses.

21 MR. HOFFMAN: Right.

22 MEMBER SKILLMAN: But I just want to put  
23 a signal in the air that the change from -- a change  
24 of 5 mils is a very tight tolerance.

25 MR. HOFFMAN: I think if you look at the



1 actual tech specs, it's in the section called "Design  
2 Features." So it's not -- it's just a design feature  
3 number in the tech specs. It's not a number that we  
4 go out and have to verify or validate. It's simply a  
5 design feature number in the specs, and again, that's  
6 a number that's carried on with additional  
7 uncertainties in the criticality analyses.

8 MEMBER SKILLMAN: Okay, thank you.

9 MEMBER SCHULTZ: Jack, before we leave  
10 this slide, you were in the process of looking at the  
11 last bullet with regard to the steam generator low  
12 level trip setpoint change, and its impact on the  
13 plant risk profile.

14 I wanted to clarify whether you were  
15 saying that this was a major change that with the EPU  
16 affected the plant risk profile in a positive way.  
17 EPU alone would have affected this in a negative way.  
18 So then you made a change.

19 MR. HOFFMAN: Right.

20 MEMBER SCHULTZ: And is what you're saying  
21 the change that was implemented more than compensates  
22 for the EPU change?

23 MR. HOFFMAN: Yeah. When you look at  
24 classical safety analyses, Chapter 15 analyses for  
25 EPU, there was no need to change the setpoint. It's

1 currently 20.5 percent, an error range greater than  
2 equal to, and that number could have been defended as  
3 part of the EPU.

4           However, when our PRA folks did their  
5 analyses and they were concerned about events such as  
6 total loss of feedwater and the amount of inventory  
7 that's in the generator for a beyond design basis  
8 event and operator timing to initiate once-through  
9 cooling, we were able to in PRA space -- we changed an  
10 RPS setpoint primarily for PRA, not for safety  
11 analyses. We could have kept it as is. But it was a  
12 risk benefit, so we made that change, and the new  
13 number is 35 percent error range.

14           MEMBER SCHULTZ: Oh, and that's important.  
15 The operator timing changes are real.

16           MR. HOFFMAN: That's right.

17           MEMBER SCHULTZ: And so you may be able to  
18 support it in safety analysis in some fashion, but the  
19 arguments are tougher to make and therefore this  
20 change is a good one to employ.

21           MR. HOFFMAN: And it was risk-driven, not  
22 safety analysis driven.

23           MEMBER SCHULTZ: Understood.

24           MEMBER BANERJEE: Yu did this with St.  
25 Lucie 1 as well?

1 MR. HOFFMAN: Correct. Same change,  
2 consistency between the units. It's actually more  
3 critical for Unit 1 than Unit 2 because of PORV  
4 sizing.

5 MEMBER BANERJEE: Right.

6 MR. HOFFMAN: But again, for operators  
7 it's human factors. We want to keep the same numbers.

8 MEMBER SCHULTZ: And on the point related  
9 to environmental qualification, the radiation  
10 shielding changes, what is the magnitude of those. Is  
11 that a change in program?

12 MR. HOFFMAN: Well ultimately it affects  
13 the programs, because the components are in the  
14 program, and what initially happened with the EPU is  
15 there was one area in the plant in the auxiliary  
16 building that went from a current mild environmental  
17 to a harsh environment.

18 We initially thought that the components,  
19 the EPU components in that now had to be evaluated for  
20 the harsh environment, and we did detail -- we  
21 initially were going to shield those component for  
22 more detailed analysis based on distance. Those  
23 components still remained in a mild environment.

24 However, the changes for EQ that we had to  
25 make for EPU are the temperature indicators inside

1 containment. There's an IEEE 323 margin. You want to  
2 have at least ten percent margin on dose, radiation  
3 dose, and we fell within the ten percent margin. So  
4 for EPU, we're replacing two of our safety-related  
5 containment, air temperature RTDs as part of the EPU.

6  
7 So that's the modification. Everything  
8 else was shown by analysis to still be within the  
9 existing qualification of the components.

10 MEMBER SCHULTZ: Thanks for the additional  
11 information.

12 MR. HOFFMAN: Okay, yep. Let's go to the  
13 next one. For the balance of plant, a number of  
14 changes are being implemented in the steam path. The  
15 low pressure steam path was replaced during the Unit  
16 2 refueling outage. It was replaced during the last  
17 Unit 2 refueling outage, I'm sorry, and the high  
18 pressure steam path will be replaced during the  
19 upcoming 2012 EPU refueling outage.

20 A modernized turbine control system,  
21 similar to that recently implemented on Unit 1, will  
22 also be implemented to replace the existing obsolete  
23 system. The main feedwater and condensate pumps will  
24 be replaced, and additional modifications to the main  
25 feedwater system include replacement of the --

1                   CONSULTANT WALLIS: Can you ask you about  
2 this steam bypass?

3                   MR. HOFFMAN: Sure.

4                   CONSULTANT WALLIS: It says that you  
5 increased the control system capacity. You mean  
6 you've increased the bypass capacity?

7                   MR. HOFFMAN: Yeah, that's correct, and  
8 actually we did -- well, we increased the speed too.

9                   CONSULTANT WALLIS: There's no bypass  
10 capacity.

11                  MR. HOFFMAN: Absolutely.

12                  CONSULTANT WALLIS: The way it reads, it's  
13 as if --

14                  MR. HOFFMAN: Yeah, yeah, yeah. There was  
15 both. We actually made a speed change to make the  
16 valves respond faster, and we also made a capacity  
17 change.

18                  CONSULTANT WALLIS: So you made something  
19 bigger in capacity change?

20                  MR. HOFFMAN: Bigger valves, bigger  
21 valves.

22                  CONSULTANT WALLIS: Bigger valves, okay.  
23 I thought that was it. Thank you.

24                  MR. HOFFMAN: As I mentioned, the main  
25 feedwater reg valve internals and actuators are being

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1 replaced with EPU in addition to the number five high  
2 pressure and number four low pressure feedwater  
3 heaters. Next slide.

4 CONSULTANT WALLIS: How did you upgrade  
5 the condenser?

6 MR. HOFFMAN: Actually, we did a lot of  
7 work on the condenser. We had a lot of experts,  
8 subject matter experts come in and do walkdowns,  
9 material condition walkdowns of the condenser during  
10 past outages. On paper analytically, there's enough  
11 design capacity to handle the additional duty.

12 But the changes we made, we put in tube  
13 stakes for vibration concerns due to the higher steam  
14 flow, and we also made improvements to the air removal  
15 system, which has been an existing ongoing problem.

16 You know, we expect to have more non-  
17 condensables. It was an existing problem, so we just  
18 improved that system. So fairly benign.

19 CONSULTANT WALLIS: You didn't change the  
20 tubing at all?

21 MR. HOFFMAN: No.

22 CONSULTANT WALLIS: I mean it's the same

23 --

24 MR. HOFFMAN: Titanium tubes that were  
25 replaced many years ago, good performance.

1                   MEMBER SKILLMAN: Getting rid of the  
2 additional non-condensables, did you change your air  
3 ejectors or change your blend condenser or anything  
4 like that?

5                   MR. HOFFMAN: No. The capacity, we had a  
6 design problem internal to the condenser, where the  
7 pickup points for the non-condensables were not  
8 necessarily optimized, and we also had some leakage  
9 problems and we -- the capacity of the system was  
10 adequate. It was more, you know, the internal  
11 configuration of the system, and eliminating flanges,  
12 because we had some air and leakage problems.

13                  MEMBER SKILLMAN: So I hear you actually  
14 made physical modifications on the condenser including  
15 staking?

16                  MR. HOFFMAN: And staking.

17                  MEMBER SKILLMAN: Changing location of  
18 suction of air ejector?

19                  MR. HOFFMAN: I'm not -- I'll have to  
20 double-check that. I know we definitely made piping  
21 changes outside the condenser on the -- maybe Dave,  
22 you can -- I'm not. I know we made piping changes  
23 outside the condenser on the air removal piping.

24                  MR. D. BROWN: Yeah. What we were looking  
25 at is -- this is Dave Brown, Florida Power and Light.

1 The problems that we were having is where the steam  
2 was coming in, where the air ejector pickoff was  
3 coming up. What we did is change some of the tray  
4 arrangements around that, so that we don't actually  
5 pick up steam instead of the air, so that we can  
6 actually get a collection of the non-condensables.

7 So it's not really a major change. It's  
8 really just kind of a tray-type change to change what  
9 the flow looks like inside the condenser going into  
10 the air ejector pickups.

11 MEMBER SKILLMAN: Okay, thank you.

12 MR. HOFFMAN: Thanks Dave. Okay, next  
13 slide. The heater drain pump internals are also being  
14 replaced for EPU and selected heater drain valves, and  
15 heater drain valve controls are being upgraded.  
16 Similar to St. Lucie Unit 1, the EPU project will also  
17 resolve another long-standing low margin issue for  
18 Unit 2.

19 The existing turbine cooling water heat  
20 exchangers have marginal heat removal capability at  
21 the current plant power level during the summer  
22 months, when the ultimate heat sink temperature is  
23 elevated.

24 To resolve the margin issue, the EPU  
25 project is replacing these heat exchangers with heat



1       exchangers having approximately 50 percent more heat  
2       transfer capability. Improved materials of  
3       construction are also being included as part of this  
4       modification.

5               MEMBER SKILLMAN: Before you jump into  
6       electrical, one more plumbing question please.  
7       Sentence one is a pair of PORVs and both arms during  
8       operation. St. Lucie 2 has two PORVs. I don't know  
9       whether they are the same size or different sizes, but  
10      one is disarmed during normal operation.

11             MR. HOFFMAN: That's correct, correct.

12             MEMBER SKILLMAN: Is this a modification  
13      for the EPU, or is this original hardware for this  
14      plant?

15             MR. HOFFMAN: Yeah. A design difference  
16      between St. Lucie Unit 1 and 2, again looking at the  
17      vintage, Unit 1 was pre-TMI, Unit 2 post-TMI. The  
18      PORVs on Unit 2 are much larger than the PORVs on Unit  
19      1, and there was -- this goes back to original  
20      design.

21             There was a concern that if both PORVs  
22      opened on Unit 2, due to their size it could become a  
23      challenging overcooling event. So we actually have a  
24      technical specification requirement on Unit 2 to keep  
25      one of the two valves blocked, and that's been carried

1 on since Day 1.

2 MEMBER SKILLMAN: Okay, thank you. The  
3 real question I had was whether this was an EPU  
4 feature or an original design feature. So it's a  
5 post-TMI design feature?

6 MR. HOFFMAN: That's correct.

7 MEMBER SKILLMAN: Got it. Thank you.

8 MR. HOFFMAN: Yep, okay.

9 CONSULTANT BONACA: Is the auxiliary  
10 feedwater system a redundant system?

11 MR. HOFFMAN: Yeah. Similar to St. Lucie  
12 Unit 1, the Unit 2 auxiliary feedwater system has two  
13 100 percent motor-driven pumps. That's a current --  
14 the way we characterize the system currently is it's  
15 two 100 percent motor-driven pumps and one greater  
16 than 100 percent steam-driven pump, and for EPU, that  
17 same design logic has been validated.

18 The motor-driven pumps remain 100 percent  
19 each, and the turbine-driven pump is a greater than  
20 100 percent capacity pump. Did a lot of analyses on  
21 Unit 2 in particular regarding aux feedwater  
22 performance, decay heat removal capability and again,  
23 just because of the design and the diversity of the  
24 system, you know, it was not an issue for either Unit  
25 1 or Unit 2.

1 CONSULTANT BONACA: Okay, thank you.

2 CONSULTANT WALLIS: Did you make changes  
3 in piping in response to FAC, flow-assisted corrosion?

4 MR. HOFFMAN: Yes, we did.

5 CONSULTANT WALLIS: Did you change the  
6 materials for some pipes?

7 MR. HOFFMAN: Oh absolutely. Yeah, yeah.  
8 We did, just a handful of what I'll call -- in the  
9 heater drains primarily on both Unit 1 and Unit 2, and  
10 whenever we make a piping change for FAC, we will  
11 upgrade to the chrome moly piping. So we minimize the  
12 inspections and potential for future replacements. So  
13 there were physical FAC modifications.

14 CONSULTANT WALLIS: Then you extrapolate  
15 behavior in the future with EPU?

16 MR. HOFFMAN: Absolutely. It's already  
17 been done and factored into the new program.

18 CONSULTANT BONACA: Since you made so many  
19 changes in the system, do you use the PRA in any way  
20 as a means of providing insights on the design of  
21 changes?

22 MR. HOFFMAN: Yes, every modification.  
23 Early on when the PRA work was initiated, each  
24 modification was looked at, as whether it provided --  
25 whether it was risk-neutral, risk-beneficial or a

1 detriment to risk, in all aspects, whether it was an  
2 internal or an external event.

3 So that was all, you know, what I'll call  
4 baked into the original PRA, and it was subsequently  
5 validated based on, you know, when we started, some  
6 other little mods came out of the woodwork, and that  
7 PRA work was validated again once our modification  
8 list was finalized.

9 CONSULTANT BONACA: Thank you.

10 MR. HOFFMAN: Okay. On the electrical  
11 side, the main generator stater was rewound and the  
12 rotor was replaced during the last Unit 2 refueling  
13 outage. During the upcoming EPU outage, the main  
14 generator hydrogen pressure will be increased to 75  
15 psi. These modifications will allow the main  
16 generator rating to be increased to a value suitable  
17 for the uprate.

18 An additional EPU electrical modification  
19 is being implemented to resolve another low margin  
20 issue. Currently, there is limited margin between the  
21 degraded voltage relay setpoints and the calculated  
22 bus voltage during the limiting electrical loading  
23 event.

24 For EPU, a number of electrical  
25 modifications are being implemented to increase this

1 voltage margin, and this is similar to what we did on  
2 Unit 1 also. So unless there are any questions for me  
3 --

4 MEMBER BROWN: I have a question of  
5 understanding.

6 MR. HOFFMAN: Sure.

7 MEMBER BROWN: Station blackout, the  
8 coping time that you all advertise, what you  
9 calculated and the staff evaluated remains at four  
10 hours. This is a two unit site. Since I'm not  
11 familiar, I don't remember the St. Lucie 1 set-up.  
12 But do each of the units have their own switchyard, or  
13 do they share a common switchyard? I don't remember  
14 from the earlier St. Lucie.

15 MR. HOFFMAN: It is a common switchyard  
16 with bays.

17 MEMBER BROWN: So the multiple, the two,  
18 the independent feeds, off-site feeds come into the  
19 common switchyard setup?

20 MR. HOFFMAN: That's correct. But the  
21 diesels between both units, you know, irrespective of  
22 the station blackout coping requirements --

23 MEMBER BROWN: They have independent  
24 diesels. It's not a shared diesel?

25 MR. HOFFMAN: Two diesels on each unit,

1 and we do have cross-connect capability.

2 MEMBER BROWN: You talked about a cross-  
3 tie.

4 MR. HOFFMAN: Right.

5 MEMBER BROWN: Now one of the reasons,  
6 again this is an understanding; I just want to make  
7 sure I understand this, okay, is that one of the bases  
8 for you all's SBO is that you have natural circulation  
9 that will allow you to maintain decay heat removal  
10 capability for that four hour coping period.

11 I'm assuming, then, that that's dependent.  
12 You still have to operate certain equipment, but  
13 that's dependent upon your battery DC power sources  
14 via whatever inverters you have. So you're still,  
15 whether it's -- that's just your method, but you're  
16 still fundamentally limited by the battery capacity,  
17 if you exceeded the four hour coping period.

18 MR. HOFFMAN: That's correct.

19 MEMBER BROWN: And then you would be, have  
20 to fall into the ability to do the cross-tie, and  
21 assume that the diesels from the other side, assuming  
22 the other side is shut down, that you then, and you  
23 haven't got off-site power back, you'd have to do  
24 that.

25 MR. HOFFMAN: That is the SBO.

1 MEMBER BROWN: Is my understanding --

2 MR. HOFFMAN: That's correct. That's the  
3 SBO licensing basis for St. Lucie Unit 2, and we did  
4 a detailed Chapter 15-type analysis for EPU, to show  
5 that again, for that four hour coping time, we could  
6 maintain the --

7 MEMBER BROWN: Yeah. No, I read it. I  
8 just wanted to make sure I understood the other  
9 connections, since I didn't have any of that  
10 information.

11 MR. HOFFMAN: Okay.

12 MEMBER BROWN: Thank you.

13 MR. HALE: Before we leave Jack's  
14 presentation, we do have an answer on your  
15 cybersecurity question, with regards to information  
16 flow.

17 MEMBER BROWN: Do you have a picture?

18 MR. HALE: Huh?

19 MEMBER BROWN: Do you have a picture?

20 MR. HALE: Don't have a picture, but --

21 MEMBER BROWN: So the thousand words will  
22 replace a simple diagram, right?

23 MR. HALE: Well, the DCS is classified in  
24 our system as a high level security computer system,  
25 and the interface between the DCS and PI, as a wall

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1 basically, a one-way diode. They call it the dama-  
2 diode (ph). It's a deterministic device that does not  
3 allow communication to flow from the PI system back to  
4 the DCS.

5 MEMBER BROWN: Okay. So when you say a  
6 one-way diode, let me make sure I understand one  
7 thing. There are one-way diodes and then there are  
8 one-way diodes. Some one-way diodes are devices which  
9 are reconfigurable to be two-way if you so desire.

10 Several methods to do that. Some can be  
11 done externally via remote means; some have to be  
12 executed at the device itself by manual means. So my  
13 question is what kind of one-way diode? Even if it's  
14 deterministic, it can still be executed either way.

15 MR. HALE: It's the latter, the one that  
16 would require -- you would require to go physically to  
17 the hardware to make changes to a diode such as that.

18 MEMBER BROWN: Okay. So somebody  
19 externally cannot do that via remote access to some  
20 software package somewhere?

21 MR. HALE: Exactly.

22 MEMBER BROWN: Okay. Let it be written  
23 and let it be recorded. Thank you.

24 MR. HALE: All right, and then we do have  
25 some of the best estimate data.



1 MR. HOFFMAN: I've got the calcs, Steve.  
2 I'll share the calcs.

3 MR. HALE: Okay, thank you.

4 MR. HOFFMAN: Yeah. Okay. Unless there  
5 are any other questions for me, I'd like to turn the  
6 presentation over to Jay Kabadi, who will discuss the  
7 EPU fuel-related analyses.

8 CHAIR REMPE: So we're running about 20  
9 minutes behind, just so everyone's aware. So go  
10 ahead.

11 Fuel and Core Design

12 MR. KABADI: Okay. My name is Jay Kabadi.  
13 I'm manager of Nuclear Fuel for Florida Power and  
14 Light. In the next few slides, I'm going to present  
15 what the EPU considerations are for fuel design and  
16 cooling towers. This slide presents for EPU, we did  
17 not have to make any changes to the fuel design.

18 We will continue to use the Combustion  
19 Engineering 16 by 16 fuel design, which we have been  
20 using for past several cycles. It has an Incanel Top  
21 Grid design, which we implemented mainly to provide  
22 additional margin to grid-to-rod fretting. Our pin  
23 burnup and assembly burnup limits remain unchanged.

24 MEMBER SCHULTZ: Jay, what are those  
25 limits for the rods?

1 MR. KABADI: I think we have real limit is  
2 on the pin burnup, and that is 60,000. Assembly  
3 burnup is mainly we maintain to ensure that pin burnup  
4 is not limited; there is no real hard limit --

5 MEMBER SCHULTZ: There's not an assembly  
6 burnup limit --

7 MR. KABADI: That is correct.

8 MEMBER SCHULTZ: --that's designated.  
9 Thank you.

10 MEMBER BANERJEE: Is this fuel being  
11 tested? This is a sort of a question which is related  
12 to GSI-191. Just for informational purposes, it is  
13 being tested for downstream effects?

14 MR. KABADI: My understanding is when  
15 there's a downstream effect, the testing is set up so  
16 that it covers all the fuel assembly types. I cannot,  
17 I do not know exactly how this product is designed,  
18 but the intent of the testing was to make, with the  
19 final results, applicable to all the fuel --

20 MEMBER BANERJEE: Because as you know,  
21 there are tests which have been done with Westinghouse  
22 and AREVA fuel.

23 MR. KABADI: Right, right, right.

24 (Simultaneous speaking.)

25 MR. KABADI: Right, and this is

1 Westinghouse. This is the Westinghouse fuel.

2 MEMBER BANERJEE: Oh, this is the  
3 Westinghouse fuel.

4 MR. KABADI: Right. This is the  
5 Westinghouse fuel. Now there were changes because of  
6 regional Combustion Engineering. So this is covered  
7 under Westinghouse program.

8 MEMBER BANERJEE: So it's substantially  
9 the same design?

10 MR. KABADI: Right. This is a period of  
11 design by the licensee, and not the one which is at  
12 Turkey Point and all. Right now, it is Westinghouse,  
13 because they put it together, but the design is the  
14 regional CE design.

15 MEMBER BANERJEE: I'm so confused by all  
16 this.

17 MR. KABADI: Westinghouse actually right  
18 now is like what you call old or traditional  
19 Westinghouse, this 16 by 16 design is not one of the  
20 original Westinghouse designs. This was the CE plants  
21 16 by 16 design. When they merged, the same design is  
22 carried over. So there is no change to the fuel  
23 design before and after CE or Combustion Engineering  
24 --

25 MEMBER BANERJEE: Let's be more direct.

1       What is the design that's being tested under this  
2       program right now?

3               MR. KABADI:   GSI-191?   Well, I cannot  
4       detail.   Only thing what we were --

5               MEMBER BANERJEE:   It's not this, right?

6               MR. KABADI:   It should be included as part  
7       of the overall program, the final results to be  
8       applicable to all the designs.

9               MR. HOFFMAN:   We'll validate that.

10              MR. KABADI:   Right.   We can validate what  
11       is exactly --

12              MEMBER BANERJEE:   Yeah.   Just give me this  
13       --

14                       (Simultaneous speaking.)

15              MEMBER BANERJEE:   I know it doesn't impact  
16       you for this EPU, but --

17              MR. KABADI:   That's okay.   We can look and  
18       see whether this particular design is included in the  
19       testing.

20              CHAIR REMPE:   But isn't the argument that  
21       was responded to in RAI is that the EPU doesn't affect  
22       --

23              MEMBER BANERJEE:   Thermal decay heats,  
24       right.

25              CHAIR REMPE:   They're basically saying

1       that it didn't affect the zone of influence that they  
2       were calculating.

3               MEMBER BANERJEE:  It's not the zone of  
4       influence.  You've got to push most coolant through  
5       the core to keep it cool.

6               CHAIR REMPE:  Yeah, okay.  That was what  
7       the staff --

8               MEMBER BANERJEE:  Does that mean the  
9       ultimate if you start to block with downstream  
10      effects.

11              CHAIR REMPE:  Okay.

12              MEMBER BANERJEE:  You're having 12 percent  
13      more power, right?

14              CHAIR REMPE:  Yeah, okay.  But I was just  
15      going to take it what's been reported in the SER, so  
16      I was just kind of wondering.

17              MEMBER BANERJEE:  They can be, let's say  
18      in the GSI-191 evaluations, you take EPU into account.  
19      That's the idea, right, and that's what every  
20      applicant is saying, before going for an EPU.  But to  
21      say it doesn't make a difference is pretty hard to  
22      defend, I would say.  You've got 12 percent more decay  
23      heat or something to deal with, right?  Does that make  
24      any sense?

25              CHAIR REMPE:  It makes sense, but it's

1 just the reporting that they had in their RAI.

2 MEMBER BANERJEE: Go ahead.

3 MR. HALE: This is Steve Hale, Florida  
4 Power and Light. Yes. If you'll remember, Dr.  
5 Banerjee, at both Point Beach and Turkey Point, we  
6 essentially followed the same approach with GSI-191.

7 It was being handled as a separate, you  
8 know, generic licensing action. But we've made sure  
9 that anything we're doing, any EPU falls within the  
10 bounds of what we're doing under GSI-191.

11 MEMBER BANERJEE: Well, you have to take  
12 into account the higher decay heats.

13 MR. HALE: That's true.

14 MEMBER BANERJEE: Sure, okay.

15 MR. HALE: But all of our efforts related  
16 to GSI-191 have already taken the EPU into account.

17 MEMBER BANERJEE: Right. I was really  
18 asking if the fuel designs are encompassed by the  
19 downstream effects testing going on. So --

20 MR. HALE: I can't answer that. We'll  
21 have to find somebody to respond to that question.

22 MEMBER BANERJEE: Okay.

23 MR. KABADI: From fuel design perspective,  
24 we have, we developed several transmission cycles for  
25 EPU to come up with the parameters that we can use in

1 the safety analysis.

2 But in general, core design limits do not  
3 change much for EPU, which is a total integrated  
4 radial peaking factor, we reduce from 1.7 to 1.6,  
5 again moderating some of the analysis to offset some  
6 of the impacts of higher power.

7 We will remit this reduced limit and the  
8 extra energy demand to higher power by changing our  
9 peak size number of assemblies, along with some  
10 arrangement placing the absorber rods in the  
11 locations. But our general loading pattern  
12 configuration remains similar. So there is no major  
13 change to the core loading plan.

14 MEMBER SCHULTZ: With the radial peaking  
15 factor affected not only by the EPU power change, but  
16 also by the thermal conductivity degradation, which  
17 we'll discuss later?

18 MR. KABADI: Actually, when we started  
19 this EPU analysis, thermal conductivity degradation  
20 was actually not where it is right now. There was not  
21 too much consideration directly given. But in  
22 general, any time your peaking was down and the power  
23 was down, it helps thermal conductivity.

24 But it was not the initial decision on  
25 making this lower; it was strictly based on fuel

1 performance and the DNB considerations.

2 MEMBER SCHULTZ: So this change was done  
3 and not affected by the thermal conductivity  
4 degradation impact?

5 MR. KABADI: That is correct.

6 MEMBER SCHULTZ: Thank you.

7 MEMBER SKILLMAN: Jay, did you change the  
8 cycle length in this application, 18 months to 24  
9 months?

10 MR. KABADI: No. We are still following  
11 18 month cycles.

12 MEMBER SKILLMAN: I understand you're on  
13 18 month cycles. Thank you.

14 MEMBER BROWN: Let me ask, it's a simple-  
15 minded question. I'm not -- if I'm completely off the  
16 wall, just tell me. So you wanted to maintain margins  
17 to fuel design limits, and in order to do that, you  
18 reduced one of your peaking factors.

19 But I mean so previously your analysis  
20 said okay, if I'm at a certain point, I've got  
21 peaking, radial peaking factors of 1.7. Now we said  
22 oh, now we're going to assume a lower number.  
23 Therefore now, I will calculate that I don't get any  
24 closer to my fuel design limits than I did before. Is  
25 there a basis for saying I can reduce my radial

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1 peaking factor? Is that --

2 MR. KABADI: No, I think this is when we  
3 did the code design on the analysis, this was actually  
4 evaluated.

5 MEMBER BROWN: It's a similar core. I  
6 mean did you all change the core in this case? I  
7 didn't get that out of the reading.

8 MR. KABADI: No, I think that -- so when  
9 we designed the core, that's when we had to put the  
10 assemblies, and the number of assemblies that reduces  
11 the peaking factor, which is --

12 MEMBER BROWN: But you made a change in  
13 the arrangement or the setup --

14 MR. KABADI: I think that remains similar,  
15 in the sense that number of assemblies, fresh  
16 assemblies will go up. But we typically follow for  
17 St. Lucie 1, in-out-in type configurations. So we put  
18 all the peripheral assemblies in as --, and the fresh  
19 and whatever turbine go inside.

20 So that pattern remained the same. But  
21 how many fresh we used slightly increased because of  
22 this, to reduce the peaking. So we are using  
23 currently in the range of 72 to 76 assemblies.

24 CONSULTANT WALLIS: So you are flattening  
25 the --

1 MR. KABADI: That's correct. So for EPU

2 --

3 MEMBER BROWN: And so you did something  
4 physically --

5 MR. KABADI: Correct, correct. So we'll  
6 be using --

7 (Simultaneous speaking.)

8 MEMBER BROWN: --but where you laid out  
9 the --

10 MR. KABADI: That's exactly right. We are  
11 using --

12 MEMBER BROWN: For whatever you did. So  
13 you would flatten the power sum and reduce the radial  
14 --

15 MR. KABADI: That's correct.

16 MEMBER BROWN: So there's a basis for  
17 saying I can go to a reduced number?

18 MR. KABADI: That's correct.

19 MEMBER BROWN: That's what I was asking.

20 MR. KABADI: That's right, exactly right.  
21 We did some --

22 CONSULTANT WALLIS: We're not saying that  
23 they actually will go to a reduce peaking --

24 (Simultaneous speaking.)

25 CONSULTANT WALLIS: That's just an

1 assumption.

2 MEMBER BROWN: I understand. That's just,  
3 I mean.

4 MR. KABADI: And we did design with these,  
5 to see that we can meet those --

6 MEMBER BROWN: I just want to make sure  
7 you just didn't reduce it because it was fun to reduce  
8 it for convenience sake, that's all.

9 MEMBER SCHULTZ: It was required to be  
10 reduced, and you spoke to it here, Jay, but it's not  
11 in the slide. But the feedback size goes up.

12 MR. KABADI: Yeah, right.

13 MEMBER BROWN: Okay.

14 MEMBER SCHULTZ: In order to accommodate  
15 and achieve the high power.

16 MR. KABADI: And as I mentioned, from 72  
17 to 76 right now you get --.

18 MEMBER SCHULTZ: Jay, one more thing. You  
19 had burnable absorber replacement here. With regard to  
20 that, is that a dramatic change that's been  
21 implemented by Westinghouse?

22 MR. KABADI: No. It's really for burnable  
23 absorber we had following the same type of strategy.  
24 We go anywhere from 8 to 20. We had gad rods and  
25 eight percent of that is very similar, around eight

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1 percent.

2 MEMBER SCHULTZ: That's not a change.  
3 That's under the normal approaches that have been used  
4 with regard to the placement of --

5 MR. KABADI: That's correct. Only change  
6 would be number of feeds to go out.

7 MEMBER SCHULTZ: And you're not  
8 implementing any additional changes with respect to  
9 gad loading, changes from what you have done in the  
10 past?

11 MR. KABADI: Exactly. No changes to the  
12 gad rod --

13 MEMBER SCHULTZ: The same choices you've  
14 used in the past, that you have available in --

15 MR. KABADI: Exactly. That is correct.

16 MEMBER SCHULTZ: Thank you.

17 MR. KABADI: Other limits which are  
18 important from core design perspective, mainly the  
19 shutdown margin and MTC (ph). Those limits also are  
20 met for EPU. So we don't have, we did not have to  
21 make any changes to those. Now as far as gadding  
22 shutdown margin and improving the boron delivery  
23 capability, we are, however, increasing the boron  
24 concentrations in all the tanks, RWD.

25 Also the safety injection tanks and also

1 in the boric acid make-up tanks, and those are tech  
2 specs changes which are covered in the EPU LAR.

3 Going to the safety analysis, there are no  
4 major changes done in terms of what methodology we  
5 have used for the analysis. We continue to use the  
6 same methods for small-break and large-break LOCA.  
7 RETRAN is used for non-LOCA, which is what we  
8 currently use.

9 Only change is we have in the current  
10 analysis for tube rupture, we have not transitioned to  
11 RETRAN, but as a part of the EPU, even the tube  
12 rupture analysis was done with RETRAN. But all these  
13 codes and the VIPRE was used in the current V&V  
14 analysis.

15 MEMBER BANERJEE: So these are, some of  
16 these are very old codes, right?

17 MR. KABADI: Those are actually old, but  
18 the current --

19 MEMBER BANERJEE: They're still approved,  
20 that's what you're saying?

21 MR. KABADI: Approved, plus the latest in  
22 the sense of the current from the CE plants for these.  
23 For example, RETRAN is Westinghouse's current method  
24 for non-LOCA.

25 MEMBER BANERJEE: No. But let's look at

1 CEFLASH.

2 MR. KABADI: Right. So that is the  
3 Westinghouse Appendix K small-break and large break  
4 current method for CE plants.

5 MEMBER BANERJEE: So your -- in this case,  
6 unlike St. Lucie 1, you're going to use Appendix K  
7 methods?

8 MR. KABADI: That is correct. We did not  
9 transition to realistic or best estimate for large  
10 break. So right now, Westinghouse, ASTRUM and other  
11 methods have not been applied to any CE plants. So we  
12 may in future take that on.

13 But right now, based on these -- if you're  
14 engaged in a big project event and are using Appendix  
15 K, we found that we can meet all the limits with  
16 Appendix K. So we did not transition, because that  
17 would require a lot of benchmarking and all that stuff  
18 to be done.

19 MEMBER BANERJEE: Okay, and you took TCD  
20 into account?

21 MR. KABADI: Right, and that's something  
22 where we have a discussion later in the EPU, when this  
23 project started. As I mentioned, we started without  
24 DCD like it is right now, but we later on did include  
25 and evaluate and see what the impact is, and we'll

1 talk this afternoon on that DCD impact.

2 Okay. Some of the key changes which are  
3 done for the safety analysis is from the code design  
4 point of view actually, which is reduced from 1.7 to  
5 1.6, and the way we do the safety analysis is we try  
6 to hold a conservative assumptions, so that planned  
7 operations don't get restricted by some of these  
8 inputs.

9 For example, we use all the plant bounding  
10 operator parameters, include the uncertainties, and  
11 going all the way to the limits of that operation.

12 CONSULTANT WALLIS: Have these changed as  
13 a result of the EPU, or are these the same  
14 conservative assumptions as before?

15 MR. KABADI: Assumptions are same. Only  
16 the values will be changing.

17 CONSULTANT WALLIS: So you did change the  
18 values as a result of the EPU?

19 MR. KABADI: Like the inlet temperature we  
20 mentioned. It goes up from 549 to 551.

21 CONSULTANT WALLIS: Okay.

22 MR. KABADI: So that is one thing. Other  
23 thing will go on the next slide that we show, some of  
24 the tolerances on the valves will increase. But the  
25 method, in terms of putting --, is about the same.

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1                   Yeah. These are some of the changes that  
2                   help and the same time consistent with our EPU, tech  
3                   spec changes and other changes we are doing as part of  
4                   the EPU analysis. Uncertainty goes down from 2  
5                   percent to .3 percent, and we talk about that.

6                   Tube plugging, several analyses in the  
7                   past have 30 percent tube plugging. Not all, but some  
8                   of the analyses are 30 percent. We are making it all  
9                   ten percent across the board for all the safety  
10                  analyses. Tolerances on both --

11                  CONSULTANT WALLIS: What's the basis for  
12                  ten percent? Is this just a guess of some sort?

13                  MR. KABADI: Ten percent, the way we  
14                  decided ten percent is we looked at the current flow,  
15                  what we have, and now we saw how much margin we have,  
16                  and we generated flows for different tube plugging  
17                  levels, and we assume that is what is the value that  
18                  most appropriate to go with.

19                  CONSULTANT WALLIS: What's the reality?  
20                  I mean you say you're assuming ten percent?

21                  MR. KABADI: Yeah. Right now --

22                  CONSULTANT WALLIS: The reality is what  
23                  one or two percent or something? What's the reality?

24                  MR. KABADI: Much less than that.

25                  MR. GIL: This is Rudy Gill, Florida Power



1 and Light. Yeah. Our current number is for the  
2 generator that has the most, is a quarter of one  
3 percent.

4 CONSULTANT WALLIS: And the experience  
5 with other plants with similar steam generators?

6 MR. GIL: Typically, the ones that I'm  
7 familiar with, that are the replacement type steam  
8 generators are also at the very low numbers. I think  
9 the only ones I know that have higher percentages are  
10 the once-through steam generators that we know have  
11 had some issues.

12 CONSULTANT WALLIS: So this is a number  
13 which is convenient, which is much larger than all the  
14 experience? There's no real basis other than that?

15 MR. KABADI: Yeah. I think other than  
16 like Rudy mentioned, about similar but -- like St.  
17 Lucie 1. We replaced the generators in 1999 time  
18 frame, and we have still less than, much less than one  
19 percent plugging there.

20 CONSULTANT WALLIS: So you could have  
21 assumed five percent or something like that, maybe  
22 wished --

23 MALE PARTICIPANT: Had to pick a number.

24 MR. KABADI: Right, and that's why we did  
25 some studies to see how much flow, minimum flow we

1 need for meeting the safety analysis and what we can  
2 accommodate in terms of plugging and decided ten  
3 percent is the --

4 CONSULTANT WALLIS: It could accommodate  
5 ten percent.

6 MR. KABADI: Yes. There were other  
7 changes to the boron concentrations in the three tanks  
8 that are included in all the analyses, where they are  
9 important.

10 CHAIR REMPE: On the steam generator tube  
11 plugging, if you for whatever reason were at ten  
12 percent, how much margin is -- I mean are you, is that  
13 the most you can accommodate based on your analysis,  
14 or is there still more margin?

15 MR. KABADI: Yeah, I think on the next few  
16 slides when I present some of the analyses, you will  
17 see that analyses has some margins and all the  
18 analyses support ten percent plugging. So there is a  
19 -- we didn't want to go all the way to the actual  
20 limit of all the accident analyses. So there is some  
21 margin to the accident analyses.

22 CHAIR REMPE: Okay.

23 MEMBER BROWN: Before you leave that one,  
24 go backwards, please. The main steam stop safety  
25 valve relief tolerances you've now moved from values

1 you show in here, and I guess I walked away from the  
2 one justification for it was that the vendor says his  
3 valve is designed to a plus or minute three percent  
4 tolerance to hold that, as opposed to your previous  
5 tolerance of plus, what you were using on an as-found  
6 evaluation basis or check basis, of plus one/minus  
7 three.

8 So now if you go out and you find, if you  
9 walk out and you find it's a plus three, you say fine,  
10 we're good to go, and away we go. So it may have  
11 changed from the last time, but there's no -- I mean  
12 it sounds like it's a convenience thing just to  
13 minimize adjustments to the steam safety valve.

14 MR. KABADI: No. I think our tech specs  
15 as left setpoint doesn't change. That is still plus  
16 one percent. So even if you find, as found three  
17 percent, when we start the plant --

18 MEMBER BROWN: I understand what you find.  
19 But if you find it at three, that's an acceptable as-  
20 found condition. So you don't have to do anything.

21 MR. HOFFMAN: Right, and just a couple of  
22 clarifications. The plus or minus three percent is  
23 the classic ASME --

24 MEMBER BROWN: I got that out of your  
25 write-up.

1 MR. HOFFMAN: Right, and these numbers  
2 that Dave's referring to are really driven by the  
3 accident analyses, the over-pressure analyses. That's  
4 what dictates, you know, how high you can go  
5 primarily, and one thing again. This is a chance for  
6 us to get --

7 MEMBER BROWN: Okay. You're saying that  
8 three percent is only used in the analyses. Now when  
9 you go out and you do your calibration checks or you  
10 do your safety valve trip check, if it was at plus two  
11 percent you would reset it, because the tech spec  
12 still says plus one percent when you get to the as-  
13 found?

14 MR. HOFFMAN: That's right.

15 MEMBER BROWN: That's not what the LAR  
16 says. It says "as-found value was changed from" --  
17 one of the documents.

18 MR. KABADI: Right. I think that is the  
19 value when the valve got tested.

20 MEMBER BROWN: So if you go out and if you  
21 do a test to verify the operation of your steam safety  
22 valves, if it comes in at plus 2.999, you can walk  
23 away and say we'll wait until the next time we test  
24 it. We're happy as a pig in a mud wallow here.

25 MR. KABADI: Yeah. That will tell them,

1 the 2.9 or whatever you find that is covered by the  
2 accident. But when they're as-left values, it still  
3 has to be plus one. So I'll have to be brought back  
4 to within plus one. This is the -- during the, there  
5 is some -- during the cycle when they test the valve,  
6 and if we analyze with one percent, and the value is  
7 found two percent, then it will be outside the  
8 analyses.

9 So we have to do some operability  
10 assessment for those. So this one allows that  
11 flexibility, that if the value is found outside that,  
12 then that is in the analyzed event.

13 MEMBER BROWN: All right. Your LAR says  
14 MSVs with a nominal setpoint of 1,000 psi, the as-  
15 found setpoint tolerances are being changed to plus or  
16 minus three percent, the as-found value.

17 MR. KABADI: Right.

18 MEMBER BROWN: Which to me means that if  
19 I find the value within that range, I don't have to do  
20 anything until I go run that test the next time and  
21 find out that it exceeds that value.

22 MR. KABADI: I think below that, there is  
23 a surveillance requirement that says the valve has to  
24 -- no, not --

25 MEMBER BROWN: No, not tech specs.

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1 MR. HOFFMAN: It's in the technical  
2 specifications, not in the text of the LAR. We can  
3 show you the tech spec page.

4 MR. KABADI: Tech spec mentions that, that  
5 you have to set it within one percent. I don't know  
6 whether that page --

7 MEMBER BROWN: When you reset it, but as  
8 -- okay, I'm really not understanding.

9 MR. HOFFMAN: We can't walk away from it.  
10 The plus three percent allows us to accept the as-  
11 found test in analytical space, but our technical  
12 specification will not allow us to walk away from the  
13 valve at plus three percent. We have to reset it  
14 before we walk away and leave it as left at plus one  
15 percent for the next operating cycle.

16 MEMBER BROWN: Okay. Let me be very, make  
17 sure I understand this now. I'm operating along, and  
18 I come up to whatever your periodicity is for checking  
19 the setpoint of your steam safety valves. You run  
20 your tests and it comes out two and a half. Do you  
21 have to reset it based on that, and go back because of  
22 some other document in the tech spec, or is that the  
23 as-found value, and it's within plus or minus three  
24 and you don't have to do anything?

25 MR. KABADI: No, we have a --

1 (Simultaneous speaking.)

2 MR. KABADI: --during the outage time,  
3 once you have that, and then the next time it starts,  
4 we have to make them. All that will be brought back  
5 into one percent.

6 MEMBER BROWN: If they exceed one percent  
7 on the plus side, they will be brought back to one  
8 percent?

9 MR. KABADI: That's correct.

10 MEMBER BROWN: Then I don't really  
11 understand why the words "as found" are used.

12 MR. HALE: Hi. This is Steve Hale,  
13 Florida Power and Light. That's fairly standard  
14 nomenclature like for instrumentation and that sort of  
15 thing. The as-found condition is when you go out and  
16 test it, you know, you want to make sure that the  
17 valve is within those bounds when you go out and test  
18 it, okay.

19 As-left is where you leave it. So if you  
20 found it above one percent, the as-left tech spec says  
21 you've got to bring it within one percent. So as  
22 found says that hey, it's within the range that we  
23 expected it to be in, okay, and you certainly want to  
24 make sure that at that as-left condition you're within  
25 your safety analysis. But we're also required by tech

1 specs to reset it.

2 MR. HOFFMAN: Steve, maybe on a break we  
3 can pull that tech spec page.

4 MEMBER BROWN: Oh no. I believe you.

5 CHAIR REMPE: You're okay?

6 MEMBER BROWN: Yeah. I believe what  
7 you're -- I'm not questioning the fact that that's  
8 set. It's the terminology that I -- all I'm trying to  
9 establish is when I first read it, it sounded like now  
10 I should walk out and see the valves at a value  
11 greater than one percent, and say I passed my test  
12 now, because I'm at less than three.

13 If you're required by some other thing to  
14 go reset it to the one percent, and all you're saying  
15 is I don't have to submit a report to the NRC because  
16 I didn't exceed the plus three percent, I don't know  
17 who you have to submit anything to.

18 MR. KABADI: No, that's right.

19 MEMBER BROWN: I guess before you would  
20 have had to submit something if you found it at two  
21 and now you don't. You just go reset it to one is my  
22 understanding.

23 CHAIR REMPE: Is everybody okay?

24 MEMBER BROWN: I'm fine.

25 CHAIR REMPE: Okay. Let's go.



1 MEMBER BROWN: Thank you. Sorry.  
2 Unfortunately, I read this stuff and --

3 CHAIR REMPE: Okay, good. Okay.

4 MR. KABADI: Next slide. Yeah. We talked  
5 about this before. As I said, there are no changes to  
6 the methodology we use except in tube ruptures we just  
7 RETRAN.

8 This slide, next we will present some of  
9 the reasons for the EPU. Now in the RCS flow,  
10 decreased category. The limiting events are loss of  
11 flow and the locked rotor, and one of the things to  
12 note here is the criteria which is mentioned here,  
13 like loss of flow 1.42, that is actually a safety  
14 analysis limit. We actually have margin built into  
15 that, roughly about eight to ten percent.

16 So when our diesels show 1.444, it is  
17 actually beyond what we set as a safety analysis  
18 limit. The actual core relation limit is something in  
19 the range of 1.33, and that's our actual design limit.  
20 So the way the Westinghouse methodology works is they  
21 embed some margin and say okay, although the design  
22 limit is 1.33, we'll put a safety analysis limit as  
23 1.42, and unless needed for some events, then we'll  
24 lower that.

25 So there is some margin built in in all

1 these MDNBR limits. So for both locked rotor and loss  
2 of flow, we meet all the acceptance criteria for  
3 locked rotor. For example, we'll use 19.7 percent  
4 fuel failures in our dose calculations. We have no  
5 failures in the actual analysis done.

6 In the peak pressure, our limiting event  
7 is the loss of condenser vacuum, and the peak pressure  
8 is .69 psia, which has significant margin to the  
9 limit. In the new event analyses that we did as part  
10 of the EPU, was both in feed line break and loss of  
11 feedwater, for the longer term AFW adequacy type  
12 analyses, we did like Chapter 15-type assumption to  
13 confirm that AFW has enough capacity to have RCS not  
14 do subcooling.

15 So this is a new subset of the regional  
16 analysis, what we did as part of the EPU. This is  
17 based on some of the staff review and there's a part  
18 of some of the request of information we requested.

19 Next slide. Yeah. Feed line break for  
20 St. Lucie 2 is also analyzed in the shorter term, for  
21 break sizes, to see the peak pressure in both in the  
22 larger breaks and the smaller breaks meet the  
23 acceptance criteria with sufficient margin in there.

24 Steam line break is the other limiting  
25 event from cooldown considerations, and as shown on

1 this slide for both, and V&V and the fuel melt, we  
2 have no fuel failures. So the dose consequence  
3 analyses remain well-bounded.

4 CEA withdrawal, this is one of the place  
5 where that limit, 1.26 which is mentioned, that has a  
6 margin built in significantly in there. The real  
7 design limit is in the range of 1.14. So we have  
8 sufficient margin in there, and the final result shows  
9 that the V&V margin is something like ten percent or  
10 so.

11 For CEA ejection, we analyzed the event  
12 for a more restrictive 200 calories per gram criteria.  
13 Our analysis shows margin to that, with more than 40  
14 calories per gram, and other limits suggest V&V and  
15 field melt for CEA ejection as not limiting and we  
16 meet the criteria for EPU.

17 CONSULTANT WALLIS: And with all these,  
18 you do something about conductivity degradation in the  
19 fuel?

20 MR. KABADI: Well, we'll talk a little bit  
21 about that later. But yes --

22 CONSULTANT WALLIS: In that analysis, you  
23 take account of that?

24 MR. KABADI: Right. But a lot of these  
25 analyses were like the center-line melt and always

1 considered, and we'll talk this afternoon how --

2 CONSULTANT WALLIS: That's included in  
3 this table here somewhere, that how it's --

4 MR. KABADI: Right. How that, why that  
5 limit is acceptable. We'll talk this afternoon, that  
6 with the thermal conductivity degradation, that's  
7 okay. Those limits we'll talk a little bit this  
8 afternoon.

9 MEMBER SCHULTZ: Jay, could you go back  
10 one slide?

11 MR. KABADI: Uh-huh.

12 MEMBER SCHULTZ: On the CEA ejection, just  
13 can you give more information related to the rods in  
14 DNB and what you're showing here, or will we discuss  
15 that in more detail this afternoon?

16 MR. KABADI: No. Rods in DNB,  
17 Westinghouse, the way the Westinghouse methodology  
18 right now works is that they have done some generic  
19 calculations, put in some bounding parameters in terms  
20 of ejector rod failure, and the coordination they use  
21 for all that. St. Lucie 2 specific EPU parameters  
22 were compared to that and found to be significantly  
23 lower.

24 The generic analyses has shown that the  
25 amount of rods or number of rods in failure are much

1 less than ten percent. So by doing a comparative-type  
2 evaluation, that was concluded that the number of rods  
3 in the NBR well below what is used in the --

4 MEMBER SCHULTZ: So it was comparative  
5 parameter evaluation, parametric?

6 MR. KABADI: That is correct.

7 MEMBER SCHULTZ: To demonstrate that the  
8 analyses essentially didn't need to be repeated --

9 MR. KABADI: Right, that is correct.

10 MEMBER SCHULTZ: --you know, with the  
11 conditions of EPU.

12 MR. KABADI: Right, particularly since the  
13 generic analysis covers the limits of all those  
14 analyses.

15 MEMBER SCHULTZ: But specifically was  
16 there an evaluation related to -- was there an  
17 analysis related to fuel melt, or was that an  
18 evaluation also?

19 MR. KABADI: Fuel melt? I think I wrote  
20 this specific analysis and Jessica, are you  
21 responsible?

22 MS. TATARCZUK: For our CA ejection event,  
23 the rods and DNB parameter of less than 9.5 percent.  
24 That was the generic analysis that Jim was speaking  
25 to, that we had our data for the EPU, and it was

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1 actually vastly bounded by the WCAP that was done, the  
2 generic analysis.

3 So we did that. But we did use that as  
4 input our state points, which come back. For the  
5 other parameters, actually they did actual data  
6 evaluation for, the rods and DNB was the portion that  
7 was the portion that was bounded by the generic  
8 analysis.

9 MEMBER SCHULTZ: Thank you.

10 MS. TATARCZUK: Sorry, just one other  
11 thing. I'm Jessica Tatarczuk from Westinghouse. I  
12 didn't introduce myself.

13 CHAIR REMPE: Yes, thank you.

14 MR. KABADI: Next slide. Yeah. You have  
15 the difference between EPU and non-EPU on that, but  
16 certain margins don't change and there is not too  
17 change to the plant configuration. One event which  
18 was done in two subevents, which was inadvertent  
19 opening of the PORV. Typically, that event was  
20 analyzed only for DNB, and that has significant margin  
21 for EPU.

22 CONSULTANT WALLIS: Now on this slide, the  
23 pressurizer volume is 1519, is that right?

24 MR. KABADI: Right.

25 CONSULTANT WALLIS: It doesn't say so.

1 MR. KABADI: Oh, okay. Yes. Pressurizer  
2 full volume 1519, and that inadvertent --

3 CONSULTANT WALLIS: So you're saying that  
4 the pressurizer does fill if no one does something, is  
5 that right?

6 MR. KABADI: In 20 minutes, the operators  
7 --

8 CONSULTANT WALLIS: At the bottom.

9 MR. KABADI: Right, and that is the same  
10 as what our current analysis is done then. But now  
11 for the inadvertent opening of PORV, that's where we  
12 analyze again for the pressurizer fill, and that  
13 pressurizer fill event for St. Lucie 2 comes out about  
14 three minutes, and that is what the operators have to  
15 take action to close the block valve or to --

16 CONSULTANT WALLIS: The operator has about  
17 three minutes to close the block valve?

18 MR. KABADI: For the inadvertent opening  
19 of PORV, and that is a new, what I call a new event  
20 which builds on the staff review. We have to also do  
21 for St. Lucie 1 and --

22 CONSULTANT WALLIS: Is time significantly  
23 less than it was before the EPU?

24 MR. KABADI: No. This event was not  
25 analyzed --

1                   CONSULTANT WALLIS: Was not analyzed  
2 before.

3                   MR. KABADI: Yeah. This is a new, it came  
4 as a part of the staff review and now, for those of  
5 you who were here for St. Lucie 1, that was also  
6 talked about as being redone for St. Lucie 1 also, and  
7 St. Lucie 1 gets larger time because the PORVs are  
8 smaller compared to St. Lucie 2.

9                   Yeah. We'll do small-break LOCA. Small-  
10 break LOCA, we use the same methodology, what we  
11 currently have, and that is called small-break LOCA  
12 SM-2, SPM (ph) methodology, which was approved by the  
13 staff.

14                  Only real change here is the tube  
15 plugging. The current analysis we have 30 percent; we  
16 ran to ten percent, and the other inputs here are  
17 related to the power, which we discussed earlier.

18                  As seen on this slide, the PCT (ph) for  
19 the EPU is 1903, with Appendix K and all the other  
20 acceptance criteria are met.

21                  MEMBER SCHULTZ: Jay, you've changed the  
22 steam generator tube plugging, and then you have PPU  
23 conditions, and the limiting break size doesn't change  
24 for the analyses? Where does this break size, where  
25 does it sit in the spectrum?



1 MR. KABADI: Yeah. I think the spectrum  
2 is run and Bob, why don't you --

3 MR. ATKINSON: Yeah. Limiting break size  
4 is a .05 square feet, and the next larger break size  
5 that was analyzed was at .06 square foot, and that had  
6 SITs injecting. So the zero-five was the break size,  
7 the largest break size within the spectrum for when  
8 SITs would not inject.

9 MR. KABADI: And then what we did, based  
10 on the staff's request for information, we did some  
11 sensitivity around that theme to show that PCT doesn't  
12 vary much around that.

13 MEMBER SCHULTZ: Okay, and the other, the  
14 other data that at least raises a question is that  
15 your maximum local oxidation has gone down. The  
16 maximum core-wide oxidation has increased limit and --

17 MR. KABADI: Yeah. I think --

18 MEMBER SCHULTZ: Have you looked at that  
19 to evaluate it?

20 MR. KABADI: Yes. I think we internally  
21 looked also on that. As you see here, one of the  
22 things to mention here, the reason PCT goes down is  
23 also because we were not taking credit for charging  
24 flow in the previous analysis on lower tech spec.  
25 Hence, charging is a part of ECCS. So we did take

1 credit for the charging flow, and that's why one of  
2 the reasons why the PCT is lower.

3 But as far as the oxidation, that's a part  
4 of the methodology, based on where you are rupturing  
5 and how you calculate. That's a conservative way of  
6 calculating the total oxidation and Doug, can you add  
7 --

8 MR. ATKINSON: That's correct. This is  
9 Doug Atkinson. Yes. The MACCS local oxidation  
10 follows with the PCT decreased. There is a change in  
11 the compression of the power. It's toward the center,  
12 and the integral effect of all the local oxidation  
13 values, you end up with a larger value for EPU.

14 MEMBER SCHULTZ: And then looking at core-  
15 wide oxidation?

16 CONSULTANT WALLIS: That goes up because  
17 of the flattening of the flux --

18 MR. KABADI: Correct, if you use -- yeah.  
19 That's where you calculate the flux, and again what we  
20 used was very bounding to that cycle, the cycle. We  
21 don't have to change anything, but meet the criteria.

22 CHAIR REMPE: So are there any additional  
23 questions? Brian?

24 CONSULTANT BONACA: I need to go back to  
25 page 24. I had a question about the CEA injection.

1 I just couldn't hear the conversation there, and the  
2 question that I had was how were these boundings  
3 calculated and how; that is, statistical results?

4 MR. KABADI: Any particular number?

5 CONSULTANT BONACA: Well --

6 MR. KABADI: Like CEA injection was  
7 specifically around -- the calculations are done for  
8 EPU from the neutronics point of view. Now in terms  
9 of DNB we just talking about, how it was done, but in  
10 terms of calories per gram, it was done following the  
11 approved methodology, which is currently Westinghouse  
12 methodology what we used.

13 CONSULTANT BONACA: Okay. So this was a  
14 3D model that was used?

15 MR. KABADI: Kim can answer rather than --

16 MR. JONES: Kim Jones here, and that was  
17 a 1D BACTRAN model. They do a pin census or a 1D-2D  
18 FQ to come up with that.

19 CONSULTANT BONACA: Okay.

20 MR. KABADI: Yes. I think the current  
21 approved methodology has a 1D-2D synthesis, and that  
22 provides effects which are generally found to be  
23 actually more bounding than the 3D analysis. That's  
24 how the current analysis is done here.

25 CONSULTANT BONACA: Okay. All right,

1       thank you.

2                   CHAIR REMPE:   Are there any -- Charlie?

3                   MEMBER BROWN:   Yeah.   I just wanted to get  
4       one follow-up on that that I forgot to ask on the SBO  
5       question.   You talked about you've got two sites,  
6       you've got two diesels at each site.   If one plant's  
7       affected, will the two diesels at the unaffected plant  
8       really be able to support both itself and the other  
9       plant?   So the capacity is begin enough to do that.  
10      Okay.   I didn't ask that.   I just wanted to make sure.  
11      Thank you.

12                  MR. HORTON:   Todd Horton, FPL.   Just a  
13      point of clarification.   It is two diesel generators  
14      per unit, four per site, and on the loss off-site, all  
15      four emergency diesel generators would start.   One  
16      thing that I think, maybe just to clarify, it is on  
17      the station blackout the operating crews are trained  
18      to immediately take action to start cross-tying power.

19                  They don't wait until the batteries start  
20      reaching their four hour depletion period.   It's  
21      immediate response for the operating crew.

22                  MEMBER   BROWN:   Well, when I think  
23      "station" I think everybody loses, that both plants  
24      lose it at the same time.   I'm just canoodling a way  
25      here, thinking well, what's the likelihood of being

1     able to get a couple of diesels back, because you are  
2     limited by that four hour period to get AC back before  
3     you start depleting your batteries in a bad manner.

4             So I'm not particularly happy with that.  
5     It's just a matter of where do you draw the line with  
6     your previous licensing condition.

7             MR. HORTON: Any one of the four diesels  
8     can provide adequate power for both units in station  
9     blackout.

10            MEMBER BROWN: Well, that means if they  
11     can recover it within the four hour period, at the no  
12     later than four hours.

13            MR. HORTON: Sure.

14            MEMBER BROWN: I just wanted to know what  
15     the --

16            MR. HORTON: The loads did go up slightly  
17     for EPU, some of the loads for the components, and  
18     that was evaluated.

19            MEMBER BROWN: Got it, okay.

20            MR. HORTON: And we have adequate diesel  
21     capacity.

22            CONSULTANT WALLIS: Let me just make sure  
23     that I heard it right. When you have SBO, it affects  
24     both units?

25            MEMBER BROWN: It's a common switchyard.

1 (Simultaneous speaking.)

2 CONSULTANT WALLIS: Well, someone said  
3 something about one unit. That's what worried me.  
4 But it is both units?

5 MR. HORTON: That's correct.

6 CONSULTANT WALLIS: Yeah, thank you.

7 CHAIR REMPE: Okay.

8 MR. HORTON: Todd Horton, FPL. Point of  
9 clarification. The loss of offsite power and the  
10 station blackout are two different events. The  
11 station blackout would be loss of offsite power  
12 coincident with the diesel generators not being  
13 available.

14 MEMBER BROWN: No, I understand. Yeah.

15 MEMBER SKILLMAN: I would like to ask  
16 Todd, when you have this event and the operators go to  
17 cross-tie all four engines, haven't you increased the  
18 vulnerability that a bus fault kills all four engines  
19 for both plants? Would it not be more prudent to keep  
20 the units separated until you know how the  
21 vulnerability is proceeding?

22 MR. HORTON: Actually, on a station  
23 blackout, we don't cross-tie all four engines. We  
24 identify a specific train of the unaffected unit and  
25 utilize its single diesel generator to supply power to

1 the affected unit. So let's say, for instance, Unit  
2 1 is the unaffected unit. It has either one or two  
3 emergency diesel generators available.

4 We would not cross-tie those diesels and  
5 then supply Unit 2 with that power. You're right. It  
6 would make the condition vulnerable for some sort of  
7 event thereafter. So we do ensure that that's part of  
8 the emergency operating procedures, is we identify  
9 which train and which emergency diesel generator is  
10 best suited to supply the affected unit, so we can  
11 reduce those vulnerabilities.

12 MEMBER SKILLMAN: Thank you, Todd.

13 CHAIR REMPE: Okay. We need to take a  
14 break. But we've talked to the staff and we're a  
15 little ahead of schedule. But they're prepared to  
16 come back and do their open session part between break  
17 and lunch. If you have any of the requests, like the  
18 table that we've mentioned and other items that you  
19 can talk about too that's open session that we could  
20 do before lunch, that would be great, although we can  
21 accommodate it later.

22 But then we're hoping after lunch and do  
23 all the closed session information, okay? Okay.  
24 Break time. Let's come back in about 15 minutes,  
25 okay. So 10 til. How about 10 til, okay?

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1 (Whereupon, a short recess was taken.)

2 CHAIR REMPE: Okay, Trace are you up, or  
3 is Sam or who's up first?

4 MR. ORF: Sam and Ben will present the  
5 safety analysis review.

6 Safety Analysis Review

7 MR. MIRANDA: Good morning. My name is  
8 Sam Miranda. I'm a technical reviewer in the Reactor  
9 Systems Branch, and I'll be presenting the long LOCA  
10 accident analyses evaluation of the St. Lucie Unit 2  
11 EPU. This was performed by another technical reviewer  
12 in the Reactor Systems Branch, Summer Sun, but he's  
13 unable to be here today, so I'm filling in for him.

14 Ben Parks, sitting to my right, will talk  
15 about the LOCA analyses and the evaluation of those  
16 accidents. Just as an introduction, having been  
17 through the St. Lucie Unit 1 EPU evaluation, I thought  
18 that would be a good place to start. We have the two  
19 units, the one, one was licensed in 1976, the other in  
20 1993, and they both came in for the same EPU power  
21 rating.

22 After the EPU is limited, they'll be rated  
23 at 3,020 megawatt thermal core power. The principle  
24 difference is that fuel supplier was AREVA for Unit 1,  
25 and Westinghouse for Unit 2, which means we were

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1 looking at accident analysis supplied by AREVA and  
2 Westinghouse using their methods.

3 The Unit 2 fuel is CE-designed fuel  
4 fabricated by Westinghouse, and Westinghouse has used  
5 their analysis methodology for the EPU analyses. Both  
6 EPUs were audited by the Reactor Systems staff just  
7 about two weeks apart, January and February of this  
8 year.

9 Next slide. I selected a few events to  
10 look at in detail, because this is where we had some  
11 challenging issues, and it's the same with the EPU for  
12 St. Lucie 1. We had to look mass-addition events  
13 because these events are most likely to violate the  
14 anticipated operation recurrence/acceptance criteria  
15 and specifically the criterion that doesn't allow an  
16 Anticipated Operational Occurrence or AOO from  
17 escalating into a more serious event.

18 This typically happens when you pressurize  
19 the fills, and causes a PORV to open and discharge  
20 water. Well, since the PORVs are not qualified for  
21 water relief, we have to assume that any PORV that  
22 discharges water will remain open, and then this would  
23 create a small-break LOCA at the top of the  
24 pressurizer, which is an event of a more serious  
25 class, and it's a violation of the acceptance

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1 criteria.

2 CONSULTANT WALLIS: But it can be closed.  
3 There's a block valve.

4 MR. MIRANDA: Yes.

5 CONSULTANT WALLIS: With most LOCAs, you  
6 don't have the valve.

7 MR. MIRANDA: That's right. It can be  
8 closed. In real life it can be closed, but in  
9 licensing, in the licensing world, the acceptance  
10 criterion has been violated. So that's what we need  
11 to follow when we do the evaluation.

12 This is what I described earlier. The  
13 charging pumps control the pressurizer. St. Lucie  
14 Unit 2, as St. Lucie Unit 1, has safety ejection pumps  
15 that are not capable of pumping against the nominal  
16 RCS pressure. But they do have charging pumps that  
17 are actuated by safety injection actuation signal.  
18 They're positive displacement pumps. They're small  
19 pumps about 49 GPM each.

20 St. Lucie 1 had three pumps. St. Lucie  
21 Unit 2 also has three pumps, but one of them is set to  
22 manual, so it's not actually actuated by the safety  
23 injection actuation signal. It's a small amount of  
24 flow, but it's sufficient to open the PORV, if allowed  
25 to go on long enough.

1                   Next slide, please. This is the criterion  
2                   that presents a lot of difficulty for Florida Power  
3                   and Light and a lot of other licensees. The properly-  
4                   designed plant would not allow a Condition 2 incident  
5                   or an AOO from becoming a more serious event. If it's  
6                   properly designed, there will be features that will  
7                   present this, and typically this is demonstrated in  
8                   accident analyses by showing that an AOO does not  
9                   result in failing the pressurizer, and therefore it  
10                  would not be possible for a PORV to open and discharge  
11                  water.

12                 Now the inadvertent opening of a PORV,  
13                 this is a relatively new issue that's come up in the  
14                 past three EPU's, and this was mentioned this morning  
15                 by FP&L. The inadvertent opening of a PORV is  
16                 classified a depressurization event or a decrease in  
17                 RCS inventory. As a depressurization event occurring  
18                 at full power, you do reduce thermal margin.

19                 This event is analyzed to show that there  
20                 is adequate protection provided in the automatic  
21                 reactor protection system to prevent an occurrence of  
22                 DNB. For a CE plant, we expect a trip would occur  
23                 from the thermal margin low pressure trip logic, in  
24                 time to prevent DNB from occurring. This event has  
25                 been provided by the licensee, and has demonstrated

1 that DNB will not occur.

2 This event is analyzed typically for a  
3 short period of time until the reactor trip occurs,  
4 and after that, there's no danger of DNB. However, if  
5 we allow this event to continue after the trip. As  
6 the depressurization continues, it eventually causes  
7 the safety injection system to be actuated on  
8 pressurized or to low pressure, and once actuated, the  
9 ECCS is capable of filling the pressurizer, especially  
10 with an open PORV. It fills the pressurizer and could  
11 eventually pass water through the PORV, and now we  
12 have a situation where this Condition 2 event could  
13 become a Condition 3 event.

14 CONSULTANT WALLIS: It sounds like a recap  
15 of TMI to some extent.

16 MR. MIRANDA: Except -- well, in TMI, the  
17 PORV was supposed to open. It needed to open. The  
18 trouble is it didn't close.

19 CONSULTANT WALLIS: Well, it's the same  
20 effect, though.

21 MR. MIRANDA: Yeah, yeah.

22 CONSULTANT WALLIS: And then the  
23 pressurizer filling is the same sort of thing.

24 MR. MIRANDA: Well, the pressurizer -- no.  
25 Actually, in TMI the pressurizer didn't fill.

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1                   CONSULTANT WALLIS: The alarm wasn't in  
2 right, that's why.

3                   MR. MIRANDA: It looked it filled. It  
4 looked like it filled, because of voids in the  
5 pressurizer. So the operators made a mistake and they  
6 thought they could turn off the safety injection with  
7 --

8                   CONSULTANT WALLIS: They won't do that  
9 this time.

10                  MR. MIRANDA: This time we have truly a  
11 fill to pressurizer.

12                  CONSULTANT WALLIS: That's even more  
13 incentive to turn off the ECCS.

14                  MR. MIRANDA: Yes, yes.

15                  MEMBER SKILLMAN: Sam, I'm confused. TMI  
16 was an under-cooling event that led to an over-  
17 pressurization, that led to both a reactor trip and an  
18 opening of a PORV, and as you mentioned, the problem  
19 is the PORV did not close and the operators failed to  
20 diagnose that and didn't close the block valve, okay.

21                  In this particular case, when I get the  
22 charging pumps running, I'm pushing up the pressurizer  
23 level, and if that continues, that level will threaten  
24 and push open a PORV, and they're not qualified for  
25 water. So I understand the logic.

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1 MR. MIRANDA: Right, right.

2 MEMBER SKILLMAN: What is the first trip  
3 out? Do I go out on high pressure on the reactor  
4 cooling system?

5 MR. MIRANDA: You go out on low pressure.  
6 Well actually you go out -- you go out on low  
7 pressure. But before that, if the reactor protection  
8 system is properly designed, the first trip should be  
9 from a thermal low margin protection, and we verified  
10 that in the accident analyses. So the reactor trips  
11 at low thermal margin; later on, defense indepth, you  
12 get a low pressurizer pressure trip. It doesn't  
13 matter, because you've already tripped.

14 MEMBER SKILLMAN: I see, okay.

15 MR. MIRANDA: And then the continuing  
16 depressurization causes the SI.

17 MEMBER SKILLMAN: SI. Thank you, Sam.

18 MR. MIRANDA: Okay. We've seen from  
19 simulator tests that operators are trained to respond  
20 to this very quickly. They can close the PORV in less  
21 than ten seconds, and if the PORV doesn't close, there  
22 is also the block valve available. Again, this is the  
23 real world, and we have to, we need to consider this  
24 at --

25 CONSULTANT WALLIS: And what is the

1 operator's indication. Is it the temperature in the  
2 line from the PORV? Is that the indication that the  
3 PORV is open?

4 MR. MIRANDA: That's one indication.

5 CONSULTANT WALLIS: One, and there's also  
6 a signal supposedly that it's open?

7 MR. MIRANDA: Yeah. There's an indication  
8 that it's open. There's also, you can also check the  
9 pressurizer pressure and determine hey, at this  
10 pressure should a PORV be open or should it have been  
11 opened? Do you want to --

12 MR. HORTON: Yes. Todd Horton, FPL. I  
13 did appreciate the Subcommittee's discussion on the  
14 operator's response at the Unit 1 Subcommittee. One  
15 of the things that I had communicated at that time is  
16 this is one of the events that is a high priority for  
17 the operating crews to train on.

18 So I did go back to this station to  
19 identify exactly when was the next sequence of  
20 training that we were going to pull this performance  
21 training on the crews, and we did pull it back in  
22 cycles so I could complete that just prior to coming  
23 here. The idea was I could come here with detailed  
24 information.

25 So we validated. In fact, the operating

1 crews did identify the inadvertent opening the pilot  
2 operator relief valve in less than ten seconds. The  
3 things that help facilitate that is we have alarms  
4 specifically tied on the position indication of the  
5 PORV itself. Almost 99 percent of the alarms in the  
6 control room have a white background.

7 We have approximately a dozen that have a  
8 red. This is one of those alarms that has a red  
9 condition, so it immediately draws the attention of  
10 the operating crew. Another thing that draws the  
11 attention of the operating crew is we have acoustic  
12 monitoring downstream of the PORV. So when the PORV  
13 opens, the acoustic monitoring also goes to alarm.

14 The third thing that really facilitates  
15 the quick identification of the event is the reactor  
16 coolant system and pressurizer pressure are right  
17 there at the PORV. So the way the event unfolds is  
18 the red alarm enunciates; the acoustic monitoring  
19 alarms; the operator sees that and looks at reactor  
20 coolant system pressure, and validates that in fact  
21 that is not a real --

22 CONSULTANT WALLIS: But the pressure  
23 doesn't really respond instantly, does it?

24 MR. HORTON: I'm sorry?

25 CONSULTANT WALLIS: Does the pressure



1 respond instantly or it takes a while?

2 MR. HORTON: The pressure starts coming  
3 down and stops, but the operator validates that  
4 pressure is still in its normal operating band. They  
5 inform the unit supervisor. They take the PORV to  
6 override, and then we actually instilled a second  
7 fault is when you go to override, the PORV should have  
8 closed, as Sam mentioned.

9 The second fault that we instilled was  
10 okay, that didn't work. Then the second action is for  
11 the operator to manually close the motor-operated  
12 valve to isolate that penetration, and we validated  
13 all crews were doing that in less than 43 seconds.

14 The lowest pressure that we saw across the  
15 crews was 2,030 pounds. Normal operating pressure is  
16 2,250. Safety injection is at 1,736 pounds, so we had  
17 quite a bit of margin.

18 So what we saw was manual action to  
19 isolate the PORV in less than ten; we mechanically  
20 isolated it in less than 45 seconds, and then we got  
21 below 2,000 pounds.

22 CHAIR REMPE: Was this standard the  
23 current in plant conditions and would you expect them  
24 to change if you dialed it up on the simulator to the  
25 EPU?

1 MR. HORTON: Actually, the simulator is  
2 modeled precisely with Unit 2.

3 CHAIR REMPE: The EPU though, or with the  
4 current?

5 MR. HORTON: The pressure post-EPU  
6 conditions will be the same, and there are no design  
7 modifications to the PORV.

8 MR. MIRANDA: So we have -- we looked at  
9 the licensee's analysis of this event, and basically  
10 we were interested in what would happen if the  
11 operator does nothing, and this slide indicates that  
12 if the operator fails to close that PORV, eventually  
13 the pressurizer will fill in very short time.

14 This is where we look at the difference  
15 between the real world. In the real world, the  
16 operator will close the PORV in less than ten seconds.  
17 But in the licensing world, we need to consider just  
18 how much time is available for the operator and what  
19 can reasonably be done following procedures and so  
20 forth.

21 So we pay attention to the time it takes  
22 for the pressurizer to fill, because that defines the  
23 time available.

24 (Off record comment.)

25 MR. MIRANDA: Okay. So to finish up on

1 that, the time that we're concerned with in this case  
2 is the time that the safety injection occurs, which  
3 will occur before the pressurizer fills. This is the  
4 time between the PORV opens and the time safety  
5 injection occurs. If the operator acts within that  
6 time, then and closes the PORV, the accident is over.

7           However, if the operator is a little bit  
8 late and safety injection is actuated, now we have an  
9 inadvertent SI actuation, a variation of that, and now  
10 the operator, in order to end the transient, has a lot  
11 more things to do to turn off the safety injection.  
12 It turns out that if the operator closes the PORV at  
13 any time after the safety injection has been actuated,  
14 that doesn't end the transient, but it does reduce it  
15 to a variety of inadvertent safety injection  
16 actuations, and it does gain more time for operator  
17 action.

18           In this case, operator action involves  
19 following procedures to turn off the safety injection,  
20 and that's going to take a lot more than ten seconds.  
21 So the staff is evaluating this event on a generic  
22 basis, and we expect to come up with a position  
23 because we expect to see more analyses like these.

24           This St. Lucie 2 is not unique.  
25 Pressurizer fill times of three and four minutes seem

1 to be pretty common. So we need to take a closer look  
2 at this.

3 MEMBER SKILLMAN: Sam, you used the words  
4 "inadvertent SI injection." Would it be accurate to  
5 communicate SI did what it was supposed to do at the  
6 pressure that it was supposed to do it?

7 MR. MIRANDA: Exactly.

8 MEMBER SKILLMAN: Thus reducing the time  
9 that the operators have to take any real significant  
10 action. Once SI starts, they have an inventory issue  
11 that they now have to deal with, a significantly  
12 greater inventory issue.

13 MR. MIRANDA: Once SI starts, and it does  
14 start. It's supposed to start. Once it starts, the  
15 operator has a real complicated situation. Simply  
16 closing the PORV will not end the transient, and  
17 that's going to take a lot more than ten seconds.

18 MEMBER SKILLMAN: My point is it is not an  
19 inadvertent actuation of SI. It is an appropriate  
20 action of SI for which there are consequences.

21 MR. MIRANDA: Right. That's why we asked  
22 for this analysis, because this is not, you know, a  
23 failure upon failure. This is what the system is  
24 supposed to do.

25 MEMBER SKILLMAN: Okay. Thank you, Sam.

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1                   CONSULTANT BONACA: I have a question for  
2 the licensee. Just for information, do you have one  
3 single simulator for both units?

4                   MR. HORTON: Todd Horton, FPL. Yes, we  
5 do. One simulator for both units. It's primarily  
6 modeled for Unit 2.

7                   CONSULTANT BONACA: But you do have  
8 setpoints different for Unit 1 and Unit 2. How do you  
9 manage that?

10                  MR. HORTON: We do have some setpoints  
11 different between the units. As you mentioned, that  
12 is a key training piece with the operating crews that  
13 we focus on quite a bit. Now there are things that we  
14 perform in the simulator to enhance training in the  
15 simulator, to get operators familiar with changes on  
16 Unit 1.

17                  Most notably is we've made some early  
18 modifications on the simulator in response to the Unit  
19 1 EPU. But as you mentioned, when operating crews go  
20 into the simulator, it is modeled after Unit 1. So  
21 the setpoints are corrected for Unit 2. So when they  
22 go in there and they perform their training on  
23 specific events, they're Unit 2 events.

24                  CONSULTANT BONACA: But is there any  
25 possibility of confusing the operators of Unit 1, for

1 example?

2 MR. HORTON: I think what the operating  
3 crews see that do license operators is the systems  
4 respond the same between the two units. Like for  
5 instance, the safety injection actuation signal on  
6 Unit 1 actuates at 1,600 pounds. On Unit 2, it  
7 actuates at 1,736 pounds. That is a unit difference  
8 between the two.

9 Now that is something that the operating  
10 crews discuss, they're trained to discuss during their  
11 briefs in those events. That is something we focus on  
12 quite a bit during our training. But the system  
13 still responds the same between the two units.

14 CONSULTANT BONACA: And one last question.  
15 Are the crews dedicated to a specific unit, or are  
16 they covering both units?

17 MR. HORTON: Their license allows them to  
18 operate on both units.

19 CONSULTANT WALLIS: You said this was a  
20 new event you're considering?

21 MR. MIRANDA: It's actually an old event.  
22 We're considering it a new way.

23 CONSULTANT WALLIS: Because it seems to me  
24 that it reminds me a lot of TMI. I mean you have a  
25 PORV open for some reason, right, and then if the

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1 operator doesn't shut it, what happens? You've got  
2 various branches, depending on whether you turn off  
3 the safety injection or whether you close the block  
4 valve, and you've got different ways you can go and so  
5 on.

6 Now this seems to me an obvious thing to  
7 do 33 years. Say look at TMI, in say post-TMI action.  
8 What happens if a PORV opens and they don't show that?  
9 That's the obvious thing to do. We seem to be looking  
10 at it. So the half hour you desire you have now if  
11 this thing happened, and you're taking all that time  
12 to do something about it.

13 MR. MIRANDA: Well, it was considered. It  
14 was considered, but there's a small-break LOCA aspect,  
15 okay. A PORV open sticks open. It's considered as a  
16 -- well, it doesn't need to be a PORV. It could be a  
17 safety valve, some opening at the top of the  
18 pressurizer. But that's not considered as an AOO.  
19 That's considered in 15.6 as a small-break LOCA.

20 This particular event is considered in  
21 15.2 as an AOO and is considered to be sure that we  
22 have DNB protection. But then recently we noticed  
23 well okay. We see that there's no problem with DNB.  
24 The reactor hasn't tripped. The AOO has been  
25 satisfied. But has it really, because if we continue

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1 the event and we continue the depressurization, we'll  
2 eventually get safety injection.

3 That's going to -- in this case, it's not  
4 needed. It's going to be causing problems. One more  
5 point I'd like to make --

6 CONSULTANT WALLIS: I understand that.  
7 I'd just wonder why it takes 30 minutes to do this.

8 MR. MIRANDA: It's a good point. Yes. We  
9 just discovered this aspect of this event, yes. One  
10 thing that was mentioned earlier --

11 CONSULTANT WALLIS: Well maybe these are  
12 the events which are most likely, the ones you didn't  
13 think about until now.

14 MR. MIRANDA: We didn't think about it  
15 enough. It's always been in there.

16 MALE PARTICIPANT: You finished beating  
17 him up yet?

18 CONSULTANT WALLIS: You're still here, so  
19 you can do it.

20 MR. MIRANDA: We did notice, by the way,  
21 quite a big difference between the two units, St.  
22 Lucie 1 and St. Lucie 2, in terms of filling the  
23 pressurizer. Pressurizer fill time in St. Lucie 2 is  
24 much, much faster than St. Lucie 1, and the difference  
25 is that St. Lucie has much larger PORVs.

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1           So we have a PORV with a capacity of  
2 something like 400,000 pounds per hour in St. Lucie  
3 Unit 2, filling the pressurizer in about three  
4 minutes; and St. Lucie Unit 1, with a PORV of about  
5 153,000 pounds per hour, it takes about seven minutes.

6           We asked the licensee about this, and  
7 they, at our request, they performed another analysis  
8 of the St. Lucie 2 event, using the St. Lucie Unit 1  
9 PORV capacity, and they reproduced the St. Lucie Unit  
10 1 results. So that the cause is the PORV capacity.

11           MEMBER SKILLMAN: Sam, isn't there another  
12 piece of information that is important, and that is  
13 that the charging pumps were not originally part of  
14 ECCS, and in the course of time on this pair of  
15 plants, the charging pumps became part of ECCS?

16           MR. MIRANDA: We got a clarification on  
17 that at the last --

18           MR. D. BROWN: This is Dave Brown with  
19 Florida Power and Light. It has to do with taking  
20 credit for the charging pumps in the analysis. The  
21 charging pumps have always started at St. Lucie on a  
22 safety injection actuation, okay. The functional  
23 difference between the units is on Unit 1, three pumps  
24 start; on Unit 2, two pumps start. That's always been  
25 the actual true plant condition. It was whether we

1 were taking credit for them in accident analysis or  
2 not that's changed.

3 MEMBER SKILLMAN: I see, thank you.

4 MR. MIRANDA: And yes, this came up at the  
5 last EPU for St. Lucie 1, and my position on that is  
6 that was a mistake.

7 MEMBER SKILLMAN: An oversight.

8 MR. MIRANDA: They didn't include the  
9 charging pumps because they didn't want to take credit  
10 for the flow, okay. I would understand that if you're  
11 doing a LOCA analysis. But when you're doing an  
12 inadvertent ECCS analysis, you need to take credit for  
13 those pumps. They need to be in there, and they  
14 weren't.

15 As a result, the EPU application we  
16 received dismissed the inadvertent ECCS analysis,  
17 because as they were modeling the ECCS without the  
18 charging pumps, it wasn't necessary to do that  
19 analysis, since the safety injection pumps just didn't  
20 have a head to pump into the RCS at nominal pressure.

21 So we asked for the analysis, and we got  
22 the results. It's the same situation with St. Lucie  
23 2. The ECCS does include the charging pumps. They  
24 are actuated by a safety injection signal, and  
25 therefore this type of analysis needs to be performed.

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1 MEMBER SKILLMAN: Thank you.

2 CONSULTANT WALLIS: It's a very nice  
3 example of what is conservative from one aspect is not  
4 conservative from another, and you always have to be  
5 careful about that.

6 MR. MIRANDA: Yes, yes.

7 MEMBER SCHULTZ: Sam, let me make sure I  
8 understand. Then we heard the discussions from the  
9 licensee's viewpoint associated with the operator  
10 action and the simulator's response, the operator's  
11 response to the event on the simulator, and the timing  
12 of the operator's actions.

13 That would take care of the  
14 event, if there is operator action. All right, and  
15 you're saying then in addition, the staff is  
16 continuing to consider the event with respect to no  
17 operator action. But this is a generic issue that is  
18 being treated separately from this amendment request?

19 MR. MIRANDA: Yes, it is, and the concern  
20 I have when I look at this is that the shortening  
21 interval between closing the PORV or the block valve  
22 and the time safety injection occurs, because it's  
23 like a two-phase event. Once safety injection occurs,  
24 now it's more difficult to terminate the event.  
25 Closing the block valve is not enough; closing the

1 PORV is not enough.

2 So you see in some plant designs this  
3 pressurizer fill time is much shorter than what we're  
4 used to seeing.

5 CONSULTANT WALLIS: So what is the status  
6 of this? This is an ongoing, evolving issue?

7 MR. MIRANDA: Yeah. I've written a draft  
8 of a generic communication that it's being reviewed.  
9 We're trying to find the proper path for the  
10 bureaucracy to get this out.

11 CONSULTANT BONACA: I want to go back a  
12 moment to the issue of training, and having the same  
13 plant training, the operators on the behavior of two  
14 different plants, and I'm not saying there is anything  
15 wrong about it. I'm just saying that I would have  
16 liked to have had evaluation of the impact, potential  
17 impact on performance of this issue.

18 It just troubles me, I mean as I talk  
19 here, I'm thinking about so many different  
20 possibilities of confusion for the operators or  
21 whatever. I don't want to blow that out of proportion  
22 right now, but certainly I would like to have the  
23 Subcommittee considers a conversation today, at close  
24 of the meeting, for what you think about that.

25 CHAIR REMPE: So you would like us to

1 consider it in our comments, but there's nothing you  
2 would like to see from the licensee or the staff?

3 CONSULTANT BONACA: Yeah. I mean it may  
4 very well be that simply it was the surprise of not  
5 knowing that, that created this concern in my mind.  
6 There may not be a concern in the back of my mind.  
7 But I certainly would appreciate your thoughts.

8 MEMBER SKILLMAN: I would like to join the  
9 concern, but I would like to respond to Todd's  
10 comment. Dr. Rempe asked about the St. Lucie 2  
11 simulator and underlying theme of Dr. Rempe's question  
12 was fidelity with regard to the current plant design,  
13 versus the upgraded plant design.

14 So in my very practical thinking, I say  
15 I've got a simulator. It's a four loop, Combustion,  
16 2,700 megawatt plant, and I would think that the crews  
17 are doing just in time training and their normal  
18 training on that simulator for St. Lucie 2, as the  
19 plant is presently licensed and configured.

20 MR. HORTON: If I can speak, Todd Horton,  
21 FPL.

22 MEMBER SKILLMAN: Yeah. Let me go one  
23 more step further.

24 MR. HORTON: Okay.

25 MEMBER SKILLMAN: Or one step further.

1 The time's going to come, presuming the Subcommittee  
2 and the full Committee are in agreement, that you will  
3 have a 3,200 megawatt plant that's really at 3,050  
4 thermal, including pumping. So back to Dr. Rempe's  
5 question.

6 For these simulator runs, were the  
7 simulator runs done with the higher power level and  
8 the higher core decay heat, or are these simulator  
9 runs, and we're talking about here today back in the  
10 2,700 megawatt configuration?

11 MR. HORTON: The core model right now  
12 utilized in the simulator is the 2,700 megawatt  
13 thermal. To add a few talking points as to our  
14 discussion, the training piece is a huge piece of the  
15 EPU project. Obviously, addressing the operator needs  
16 and putting them in the best position possible, as we  
17 go through these EPU outages, has always been right at  
18 the forefront of implementing EPU.

19 Just in time training. Coming out of the  
20 last Unit 1 outage, even though we haven't gone to the  
21 higher power rate on Unit 1, a lot of the systems that  
22 support the EPU are in place. So we had very  
23 extensive just in time training for the operating  
24 crews as those systems came back to them, during  
25 coming out of the outage.

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1           We did a very extensive evaluation of the  
2 simulator itself, to see which systems in the  
3 simulator did we need in place prior to implementing  
4 EPU. So things like the digital turbine control  
5 system that we talked about when you were here for  
6 Unit 1. We put that in place on the simulator, even  
7 though it wasn't in place on Unit 2, so the operating  
8 crews would really understand how that system works  
9 and responds on Unit 1 coming out of the outage.

10           One key piece that maybe we could discuss  
11 is the training program for the licensed operator, as  
12 we know, is an accredited training program. At St.  
13 Lucie, like a number of other stations, there are  
14 distinct differences between the units. That is  
15 something that is a key piece of the licensed  
16 operator's initial and continuing training.

17           We have shown high performance in those  
18 areas, but there's always gaps that we're always  
19 looking for and attempting to address. One of the  
20 things that's been a -- that was one of the things  
21 that the station put forward as a goal as we go  
22 through into EPU, is the goal is to not take the units  
23 farther apart, but to get the units closer together.

24           As I mentioned, functionally the systems  
25 to the operators, they appear almost identical. There

1 are a few distinct differences with the set points  
2 that we talk about, that we find ways to challenge the  
3 operators, to make sure they understand the  
4 differences between the units. But the way the  
5 systems respond and the way they look to them in a  
6 simulator is almost identical.

7 But as I said, the accredited training  
8 program takes that into account, and makes sure that  
9 those specific items we have definitely training  
10 requirements, to ensure that the operators understand  
11 the differences, what that means to them in the impact  
12 of operating the plant, and then we test them on a  
13 basis to make sure that they can demonstrate that.

14 MR. HALE: Yeah, and if I could, yes, our  
15 training program, our license operator training  
16 programs come under a lot of scrutiny from the NRC and  
17 INPO, and these guys can tell you what they go through  
18 to get that accreditation. It includes explaining how  
19 we accommodate and ensure that the operators  
20 understand the differences between the units.

21 Now with regards to the inadvertent  
22 opening of the PORV done at EPU versus the current  
23 power condition, it's very insensitive to power level,  
24 an overfill event. If we're looking at DNB like we  
25 typically look at this event, then yes, the decay heat

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1 comes into play. But when you're really looking at it  
2 strictly from an overfill event, the power levels, the  
3 event's fairly insensitive in terms of fill time to  
4 power level, okay.

5 Really, we did that just to show, you  
6 know, how quickly we can confirm, because we didn't  
7 have that data the last time we were here for Unit 1,  
8 okay.

9 MR. HORTON: And just to add, as we've  
10 gone through this EPU process, one of the things that  
11 I am real pleased with, as I think most of us who are  
12 familiar know, that there's no tougher customer than  
13 an operator in a training program, and they've really  
14 challenged this site, to make sure that the EPU  
15 modifications are presented in a way that puts the  
16 operating crews' ability to be able to operate those  
17 systems, understand them and implement them, prior to  
18 actually them being in place and turned over to the  
19 operating crews.

20 CHAIR REMPE: With respect to Mario's  
21 question, is St. Lucie unique, that they have one  
22 simulator for two different units and training  
23 operators for both units, or is that standard across  
24 the commercial fleet? I just would like a --

25 MR. HORTON: We're not unique. I wouldn't

1 go as to say -- I wouldn't be able to speak to the  
2 standard, but I know we're not using --

3 MR. HORTON: It's common.

4 CHAIR REMPE: It's fairly common?

5 MR. HORTON: It's fairly common.

6 MR. JENSEN: Joe Jensen, Site Vice  
7 President. Having worked in the industry for 35 years  
8 and at various plants around the country, there's  
9 virtually no two unit facility where the plants are  
10 100 percent identical. In virtually every case, there  
11 are deltas between the two units, and in virtually  
12 every case, they train on a single simulator.

13 I think the only exception I can think of  
14 probably is Beaver Valley, where they have two  
15 separate operating licenses, and so they have two  
16 simulators. But it is standard practice. We do delta  
17 training between the unit that is modeled on a  
18 simulator and the unit that is not.

19 We have to remember that there's a number  
20 of other training venues that we use to make sure our  
21 operators are well-trained. That includes our  
22 classroom training, that includes job performance  
23 measures where we physically take the operators into  
24 the plant on the operating unit, and they step through  
25 those activities that are necessary, in order to

1 respond to the various events. In addition to that,  
2 the on-shift training takes place in both units. So  
3 the operators are exposed and have to run through a  
4 number of reactivity manipulations and other events  
5 and activities on both units.

6 So the simulator, while important, isn't  
7 the only tool that we use to ensure that the operator  
8 are well-trained and can respond to those events.

9 CHAIR REMPE: Thank you.

10 CONSULTANT WALLIS: Now it seems to me  
11 that the Committee has to say something about this in  
12 its letter. It's not a trivial matter. Now the  
13 question is is it a matter of the EPU, or is it sort  
14 of a generic thing around the fleet? I'm not quite  
15 sure how you know whether it's a matter for the EPU,  
16 and we're told it's very insensitive to the power  
17 level. But until we see some numbers, we can't tell  
18 what that means.

19 MR. MIRANDA: I agree that it is  
20 insensitive. With respect to overfill, it's --

21 CONSULTANT WALLIS: Makes no difference to  
22 your arguments at all?

23 MR. MIRANDA: Not with overfill.

24 CONSULTANT WALLIS: Okay. So if some of  
25 that can be very clearly shown, then I think we're

1       okay.  Otherwise, we have to figure out or maybe wait  
2       for what the staff position is going to be on how do  
3       you satisfy the regulations --

4               MEMBER BANERJEE:  Well, I think there are  
5       two separate issues.  This came up, of course, before.

6               CONSULTANT WALLIS:  But this is a bigger  
7       PORV and all sorts of things.

8               MEMBER BANERJEE:  So one issue is how does  
9       is it affected by the EPU.  My understanding was that  
10      it's not greatly affecting the EPU, right.

11              MR. MIRANDA:  I agree.

12              MEMBER BANERJEE:  So the real issue is  
13      what should you do about it, and that's more of a  
14      generic issue.

15                      (Simultaneous speaking.)

16              CONSULTANT WALLIS:  --affecting EPU be  
17      quantified in some very discrete way?

18              MEMBER BANERJEE:  Well, because of the  
19      times available yeah, you can -- I think -- have you  
20      got it quantified or not, Sam, in the -- how much the  
21      times are affected for various actions.  It wasn't  
22      very much, if I remember, right?

23              MR. MIRANDA:  We're talking about the  
24      period of time until reactor trip, which you know,  
25      might be ten seconds, and the difference in power

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1 level would be, you know, 300 megawatts for a period  
2 of ten seconds, and then after that it's strictly  
3 mass-in and mass-out.

4 MEMBER BANERJEE: Right.

5 MR. MIRANDA: So I don't see a significant  
6 effect due to the EPU.

7 CONSULTANT WALLIS: So this mass is being  
8 heated, isn't it? It's not just mass-in/mass-out.  
9 It's also volume.

10 MR. MIRANDA: Well yes, yes of course.  
11 The SI water's coming in at about 70 degrees, and it  
12 goes up to 600 degrees.

13 CONSULTANT WALLIS: But a greater power  
14 level heats it and swells it up more, so that it rises  
15 more. So it's not just mass-in and mass-out.

16 MR. MIRANDA: Right.

17 CONSULTANT WALLIS: It's a response of the  
18 whole system.

19 MR. MIRANDA: Yes, yes. But if we're  
20 talking about differences, the differences is about --  
21 is the period of time before the reactor trip occurs.  
22 The difference is the amount of the EPU, approximately  
23 ten seconds. We're talking about a fill time here  
24 that's on the order of three to seven minutes.

25 CONSULTANT WALLIS: So it's, how much does

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1 it change, does the fill time change with the EPU? It  
2 goes from three minutes to something else?

3 MR. MIRANDA: Well, I haven't done that  
4 case.

5 CONSULTANT WALLIS: If it went from three  
6 minutes to two minutes, would that concern you?

7 MR. MIRANDA: I don't think we'd be even  
8 -- I don't think it would be even 30 seconds.

9 CONSULTANT WALLIS: Well, it would be  
10 useful to have some numbers there, I think.

11 CHAIR REMPE: One of the changes for the  
12 EPU are changes in the NSSS setpoints. Would any of  
13 those changes affect the timing for this event, or  
14 have you already implemented those changes into the  
15 simulator?

16 MR. HORTON: Todd Horton, FPL. The  
17 changes would not impact. I think what Sam and his  
18 group has looked at is from the time you get the  
19 safety injection signal and the ECCS pumps started at  
20 about 1,200 pounds, the high pressure safety injection  
21 pumps start injecting.

22 That's really your primary driver for  
23 filling the pressurizer. Nothing associated with  
24 those systems are going to change post-EPU. What's in  
25 place now will be in place then. Now one thing, just

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1 to clarify, one of the things that we talked about was  
2 okay, well what's the differences between this and  
3 TMI?

4 It's kind of like I believe the point that  
5 was brought up, and I don't know if it was, you know,  
6 discussed enough, but one of the things that was  
7 mentioned is once you had the safety injection signal,  
8 it's not an inadvertent safety injection. It's a real  
9 safety injection. At that point, the ECCS pumps start  
10 and start injecting, as needed, as a result of the  
11 safety injection signal.

12 The operating crew wouldn't just  
13 immediately turn the pumps off. At that point, you  
14 would have a real safety injection. You'd enter the  
15 emergency operating procedures, and you've got very  
16 distinct actions to take, to validate proper inventory  
17 before taking manual control of those pumps. That's  
18 the difference between this condition and TMI.

19 MR. KABADI: Yeah, and this is Jay Kabadi,  
20 FPL. I just want to verify that the three-way timing  
21 which is presented, that is for EPU. That analysis  
22 done is the EPU analysis.

23 (Off record comment.)

24 MR. MIRANDA: We've seen from this  
25 analysis for St. Lucie 2 the important factors

1 determining the fill time. It is of course the rate  
2 of safety injection, and the rate of safety injection  
3 is largely determined by the depressurization rate or  
4 the back pressure the safety injection system is  
5 seeing. That is highly dependent upon the PORV  
6 capacities. We saw that in the difference between the  
7 St. Lucie Units 1 and 2, the difference in the PORV  
8 capacities.

9 So the EPU or power level in general has  
10 a very small effect on the pressurizer fill time. The  
11 power level is important in the beginning of the  
12 transient, when we're looking at DNB. Any more  
13 questions?

14 CONSULTANT WALLIS: Less than three  
15 minutes isn't very specific, is it? I think you need  
16 to be more specific, and say that there is at least  
17 three minutes for them to act, because less than three  
18 minutes could mean ten seconds.

19 MR. MIRANDA: That's right, and I think  
20 that yeah, that is not specific.

21 CONSULTANT WALLIS: That's not very  
22 reassuring as it stands.

23 MR. MIRANDA: It conveys our concern that  
24 this time is short.

25 CONSULTANT WALLIS: I think you need to



1 say the pressurizer fills in greater than something.

2 MR. KABADI: This is Jay Kabadi from FPL.  
3 FPL time in the analysis was 174 seconds.

4 CONSULTANT WALLIS: That's less than three  
5 minutes. I think you've got to show that there's  
6 enough time.

7 MR. MIRANDA: Well, we're not sure that  
8 there's enough time.

9 CONSULTANT WALLIS: Okay, you're not sure.

10 MR. MIRANDA: That's way, you know, it  
11 conveys our concern, and we have a very small time,  
12 less than three minutes. Less than four minutes would  
13 also be a concern. That's why we're looking at this  
14 generically.

15 MEMBER SCHULTZ: So in presenting the  
16 concern, it's approximately three minutes, which your  
17 concern is that's not a big number.

18 MEMBER BANERJEE: I think it's a generic.  
19 I mean it's not EPU-related. That's all we're saying.

20 MR. MIRANDA: Yeah. We need to take a  
21 closer look at it, because these times are getting  
22 shorter and shorter.

23 MEMBER BANERJEE: So what is -- I mean  
24 maybe this is not the venue to address this, but what  
25 do the staff plan to do about this? You're dealing

1 with this on several EPU's, right? So what are the  
2 plans?

3 MR. MIRANDA: I've written a generic  
4 communication. It's pointing out that this is an  
5 issue, and for certain plants.

6 MEMBER BANERJEE: Right.

7 MR. MIRANDA: Other plants it's not a  
8 concern, but it 's an issue for certain plants and as  
9 a regulator, I'm not going to tell people how they  
10 need to fix it, just that they need to pay attention  
11 to this and present to the NRC staff a credible  
12 rationale for dealing with this, something that will  
13 hold up to licensing standards.

14 MEMBER BANERJEE: So what is the state we  
15 are at right now? Have letters gone out to operators  
16 or licensees?

17 MR. MIRANDA: The stage we're at now is  
18 that I've written a draft of a communication, which it  
19 needs to be reviewed and issued, and we have written,  
20 I think so far, three safety evaluations, Turkey  
21 Point, St. Lucie Units 1 and 2 --

22 MEMBER BANERJEE: Right.

23 MR. MIRANDA: --where this is an issue,  
24 and we have come up with an argument as to why it's  
25 acceptable for the EPU, but we reserve the right to

1       revisit this on a generic basis.

2                   MEMBER BANERJEE:   Who is this draft letter  
3       with, your branch head or something right now?

4                   MR. MIRANDA:   No.

5                   MEMBER BANERJEE:   Where is the review  
6       process?   What point is it at?

7                   MR. MIRANDA:   Well, at this point, I sent  
8       it to my branch chief for his review.

9                   MEMBER BANERJEE:   Now he's taken off for  
10      some --

11                  MR. MIRANDA:   Yeah.   I don't think he's  
12      going to be reviewing it.

13                  MEMBER BANERJEE:   Right.

14                  MR. MIRANDA:   So I'm acting for him, so I  
15      guess I'm reviewing it.

16                  (Laughter.)

17                  CONSULTANT WALLIS:   Would it help you if  
18      ACRS said something about this issue?

19                  MEMBER BANERJEE:   I mean all we can say at  
20      the moment is that we recognize this should be treated  
21      on a generic basis or something, right?

22                  MR. MIRANDA:   Yeah.   Basically, where we  
23      are is we don't think this is a reason to hold up an  
24      EPU.   We have written a safety evaluation that says  
25      it's -- well, at this point it's good enough, but we

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1 want to look at it generically and come up with a  
2 better solution.

3 CONSULTANT WALLIS: It's an issue for not  
4 in EPU. It was an issue before EPU.

5 MR. MIRANDA: Yes, yes, that's right. I  
6 would say this is not --

7 MEMBER BANERJEE: EPU has very little to  
8 do with it.

9 MR. MIRANDA: That's right.

10 CONSULTANT WALLIS: The interesting thing  
11 will be to see how quickly the agency can respond.

12 MR. MIRANDA: So yeah. If you can raise  
13 the --

14 MEMBER BANERJEE: We've done this in some  
15 letters in the past, where we know that this is not a  
16 specific issue for this EPU, but we mention it in some  
17 generic sense, whether it be methods related to  
18 whatever, you know. We've done it. We've made  
19 comments on reactor physics codes, that sort of thing,  
20 in past letters.

21 However, with this aspect, if you've  
22 already got something underway and there's no issue  
23 with your going forward with it, then ACRS has not  
24 much of a role to play, I would think, you know. If  
25 you encounter resistance, that's a different matter.

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1 This is the last EPU for a while.

2 MR. MIRANDA: Well we intend to continue  
3 with this, because it goes beyond EPUs.

4 MEMBER BANERJEE: Right. It goes well  
5 beyond, like the TCD issue. It goes beyond EPUs,  
6 right? So you're going to take some action on it.

7 MR. MIRANDA: Yes.

8 MR. PARKS: If I may in the interim, the  
9 staff's review activities consider this event even  
10 when it's not an EPU. I had a license action request  
11 on my desk a couple of months ago, and I know while we  
12 have to ask about this, the licensee showed that its  
13 safety margins were significantly reduced, and the  
14 staff's decision-making in that matter was following  
15 the licensee's awareness of the issue, appropriate.

16 The key message there being the staff  
17 considers this -- I was awfully vague. You know, we  
18 consider this --

19 MEMBER BANERJEE: That was a lot of  
20 legalese, Ben.

21 MR. PARKS: The staff's aware. We  
22 consider it in other things, not just EPUs, bottom  
23 line.

24 MEMBER SCHULTZ: And again, it goes to the  
25 importance of the operator actions as they are being

1 proposed and taken and demonstrated that they can be  
2 achieved, but then also the success of those operator  
3 actions, being effective.

4 MR. MIRANDA: And I think this is where  
5 Dr. Bonaca's comments come into play, because whatever  
6 solution is arrived at for this event, and also the  
7 inadvertent ECCS actuation. The protection against  
8 these events is not an automatic reactive protection  
9 system. It's in operator actions.

10 MEMBER SCHULTZ: Yes.

11 CONSULTANT WALLIS: This is where you  
12 might be reminded about TMI. I mean it was the  
13 operator actions that seemed to have led to the  
14 progression of the event the way it did.

15 MR. MIRANDA: Yes. They thought they were  
16 doing the right thing, but they weren't.

17 CONSULTANT WALLIS: Well, here they've got  
18 two things to balance. That's where they get in  
19 trouble. They do the right thing for one and then  
20 later on, you know, they fix the other one.

21 MR. MIRANDA: Yeah. They need to undo the  
22 automatic reactor protection system.

23 CONSULTANT WALLIS: It's not taboo to do  
24 that.

25 MR. MIRANDA: Not if you've followed all

1 the procedures.

2 MEMBER SKILLMAN: Let me make sure I've  
3 got this straight. What I think this, I think very  
4 valuable discussion has created in my mind is the  
5 recognition that the SI actuation of the charging  
6 pumps has always been part of this design, but the  
7 mass flow rate contributed by those pumps was not  
8 previously credited, and when it is credited, that  
9 mass volume has the capability to take an AOO to a  
10 small-break LOCA.

11 MR. MIRANDA: I would agree with that,  
12 yes.

13 MEMBER SKILLMAN: And that is an event  
14 that is entirely independent from the power uprate  
15 discussion. That is a basic design issue for this  
16 plant that we are talking about today, independent of  
17 what other plants it may be part of.

18 MR. MIRANDA: Yes.

19 MEMBER SKILLMAN: Thank you. I got it.  
20 Thank you.

21 MR. MIRANDA: Any more questions?

22 (No response.)

23 MR. MIRANDA: If we can move on to LOCA.  
24 Ben?

25 Large-Break LOCA Safety Analysis

1 MR. PARKS: I'm Ben Parks. I was not the  
2 reviewer for lost coolant accidents. That reviewer  
3 was Jennifer Gall. She is not able to be here today.  
4 She had long-standing prior obligations. So I'll  
5 present the results of her review.

6 I reviewed her safety evaluation and  
7 provided some feedback, so I am familiar with her  
8 review activities. This slide is the summary of the  
9 licensee's approach for ECCS evaluation. The  
10 licensee's methods for St. Lucie Unit 2 are based on  
11 and conformant to Appendix K of 10 C.F.R. Part 50. So  
12 the results are going to be quite a bit different,  
13 especially for the large-break loss of coolant  
14 accident analysis than they were for St. Lucie Unit 1.

15 Here's a list of the methods that the  
16 licensee used, and a note becomes important a little  
17 bit later in the presentation. The limiting PCT is  
18 calculated to occur during the late reflood. For the  
19 limiting large-break case, it's around 300 seconds.

20 MEMBER BANERJEE: So this is quite  
21 different?

22 MR. PARKS: Yes, yes sir.

23 MEMBER BANERJEE: Because of the methods.

24 MR. PARKS: In essence --

25 MEMBER BANERJEE: It's not due to the



1 plant.

2 MR. PARKS: That is correct. It's  
3 basically the most significant driver here, I think,  
4 or one of the most significant drivers is a very  
5 conservative decay heat model. For the next --

6 MEMBER SCHULTZ: Conservative, in that --  
7 oh, there it is. 20 percent above, okay.

8 MR. PARKS: We use a 20 percent multiplier  
9 -- well, the staff doesn't use. The licensee uses a  
10 20 percent multiplier and applies that to the ANS 1971  
11 standard, as required by Appendix K.

12 CONSULTANT WALLIS: You mean 120 percent  
13 multiplier?

14 MR. PARKS: I apologize. Yes, I do. The  
15 licensee made the point in its application or in the  
16 first layer of RAI correspondence that thermal  
17 conductivity degradation is not important because our  
18 analysis methods are conservative, and it turns out  
19 there's a regulatory reason to make that argument.

20 When we promulgated the realistic rule in  
21 1988, the Commission said, you know, significant  
22 public comment was made, as to whether Appendix K  
23 methods remain valid, and the Commission came back and  
24 said Appendix K is conservative, and so many features  
25 of its requirements are going to be retained, and

1 licensees may continue to use Appendix K.

2           The staff did, however, question a little  
3 bit deeper regarding the effect that TCD could have on  
4 this particular limiting transient. It was shown,  
5 through some sensitivity studies, that a substantial  
6 increase in fuel-stored energy would be required to  
7 drive blowdown peak higher than the reflood peak that  
8 we had seen in the results.

9           The reason that that study was done that  
10 way is because it's a system of codes that are used in  
11 various phases of the transient. So we ask for a  
12 sensitivity study on the first code. I believe  
13 CEFLASH is the blowdown code. We asked for the  
14 sensitivity studies in CEFLASH and we chose to leave  
15 alone the COMPERC results.

16           I believe that there is a 30 percent  
17 increase required in the stored energy, in order to  
18 get the blowdown peak to approach the reflood peak.  
19 It was quite a difference, and quite a bit of an  
20 increase in the stored energy.

21           CONSULTANT WALLIS: That's strange, to  
22 tweak the energy, because it's really the conductivity  
23 which matters.

24           MEMBER BANERJEE: Which is of course  
25 ultimately --

1 (Simultaneous speaking.)

2 CONSULTANT WALLIS: It also determines how  
3 quickly it comes out, doesn't it? So it's probably  
4 also, yeah.

5 MEMBER BANERJEE: But let me ask you this.  
6 This plant filled a lot of emergency core cooling  
7 available, right? So why, is it purely an artifact of  
8 the method, that you're getting a reflood peak rather  
9 than a blowdown peak? If you did a realistic  
10 calculation, you'd expect that you'd get a blowdown  
11 peak on this plant, right?

12 MR. PARKS: The best information I have  
13 available to me is obviously the St. Lucie Unit 1  
14 results.

15 MEMBER BANERJEE: Right.

16 MR. PARKS: They have similar emergency  
17 core cooling systems and yes, I think if you applied  
18 more realistic assumptions, you would find that the  
19 limiting peak is either in the blowdown or in the  
20 early reflood.

21 MEMBER BANERJEE: Okay, yeah. So what is  
22 it about this methodology that is physically or not  
23 physically, because it's not a physical methodology,  
24 but why are you getting the reflood peak? What's  
25 happening there?

1 MR. PARKS: I believe in this case it's a  
2 difference in the decay heat modeling.

3 CONSULTANT WALLIS: Only the decay heat.

4 MR. PARKS: I can't say it's only the  
5 decay heat model. But I think that that's a  
6 significant driver.

7 CONSULTANT WALLIS: It's not that you're  
8 throwing away a lot of the available emergency water  
9 coming in --

10 MR. PARKS: Well yes. This method  
11 requires that the accumulator flow be largely  
12 bypassed.

13 MEMBER BANERJEE: right.

14 MR. PARKS: ECC bypass is a difficult  
15 thing to model, and I don't know that the realistic  
16 model is a whole lot more realistic with respect to  
17 ECC bypass. Those methods tend to throw a lot of  
18 cooling or yeah, accumulator cooling out the break  
19 also.

20 MEMBER BANERJEE: So it's not that which  
21 is causing the --

22 MR. PARKS: I can't say for certain. I  
23 truly don't know.

24 MR. KABADI: This is Jay Kabadi from  
25 Florida Power and Light. I think for the Appendix K

1 models, also there are very conservative, the transfer  
2 correlations used in the reflood phase. That's what  
3 drives the PCT during reflood much higher than what  
4 the realistic LOCAs would do.

5 MEMBER BANERJEE: Is this to do with the  
6 heat transfer to the dispersed, during the dispersed  
7 --

8 MR. KABADI: Yeah, I think that's correct.  
9 I think there requirements that once your flooding  
10 rate is below something, you cannot get ready for a  
11 lot of correlations that could be used in a best  
12 estimate test analysis.

13 MEMBER BANERJEE: So this is sort of an  
14 unusual result, because the reason we sort of fought  
15 the St. Lucie 1 situation and why we got such low PCTs  
16 compared to Turkey Point was due to the fact that it  
17 was dominated by the blowdown piece. I mean in Turkey  
18 Point if you recall, it was the reflood piece --

19 MR. PARKS: Early reflood, about 30 --

20 MEMBER BANERJEE: Oh maybe early, yeah.  
21 But whatever it was, the mechanisms was somewhat  
22 different, which is why you had a sort of 400 degree  
23 margin or maybe even larger in the best estimate  
24 calculations for St. Lucie compared to Turkey Point,  
25 which is much closer to the 2,200.

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1 MR. PARKS: There were also some other  
2 fundamental design differences as well. I don't know,  
3 I'm not terribly familiar with the types of  
4 containment design, but the containment design any  
5 differences there could have been attributable to  
6 differences in the predicted PCTs and also the  
7 accumulators are much different.

8 MEMBER BANERJEE: Yes, of course.

9 MR. PARKS: At Turkey Point, they're a  
10 higher pressure.

11 MEMBER BANERJEE: Right, and that's more  
12 or less what we attributed. We were trying to make  
13 sense of why St. Lucie 1 came in so much lower than  
14 Turkey Point, you know, in the best estimate  
15 calculations. I think we rationalized that. Now we  
16 see a plant which is essentially identical in terms of  
17 this emergency cooling and so on to St. Lucie 1,  
18 coming in with a result which is showing, you know,  
19 completely different behavior due to the methods  
20 primarily.

21 So and we're trying to understand what it  
22 is about the methods which is causing this. So I can  
23 understand that the correlations that you're using are  
24 much more conservative. You're probably throwing away  
25 more water. I'm not sure of that. You're using a

1 much higher decay heat than a realistic calculation.  
2 Are there any other factors that we should be aware  
3 of?

4 MR. PARKS: I believe there's a difference  
5 in the accumulator pressure. I think that St. Lucie  
6 Unit 2 has higher accumulated pressure --

7 (Simultaneous speaking.)

8 MR. KABADI: This is Jay Kabadi of FPL.  
9 Yes. At St. Lucie 2, accumulator pressure is 500 psia  
10 and psig, which is much higher than St. Lucie 1.

11 MEMBER BANERJEE: What was St. Lucie 1?

12 MR. KABADI: St. Lucie 1 was originally  
13 200 and they raised that to 230 as part of this EPU.  
14 One of the reasons the PCTs in Appendix K model that  
15 PCT in heat flux is so-called artificially driven so  
16 high, dictated by decay heat, that other changes will  
17 change that. That is like photo slide that was grid  
18 and stored and feed down to blowdown PCT, much, much  
19 higher than what this PCT was.

20 That still is below the reflood PCT  
21 because reflood PCT is calculated very high in the  
22 Appendix K model because of the decay heat and the  
23 correlations.

24 MR. PARKS: The other important piece of  
25 information that you might get, you kind of glean from

1 the ECCS research is the significance of these  
2 mechanism at a given phase in the transient. Decay  
3 heat's more significant. I think in the NRC's part,  
4 I think it's rated at about an eight in late reflood,  
5 and it's much less significant earlier.

6 The stored energy is rated very highly,  
7 and in early reflood it comes down to about a two, and  
8 then it's insignificant. So there's a combination of  
9 the way these phenomena are being treated  
10 analytically, and their significance at the given time  
11 in the transient.

12 MEMBER BANERJEE: Yes.

13 So it's an artifact of the calculational  
14 methodology here, and you can explain this. You've  
15 satisfied yourself, your colleague has.

16 MR. PARKS: I watched as my colleague  
17 satisfied herself.

18 MEMBER BANERJEE: Right, right, that you  
19 can explain this behavior.

20 MR. PARKS: In my opinion, I think that  
21 justified the staff's review approach here, where  
22 rather than sort of, for lack of a better word,  
23 require the licensee to do a complete reanalysis or  
24 explicitly address thermal conductivity degradation in  
25 this event, to ask instead that they do sensitivity

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1 studies to show us what are we missing by leaving this  
2 out?

3 I think that that ties back. That's why  
4 I mentioned the rulemaking and the history there,  
5 because I think that that follows the Appendix K  
6 regulatory approach.

7 MEMBER BANERJEE: So you're saying you  
8 bumped up the stored energy by about 30 percent, and  
9 you still had the reflood peak?

10 MR. PARKS: That is correct. I think the  
11 results were, and I would have to confirm this, it  
12 increased the blowdown peak by about 250 degrees, and  
13 I have a picture of the limiting transient provided by  
14 the licensee. Do you have that slide?

15 MR. ORF: Is that part of this afternoon?

16 MR. PARKS: Yeah, probably this afternoon.  
17 I'm not sure.

18 MEMBER BANERJEE: If you like, you can  
19 defer this, yeah. You can defer the discussion.

20 (Simultaneous speaking.)

21 MR. PARKS: That's a closed session  
22 discussion, so let's don't go there.

23 MEMBER BANERJEE: Yeah. We can defer the  
24 discussion.

25 CHAIR REMPE: Yeah, and in fact --

1 MR. PARKS: Okay. Well, the slide was  
2 publicly available. It wasn't proprietary.

3 MEMBER BANERJEE: Okay.

4 CHAIR REMPE: Well, do you think you can  
5 go through the rest of this presentation in 15  
6 minutes, or do you want take a break and come back  
7 after lunch?

8 MR. PARKS: I think I'll push it in 15  
9 minutes or less. There's not much more information to  
10 provide.

11 CHAIR REMPE: Okay.

12 MR. PARKS: We don't have the slide. It  
13 shows a blowdown or a reflood peak.

14 MEMBER BANERJEE: Well, we can look at  
15 them later.

16 CHAIR REMPE: Let's see if we can finish,  
17 okay.

18 MEMBER BANERJEE: Yeah, later.

19 MR. PARKS: Okay. So this is the large-  
20 break LOCA. Let's see. There are a couple of other  
21 things the staff addressed. The staff asked some  
22 questions about downcomer boiling, the downcomer model  
23 for CEFLASH was pretty simple, and so the staff asked  
24 for some sensitivity studies to --

25 CONSULTANT WALLIS: SITs or the tanks or

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1 the --

2 MR. PARKS: The accumulators.

3 CONSULTANT WALLIS: Accumulators, right.

4 How does the downcomer get filled in a cold-like  
5 break? There's steam going up there, isn't there?

6 MR. PARKS: At some point, there's enough  
7 liquid, and I'm thinking through. I'm not working  
8 from memory, Dr. Wallis. It seems that you have to  
9 inject enough liquid that you get some sort of  
10 countercurrent flow limitation. You have enough heavy  
11 liquid that's not boiling.

12 CONSULTANT WALLIS: How does the steam get  
13 out then?

14 MR. PARKS: The steam is going to entrain  
15 the liquid from the safety injection tanks for a  
16 while. It's going to go out the break, as the break  
17 flow reduces and you have easier lower plenum steam  
18 conversion, lower plenum flashing, I suppose.

19 CONSULTANT WALLIS: The steam has to get  
20 to the break somehow, as in -- I'm not quite sure how  
21 the downcomer fills with water?

22 MEMBER BANERJEE: Eventually, the steam  
23 has to go the other way.

24 MR. KABADI: Yeah, this is Jay Kabadi.

25 MEMBER BANERJEE: It's got to come out

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1       somehow, eventually.

2                   MR. KABADI:  Yeah, this is Jay Kabadi for  
3       Florida Power and Light.  I think that Appendix K  
4       model, that's one of the things, that is one of the  
5       ways.

6                   You go through the blowdown period, and  
7       that's why 900 water injector goes in other core.  
8       That's assumed to all go out.  Once the pressure,  
9       that's the end of blowdown, where the pressure in the  
10      containment gets higher than the pressure in the RCS.  
11      That's when you want to start setting into --

12                  CONSULTANT WALLIS:  Well, it gets down  
13      there all right, but it doesn't fill downcome does it?  
14      I mean there's stuff steaming in the downcomer, isn't  
15      it?

16                  MR. PARKS:  Yeah.

17                  CONSULTANT WALLIS:  It can't get to the  
18      break without going through the downcomer, unless I've  
19      got it all mixed up.

20                  MEMBER BANERJEE:  No.  I think it has to  
21      go down the downcomer.

22                  CONSULTANT WALLIS:  Well, there has to be  
23      counter-current flow.  So there's no way the downcomer  
24      can be filled with water.  I don't understand this  
25      rationale.

1 MR. PARKS: I see what you're saying. I  
2 think the staff may have characterized the  
3 phenomenology a bit out of order.

4 CONSULTANT WALLIS: Well maybe if you get  
5 to the full Committee, you can give a better  
6 explanation?

7 MR. PARKS: Absolutely.

8 MEMBER BANERJEE: Maybe filled is too  
9 strong a word?

10 CONSULTANT WALLIS: Yeah, it would be  
11 enough to suppress boiling somehow.

12 MR. KABADI: This is Jay Kabadi, FPL. Let  
13 me just -- I think what happens is once the pressure  
14 in RCS gets lower, the volume which goes through the  
15 loops, and that is what is balanced by the containment  
16 pressures. There is only the driving force coming  
17 from the containment side, and as the water gets in,  
18 whatever volume that goes inside the core gets through  
19 the loops and it goes through the loops.

20 CONSULTANT WALLIS: It doesn't go out the  
21 cold leg break, does it?

22 MR. KABADI: That is correct. Once the  
23 vessel --

24 CONSULTANT WALLIS: That's what's  
25 happened, that's what's happened.

1 MR. PARKS: Okay. So here are the EPU  
2 results and compared to the pre-EPU. During the  
3 staff's review, we considered the fact that the PCT  
4 decrease, we asked about that. In the license report,  
5 I think there is a very vague statement regarding  
6 credit, not fully crediting the improved features of  
7 the new steam generator.

8 The reviewer asked questions about that  
9 and then obtained sort of a rack-up list, if you will,  
10 of all the different changes they had made in their  
11 assumptions from the prior analysis to the current, to  
12 show what's the PCT effect of each bit and piece.  
13 Looked over that and they add up to this result. So  
14 the staff reviewed this difference.

15 MEMBER BANERJEE: What was the main reason  
16 that it decreased, which is so slightly strange?

17 MR. PARKS: I don't recall the exact rack-  
18 up. I intended to bring it with me and I don't have  
19 it.

20 MR. KABADI: Yeah. This is Jay Kabadi  
21 from Florida Power and Light. I think the back-up  
22 slides, the impact of the EPU by itself was in the  
23 range of 50, something in 50's, the temperature going  
24 up. Then the benefit came from the higher flow, which  
25 we increased in the reactor coolant system.

1                   Their own analysis did use 335,000. We're  
2                   using this one, 375,000, which is one of the changes  
3                   we talked about, and the reduction in the peaking  
4                   factor. The two together provide balance, and the  
5                   actual number came out slightly lower in report.

6                   MEMBER BANERJEE: But you've got a higher  
7                   decay heat, right, and now your peak temperature is in  
8                   the reflood peak, where decay heat matters. And, you  
9                   know, the fact that you have a higher flow affects the  
10                  stored energy, and you're saying the stored energy  
11                  doesn't really matter as much as the decay heat. So  
12                  I find that rationale pretty hard to understand. Do  
13                  you follow what I'm saying?

14                 MR. KABADI: Right, right. But I think  
15                 the 54 degrees or so that came out strictly what they  
16                 ventured about the EPU.

17                 MEMBER BANERJEE: So the EPU gives you 10  
18                 percent or 12 percent or whatever more decay heat,  
19                 right, than you had assumed?

20                 MR. KABADI: Right, and that raised the  
21                 PCT. That's correct.

22                 MEMBER BANERJEE: That has to raise the  
23                 PCT?

24                 MR. KABADI: That is correct.

25                 MEMBER BANERJEE: Because this is a

1       reflood peak, right?

2                   MR. KABADI: Right.

3                   MEMBER BANERJEE: And if you didn't change  
4       any methods between the pre-EPU and the EPU, you'd get  
5       an increase in that temperature. Now your higher flow  
6       --

7                   CONSULTANT WALLIS: In some ways, he said  
8       he's injecting more water. I think he said he's  
9       injecting more water.

10                  MEMBER BANERJEE: How is he injecting more  
11       water?

12                  CONSULTANT WALLIS: Ask him.

13                  MEMBER BANERJEE: Are you changing  
14       something else?

15                  CHAIR REMPE: Radial peaking.

16                  MEMBER BANERJEE: The peaking factor I can  
17       see has an effect.

18                  MR. KABADI: Right. Yeah, I think a  
19       little like -- well, we've had some sensitivities on  
20       these, and those are the reasons what I presented,  
21       like you mentioned that why you mentioned like why are  
22       such slow decreases to PCT and that sort of thing.  
23       I'm just looking at the Westinghouse --

24                  MEMBER BANERJEE: Well, increasing the RCS  
25       flow will reduce the stored energy, and but on the

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1 other hand, you're also increasing the amount of  
2 power. So I mean the two things will sort of balance,  
3 to some extent. You know, I think we need a rationale  
4 for this, where you say the stored energy is affected  
5 by that much, by increasing the RCS flow, and the  
6 effect of the decay heat is this much.

7 So we understand. I'm sure that your  
8 colleague looked through this. It's a startling  
9 result.

10 MR. PARKS: It is, although this is fairly  
11 minor, I think it looks like about 25 degrees.

12 MEMBER BANERJEE: Yeah.

13 MR. PARKS: Fahrenheit. We'll look. Over  
14 lunch, we'll get the rack-up list. We'll have a look  
15 at it. You know, the original statement from the  
16 licensee was changes in the steam generator modeling,  
17 full credit, which implies that there be some primary  
18 to secondary heat transfer in play here. That makes  
19 sense for later in a greater stage of decay heat.

20 MEMBER BANERJEE: That makes more sense.  
21 That makes more sense because your decay heat is going  
22 up, and if you get the heat out through the steam  
23 generator, it makes more sense, okay.

24 MR. PARKS: So these are the results, and  
25 onto the small-break LOCA. We got a fairly coarse

1 break spectrum initially from the licensee, and the  
2 staff requested a more detailed one. I don't believe  
3 that the detailed break spectrum changed the limiting  
4 result. I think it was .05, or yes. .05 square feet  
5 was the limiting result.

6 The staff also requested and obtained an  
7 analysis of a severed injection line. The dynamics of  
8 the transient are a bit different, and it also affects  
9 how much ECCS you can get. On the next slide, we have  
10 --

11 MEMBER BANERJEE: What about the loop seal  
12 clearing? Did you ask for that as well?

13 MR. PARKS: I would have to check with the  
14 reviewer to see how it was addressed, and we can  
15 certainly do that.

16 MEMBER BANERJEE: Okay.

17 CHAIR REMPE: So we'll get answers to  
18 these questions today after lunch you think?

19 MR. KABADI: I think I have loop-seal  
20 clearing the -- at the approved methodology which we  
21 use for here, requires doing some sensitivities on the  
22 loop sealant, take the worst reasons.

23 MEMBER BANERJEE: And also making sure  
24 that ultimately only one of them clear, right?

25 MR. KABADI: We can check how many clear,

1 but there is some sensitivity in the different  
2 configurations, and the worst result is reported. So  
3 we can check and see how many cleared and --

4 MEMBER BANERJEE: Yeah. Just let me know  
5 what the worst cases are.

6 MR. KABADI: Right. We can check on that,  
7 yeah.

8 CONSULTANT WALLIS: St. Lucie 1 used a  
9 very complicated loop seal clearing model, which I  
10 didn't understand.

11 MEMBER BANERJEE: Well, it was a very,  
12 eventually a very conservative one, yeah. Nobody can  
13 understand it, but nobody knows anything about loop  
14 seal clearing.

15 CONSULTANT WALLIS: But they know that  
16 they can make a difference.

17 (Simultaneous speaking.)

18 MR. PARKS: These are the results for the  
19 small-break LOCA, and with that, we hope the  
20 presentation's concluded.

21 MEMBER BANERJEE: Again, you've got a  
22 lower peak clad temperature, with a higher decay heat.  
23 That's a remarkable result.

24 MR. PARKS: If the key driver is the same  
25 as for the large break, this transient has a large, a

1       boildown. It would make sense.

2                   MEMBER BANERJEE: So if it's a steam  
3 generator, it does make some sense, yeah.

4                   MALE PARTICIPANT: Yeah, I'd like to see  
5 that --

6                   MR. KABADI: This is Jay Kabadi from FPL.  
7 Really, the main driver was a built-in credit for the  
8 charging flow. It was not written up by any model  
9 without getting early into transient health  
10 significantly. In the previous analyses under the  
11 CCS, charging flow pumps were part of the CCS. They  
12 have not credited charging pumps in this model.

13                   CONSULTANT WALLIS: You're putting more  
14 water in, the same as large-break LOCA, I think.

15                   MR. KABADI: Right. But the charging  
16 flow, again constant flow (mouth close to mic). Once  
17 the SI signal comes in, they start injecting into the  
18 small break, and that (mouth close to mic).

19                   MEMBER BANERJEE: Okay. You have to  
20 rationalize it for us.

21                   CHAIR REMPE: You want more then?

22                   MEMBER BANERJEE: Yeah. We want to  
23 understand why.

24                   CHAIR REMPE: Okay. So the staff will  
25 help address this today or the licensee?

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1                   MEMBER BANERJEE: Staff and the licensee  
2 together.

3                   MR. PARKS: The staff will make its best  
4 attempt to provide clearest rationalization. Without  
5 the actual reviewer present, we may not be able to  
6 fully address the concerns. So I would say what we  
7 can't get done today we'll absolutely do early next  
8 week, when you're owed some materials, and definitely  
9 plan to talk about it at the full Committee meeting.

10                  CHAIR REMPE: That sounds great.

11                  MEMBER BANERJEE: When is the full  
12 Committee --

13                  CHAIR REMPE: The week after the week of  
14 the 4th, like --

15                  MR. PARKS: 10, 11, 12, 13.

16                  CHAIR REMPE: Yeah.

17                  CONSULTANT WALLIS: It seems to me when  
18 your staff member expert isn't here, then you need to  
19 anticipate the questions that we will ask, and get  
20 answers ahead of time.

21                  MEMBER BANERJEE: He's just giving you a  
22 hot time, Ben. I apologize.

23                  CHAIR REMPE: I know we all want to go to  
24 lunch and take a break, but there is a staff member  
25 who can answer Charlie's question, and so we're going

1 to get Charlie, and it will be a brief answer, and so  
2 if we'll just have that response, it will help. This  
3 is the anticipated outage time response; correct, is  
4 the question of Charlie's?

5 MR. BROADDUS: Actually, we were hoping he  
6 would be here to make sure he can clarify the question  
7 for the gentleman.

8 CHAIR REMPE: Okay. Charlie is in the  
9 other room, and Weidong is getting him, so just be  
10 patient.

11 MR. BROADDUS: Okay, thank you.

12 CHAIR REMPE: Okay. Your name is?

13 MR. MOSSMAN: I'm Tim Mossman. I work in  
14 the Instrumentation and Control Branch. Dr. Chung,  
15 who did the review of the measurement uncertain  
16 recapture on Unit 2 is unfortunately not here today.  
17 But I was his peer reviewer on his safety evaluation  
18 input, so I am familiar with the measure uncertainty  
19 recapture, and I will do my best to answer whatever  
20 questions.

21 CHAIR REMPE: Okay. I believe the  
22 question of interest is the allowable outage time, the  
23 daily FM, which may be beyond just this EPU. It may  
24 be something that the staff has agreed upon in prior  
25 reviews or --

1 MR. MOSSMAN: In fact, I just looked at  
2 the safety evaluation before coming over here.

3 CHAIR REMPE: And here he comes.

4 MR. MOSSMAN: Oh.

5 MEMBER BROWN: I thought you were doing  
6 this after lunch.

7 CHAIR REMPE: Well, the gentleman who's  
8 responding can't be here after lunch.

9 MEMBER BROWN: Well, that's a good answer.

10 CHAIR REMPE: Okay. So thank you.

11 MEMBER BROWN: Who's the gentleman  
12 responding?

13 MR. MOSSMAN: Tim Mossman.

14 MEMBER BROWN: Hi. I recognize you.

15 MR. MOSSMAN: Yeah. I've been here  
16 before.

17 MEMBER BROWN: Either good or bad, one of  
18 them.

19 MR. MOSSMAN: I was told the question was  
20 about the allowable outage time for the OEFM?

21 MEMBER BROWN: Yeah. I'm trying to recall  
22 what I said now.

23 CONSULTANT WALLIS: Two days, but no --

24 MEMBER BROWN: Oh yeah. No, I understand  
25 the two days. They had made a proposal on the AOT,

1 and the rationalization was that going for two days  
2 was based on the normalization they do every day at  
3 midnight or whatever the witching hour is, and  
4 therefore the ability of the thing to change over a  
5 two-day period of the alternate system was small.

6 There were some other words relative to  
7 that, in that they had evaluated and reviewed data to  
8 show that the change in that system was small. I'm  
9 forgetting the time frame, but it was a long, it was  
10 like 18 months of data they said. I don't know how  
11 many data sets of 18 months they took to say that  
12 yeah, that's a consistent set of data, and I'm not a  
13 statistics person.

14 So I had no idea how much data they used  
15 within that 18 month period to come to that  
16 conclusion. So I had two questions. Number one, did  
17 you all look at that, the data, how they came to the  
18 conclusion that it didn't change much. They claimed  
19 it was less than a .025 percent change over an 18  
20 month period.

21 I just wanted to make sure somebody  
22 confirmed that their analysis of that data  
23 independently was .025 percent over that 18 month  
24 period. Did you all look at that?

25 MR. MOSSMAN: I would have to ask Dr.



1 Chung specifically what he looked at with that regard.  
2 But I know we've historically asked licensees. They  
3 generally, like you said, they generally hyper  
4 calibrate their venturis to the LEFM readings, and  
5 then they're using their venturi for that 48 hour or  
6 72 hour period is generally what we've approved.

7 MEMBER BROWN: No. My concern was they  
8 keep recalibrating it all the time, and therefore how  
9 do you get 18 months' worth of data that says it  
10 doesn't change.

11 MR. MOSSMAN: I have seen other -- I've  
12 seen other licensees' values that they presented. In  
13 fact, we have one now, where they did the similar  
14 thing. They collected on multiple units for a year,  
15 ten-day drift times on all their transmitters  
16 associated with their venturis, and the number, I  
17 don't want to quote the exact number, they found is  
18 bounding, but it's very consistent with the .025  
19 percent you quoted. It's a very small value on the  
20 transmitter drift.

21 MEMBER BROWN: Now but is that on  
22 transmitters, or is that the results of --

23 MR. MOSSMAN: It's the whole, yeah.

24 MEMBER BROWN: The results of the whole  
25 calculation, or just the flow information that's

1 going?

2 MR. MOSSMAN: It should be the signal  
3 coming from the venture. It's the air you're focused  
4 on.

5 MEMBER BROWN: So where does the  
6 normalization take place? Is that downstream or yeah,  
7 downstream where it all goes, so they can go get that  
8 data? They're not recalibrating -- okay, let me go  
9 backwards.

10 I've got DP cells, all kinds of stuff on  
11 venturis. So you run a calibration, pop up little  
12 devices and you make sure that the readouts come out  
13 and the right voltages are where they're supposed to  
14 be, and they feed out to the converters, etcetera.  
15 Now when they normalize, they're not fiddling with  
16 that data?

17 MR. MOSSMAN: Not the raw feed.

18 MEMBER BROWN: Not the raw feed.

19 MR. MOSSMAN: My understanding --

20 MEMBER BROWN: Is that's the data that  
21 they take to make this determination, that the venturi  
22 and its detectors are not going to vary over 18  
23 months? Which data are they using?

24 MR. MOSSMAN: Oh, for the 18 month data?

25 MEMBER BROWN: The output of the --

1 MR. MOSSMAN: Oh, yeah.

2 MEMBER BROWN: The output of the venturi  
3 downstream, you know, when it's coming out of lots of  
4 amplifiers and all the gain adjustments have been made  
5 and they're normalized or whatever they are, or is it  
6 the actual raw data off the venturi, or the RTDs  
7 themselves?

8 MR. MOSSMAN: I would have -- unless  
9 somebody from St. Lucie has that off the top of their  
10 head, I have to check on that. That was something  
11 that Dr. Chang looked at.

12 MEMBER BROWN: That was my question.

13 MR. MOSSMAN: Okay.

14 MEMBER BROWN: If you're taking normalized  
15 data every day, and you then do your 18 month review  
16 based on normalized information somewhere downstream,  
17 that doesn't seem to -- I'm not a statistician, and  
18 I'm not an analyst, but that doesn't seem to make  
19 sense to me, if they're taking the raw data over the  
20 --

21 MR. BROADDUS: Yeah, excuse me. Maybe  
22 this will help. This is Dave Brown from Florida Power  
23 and Light. When we talk about normalizing the  
24 venturis to the LEFM, that's not something that has  
25 occurred yet. We don't have an LEFM that's in service

1 that we're going through this process on. So what we  
2 did is we went and we looked at what was the venturis  
3 giving us over a period of time, to look at how acute  
4 is there a change or is it a chronic long-term effect  
5 that's occurring over a period of time, and use that  
6 fact that they're not changing as a justification for  
7 the time frame of being able to run with it at a  
8 steady state power level, with an LEFM out of service,  
9 and use the venturis as an accurate power indicator.

10 CONSULTANT WALLIS: How do you know if the  
11 venturis are changing if you don't have anything to  
12 compare them with? How do you know if the venturis  
13 are changing in the way they operate, if you have  
14 nothing to compare them with?

15 MEMBER BROWN: You do a calibration or --  
16 when you took this 18 months' worth, how often do you  
17 recalibrate the venturis?

18 CONSULTANT WALLIS: How often?

19 MEMBER BROWN: Well, you've got a venturi  
20 --

21 MR. MOSSMAN: How often? I don't have  
22 that answer off the top of my head. That's an I&C  
23 activity, so I'd have to take, I'd have to look that  
24 up.

25 MEMBER BROWN: I guess --

1                   CONSULTANT WALLIS: That's what I'm  
2 saying. How can you calibrate with nothing to  
3 calibrate them against?

4                   MEMBER BROWN: At some point, you have to  
5 go, in order to get this data, you have to go check  
6 your calibration of your venturi instrumentation. The  
7 only way to do that is to go, you make two  
8 assumptions. Number one, the venturi itself doesn't  
9 change internally. That's kind of hard to do.

10                   The second thing is to make sure your  
11 detectors, which are measuring the differential  
12 pressure across your venturis, those have not changed.  
13 In other words, your detector data hasn't changed, and  
14 you've got to figure out well gee, did the detector  
15 data change because the venturi changed? You can  
16 argue about that all you want to.

17                   But in other words, how did you get the  
18 data, and who looked at it?

19                   MR. MOSSMAN: I don't have an answer for  
20 what that frequency is, so I can't give you that  
21 answer.

22                   MEMBER BROWN: That's kind of that  
23 question. Okay, that's one question. Okay, all  
24 right. The second question was nibbling, they gave  
25 you a multiple set of degradations. I think there

1       were three lines?

2                   MR. MOSSMAN:   They had two LEFMs installed  
3       --

4                   MEMBER BROWN:   Yeah, but one and then a  
5       couple of them and then something else, and I don't  
6       want to get into what they were.   But they had three  
7       numbers, and you all came back and said umm gee, we  
8       think you ought to have -- those numbers ought not be  
9       as big as you're using.   We want you to decrease power  
10      a little bit more, if I remember.

11                  MR. MOSSMAN:   It was -- yeah, and I took  
12      a quick look at this.   It was very similar to one.   We  
13      had, we first saw this, I think it was in Shearon  
14      Harris, where depending on the number of LEFMs  
15      installed, they constitute two different -- they have  
16      --

17                  MEMBER BROWN:   They've got two.

18                  MR. MOSSMAN:   Yeah, they have two, but  
19      each LEFM has two planes of detectors where they  
20      collect data from.   Each LEFM, if one plane of  
21      detectors drops out of service for some reason, it can  
22      go into what they would now term a degraded mode for  
23      the LEFM check plus, which would be very analogous to  
24      the original system that they submitted and got  
25      approval for, which was the LEFM check.

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1 MEMBER BROWN: And these were used?

2 (Simultaneous speaking.)

3 MEMBER BROWN: They said they haven't done

4 --

5 MR. MOSSMAN: Yeah. If there was any  
6 checks, they would have been very early ones quite a  
7 number of years ago. The check plus represented an  
8 increase in accuracy, by adding additional detectors.  
9 But they actually had analysis and data that staff  
10 looked at in ER -- Norbert help me -- ER-80P, which  
11 was the original topical report on the one-plane  
12 system.

13 I believe for both Shearon Harris and I  
14 believe for St. Lucie, that Alden Labs, that did their  
15 specific testing of the LEFMs and the typing  
16 configurations that were supposed to go into the  
17 plant, looked at both fully functional and degraded  
18 modes, where you lose one plane of operation. So they  
19 do have reasonable data to make accuracy claims, as to  
20 how good the instrument is, if you do lose essentially  
21 your right or left hand of the instrument.

22 In this case, and in Shearon Harris, they  
23 had more than two. They had multiple, and we got an  
24 application that listed six or seven different  
25 degraded modes you could go into, depending on which

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1 planes --.

2 As a branch we had significant discussions  
3 about how much credit you wanted to give somebody for  
4 degraded modes of operation like this, and the feeling  
5 was that given how highly reliable the instrument was,  
6 the odds of you getting into one of these kind of  
7 corner cases, where the right hand over here has  
8 failed, the left hand over here has failed, the left  
9 hand over here has failed, should be an extremely  
10 remote case for operation.

11 The value was probably not worth the  
12 additional complexity to their procedures, to grant  
13 that many tiers of operation. That being said, if I  
14 was the system engineer, I'd still ask for it, and I  
15 don't know specifically what Dr. Chung, if that was  
16 the same logic he used here.

17 But my guess is that was looking at the  
18 Shearon Harris precedent that we had approved  
19 previously, one tier of degradation, at the point in  
20 time where you have two systems degraded, that should  
21 be a fairly remote mode of operation.

22 MEMBER BROWN: Yeah, that's kind of what  
23 you did. You went from instead of having that third  
24 two megawatt list, you went full to the 2968 as soon  
25 as you hit the third category. So that was your



1 thought process, qualitative thought process in other  
2 words.

3 MR. MOSSMAN: Yeah, yeah. That it should,  
4 erring on the side of conservatism, at the point of  
5 time where you have both your instruments partially  
6 degraded in this case, it's probably a lot easier to  
7 operate and a lot safer, a lot more conservative to go  
8 back to your old power rate.

9 MEMBER BROWN: Okay. Now your SER states  
10 that "there are two CPUs. They are physically  
11 separate and redundant, each capable of processing all  
12 the data from both tool pieces."

13 MR. MOSSMAN: That sounds correct.

14 MEMBER BROWN: I'm just reading right from  
15 your SER, so I'm not making this up as I go here.  
16 I've been known to do that, so be careful. "The  
17 active CPU data source will be automatic for the DCS  
18 calorimetric calibrations, for where the analysis and  
19 all the algorithms are, "will be automatically  
20 swapped," swapped, swapped, S-W-A-P-P-E-D, "by the DCS  
21 when necessary, based on quality status flags of the  
22 LEFM and the Ethernet interface module between the  
23 two, LEFM and DCS."

24 Now if they automatically get swapped,  
25 does that automatically qualify as a degradation, and

1 is somebody going to move 3,020 megawatts down to  
2 3,015? That just sounds like gee, if one loses-- if  
3 we can get something that says gee, that one's not  
4 working right. I'm going to swap to the other one.

5 MR. MOSSMAN: Yeah. I will --

6 MEMBER BROWN: Are there alarms that go  
7 off and somebody says now I have to run down and  
8 reduce my power by five megawatts? There's nothing  
9 that addresses --

10 MR. MOSSMAN: We typically get, yeah. I  
11 did not see it in the safety evaluation, but I know we  
12 typically do ask and we do get usually details as to  
13 what constitutes going into those degraded modes. I  
14 would have to check the original license amendment  
15 material to see what was described. I don't have that  
16 handy.

17 MEMBER BROWN: Well, I would, okay. So  
18 then my two questions, I guess it's still kind of  
19 hanging around, is how did they get this 18 months'  
20 worth of data, where did it come from?

21 MR. MOSSMAN: Okay.

22 MEMBER BROWN: Okay, which is how do you,  
23 you know, what did they compare it to? I presume it  
24 was within a prime standard alignment check of some  
25 sort, and how many data points did they have over the

1 18 month period, because you don't normally go in and  
2 pump these things up, take them out of service and  
3 pump it up and down every week. It's kind of a pain  
4 to do that.

5 Then the next would be okay, how do they  
6 know if these things were being swapped? Is that one  
7 -- every time something goes out, like you lose one  
8 section of the plane, does it automatically get  
9 swapped out and nobody has a choice? And then an  
10 alarm goes off and somebody knows that they're  
11 supposed to reduce power by five megawatts.

12 That's kind of the open questions, two  
13 open questions.

14 MR. MOSSMAN: Okay.

15 MEMBER BROWN: Now hopefully I'll be able  
16 to remember those for the next time.

17 MR. MOSSMAN: I will track those down  
18 ASAP.

19 MEMBER BROWN: Okay. Are you the one  
20 that's not going to be there afternoon?

21 MR. CARTE: No. I'm the one who's  
22 supposed to be here this afternoon. Norbert Carte.  
23 I think the underlining criteria for the swapping is  
24 whether you have one or two planes active, I mean for  
25 the degraded mode. So as long as you have two planes

1 of sensors active, you have heightened accuracy of the  
2 LEFM check plus system.

3 MEMBER BROWN: Full functionality.

4 MR. CARTE: Full functionality. So  
5 whatever failure causes you to have only one plane is  
6 when you degrade your level of acceptable power  
7 operations.

8 MEMBER BROWN: But does it also get  
9 swapped to the other CPU? How does somebody know  
10 that, and know it in time, in a timely manner?

11 MR. CARTE: Well, I think the typical  
12 case, I'm not sure about the swapping case. But the  
13 typical case is a sense failure. That's what  
14 typically causes you to lose a plane of operation. If  
15 you have redundancy views and they're swapping, I'm  
16 not sure about the answer. But the criteria is if you  
17 swap and you still have all your planes, then there's  
18 no problem.

19 MEMBER BROWN: How could you swap if it --

20 MR. CARTE: Well, if you have redundancy  
21 --

22 MEMBER BROWN: This says "quality status  
23 flags," which sounds like something's not operating  
24 right. So --

25 MR. CARTE: Right. So the processors --

1 I'm speculating, so I have to stop. But in essence,  
2 if you have redundant processors, that's their  
3 function, to detect when one is misoperating and  
4 switch to the other one.

5 MEMBER BROWN: I've tried to do that  
6 before with redundant processors, and it is very  
7 difficult to get it right, particularly if it's an  
8 automatic control system. We made it work, but it --

9 MEMBER BANERJEE: These aren't completely  
10 redundant either, because what they're doing, it's a  
11 very simple instrument. They have the speed of sound  
12 in this thing and they --

13 MEMBER BROWN: It's an ultrasonic flow  
14 detector.

15 MEMBER BANERJEE: So but they're sort of  
16 shooting across. But in order to get the velocity  
17 profile effects in, they shoot across at various  
18 locations. So even if you lose one of those sensors,  
19 it degrades your signal substantially. So you've got  
20 to do something about that.

21 MEMBER BROWN: You talked about angles in  
22 some of these also.

23 MEMBER BANERJEE: Yeah, there's also some  
24 -

25 (Simultaneous speaking.)

1 MEMBER BROWN: --from what I understand.  
2 But I don't want to get into the details --

3 MEMBER BANERJEE: So all you have to do is  
4 degrade one of those signals, and then that whole  
5 plane is not going to give you accurate results.

6 MEMBER BROWN: Okay. I guess two  
7 questions are still open, where did we get the data,  
8 okay, in order to verify that the venturi variations  
9 are small, or the detectors, whatever it is that  
10 causes it. Quite frankly the venturi, based on -- I  
11 actually took venturis and flow nozzles out of a plant  
12 after 25 years and found that their calibration in a  
13 calibrated facility varied so little we could barely  
14 measure it.

15 But that was 1975. So it was pretty good.  
16 The detectors on the other hand though, differential  
17 pressure. Those are different, and they will vary.

18 MEMBER BANERJEE: Well, the venturis tend  
19 to roughen slightly --

20 MEMBER BROWN: I understand, absolutely.  
21 Your nozzle coefficients and everything else will  
22 become slightly different. Anyway, those are the two  
23 questions. And then how do they know that they've go  
24 into the degraded mode?

25 MR. MOSSMAN: Yes.

1                   MEMBER BROWN: It is an alarm that goes  
2 ringing because they swapped, or because something  
3 else. That's all.

4                   MR. MOSSMAN: We typically have seen a  
5 fairly conservative approach to what constitutes  
6 degraded. So any kind of failure --

7                   MEMBER BANERJEE: Did you consider any one  
8 sensor not operating properly as a failure of the  
9 whole plane?

10                  MR. MOSSMAN: That's typically the way  
11 it's been interpreted, and as soon as one sensor in  
12 the plane, they fail the plane.

13                  MEMBER BANERJEE: That's correct, good.

14                  CHAIR REMPE: Okay. So we have one quick  
15 comment, and then I want to make a couple of comments.

16                  MR. HOFFMAN: All right. This is Jack  
17 Hoffman, Florida Power and Light. Just one  
18 suggestion. We can make our lead I&C engineer  
19 available this afternoon. I know he is very familiar  
20 with the St. Lucie installation. Can answer all the  
21 questions he just had on factory acceptance testing  
22 today. We'll track him down and we can set up a time  
23 to get all these questions answered. He's the subject  
24 matter expert.

25                  CHAIR REMPE: Great. That sounds great.

1 MEMBER BROWN: Will he have the how you  
2 get the data to say it's okay for 18 months?

3 MR. HOFFMAN: Knowing the individual, I  
4 would be shocked if he doesn't have it. He should.  
5 He is the subject matter expert that's been involved  
6 with this device since its conception.

7 MR. JENSEN: Well let's make sure he has  
8 the questions before we get him to the table.

9 MR. HOFFMAN: Of course.

10 CHAIR REMPE: And whatever we can't get  
11 this afternoon, we'll hit in the near week or so, we  
12 hope.

13 MR. HOFFMAN: We'll track down.

14 MEMBER BROWN: Yeah. I'll be in town. I  
15 live here.

16 CHAIR REMPE: We'll send it to everyone on  
17 disk or whatever, okay. So I'd like to close for  
18 lunch and restart at 1:30. Thanks.

19 (Whereupon, the above-entitled meeting  
20 went off the record at 12:31 p.m., and resumed at 1:36  
21 p.m.)

22 CHAIR REMPE: Okay. At this point I'm  
23 going to reopen the meeting, and we're going to start  
24 off with some answers to questions from the licensee.  
25 And then we'll close the meeting, and proceed with the



1 scheduled sessions. Okay?

2 MR. HOFFMAN: Very good.

3 CHAIR REMPE: And we have an individual on  
4 the line. Will you state your name, please, and start  
5 answering -- are you aware of the questions, or do we  
6 have to repeat them?

7 MR. J. BROWN: No, I'm generally aware of  
8 the questions, and my name is Jeff Brown. I'm the I&C  
9 supervisor for the EPU project.

10 CHAIR REMPE: Okay. Go ahead and start  
11 answering the questions.

12 MR. J. BROWN: Okay. As I understand it,  
13 the first question pertains to the justification for  
14 the 48 hour AOT. Is that correct?

15 CHAIR REMPE: Yes.

16 MEMBER BROWN: Yes. In other words, how  
17 did you generate the data to determine that the  
18 venturi is stable -- or the data from that alternate  
19 system is stable for at least 48 hours, based on your  
20 18 months of data collection? I just want to know  
21 what data you got, and what was the source of it, what  
22 were the devices, whatever.

23 MR. J. BROWN: Okay. So each venturi --  
24 the two-headers, the venturi on each side is monitored  
25 by three Rosemont differential pressure transmitters

1 that develop the input signal directly into our DCS  
2 system. So what I did was, I looked at the last five  
3 calibration cycles, 18-month calibration frequencies  
4 on each of those transmitters, and looked at the drift  
5 that we'd see on each of those channels over an 18-  
6 month surveillance.

7 Typically with the Rosemont transmitters,  
8 they were within our quarter percent calculation  
9 tolerance, even with an 18-month frequency. So over  
10 a two-day period of time, 48 hours, the drift is very,  
11 very minimal.

12 In addition to that, the thing that could  
13 cause significant drift would be a significant change  
14 in plant power, which could change the venturi fouling  
15 that is seen at that point in time. And under those  
16 circumstances, we have a requirement to down-power,  
17 enter the LCO.

18 MEMBER BROWN: Okay. Before you go any  
19 further, there's enough snaps, crackles and pops that  
20 I'm not sure I caught all of the data, 18-month data.  
21 You said something about five calibration cycles?

22 MR. J. BROWN: I reviewed data on over  
23 five calibration cycles.

24 MEMBER BROWN: And how long is a  
25 calibration -- is that the time between calibrations?

1 MR. J. BROWN: The calibration frequency  
2 is 18 months.

3 MEMBER BROWN: Okay. So once every 18  
4 months, you recalibrate the detectors.

5 MR. J. BROWN: That's correct. Yes.

6 MEMBER BROWN: I'm writing. Okay. So you  
7 took five calibration cycles, or seven and a half  
8 years, worth of data.

9 MR. J. BROWN: That's correct. Yes.

10 MEMBER BROWN: So five data points,  
11 effectively, over seven and a half years.

12 MR. J. BROWN: On each channel.

13 MEMBER BROWN: Each -- a channel being one  
14 venturi's worth?

15 MR. J. BROWN: Right. So statistically,  
16 there's a lot more data than would be implied with a  
17 population of only five points.

18 MEMBER BROWN: I guess I'm not quite sure  
19 I understand that. A venturi -- this is not the LEFM.  
20 This is the old Rosemont detectors, and the venturi  
21 feeding them. Correct?

22 MR. D. BROWN: I think the key here is,  
23 there are three of these on each of the two venturis.  
24 So when you're collecting the data for an 18-month  
25 cycle, you're actually getting six data points over

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1 five sampling periods, so a total of 30 data points.

2 MEMBER BROWN: Your math is too fast for  
3 my old brain. I've got three detectors per venturi,  
4 I've got that.

5 MR. D. BROWN: Well, I've got two headers,  
6 three detectors on each.

7 MEMBER BROWN: Okay.

8 MR. D. BROWN: And he sampled that five  
9 times, so we've really got 30 data points.

10 MEMBER BROWN: Fifteen times two, with two  
11 venturis. Right?

12 MR. D. BROWN: Correct.

13 MEMBER BROWN: Okay. I got that. So  
14 you're -- okay.

15 MR. HOFFMAN: And Jeff, this is Jack  
16 Hoffman with FPL. Just to clarify, for each one of  
17 those -- I don't want to put words in your mouth, but  
18 I believe I heard for each of those 30 data points,  
19 you were within the quarter percent?

20 MR. J. BROWN: I think what's accurate to  
21 say is that our general site experience with the  
22 Rosemont transmitters is that we very frequently find  
23 them within tolerance at an 18-month calibration  
24 frequency. And in this particular case, with these DP  
25 channels off the venturis, that was generally true

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1 also.

2 MEMBER BROWN: What do you mean by  
3 generally?

4 MR. J. BROWN: I can't say that every  
5 single one of these 30 data points was found within  
6 tolerance, but a large majority were.

7 MEMBER BROWN: Well, what does that mean?  
8 How many were out of tolerance?

9 MR. J. BROWN: Well, and then for values  
10 that are found out, they are just slightly out.  
11 Generally speaking, the performance, drift-wise, on  
12 the Rosemont transmitters, is extremely good.

13 MEMBER BROWN: So how did you come up with  
14 0.25 percent variation? You discounted the ones that  
15 were out of spec, or did you add them all up and  
16 average them, or did you take the boundary of the  
17 worst-case ones?

18 MR. J. BROWN: No, when we're looking at  
19 the transmitters being within spec at an 18-month  
20 frequency, we're saying that they're drifting a  
21 quarter-percent in 18 months. So over a two-day  
22 period, the drift is negligible.

23 MEMBER BROWN: Okay, but you also said  
24 some of them were outside the spec, also, though. The  
25 data says they were only a little bit outside. Does

1       that mean a little bit is a little bit? I'm being  
2       picky, but this is kind of a qualitative assessment,  
3       as opposed to a quantitative assessment.

4               MR. J. BROWN: They are found to be very  
5       slightly out of tolerance when they are out of  
6       tolerance.

7               CHAIR REMPE: So, can you put a number on  
8       it? Is it less than a percent?

9               MR. J. BROWN: It's certainly less than a  
10      percent. I's less than a half a percent.

11              CHAIR REMPE: Okay.

12              MR. HOFFMAN: Over 18 months.

13              CHAIR REMPE: Yes.

14              MEMBER BROWN: Okay. He's answered that  
15      question.

16              MR. HOFFMAN: Okay.

17              MEMBER BROWN: I'm not saying I agree or  
18      disagree. I'm just saying he answered the question.

19              MR. HOFFMAN: Sure. Jeff, I believe the  
20      next question revolves around out of service time, and  
21      the design features of the system, and what's required  
22      for the system to go from the nominal 3020 to the  
23      3015, and then to the ultimate down-power scenario?

24              MEMBER BROWN: No, that's a table. You  
25      gave that table, and the NRC modified it. The table's

1 a table. I guess what I was interested in is, how  
2 does the operator know he's supposed to do something?  
3 When I read the -- see if I can find it again. When  
4 I read the LAR --

5 MR. D. BROWN: That's probably best  
6 illustrated by looking at the -- this is Dave Brown,  
7 FPL -- by looking at the diagram here, the simplified  
8 diagram, looking at the two feedwater lines coming up  
9 to the LEFM transmitter boxes off of each one, and  
10 then going to the two CPUs.

11 Now, there'd been a question earlier, and  
12 I want to make sure we address that, about the auto-  
13 swap. The auto-swap that was being discussed up there  
14 was actually an auto-swap between the two CPUs, so  
15 you'll have --

16 MEMBER BROWN: What does that mean?

17 MR. D. BROWN: Well, what it means is,  
18 you've got all the data coming from both LEFM, from  
19 all four boxes, that's going to both CPUs. If there's  
20 a problem with one of the CPUs or an input to one of  
21 the CPUs, it will swap and just use the data on the  
22 other CPU and give us an alarm to tell us that it has  
23 done that. Okay?

24 So it's not anything that has degraded the  
25 system. These are two 100 percent redundant systems,

1 both getting all the inputs. And you can see that by  
2 the multiple lines going into each one of those two  
3 boxes.

4 MEMBER BROWN: All four transmitters go to  
5 both boxes?

6 MR. D. BROWN: That's correct.

7 MEMBER BROWN: Where's the digital to  
8 analogue conversion done? Is that in the CPU inputs?

9 MR. J. BROWN: No, the D to A is in the  
10 transmitter boxes. I mean, A to D.

11 MEMBER BROWN: So it's a serial data  
12 stream that goes out to the CPUs?

13 MR. J. BROWN: That's correct. It's RS485  
14 communication link between the transmitter boxes and  
15 the CPUs.

16 MR. D. BROWN: So if we lose any one of  
17 the four inputs going into the process, which is our  
18 first step of degradation, recognizing there's two on  
19 the Alpha leg and there's two on the Bravo leg, not  
20 only will that give me an alarm inside the DCS system,  
21 but that will give me a control room annunciator. The  
22 control room annunciator response procedure will drive  
23 me to the off-normal.

24 I start a 48-hour clock, and if at the end  
25 of 48 hours I have not gotten myself back into a four

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1 out of four availability and operable, then I have to  
2 down-power by five megawatts.

3 MEMBER BROWN: So when it does a swap, it  
4 gets annunciated.

5 MR. D. BROWN: This is not a swap.  
6 Remember, all four of these are feeding into both  
7 CPUs, okay? So they're actually kind of separate  
8 issues. If one of these four is no longer good, when  
9 you come down here -- your two planes, you've got one,  
10 two, three, four --

11 MEMBER BROWN: You don't have to go that  
12 deep, I just --

13 MR. D. BROWN: Okay. Any one of these  
14 four fail, okay, then I get an alarm in the control  
15 room that says you're in what's called a check,  
16 instead of a check-plus, on one, and you're still in  
17 check-plus on the other. I start a 48-hour clock. At  
18 the end of 48 hours, if I have not got both of them  
19 into a check-plus, i.e. two, both redundant  
20 transmitters in service, then I reduce power by five  
21 megawatts.

22 Any loss of the system beyond that,  
23 whether it's one out of two here and one out of two  
24 here, or two out of two here, failures, goes to the  
25 full 48 hours reduce the two percent power, or the 1.7

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1 percent, to get myself down inside the criteria.

2 MEMBER BROWN: What happens if one of the  
3 CPUs locks up? Like if you move the mouse, and your  
4 pointer doesn't move on your computer?

5 MR. D. BROWN: So the CPU is no longer  
6 processing?

7 MEMBER BROWN: Yes, if you no longer -- it  
8 locks up.

9 MR. D. BROWN: Jeff, do you want to speak  
10 to that?

11 MR. J. BROWN: Yes. Let me first of all  
12 say that each CPU has hard-wired outputs to the plant  
13 annunciator system, so the operators are notified of  
14 something wrong with the CPU independent of our  
15 communications to the DCS system. And then, within  
16 the DCS graphics that's used for the power metric,  
17 which we call our thermal power trend display, our  
18 analogue point is presented there for feedwater flow  
19 and temperature off of each header, those analogues  
20 out have built-in quality flags associated with them  
21 that drive color schemes, which are our human factors,  
22 to be consistent with the rest of DCS.

23 So the operators are notified in numerous  
24 ways of different failures in the system.

25 MEMBER BROWN: What's a quality flag?

1 MR. J. BROWN: Okay. So, out of each CPU,  
2 there are four possible quality statuses being  
3 transmitted to DCS. Four discrete values, zero  
4 through three. Zero means that the CPU is recognizing  
5 the LEFMs as completely normal. One means that there  
6 is a low level failure of some sort in the LEFM that  
7 doesn't reduce the accuracy of the system at all, but  
8 there's some minor maintenance item. Two would  
9 indicate that the LEFM is operating in a check mode.  
10 And three means that side LEFM is in a fail status.

11 So those quality flags, or the points that  
12 can take on those four discrete values, are also  
13 depicted on that calorimetric graphic.

14 MEMBER BROWN: Is that what swaps -- I  
15 still don't understand what the swap means, then.  
16 Swapped by the DCS.

17 MR. J. BROWN: Okay. Let me address that  
18 question by kind of presenting a failure mode to  
19 illustrate that. If I lose a transducer on one of the  
20 meters, what that would do is, within the Cameron  
21 system, because of the way they integrate the four  
22 measurement points in each plane worth of data, that  
23 would put that meter into a check mode. Effectively,  
24 the system is saying all of the data from that plane  
25 is no longer valid, so the system is then only using

1 the other four measurements of velocity of sound  
2 upstream and downstream to calculate a flow value. So  
3 a failure at that level of the system would be equally  
4 realized by both CPUs, and both CPUs would sense that  
5 and say "That meter, on that header, is operating in  
6 the check mode."

7 Now, if I had a different failure  
8 scenario, where I lost one of those RS485  
9 communication links from an individual transmitter  
10 back through an individual CPU, then that type of  
11 failure would only be sensed by one CPU, the one  
12 that's affected by that comm link. So the other CPU  
13 would be a better source of data for DCS than the one  
14 with the failed RS485 comm link, and the system would  
15 automatically transfer over to that preferred source,  
16 then. And all of the data that's then being used, the  
17 flow and temperature data into the calorimetric, would  
18 remain completely valid, because it's being processed  
19 by the good CPU. And that is the automatic fail-over  
20 that you're talking about.

21 MEMBER BROWN: Okay.

22 CHAIR REMPE: Okay?

23 MEMBER BROWN: I didn't say it was okay,  
24 I said I'm done.

25 CHAIR REMPE: Okay. We're going to say,

1       then -- let's go to the other, real quick,  
2       presentation that goes with this response to the best  
3       estimate values. Thank you, Jeff. I think we're done  
4       with you from the phone.

5                   MEMBER BROWN: Oh, yes. We're done for  
6       now.

7                   MR. HOFFMAN: This is the best estimate.

8                   CHAIR REMPE: Right.

9                   MR. HOFFMAN: The question was asked  
10       earlier -- again, this is Jack Hoffman. And what  
11       we've passed out -- it was shared with Dr. Wallis  
12       earlier this morning -- is the actual calculation that  
13       Westinghouse performed to determine what the best  
14       estimate, or the way the plant is actually predicted  
15       to perform with the actual power level, no additional  
16       uncertainty or conservatism, actual flow. And what  
17       you have in front of you is a simplified output of  
18       that calculation for Unit 2 that has the actual  
19       expected megawatt for the plant, the 3020 megawatt in  
20       the core, plus the 14 additional megawatts of the  
21       reactor coolant pumps. You see our best estimate flow  
22       that was measured via RCS calorimetrics, and then you  
23       simply do the math in the computers, the thermodynamic  
24       math, to come up with the actual, what we can tell the  
25       operators that these are the numbers. That if they

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1 have 551, if they program 551 T-cold, then they can  
2 expect to see an approximate -- I don't have the page  
3 in front of me, 602?

4 CHAIR REMPE: Point six.

5 MR. HOFFMAN: Which is a nominal number.  
6 It's not a bounding number that we would use in  
7 engineering analyses to ensure we have added  
8 conservatism.

9 CHAIR REMPE: Okay. With that, let's go  
10 on, if there aren't any questions, into the closed  
11 portion of this meeting. And we're unfortunately a  
12 little behind now, so let's all try and be mindful of  
13 the time a bit more, if it's possible.

14 (Whereupon, the above-entitled meeting  
15 went into closed session at 1:55 p.m., and resumed in  
16 open session at 5:52 p.m.)

17 CHAIR REMPE: Okay, is anyone still out  
18 there that's from the public that would like to make  
19 any comments? And just to verify, we do have an open  
20 phone line with someone out there that can verify that  
21 they're there. Maybe there's no one watching it. Is  
22 someone out there that can speak up and so we just  
23 know that there's someone out there?

24 Okay. Is there anyone left in the  
25 building that wants to make any comments?

1                   Okay, I think we probably should go around  
2                   the table, and this time I'll get someone to start  
3                   with the consultants. And Mario, do you have some  
4                   closing comments that you would like to share with us  
5                   here?

6                   CONSULTANT BONACA: I mean generally the  
7                   application was well put together. I didn't see any  
8                   issues except we expect that this to be an issue. And  
9                   after you look at all the information, clearly there  
10                  is a problem there, but the fortunate thing is that  
11                  the results of the third assessment is coming close,  
12                  and it may support the view that you have presented.

13                  So I think you have a plan that you're  
14                  using to monitor and assess and may be adequate in and  
15                  of itself, but this is a big issue, of course, and I  
16                  don't need to tell you that.

17                  MR. GIL: It's really driven by the, you  
18                  know, the operational assessment is obviously we want  
19                  to get an understanding of what's going on with these  
20                  generators, but it is driven by the data that we're  
21                  seeing. So that is very important. If the data for  
22                  the third inspection tells us differently --

23                  CONSULTANT BONACA: Looking at a day that  
24                  you may be able to go through a cycle maybe and, but  
25                  you'll exceed 40 percent. But anyway that's

1 speculation.

2 Another issue I raised this morning was  
3 about the training simulator representing one plant or  
4 the other. I don't think it's a measure issue. I  
5 think it's more of an information issue for the  
6 Committee. I think that one way it could be handled  
7 is by the licensee presenting briefly what they do to  
8 the full committee as far as the documentation, just  
9 because information is important and you don't want to  
10 have people surprised as I was this morning.

11 So I think I have some other thoughts but  
12 I'll send it to you in a letter.

13 CHAIR REMPE: Okay.

14 Graham?

15 CONSULTANT WALLIS: Yes, I will send a  
16 letter too. I thought we were doing well until we got  
17 to the steam generator. It took a little while but  
18 most of the questions that we had eventually got  
19 answered and the new evidence that was behind the  
20 claims emerged. So I felt pretty good until I got to  
21 the steam generator.

22 Steam generator, I think is a significant  
23 issue. I agree with Sanjoy that we need, you almost  
24 need a whole day to look at the issue by itself and  
25 what the evidence is and then you need to weigh it,



1       instead of is it really appropriate to move ahead with  
2       an EPU when there are some uncertainties about this  
3       wear? Root cause analysis is all very well but it's  
4       a very unusual event, and so you don't just accept the  
5       first root cause analysis, you see, without a lot of  
6       thorough investigation of it. So I would think that  
7       you need to have another meeting on the steam  
8       generator issues before you go to the full committee  
9       with the EPU.

10               CHAIR REMPE: That's a valid point.

11               Charlie?

12               MEMBER BROWN: First of all, they answered  
13       all my questions satisfactorily from your earlier part  
14       so you can put those aside relative to concerns in  
15       anything to deal with otherwise.

16               I'm not a thermal hydraulics guy as is  
17       Sanjoy and some of these other learned individuals,  
18       but I'm going to give you my thoughts unabashed from  
19       what I would call a pedestrian electrical engineer guy  
20       that has dealt with plants for a long, long time and  
21       also listened to the steam generator guys in my  
22       program for a long, long time, vibrations.

23               Number one, all the initial analyses --  
24       and I'm just going to say what I got out of the  
25       presentations and the discussions which were pretty

1 extensive. None of the initial analyses predicted  
2 anything of what you observed in the initial round.  
3 You made that statement. And not only did they not  
4 predict it, the indications were extensively more than  
5 expected, almost in the zero or close to zero you  
6 would have expected.

7           The wear after the second cycle was less  
8 but it was still a lot. You did your root cause  
9 analysis and assessed the issue as a nonuniform or  
10 nonhomogeneous, whatever the proper terminology is,  
11 gap and with between the tubes and the tubes support  
12 antivibration bars. There was some, I guess,  
13 modifications to the analysis. I'm not quite sure of  
14 all the details -- don't ask me -- where you said, oh  
15 okay, now we've taken this into consideration and  
16 looked at this nonuniformity and we can now predict  
17 that to some, what we saw and kind of duplicated the  
18 pattern or the distribution somewhat.

19           And therefore the conclusion is that based  
20 on our ability to take that modification, we can then  
21 take it and apply that to the EPU conditions and come  
22 to the conclusion that our wear rates will be within  
23 the boundaries which are deemed acceptable in the  
24 design and operational world. That's an extrapolation  
25 though without basis of any empirical results.

1           And if you had only had a few indications  
2           I would have maybe come to a different conclusion, but  
3           because of the thousands of indications, I guess I  
4           wouldn't really be convinced that it would be okay to  
5           go to the EPU conditions. And if these gentlemen can  
6           convince me of that, that would be fine. Okay.  
7           Without completing, number one, the third inspection  
8           to see how far it's come, that's under the pre-EPU  
9           conditions, and then if a decision is made to go on  
10          and allow the EPU to proceed, I don't think I would  
11          agree with at least today that it would be okay to go  
12          for a full 18 months or whatever, two-year, I don't  
13          know what you all's refueling cycle is.

14                 MR. HALE: Eighteen.

15                 MEMBER BROWN: Okay. Without another  
16          inspection or two mid-cycle or at third cycles,  
17          whatever it is, no matter how aggravating those are,  
18          where you could now take your EPU condition analyses  
19          and predict what additional wear you should possibly  
20          see and then see what you get in either a mid-cycle  
21          and end-of-cycle inspection or some other combination  
22          in between, as onerous as that sounds, so that's a  
23          path forward relative to the technical aspects.

24                 The other, being a non-steam generator  
25          guy, it blows my mind that the number of indications

1       were thousands on the first cycle. That just seems to  
2       be out of bounds for the most part. I have a hard  
3       time coming to grips with why that is okay under any  
4       circumstances.

5               And I find it difficult from a qualitative  
6       standpoint to think it's okay to kind of wear myself  
7       into acceptable additional later wear rates as we  
8       continue to operate.

9               Now, it may be okay. It's just when you  
10      look at, you know, the numbers that you were given and  
11      the fact that you had to go and that's a qualitative,  
12      strictly visceral, qualitative look at what you  
13      presented.

14              I thought you did a good job of presenting  
15      the information you had and you were straightforward  
16      and open about it. I thought that was very, very  
17      useful and that that's kind of the way my non-initiate  
18      thought process goes on this.

19              Again, I would be open. Now, there's  
20      other folks sit here and pound me into submission.  
21      There's an outside chance that I might agree.

22              MR. GIL: No, I appreciate the input  
23      because that gives us the things that we think we need  
24      to --

25              MEMBER BROWN: And I tend to agree, that

1 I don't think a full committee meeting in July is  
2 going to be very useful. You'll have an hour and a  
3 half or two hours. You can do it and make an initial  
4 presentation. I think that's been done before where  
5 there was a full committee meeting.

6 I'm thinking process right now, and you're  
7 familiar with one of them, where you got through what  
8 I would call 95 percent of the things and you came  
9 back with the last 5 percent at a second meeting and  
10 that may be an acceptable approach.

11 I don't have any problem with that, but it  
12 ought to be understood what the basis is and we ought  
13 not get wrapped around the axle on this issue because  
14 this issue could take up the entire meeting or a whole  
15 morning alone.

16 So you wouldn't be able to get through the  
17 rest of the things. That's my concern to you, Joy,  
18 when you make your recommendation so, anyway, I'll  
19 stop there.

20 CHAIR REMPE: Okay, thank you. Dick, I  
21 want to ask for your comments but also I know there  
22 were a lot of issues you had.

23 There are some requests for things we've  
24 asked for, but let us know if there's any outstanding  
25 issues and other things besides this last issue coming

1 up a lot with various members.

2 MEMBER SKILLMAN: At this point no  
3 additional issues.

4 CHAIR REMPE: Good, okay.

5 MEMBER SKILLMAN: But let me make my  
6 comments. I would like to thank the FPL team and the  
7 NRC staff for a very comprehensive presentation. This  
8 has not been easy and you stayed on the watch and  
9 thank you for doing that.

10 I concur with Dr. Wallis and Dr. Banerjee.  
11 I think we need more information on the steam  
12 generator phenomenon and that's how I would like to  
13 describe it.

14 It seems to me that there is an additional  
15 mechanism or phenomenon at work that's beyond the  
16 secondary side flow energy, beyond rarefaction, beyond  
17 vibration and manufacturing. It seems to me that  
18 there is another issue that we haven't discovered.

19 And I think it's been easy to point to the  
20 thermal hydraulics when there may be another very  
21 reasonable explanation for why this wear is occurring  
22 and I would like that to be explored.

23 With regard to the small-break LOCA and  
24 the large-break LOCA, I recognize that what FPL has  
25 done is taken credit for built-in conservatisms in the

1 basic plant design and in your tech specs.

2 But I believe that when one looks at the  
3 EPU peak clad temperature for large-break LOCA and the  
4 EPU analysis peak clad for small-break LOCA and learns  
5 that they are, in fact, lower in absolute value than  
6 the pre-EPU values and the oxidation is also lower,  
7 that that is counterintuitive.

8 One would say more heat, more decay heat  
9 generation rate, those numbers should have gone up.  
10 Why did they go down?

11 I believe that needs a more thorough  
12 explanation, perhaps as simple as a table that shows  
13 the increments that were used to end up with a final  
14 result under EPU conditions that are, in fact, cooler  
15 fuel, lower temperatures and less oxidation. So those  
16 are my comments and I thank you for letting me speak.

17 CHAIR REMPE: Actually what I wish I'd  
18 done before I started our comments was ask the staff  
19 in light of what they've heard about all the steam  
20 generator discussion today if they have any last-  
21 minute comment that they wanted to say.

22 MR. ORF: I don't have anything.

23 MALE PARTICIPANT: Use your mic.

24 MR. ORF: Oh, I'm sorry.

25 CHAIR REMPE: You can come up here.

1 MR. ORF: This is Trace Orf. I don't have  
2 any additional comments but we do have other --

3 (Off microphone discussion)

4 MR. ORF: No. I guess none of our  
5 reviewers have any other comments as well.

6 CHAIR REMPE: Okay. I have a process  
7 question too for you. With this August inspection,  
8 the staff should be involved in any decision with  
9 respect to the data too and that is part of the plan  
10 which I hadn't seen discussed anywhere, right?

11 MR. ORF: Typically whenever these  
12 inspections are done we have steam generator experts  
13 on the staff who do --

14 CHAIR REMPE: Because, see, but there  
15 could be some midway data where you see something may  
16 be close but a bit more and would you still go forward  
17 with the EPU? I mean, you know, the cart's before the  
18 horse is, I guess, an issue that I think I'm wondering  
19 about.

20 You know, it may not continue to go down.  
21 What if it stays level? Would you still say that's  
22 the one with the EPU? I mean, there's some midway  
23 kind of data that might come out of it and I'm just  
24 kind of wondering how that data would be treated too.

25 MR. GIL: We will, but it really is at the



1 request of the staff. We'll have conference calls.  
2 Especially if we have something that's out of the  
3 ordinary, we'll have conference calls with the staff  
4 and go over with them what the results are. And we  
5 wouldn't want to do that before the end of the outage  
6 where they can determine whether --

7 CHAIR REMPE: A question I had for you too  
8 is that if you were to come in July and you see the  
9 whole committee behave similarly to the subcommittee  
10 in their comments, and they say we'd like you to come  
11 back, we don't have a full committee meeting in August  
12 so we're talking September and so that's something  
13 that might want to influence your decision too but --

14 MR. HALE: Steve Hale, Florida Power &  
15 Light. What we found is, you know, if we can be  
16 successful at subcommittee, you know, our biggest  
17 issue is that we're shutting down in August and we're  
18 going to be implementing all our EPU modifications.

19 But if we feel comfortable getting through  
20 subcommittee, you know, we'll proceed with all those  
21 modifications and implementation, that sort of thing,  
22 so, you know, we kind of figured that would be a  
23 potential.

24 So a September full committee meeting I  
25 think would work for us but, you know, I guess we

1 would be looking for a subcommittee in July, maybe  
2 just focused on steam generators I guess. Would that  
3 be --

4 CHAIR REMPE: Well, you won't have data by  
5 July.

6 MR. HALE: Right.

7 CHAIR REMPE: And so you may not get what  
8 you want is what I'm kind of saying.

9 MEMBER BROWN: There are subcommittee  
10 meetings in August.

11 CHAIR REMPE: There are subcommittee  
12 meetings in August but, again, is it worth even going  
13 to full committee to present some information because  
14 if I were a betting person I'd say you're going to  
15 have some issues with the steam generators and --

16 MR. HALE: I need to bring out something.  
17 First off, the inspection, steam generator inspection  
18 was never tied to the EPU. The one that we're doing  
19 in August.

20 CHAIR REMPE: Right.

21 MR. HALE: Okay. Not that it can't be,  
22 but the current plan going forward was that would just  
23 be a follow-up inspection. We'd factor it into the  
24 operational assessment and that sort of thing.

25 You know, that's certainly something we

1       could say, hey, we would not go to EPU until we  
2       complete or we make a license condition. We wouldn't  
3       go to EPU until we confirm the data from that  
4       inspection.

5               In the absence of data, I've heard a  
6       couple of folks mention a possible mid-cycle outage as  
7       a potential way to resolve it.

8               CHAIR REMPE: Yes, and that would be a way  
9       to resolve it.

10              MR. HALE: Certainly we would have to go  
11       back and discuss that internally, but I guess my  
12       question would be would that be an alternative to  
13       resolving this issue with full committee?

14              CHAIR REMPE: I can't answer for the full  
15       committee but I think that's a way that it seems  
16       reasonable to go ahead and go forward with the full  
17       committee meeting, that you would get a letter.

18              And, again, if you were to offer up the  
19       mid-cycle inspection in full committee, I bet things  
20       would go easier but that's up to you guys. But then  
21       I would say, well, let's go ahead and go forward with  
22       the meeting as we planned.

23              Otherwise I think things could really,  
24       but, you know, it's worth going ahead. It sounds like  
25       you realize the risks and we'll see you in July.

1 MR. HALE: Terry, would you like to weigh  
2 in at all on it?

3 MR. JONES: Terry Jones, FPL. First and  
4 foremost we want to make sure that, you know, we're  
5 nuclear safe and I think there's been a  
6 mischaracterization that there's not data. There is  
7 lots of data.

8 So maybe our approach here was when we  
9 decided to present our conclusions, maybe we'd been  
10 better off starting with here's the root cause of why  
11 we have indications in the steam generators and here's  
12 what we know and here's what we understand and here's  
13 where we are and here's what supported our data.

14 So it doesn't look like we got all the  
15 data on the table in the time to thoroughly, you know,  
16 vet that data as an observer watching this proceeding.

17 So what I'm very much concerned about from  
18 my perspective and my role in this is I'm happy to be  
19 the guy in charge of all the EPU's, Point Beach, Turkey  
20 Point, and St. Lucie, that is. I happen to know we  
21 have thousands of people on site and what we have  
22 invested up to this point.

23 And so I also, having been in this  
24 business for 30 years, based on the data that I've  
25 been presented with and involved in the root cause, I

1 don't have any nuclear safety concerns. We obviously  
2 did not successfully address those here so I  
3 understand your position.

4 I'd like to be able to have an opportunity  
5 to present and get the data on the table and get it  
6 thoroughly vetted and reviewed. We had a hard time  
7 getting to what the actual root cause was here today.

8 So at the same time, given what we have at  
9 risk as a company, I can't go into an outage, not at  
10 least having been through a successful ACRS, whether  
11 it be subcommittee or full committee.

12 And so like having a subcommittee some  
13 time in August for us would kill the project, just  
14 that's the logistics that we have. So if we can get,  
15 whether it be full committee or some sort of  
16 subcommittee review dedicated to the steam generators  
17 so that everybody could be satisfied, that would be  
18 good.

19 License conditions are good too. The  
20 scientific methods that everybody in the world uses to  
21 know if it's safe to operate their steam generators  
22 from one cycle to the next, whether they have one  
23 indication or a thousand indications, is the same in  
24 a well-vetted and proven process.

25 And so whether it be a mid-cycle

1 inspection or a license condition that says if our  
2 data is not borne out on the third inspection no  
3 review. We certainly would entertain those kind of  
4 things.

5 So I would respectfully request that we  
6 look for when we can come back and, you know,  
7 thoroughly vet the root cause and the data that backs  
8 up the root cause including the data from our two  
9 inspections.

10 MEMBER BROWN: So you would want that in  
11 July then? You said August was kind of a non-starter.  
12 I'm just trying to make sure I understood your  
13 comment.

14 MR. JONES: Yes, the reactor runs out of  
15 fuel August the 5th and so there's, you know --

16 CHAIR REMPE: Well, you can always refuel  
17 and continue going on the way you are, right?

18 MR. JONES: Not without hundreds of  
19 millions of dollars of impact on the company.

20 CHAIR REMPE: I know. I'm guessing what  
21 we should probably do is go ahead and have the full  
22 committee meeting in July and there'll be less time.  
23 You're not going to go through all the steam generator  
24 information obviously then.

25 I'm not sure. I don't make the decisions

1 on the scheduling for the next subcommittee meeting  
2 but, you know, what you will probably end up with will  
3 be what you end up with with the full committee and,  
4 you know, we'll just have to see what happens but --

5 MR. JONES: Well, for one of our other  
6 plants, we came back to a subcommittee.

7 CHAIR REMPE: Yes, I know we did that with  
8 Turkey Point with thermal conductivity degradation and  
9 --

10 MR. JONES: Right, with the thermal  
11 conductivity there was no way that anyone had enough  
12 time to vet that and so none of us were comfortable  
13 going forward.

14 And so we came back to a full committee in  
15 September even though I'm in the outage and even  
16 though I've chopped up the plant, to put it quite  
17 bluntly, and there's no way to restart, you know,  
18 without that approval.

19 If we're through a successful subcommittee  
20 -- that's what we did with Turkey Point. We got  
21 through subcommittee. The full committee didn't occur  
22 until we were already in the outage. Same was the  
23 case for Point Beach.

24 I think it's undue pressure, unreasonable  
25 and if the full committee needs to happen at a

1 different date in September that still gives us  
2 adequate time on the back end to receive the LAR in  
3 time to start the unit up.

4 I just think that, you know, if an all-day  
5 subcommittee is what's right and appropriate for the  
6 steam generator, I just would respectfully request  
7 that we be given an opportunity to do that in July.

8 (Off microphone discussion)

9 CHAIR REMPE: In light of the discussion,  
10 do you want to come to the full committee in July?

11 MR. HALE: Well, I think the problem with  
12 that is that you have such limited time, you know?

13 CHAIR REMPE: Absolutely.

14 MR. HALE: And, you know, I feel, based  
15 on, you know, the feedback here, we probably need to  
16 vet out some of the details of what we found, you  
17 know, in terms of inspection data similar to what  
18 Terry has said, you know, because we did go to full  
19 committee at Turkey Point and, you know --

20 CHAIR REMPE: Yes, it's going to be more  
21 money for you, more trips and everything.

22 MR. HALE: Right, and it quickly, you  
23 know, it was obvious that we needed to go back to  
24 subcommittee. I know that Sanjoy was really  
25 interested in it. We might want to make sure that we



1 resolve his concerns as well.

2 And I think it would be worthwhile if,  
3 indeed, I mean, we need to go back and we need to look  
4 at what other options there may be there and I think  
5 that we would like to discuss those options with the  
6 subcommittee as well so that when you do go to the  
7 full committee we have a direction.

8 CHAIR REMPE: That would be a better  
9 approach.

10 MR. HALE: Yes.

11 CHAIR REMPE: Where did Tanny go?

12 MR. WANG: Tanny went to check for the  
13 schedule I believe.

14 CHAIR REMPE: Okay.

15 MEMBER BROWN: Something's going to have  
16 to be moved probably so --

17 CHAIR REMPE: July, I'm guessing is going  
18 to be tough because of the schedule. August, I know  
19 there's a Monday that actually is available but that's  
20 subcommittee in August and then you'd be at September  
21 before --

22 MEMBER BROWN: Full committee week in July  
23 is locked up Monday through Friday but the second  
24 round, if my memory serves me right, is thinner on the  
25 second week.

1 CHAIR REMPE: It is except that I have  
2 another commitment and I don't know about other folks.

3 MEMBER BROWN: Outrageous.

4 CHAIR REMPE: And so I can't come in until  
5 the naval reactors thing on the Wednesday.

6 MEMBER SKILLMAN: We've got naval reactors  
7 and that --

8 MEMBER BROWN: Yes, well, that's what I'm  
9 saying. That week it's naval reactors and then if you  
10 look at the other, there's another meeting.

11 CHAIR REMPE: I think APWR is later in the  
12 week, isn't that what it is?

13 MEMBER BROWN: It's APWR, yes.

14 CHAIR REMPE: I think that's what it was.

15 MEMBER SKILLMAN: In August we're into  
16 Recommendation 1 in Fukushima again.

17 MEMBER BROWN: That's at the end of August  
18 though, isn't it?

19 MR. HALE: Couldn't we replace the full --  
20 well, I guess that wouldn't work either.

21 MR. JONES: Maybe one of the options is to  
22 package the information appropriately, distribute the  
23 information early next week and stick with the full  
24 committee since that date's already there.

25 And if all we get through is steam

1 generator, then all we get through is steam generator  
2 but at least we know what the September full committee  
3 would be like.

4 CHAIR REMPE: Generally speaking, there  
5 doesn't seem to be many issues other than the steam  
6 generator issue.

7 MR. HALE: I think we've answered all the  
8 questions. I know Bonaca wanted us to talk a little  
9 bit about training.

10 CHAIR REMPE: I think it actually would be  
11 --

12 MR. JONES: That may be the best plan, is  
13 for us just to take the feedback here, put a package  
14 together, distribute it next week to the members of  
15 the full committee and let's start with that issue on  
16 the full committee on July the 11th.

17 CHAIR REMPE: Yes, I actually do and then  
18 keep in mind, please, that you won't have data for EPU  
19 and so, frankly, offering up a mid-cycle inspection  
20 might be a way that you could actually even have a  
21 letter from the full committee in July.

22 MEMBER BROWN: That's why I brought that  
23 up.

24 CHAIR REMPE: I think a lot of people have  
25 brought that up. You heard Sanjoy say it too.

1 MR. HALE: Yes, Sanjoy, I know.

2 CHAIR REMPE: And so, again, it's kind of  
3 your decision but I think that would be good. This is  
4 a little different, kind of jointly talking about what  
5 the path forward is.

6 But I'd rather have everybody's buy-in  
7 that it is worthwhile to spend the money to come back  
8 for full committee in July and to think about the  
9 options and --

10 MEMBER SKILLMAN: I think packaging the  
11 LOCA information, getting clarity between present  
12 condition, what will be for upright and how you got  
13 there so that we really don't have to retread how in  
14 the world could those temperatures be different?

15 MR. HALE: Yes, I thought we had the  
16 rackups, didn't we? Jay, didn't we? I thought we  
17 responded to that question.

18 MEMBER SKILLMAN: Not incrementally. You  
19 just said EPU and not EPU.

20 MR. HALE: Yes, but I thought we --

21 CHAIR REMPE: They actually did for the  
22 large-break LOCA and the small-break LOCA.

23 MR. JONES: Yes, we did provide --

24 CHAIR REMPE: You were the person who  
25 read, no. You were the person who read off the

1 numbers, yes.

2 MEMBER SKILLMAN: The question isn't us.  
3 It's the full committee.

4 CHAIR REMPE: Right.

5 (Simultaneous speaking.)

6 MEMBER SKILLMAN: And we're going to bring  
7 that in front of people who have not seen that.

8 MR. HALE: Okay, understood.

9 MEMBER SKILLMAN: And so the question is  
10 how to get through the full committee swiftly and  
11 focus on the steam generators, and it's by having that  
12 information as smooth as it can be and then either  
13 having a license condition or a commitment for the  
14 steam generator inspection, something like that.

15 I think that that might get us into that  
16 full committee meeting with the capability for our  
17 colleagues to be able to say got it, understand and  
18 I'm almost there or I'm there.

19 MR. HALE: We could provide that in  
20 advance as well to Weidong so he could distribute that  
21 to the members, the rackup.

22 CHAIR REMPE: I'd minimize the early  
23 discussion. And with Grand Gulf, didn't the staff  
24 give most of the information other than a couple of  
25 issues?

1 And you might want to work together on how  
2 to make sure we get through the information and have  
3 enough time for steam generator tube ruptures. Yes,  
4 sir.

5 MR. HOFFMAN: Dr. Rempe, I'm not sure if  
6 there were any comments from the other member who left  
7 early, just for completeness.

8 CHAIR REMPE: Stephen Schultz, is he who  
9 we're discussing?

10 (No response.)

11 CHAIR REMPE: I talked to him informally  
12 and so I don't know if second-hand information is  
13 worthwhile repeating, but the steam generator issue  
14 was the same thing that he had. He had -

15 MR. HOFFMAN: I was just curious if he had  
16 an open issue that we responded to.

17 CHAIR REMPE: He was fine with the way you  
18 responded to the field performance and so he  
19 appreciated that.

20 MR. HOFFMAN: Okay. So we have no open  
21 issues to go.

22 CHAIR REMPE: With that, I appreciate  
23 everybody who stuck around till the bitter end and  
24 have a good night and I'll close the meeting.

25 (Whereupon, the meeting in the above-

1 entitled matter was concluded at 6:22 p.m.)



# **St. Lucie Unit 2 Extended Power Uprate (EPU) ACRS Subcommittee**

**June 22, 2012**



## Agenda

### ➔ EPU Overview

- Introduction..... Joe Jensen
- Plant Changes..... Jack Hoffman
- **Analyses**
  - Fuel and Core ..... Jay Kabadi
  - Safety Analysis ..... Jay Kabadi
  - TCD / LBLOCA (Proprietary) ..... Jay Kabadi
- **Materials**
  - Steam Generators (Proprietary) ..... Rudy Gil
- **Acronyms**

## St. Lucie Unit 2

- **Located on Hutchinson Island, southeast of Fort Pierce, Florida**
- **Pressurized Water Reactor (PWR)**
- **Combustion Engineering Nuclear Steam Supply System (NSSS)**
- **Westinghouse Turbine Generator**
- **Architect Engineer – Ebasco**
- **Fuel supplier - Westinghouse**
- **Unit output 907 MWe gross**



- **Original operating license issued in 1983**
- **Renewed operating license issued in 2003**
- **Installation of a new single-failure proof crane to support spent fuel dry storage operations in 2003**
- **Steam Generators (SGs) replaced in 2007**
- **Reactor Vessel Head was replaced in 2007**
- **Replaced 2 of 4 Reactor Coolant Pump motors in 2007 and 2011**
  - The remaining motor replacements planned for 2012 and 2014

- **Licensed Core Power**

- Original Licensed Core Power 2560 MWt
- Current Licensed Core Power 2700 MWt
  - 5.5 % Stretch Uprate (1985)
- EPU Core Power 3020 MWt
  - Implement 2012

## **FPL is requesting approval for a 12% power level increase for St. Lucie Unit 2**

- **12% increase in licensed core power level (3020 MWt)**
  - 10% Power Uprate
  - 1.7% Measurement Uncertainty Recapture
  - $(2700 \times 1.10) \times 1.017 \sim 3020 \text{ MWt}$
- **Classic NPSH requirements for ECCS pumps are met without credit for containment overpressure**
- **Grid stability studies have been completed and approved for the EPU full power output**
- **Final modifications to support EPU operation are being implemented in 2012**

**EPU License Amendment Request (LAR) was prepared utilizing the guidance of *RS-001, Review Standard for Extended Power Upgrades***

- **Addressed lessons learned from previous PWR EPU reviews**
- **Evaluations consistent with the St. Lucie Unit 2 Current Licensing Basis (CLB) per RS-001**
- **License Renewal evaluated in each License Report section consistent with RS-001 requirements**
- **Measurement Uncertainty Recapture evaluated the proposed Leading Edge Flow Meter (LEFM) system using the Staff's criteria contained in *RIS 2002-03, Guidance on the Content of Measurement Uncertainty Recapture Upgrade Applications***

## **Engineering studies were performed to evaluate systems, structures and components to determine the ability to operate at EPU conditions**

- Analyzed the effects of increases in Reactor Coolant System temperature and power, and increases in steam flow, feedwater flow and electrical output**
- Heat balances developed for current power level and EPU NSSS power level of 3050 MWt (core + pump heat)**
- Changes in major parameters addressed for Balance of Plant (BOP) systems and components**
- Hydraulic analyses performed on feedwater, condensate and heater drain systems**
- Plant normal, off-normal and transient conditions evaluated**
- Operating experience was evaluated and applied**

## Analyses were performed to evaluate the changes in design parameters

Parameter	Original	Current	EPU	EPU Change
Core Power (MWt)	2560	2700	3020	+320
RCS Pressure (psia)	2250	2250	2250	0
Taverage (°F)	571.6	573.5	578.5	+5.0
Vessel Inlet (°F)	548.0	549.0	551.0	+2.0
Vessel Outlet (°F)	595.2	598.0	606.0	+8.0
Delta T (°F)	47.2	49.0	55.0	+6.0
Thermal Design Flow (gpm/loop)	185,000	187,500	187,500	0
Core Bypass (%)	3.7	3.7	3.7	0
Steam Pressure (psia)	893	896	895	-1
Moisture Carryover (maximum, %)	0.20	0.10	0.10	0
Steam Mass Flow (10 <sup>6</sup> lb/hr)	11.19	11.80	13.42	+1.62



## **Modifications will be made in support of safety**

- **Nuclear Steam Supply System (NSSS) setpoints**
- **Control room air conditioning margin improvement**
- **Charging pump control circuit modification**
- **Chemical and Volume Control System (CVCS) vents**
- **Add neutron absorption material to Spent Fuel Pool storage racks**
- **Install Leading Edge Flow Measurement (LEFM) System**
- **Environmental Qualification (EQ) radiation shielding changes for electrical equipment**
- **Component Cooling Water piping support modifications**
- **Raise Reactor Protection System (RPS) Steam Generator low-level trip setpoint (plant risk profile enhancement)**

## **Modifications will be made in support of power generation at the EPU power level**

- **Steam Path**

- Replace High and Low Pressure Turbine steam paths
- Replace main turbine Electro Hydraulic Control (EHC) System
- Replace Moisture Separator Reheaters (MSRs) and upgrade level controls
- Increase Steam Bypass Control System capacity
- Upgrade steam and power conversion system instrumentation
- Modify Main Steam piping supports

- **Condensate and Feedwater**

- Replace Main Feedwater and Condensate Pumps
- Upgrade Main Feedwater Regulating Valves and controls
- Replace #5 High Pressure Feedwater Heaters
- Replace #4 Low Pressure Feedwater Heaters
- Upgrade Main Condenser
- Modify Main Feedwater and Condensate piping supports

- Continued on next page -

## **Modifications will be made in support of power generation at the EPU power level (continued)**

- **Heater Drains**
  - Replace Heater Drain pumps
  - Upgrade Heater Drain valves
- **Auxiliary Support Systems**
  - Replace Turbine Cooling Water heat exchangers
- **Other Balance of Plant items**
  - Balance of Plant (BOP) setpoints

## **Modifications will be made in support of power generation at the EPU power level (continued)**

- **Electrical Modifications**

- Generator upgrades including
  - Stator rewind
  - Rotor replacement
  - Replace bushings and current transformers
  - Replace hydrogen coolers
  - Increase hydrogen pressure
  - Replace exciter air coolers
- Install Power System Stabilizer
- Upgrade Iso-Phase Bus Duct cooling system
- Increase margin on AC electrical buses
- Replace Main Transformers
- Switchyard modifications

## Agenda

- **EPU Overview**

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# Fuel design maintains margin to limits

## Fuel Design

- **16x16 CE Standard Fuel Design – same as in previous cycles**
  - Includes Inconel Top Grid design which was implemented to increase grid-to-rod fretting margin
- **Peak rod and assembly burnup will be maintained within current limits**

# Margins to key safety parameters are maintained

## Core Design

- **Representative core designs were used for EPU analyses**
- **Core design limits are reduced to offset effect of EPU and maintain margins to fuel design limits**
  - Total integrated Radial Peaking Factor ( $F_r^T$ ) COLR limit reduced from 1.70 to 1.60
  - Linear heat rate COLR limit remains at 12.5 kW/ft
- **Normal incore fuel management methods utilized to meet reduced limits with increased energy needs**
  - Feed batch size and enrichment
    - Maximum planar average enrichment increased from 4.5 wt% to 4.6 wt% U-235
  - Burnable absorber placement
  - Core loading pattern

## **Margins to key safety parameters are maintained (continued)**

### **Core Design Changes (continued)**

- **Moderator Temperature Coefficient limits are unchanged**
- **Shutdown Margin requirement is unchanged for at-power operation**
  - Larger doppler power defect at EPU conditions, but Shutdown Margin (SDM) remains acceptable
- **Boron requirements met**
  - Boron delivery capability improved by changes to boron requirements for the Boric Acid Makeup Tank (BAMT), Refueling Water Tank (RWT) and Safety Injection Tanks (SITs)
  - Minimum refueling boron increased to 1900 ppm



## Approved methods used for safety analysis as supplemented by subsequent RAI responses

- **Codes and methodologies**
  - CEFLASH-4A/CEFLASH-4AS: large & small break LOCA
  - RETRAN: Non-LOCA transients
  - VIPRE-W: DNB analysis of the nuclear fuel

# Safety analyses demonstrate acceptable results

- **Key changes beneficial to safety analysis**
  - Reduction of Radial Peaking Factor ( $F_r^T$ )
- **Conservative inputs/assumptions**
  - Conservative physics parameters
  - Bounding plant operating parameters include measurement uncertainties and operating bands
  - Conservative trip setpoints and delays
  - No credit for non-safety grade equipment to mitigate events
  - Input parameters biased in the conservative direction for limiting events; e.g.:
    - RCS pressure, temperature
    - Pressurizer level (nominal  $\pm$  uncertainty)

## **Safety analyses include appropriate input changes**

- **Power measurement uncertainty at Rated Thermal Power (RTP) reduced from 2% to 0.3%**
- **Maximum steam generator tube plugging reduced from 30% to 10%**
- **Main Steam Safety Valve setpoint tolerance revised from +1%/-3% (Banks 1 and 2) to +3%/-3% (Bank 1) and +2%/-3% (Bank 2)**
- **Pressurizer Safety Valve setpoint tolerance increased from  $\pm 2\%$  to  $\pm 3\%$**
- **SIT and Refueling Water Tank (RWT) boron concentration requirement revised from between 1720ppm and 2100ppm to between 1900ppm and 2200ppm**

# Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria

## Analysis Methodologies

Method	Pre- EPU	EPU
Non-LOCA System Transient Analysis	RETRAN, CESEC, & TWINKLE/FACTRAN Computer Codes	RETRAN & TWINKLE/FACTRAN Computer Codes
Thermal-Hydraulic Core Analyses	VIPRE-W	VIPRE-W
	ABB-NV CHF correlation W-3 CHF Correlation (SLB)	ABB-NV CHF correlation W-3 CHF Correlation (SLB)

## Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
<b>Decrease in RCS Flow</b>	Loss of Flow (AOO)	MDNBR $\geq 1.42$	1.44
	Locked Rotor (PA)	Rods-in-DNB $\leq 19.7\%$	0%
<b>RCS Overheating (Decrease in Secondary Heat Removal)</b>	Loss of Condenser Vacuum (AOO)	RCS Press. $\leq 2750$ psia	2669 psia
		MSS Press. $\leq 1100$ psia	1094 psia
	Loss of Load to one SG (Asymmetric Steam Generator Transient) (AOO)	MDNBR $\geq 1.42$	2.22
	Loss of Feedwater (AOO)	Liq. Vol. $\leq$ Pressurizer Vol. (1519 ft <sup>3</sup> )	1263 ft <sup>3</sup>
		RCS Subcooling $\geq 0^{\circ}\text{F}$	85 $^{\circ}\text{F}$
	FW Line Break (PA)	RCS Subcooling $\geq 0^{\circ}\text{F}$ @ time when AFW heat removal matches core decay heat	9 $^{\circ}\text{F}$

## Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
<b>RCS Overheating</b>	FW Line Break (PA)	MDNBR $\geq 1.42$	2.21
		RCS Pressure $\leq 3000$ psia (Large Breaks)	2704 psia
		RCS Pressure $\leq 2750$ psia (Small Breaks)	2700 psia
		MSS Pressure $\leq 1100$ psia	1094 psia
<b>RCS Overcooling (Increase in Secondary Heat Removal)</b>	Feedwater Malfunction (AOO)	Increased FW Flow MDNBR $\geq 1.42$	1.96
		Decreased FW Temperature MDNBR $\geq 1.42$	1.97
	HFP Pre-scrum MSLB (PA)	Rods-in-DNB $\leq 1.2\%$ (OC) & $\leq 21\%$ (IC)	0%
		Fuel Melt $\leq 0.29\%$ (OC) & $\leq 4.5\%$ (IC)	0%
	HZP Post-scrum MSLB (PA)	Rods-in-DNB $\leq 1.2\%$ (OC) & $\leq 21\%$ (IC)	0%
		Fuel Melt $\leq 0.29\%$ (OC) & $\leq 4.5\%$ (IC)	0%

## Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
<b>Reactivity Addition</b>	CEA Withdrawal @ HZP (AOO)	MDNBR $\geq 1.26$	1.284
		Fuel CL Temp. $\leq 4717^{\circ}\text{F}$	3432 $^{\circ}\text{F}$
	CEA Withdrawal @ Power (AOO)	MDNBR $\geq 1.42$	1.74
		RCS Press. $\leq 2750$ psia	2485 psia
	CEA Malfunction (AOO)	MDNBR $\geq 1.42$	$> 1.42$
		Peak LHR $\leq 22$ kW/ft	13.76 kW/ft
	CEA Ejection (PA)	RCS Press. $\leq 3000$ psia	$< 2800$ psia
		Fuel Enthalpy $\leq 200$ cal/g	151.5 cal/g
		Rods-in-DNB $\leq 9.5\%$	$< 9.5\%$
		Fuel Melt $\leq 0.5\%$	0%

## Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
<b>Reactivity Addition</b>	Boron Dilution (AOO)	Time-to-Criticality $\geq$ 15 min. (Modes 1 – 5)	> 15 min.
		Time-to-Criticality $\geq$ 30 min. (Mode 6)	> 30 min.
<b>RCS Mass Addition</b>	Inadvertent ECCS/CVCS (AOO)	Liq. Vol. $\leq$ Pressurizer Vol.	~1512 ft <sup>3</sup> @ 20 min. after High Level Alarm
<b>RCS Depressurization</b>	Inadvertent Opening of a Pressurizer PORV (AOO)	MDNBR $\geq$ 1.42	1.73
		Liq. Vol. $\leq$ Pressurizer Vol.	1519 ft <sup>3</sup> @ ~3 min. after PORV opens



## Small Break LOCA safety margin is assured by key changes

Parameter	SBLOCA Pre-EPU Value	SBLOCA EPU Value
Licensed Core Power (MWt)	2700	3020
Power Measurement Uncertainty (%)	2.0	0.3
Analyzed Core Power Level (MWt)	2754.0	3030.0
Peak Linear Heat Rate (kW/ft)	13.0	13.0
Steam Generator Tube Plugging (%)	30	10
Minimum SIT Pressure (psig)	485	485

## Small break LOCA analysis demonstrates acceptable results and is not impacted by thermal conductivity degradation

	Pre – EPU (Appendix K)	EPU (Appendix K)	Limit
Limiting Break Size (ft <sup>2</sup> )	0.05	0.05	-
PCT (°F)	1943	1903	2200
Maximum Transient Local Oxidation (%)	9.80	9.21	17.0
Maximum Core-Wide Oxidation (%)	0.64	0.94	1.0

## Agenda

- **EPU Overview**

- Introduction..... Joe Jensen
- Plant Changes..... Jack Hoffman

- **Analyses**

- Fuel and Core ..... Jay Kabadi
- Safety Analysis ..... Jay Kabadi
- TCD / LBLOCA (Proprietary) ..... Jay Kabadi

- **Materials**

- Steam Generators (Proprietary) ..... Rudy Gil

## **Acronyms**

# Acronyms

AC	Alternating Current	MDNBR	Minimum Departure From Nucleate Boiling
AOO	Anticipated Operational Occurrences	MSLB	Main Steam Line Break
AVB	Anti-Vibration Bar	MSR	Moisture Separator Reheater
BAMT	Boric Acid Makeup Tank	MSS	Main Steam System
BOP	Balance of plant	MWe	Megawatts electric
CHF	Critical Heat Flux	MWt	Megawatts thermal
CLB	Current Licensing Basis	NPSH	Net Positive Suction Head
COLR	Core Operating Limits Report	NSSS	Nuclear Steam Supply System
CVCS	Chemical and Volume Control System	OC	Outside Containment
DNB	Departure From Nucleate Boiling	OD	Outside Dimension
ECCS	Emergency Core Cooling System	PA	Postulated Accident
EHC	Electro Hydraulic Control	PLHR	Peak Linear Heat Rate
EPU	Extended Power Uprate	PORV	Power Operated Relief Valve
EQ	Environmental Qualification	PPM	Parts per Million
F	Fahrenheit	PSIA	Pounds per square inch - absolute
$F_r^T$	Total Radial Peaking Factor	PWR	Pressurized Water Reactor
ft	Feet	PZR	Pressurizer
FW	Feed Water	RCS	Reactor Coolant System
GPM	Gallons per minute	RIS	Regulatory Issue Summary
HFP	Hot Full Power	RPS	Reactor Protection System
HTP	High Thermal Performance	RTP	Rated Thermal Power
HZP	Hot Zero Power	RWT	Refueling Water Tank
IC	Inside Containment	SIT	Safety Injection Tank
Keff	K-effective	SDM	Shutdown Margin
lb/hr	Pounds per hour	Sec	Second
KW	Kilowatt	SLB	Steam Line Break
LEFM	Leading Edge Flow Meter	SG	Steam Generator
LHGR	Linear Heat Generation Rate	V	Velocity
Liq	Liquid	$\rho$	Density
LOCA	Loss of Coolant Accident		

# LEFM ✓ + System Overview

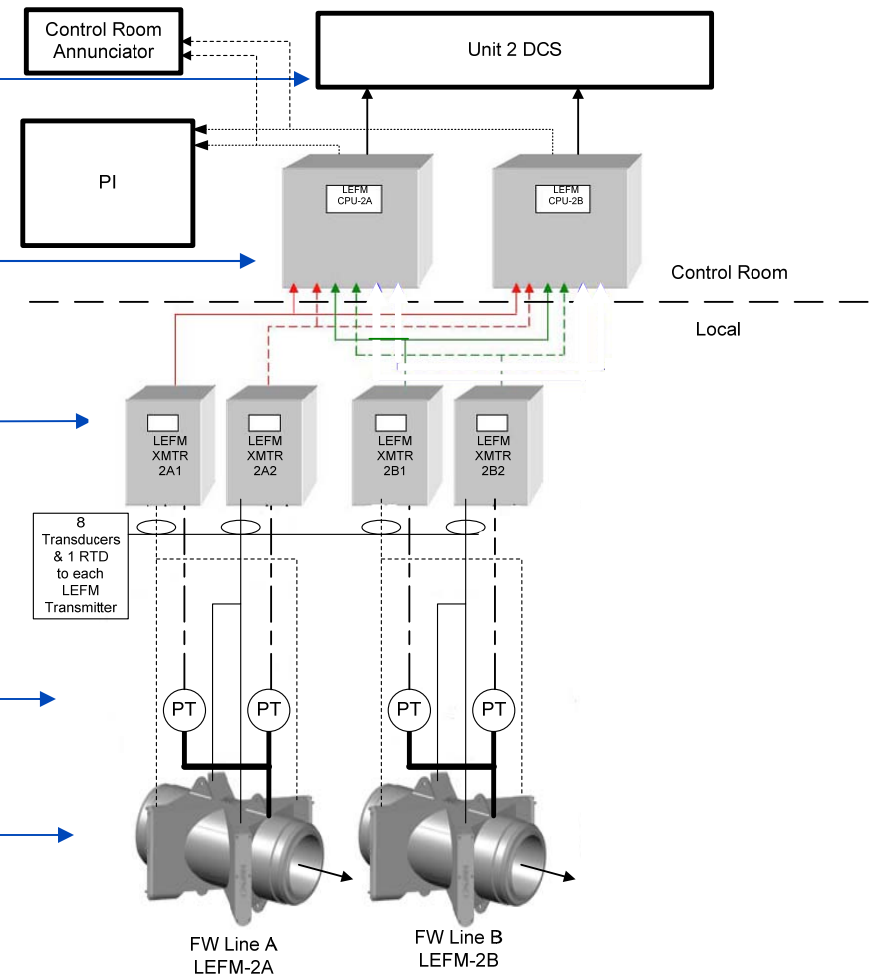
**Current plant DCS system**  
Contains calorimetric calculation

**LEFM CPUs**  
Calculates FW total mass flow & monitors  
LEFM system condition

**LEFM Transmitters**  
Receives & calculates SG system flow from  
transducers in spool pieces

**FW Pressure Transmitters**  
Used to determine FW density

**LEFM Spool Pieces**  
Contain LEFM transducers





**U.S.NRC**

UNITED STATES NUCLEAR REGULATORY COMMISSION

*Protecting People and the Environment*

# **ACRS Subcommittee on Power Upgrades**

## **NRC Staff Review St. Lucie, Unit 2 Extended Power Upgrade**

**June 22, 2012**

# Opening Remarks

**Michele G. Evans**

Division Director

Division of Operating Reactor Licensing  
Office of Nuclear Reactor Regulation

# Opening Remarks

- NRC staff effort
  - ❖ Pre-application review and public meetings
  - ❖ Requests for additional information
  - ❖ Audits
- Challenging review areas included:
  - ❖ Inadvertent Opening of a PORV analysis
  - ❖ Inadvertent ECCS actuation
  - ❖ CVCS malfunction



# Introduction

Tracy J. Orf

Project Manager

Division of Operating Reactor Licensing

Office of Nuclear Reactor Regulation

# Introduction

- Background

- ❖ St. Lucie 2 EPU Application – February 25, 2011
- ❖ 2700 to 3020 MWt, 12 % increase (320 MWt)
  - Includes a 10 % power uprate and a 1.7 % MUR
  - 18 % increase above original licensed thermal power

- EPU Review Schedule

- ❖ Followed RS-001
- ❖ Supplemental responses to NRC staff RAIs and Audits
- ❖ EPU Implementation
- ❖ Fuel storage criticality analysis separated into separate license amendment for scheduling purposes

# Topics for Subcommittee

- EPU Overview
- Fuel and Core
- Safety Analyses
- Materials – Steam Generators



## **St. Lucie Unit 2 EPU Accident Analyses**

**Samuel Miranda and Benjamin Parks**  
Reactor Systems Branch  
Office of Nuclear Reactor Regulation

# EPUs for St. Lucie Units 1 and 2

	Unit 1	Unit 2
Operating license	1976	1983
Current licensed core power (MWt)	2700	2700
EPU core power (MWt)	3020	3020
Fuel Supplier	AREVA	Westinghouse
Audited by NRC staff	Jan 2012	Feb 2012

## **Review of Mass Addition Event Analyses**

- Inadvertent ECCS actuation
- CVCS Malfunction
- Inadvertent pressurizer PORV opening

## **Inadvertent Actuation of ECCS and CVCS Malfunction**

- Charging pumps can fill the pressurizer, and pass water through the PORVs.
- A small break LOCA is created if a PORV sticks open.
- AOOs are not permitted to develop into events of a more serious class.

# Inadvertent Actuation of ECCS

- Charging pumps (PDPs) are in the ECCS and started by the SIAS
- Charging pumps can fill the pressurizer and can cause the PORVs to open and discharge water
- PORVs that relieve water are assumed to stick open



# Non-Escalation Criterion

- “By itself, a Condition II incident cannot generate a more serious incident of the Condition III or IV type without other incidents occurring independently.”
- NRC reminded licensees that this criterion is in the plant licensing bases, and therefore must be met (RIS 2005-29).

# Inadvertent Opening of a PORV

- RG 1.70 classifies this AOO as a decrease in RCS inventory event
- RCS depressurization reduces thermal margin, which leads to trip
- RCS continues to depressurize and reaches low pressure SI setpoint
- Lower RCS pressure boosts ECCS delivery rate. Pressurizer can fill.

# Inadvertent Opening of a PORV

- Operator can close the PORV very quickly after it opens ( $< 10$  sec)
- With no operator action:
  - SI signal is generated in  $< 1$  min
  - Pressurizer fills in  $< 3$  min
  - Charging pumps can cause PORVs to open and relieve water
  - A PORV can stick open (SBLOCA)

# Review of LOCA

- Appendix K Large Break
  - Analysis accordant with CENPD-132, Supplement 4-P-A, *“Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model”*
  - Limiting PCT occurs during late reflood
- Small Break
  - Licensee implemented CENPD-137, Supplement 2-P-A (S2M), *“Calculative Methods for the ABB CE Small Break LOCA Evaluation Model”*

# Appendix K Large Break LOCA

- PCT occurs during late reflood
  - 1.2 multiplier applied to ANS 1971 standard for decay heat
  - Decay heat is more significant than fuel initial stored energy for later PCT
  - Sensitivity study to see how TCD affected blowdown PCT
    - Substantial increase in stored energy required to drive blowdown peak higher than the reflood peak

# **Appendix K Large Break LOCA**

- Downcomer Boiling
  - CE design of large SITs ensure downcomer is filled when the SITs inject
  - Sensitivity studies were provided to demonstrate that downcomer boiling is not a concern

# Appendix K Large Break LOCA

- Conclusions
  - Results demonstrate compliance with 10 CFR 50.46 requirements

Parameters	Pre- EPU	EPU	10 CFR 50.46 Limits
Peak Clad Temperature	2104 °F	2087 °F	2200 °F
Maximum Local Oxidation	16.06	14.48	17.0%
Maximum Total Core-Wide Oxidation (All Fuel)	0.789	0.954	1.0%

# Small Break LOCA

- Break Spectrum
  - Supplemental analysis with more refined break spectrum provided
  - analysis of a severed injection line break provided



# Small Break LOCA

- **Conclusions**
  - Results demonstrate compliance with 50.46 requirements

Parameters	Pre-EPU Analysis	EPU Analysis	10 CFR 50.46 Limits
<b>Limiting Break Size</b>	0.05 ft <sup>2</sup>	0.05 ft <sup>2</sup>	NA
<b>Peak Clad Temperature</b>	1943 °F	1903 °F	2200 °F
<b>Maximum Local Oxidation</b>	9.80 %	9.21%	17.0%
<b>Maximum Total Core-Wide Oxidation (All Fuel)</b>	0.64%	0.94%	1.0%